Appendix E

Applicant's Environmental Report

Operating License Renewal Stage

Cooper Nuclear Station

INTRODUCTION

Nebraska Public Power District (NPPD) submits this Environmental Report (ER) in conjunction with the application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Cooper Nuclear Station (CNS) for twenty (20) years beyond the end of the current license term. In compliance with applicable NRC requirements, this ER analyzes potential environmental impacts associated with renewal of the CNS Operating License. This ER is designed to assist the NRC staff with the preparation of the CNS-specific Supplemental Environmental Impact Statement (SEIS) required for license renewal.

The CNS ER is provided in accordance with 10 CFR 54.23, which requires license renewal applicants to submit a supplement to the ER that complies with the requirements of Subpart A of 10 CFR Part 51. This report also addresses the more detailed requirements of NRC environmental regulations in 10 CFR 51.45 and 10 CFR 51.53(c), as well as the intent of the National Environmental Policy Act (NEPA), 42 USC 4321 et seq. For major federal actions, NEPA requires federal agencies to prepare a detailed statement that evaluates environmental impacts, alternatives to the proposed action, and irreversible and irretrievable commitments of resources associated with implementation of the proposed action.

NPPD used Supplement 1 to Regulatory Guide 4.2, "Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses," as guidance on the format and content of this ER. In addition, it utilized the Generic Environmental Impact Statement (GEIS) for License Renewal for Nuclear Plants (NUREG-1437) and Appendix B to 10 CFR Part 51 in preparation of this report. The level of information provided on the various topics and issues in this ER are commensurate with the environmental significance of the particular topic or issue.

Based upon the evaluations discussed in this ER, NPPD concludes that the environmental impacts associated with renewal of the CNS Operating License are small. No plant refurbishment activities have been identified as necessary to support the continued operation of CNS beyond the end of the existing operating license term. Ongoing plant operational and maintenance activities will be performed during the license renewal period, but no significant environmental impacts associated with such activities are expected since established programs and procedures are in place to ensure that proper environmental monitoring continues to be conducted throughout the renewal term.

ACRONYMS AND ABBREVIATIONS

AOG	augmented off-gas
AMSL	above mean sea level
btu	British thermal unit
BWR	Boiling Water Reactor
°C	degrees Celsius
CA	Conservation Area
CaO	calcium oxide
CDF	Core Damage Frequency
CEDS	Comprehensive Economic Development Strategy
CEQ	Council on Environmental Quality
CERCLA	Comprehensive Environmental Response and Liability Act
CET	Containment Event Tree
CFR	Code of Federal Regulations
cfs	cubic feet per second
Ci	Curies
CNS	Cooper Nuclear Station
CO	carbon monoxide
CPPD	Consumers Public Power District
CST	condensate storage tank
CWA	Clean Water Act
CWIS	circulating water intake structure
DF	decontamination factor
DOE	United States Department of Energy
DOT	Department of Transportation
E	East
E	Endangered

ACRONYMS AND ABBREVIATIONS (CONTINUED)

EAB	Exclusion Area Boundary
EDG	emergency diesel generator
EIA	Energy Information Administration
EIS	Environmental Impact Statement
El.	elevation [above sea level]
ENE	east-northeast
EPA	United States Environmental Protection Agency
ER	Environmental Report
ERP	elevated release point
ESE	east-southeast
°F	degrees Fahrenheit
FAA	Federal Aviation Administration
FAPRI	Food and Agricultural Policy Research Institute
FCS	Fort Calhoun Nuclear Station
FEIS	Final Environmental Impact Statement
FES	Final Environmental Statement
FIVE	Fire Induced Vulnerability Evaluation
fps	feet per second
ft	foot
ft^3	cubic feet
GEIS	Generic Environmental Impact Statement
gpd	gallons per day
GPI	Groundwater Protection Initiative
gpm	gallons per minute
HMTA	Hazardous Materials Transportation Act
IA	Iowa

ACRONYMS AND ABBREVIATIONS (CONTINUED)

IM	impingement mortality
in.	inch
IPEEE	Individual Plant Examination of External Events
ISFSI	Independent Spent Fuel Storage Installation
ISO	International Standards Organization
km	kilometer
KS	Kansas
KWh	kilowatt hour
lb	pound
LLRW	low-level radwaste
LOS	level of service
LRW	liquid radwaste
m	meter
MACCS2	Melcor Accidents Consequences Code System 2
mg/l	milligrams per liter
m/s	meters per second
m^2	square meters
m^3	cubic meters
MDC	Missouri Department of Conservation
mi	mile
ml	milliliter
mm	millimeter
MO	Missouri
MODOT	Missouri Department of Transportation
mrem	millirem [Roentgen equivalent man]
MSL	mean sea level

ACRONYMS AND ABBREVIATIONS (CONTINUED)

mSv	milli-Sievert
MT	Montana
MTU	metric ton uranium
MUR	Measurement Uncertainty Recapture
MWD	megawatt-days
MWe	megawatts electric
MWt	megawatts thermal
N	north
NA	not applicable
NAS	National Academies of Sciences
NASS	National Agricultural Statistics Service
NC	not calculated
ND	North Dakota
NDEC	Nebraska Department of Environmental Control
NDEQ	Nebraska Department of Environmental Quality
NDNR	Nebraska Department of Natural Resources
NDOR	Nebraska Department of Roads
NE	Nebraska
NE	northeast
NEPA	National Environmental Policy Act
NESC	National Electrical Safety Code
NGPC	Nebraska Game and Parks Commission
NHPA	National Historic Preservation Act
NNE	north-northeast
NNRD	Nemaha Natural Resources District
NNW	north north-west

ACRONYMS AND ABBREVIATIONS (CONTINUED)

NO_x	nitrogen oxides
NPA	Nebraska Power Association
NPDES	National Pollutant Discharge Elimination System
NPPD	Nebraska Public Power District
NRC	United States Nuclear Regulatory Commission
NRHP	National Register of Historic Places
NRR	Nuclear Reactor Regulation
NSPS	New Source Performance Standard
NW	northwest
ODAM	Offsite Dose Assessment Manual
OECR	off-site economic cost risk
OEDP	Overall Economic Development Plan
OL	Operating License
OPPD	Omaha Public Power District
OSHA	Occupational Health and Safety Administration
PC	personal computer
PCB	polychlorinated biphenyl
PDR	population dose risk
pf	power factor
PIC	Proposal for Information Collection
PMIS	Plant Management Information System
PSA	Probabilistic Safety Assessment
PV	photovoltaic
RA	recreation area
RAI	Request for Additional Information
REMP	Radiological Environmental Monitoring Program

ACRONYMS AND ABBREVIATIONS (CONTINUED)

RHR	residual heat removal
RM	river mile
ROI	region of interest
RMP	Risk Management Plan
ROW	right-of-way
RWCU	reactor water cleanup
RWD	rural water district
S	south
S	sulfur
SAMA	Severe Accident Management Alternatives
SC	species of concern
scfm	standard cubic feet per minute
SD	South Dakota
SE	southeast
sec	second
SEIS	Supplemental Environmental Impact Statement
SHPO	State Historic Preservation Officer
SJAE	steam jet air ejectors
SO_2	sulfur dioxide
SO_x	oxides of sulfur
SPCC	Spill Prevention, Control and Countermeasure
SRA	State Recreation Area
SSE	south-southeast
SSW	south-southwest
SW	southwest
T	temperature

ACRONYMS AND ABBREVIATIONS (CONTINUED)

T	threatened
TC	total catch
TLAP	Transmission Line Assessment Program
TSM	temporary storage modules
TSP	total suspended particulates
USACE	United States Army Corps of Engineers; USACE Mitigation Project
USAR	Updated Safety Analysis Report
USC	United States Code
USCB	United States Census Bureau
USFWS	United States Fish and Wildlife Service
USGS	United States Geological Survey
USNRC	United States Nuclear Regulatory Commission
W	West
WAPA	Western Area Power Administration
w.g.	water gauge
WHPA	Wellhead Protection Areas
WMA	wildlife management area
WNW	west-northwest
WSW	west-southwest
YOY	young-of-the-year
yr	year

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1.0 PURPOSE AND NEED FOR THE PROPOSED ACTION

For license renewal, the NRC has adopted the following definition of purpose and need, stated in Section 1.3 of NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants*: "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."

Nuclear power plants are initially licensed by the NRC to operate up to 40 years, and the licenses may be subsequently renewed [10 CFR 50.51] for periods up to 20 years. 10 CFR 54.17(c) states, "[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 is to renew the operating license (OL) for CNS which would provide the option for NPPD to continue to operate CNS through the 20-year period of extended operation. For CNS (Facility Operating License DPR-46), the requested renewal would extend the existing license expiration date from midnight, January 18, 2014, to midnight January 18, 2034.

1.1 Environmental Report

NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit with its application a separate document entitled, "Applicant's Environmental Report—Operating License Renewal Stage." This appendix to the CNS license renewal application fulfills that requirement.

Nebraska Public Power District (NPPD) has prepared Table 1.1-1 to document, in checklist form, that the 10 CFR Part 51 requirements for information to be provided in an ER in support of a license renewal application have been met. The requirements regarding information to be included in an ER are codified at 10 CFR 51.45 and 51.53(c). Table 1.1-1 provides the 10 CFR Part 51 regulatory language and regulatory citation, along with the ER section(s) that satisfy the 10 CFR Part 51 requirements.

1.2 Licensee and Ownership

NPPD is the owner of CNS and is licensed to operate it pursuant to Facility Operating License DPR-46. NPPD is the applicant for the CNS renewed operating license.

Table 1.1-1
Environmental Report Responses to License Renewal Environmental Regulatory Requirements

Description	Requirement	ER Section(s)
Environmental Reports—General Requirements [10 CFR 51.45]		
Environmental report contains a description of the proposed action.	10 CFR 51.45(b)	3.0
Environmental report contains a statement of the purposes of the proposed action.	10 CFR 51.45(b)	1.0
Environmental report contains a description of the environment affected.	10 CFR 51.45(b)	2.0
Environmental report discusses the impact of the proposed action on the environment.	10 CFR 51.45(b)(1)	4.0
Environmental report discusses any adverse environmental effects which cannot be avoided should the proposal be implemented.	10 CFR 51.45(b)(2)	6.3
Environmental report discusses alternatives to the proposed action.	10 CFR 51.45(b)(3)	7.0 and 8.0
Environmental report discusses the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity.	10 CFR 51.45(b)(4)	6.5
Environmental report discusses any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.	10 CFR 51.45(b)(5)	6.4
Environmental report includes an analysis that considers and balances the environmental effects of the proposed action, the environmental impacts of alternatives to the proposed action, and alternatives available for reducing or avoiding adverse environmental effects.	10 CFR 51.45(c)	4.0, 6.0, 7.0, and 8.0
Environmental report lists all Federal permits, licenses, approvals and other entitlements which must be obtained in connection with the proposed action and describes the status of compliance with these requirements.	10 CFR 51.45(d)	9.0

**Table 1.1-1 (Continued)
Environmental Report Responses to License Renewal
Environmental Regulatory Requirements**

Description	Requirement	ER Section(s)
Environmental Reports—General Requirements [10 CFR 51.45]		
Environmental report includes a discussion of the status of compliance with applicable environmental quality standards and requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection, including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements.	10 CFR 51.45(d)	9.0
The discussion of alternatives in the report includes a discussion of whether the alternatives will comply with such applicable environmental quality standards and requirements.	10 CFR 51.45(d)	8.0
The information submitted pursuant to 10 CFR 51.45 (b) through (d) should not be confined to information supporting the proposed action but should also include adverse information.	10 CFR 51.45(e)	4.0 and 6.3
Operating License Renewal Stage [10 CFR 51.53(c)]		
Environmental report description of the proposed action includes the applicant's plans to modify the facility or its administrative control procedures as described in accordance with §54.21. The report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment.	10 CFR 51.53(c)(2)	3.3 and 3.4
The environmental report must contain analyses of the environmental impacts of the proposed action, including the impacts of refurbishment activities, if any, associated with license renewal and the impacts of operation during the renewal term, for applicable Category 2 issues, as discussed below.	10 CFR 51.53(c)(3)(ii)	4.0
Plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15 x 10^{12} ft^3/year (9 x 10^{10} m^3/year)		
Environmental report contains an assessment of the impact of the proposed action on the flow of the river.	10 CFR 51.53(c)(3)(ii)(A)	4.1 and 4.6

**Table 1.1-1 (Continued)
Environmental Report Responses to License Renewal
Environmental Regulatory Requirements**

Description	Requirement	ER Section(s)
Environmental report contains an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow.	10 CFR 51.53(c)(3)(ii)(A)	4.1 and 4.6
Related impacts on in-stream and riparian ecological communities are provided.	10 CFR 51.53(c)(3)(ii)(A)	4.1 and 4.6
Plant utilizes once-through cooling or cooling pond heat dissipation systems		
A copy of current Clean Water Act 316(b) determinations and, if necessary, a 316(a) variance in accordance with 40 CFR Part 125, or equivalent State permits and supporting documentation are provided, **OR**	10 CFR 51.53(c)(3)(ii)(B)	4.2, 4.3, and 4.4
Environmental report contains an assessment of the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.	10 CFR 51.53(c)(3)(ii)(B)	4.2, 4.3, and 4.4
Plant uses Ranney wells or pumps more than 100 gallons (total onsite) of groundwater per minute		
Environmental report contains an assessment of the impact of the proposed action on groundwater use.	10 CFR 51.53(c)(3)(ii)(C)	4.5 and 4.7
Plant is located at an inland site and utilizes cooling ponds		
Environmental report contains an assessment of the impact of the proposed action on groundwater quality.	10 CFR 51.53(c)(3)(ii)(D)	4.8
All Plants		
Environmental report contains an assessment of the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats.	10 CFR 51.53(c)(3)(ii)(E)	4.9 and 4.10
Environmental report contains an assessment of the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act.	10 CFR 51.53(c)(3)(ii)(E)	4.9 and 4.10
Plant is located in or near a Clean Air Act non-attainment or maintenance area		
Environmental report contains an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce in accordance with the Clean Air Act as amended.	10 CFR 51.53(c)(3)(ii)(F)	4.11

Table 1.1-1 (Continued)
Environmental Report Responses to License Renewal Environmental Regulatory Requirements

Description	Requirement	ER Section(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 x 10^{12} ft^3/year (9 x 10^{10} m^3/year)		
Environmental report contains an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water.	10 CFR 51.53(c)(3)(ii)(G)	4.12
Plants with transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system		
Materials demonstrating that transmission lines meet the recommendations of the National Electric Safety Code for preventing electric shock from induced currents are provided, **OR**	10 CFR 51.53(c)(3)(ii)(H)	4.13
Environmental report contains an assessment of the impact of the proposed action on the potential shock hazard from the transmission lines.	10 CFR 51.53(c)(3)(ii)(H)	4.13
All Plants		
Environmental report contains an assessment of the impact of the proposed action on housing availability.	10 CFR 51.53(c)(3)(ii)(I)	4.14
Environmental report contains an assessment of the impact of the proposed action on land-use.	10 CFR 51.53(c)(3)(ii)(I)	4.17 and 4.18
All Plants		
Environmental report contains an assessment of the impact of the proposed action on public schools (impacts from refurbishment activities only) within the vicinity of the plant.	10 CFR 51.53(c)(3)(ii)(I)	4.16
Environmental report contains an assessment of the impact of population increases attributable to the proposed project on the public water supply.	10 CFR 51.53(c)(3)(ii)(I)	4.15
Environmental report contains an assessment of the impact of the proposed project on local transportation during periods of license renewal refurbishment activities and during the term of the renewed license.	10 CFR 51.53(c)(3)(ii)(J)	4.19
Environmental report contains an assessment as to whether any historic or archaeological properties will be affected by the proposed project.	10 CFR 51.53(c)(3)(ii)(K)	4.20

Table 1.1-1 (Continued)
Environmental Report Responses to License Renewal Environmental Regulatory Requirements

Description	Requirement	ER Section(s)
Plants for which 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		
Environmental report considers alternatives to mitigate severe accidents.	10 CFR 51.53(c)(3)(ii)(L)	4.21
All Plants		
Environmental report must contain a consideration of alternatives for reducing adverse impacts for all Category 2 license renewal issues.	10 CFR 51.53(c)(3)(iii)	4.0 and 6.2
Environmental report must contain any new and significant information regarding the environmental impacts of license renewal of which the applicant is aware.	10 CFR 51.53(c)(3)(iv)	5.0

2.0 SITE AND ENVIRONMENTAL INTERFACES

2.1 Location and Features

Cooper Nuclear Station (CNS), located in Nemaha County, Nebraska, is on the west bank of the Missouri River at river mile (RM) 532.5, referred to by the United States Army Corps of Engineers (USACE) as the Lower Brownville Bend. The site is owned and operated by Nebraska Public Power District (NPPD). Facilities for CNS are located on approximately 55 acres of the site, which consists of approximately 1,359 acres inclusive of the 239 acres on the opposite bank (east) of the Missouri River in Atchison County, Missouri (205 of the 239 acres are deeded and the remaining 34 acres have been acquired through accretion) (see Figure 2.1-4 and Figure 3.2-1). Of the 1,359 acres, 949 acres are currently leased for agricultural activities such as farming and livestock: 234 acres in Missouri and 715 acres in Nebraska. The 234 acres leased on the Missouri side sporadically floods and are mostly woods that are unarable. The farming leases do not have any stipulations on the farmers' actions as to the exclusion area boundaries.

Vicinity Features

The land area where CNS is located is bounded on the east by the Missouri River and by non-NPPD owned property on the north, south, and west. Lincoln, Nebraska, is located approximately 60 miles west northwest of the site. The nearest community within six miles of the site is the Village of Brownville, which is located approximately 2.25 miles northwest of the site. The location of the site is shown in Figures 2.1-1 and 2.1-2.

The site surroundings are predominantly agricultural with zero population within a one-half mile radius of the plant. Brownville, Nebraska, is the nearest developed community, at a distance of approximately 2.25 miles from the site. Brownville had a 1990 population of 148 and a 2000 population of 146 [USCB 1990; USCB 2006a]. In 2005, Brownville had a population of approximately 137. The next closest town of Nemaha, Nebraska, located 2.5 miles southwest, had a 2005 population of approximately 177 and is also the largest town within 6 miles. Rock Port, Missouri, with a 2005 population of 1,343 is located approximately 7.4 miles northeast of CNS. Phelps City, Missouri, with a population of 76, located approximately 4 miles northeast of the site, is the closest community with industry. The largest town with industry within 10 miles is Auburn, Nebraska, located to the west, with a 2005 population of approximately 3,076. Nebraska City, located approximately 24 miles northwest of the site, is the closest major town and had a 2005 population of 7,035. [USCB 2006a] Maryville, Missouri, located approximately 40 miles east of the plant, is the largest community within 50 miles and had a 2005 population of approximately 10,567 [USCB 2006b]. The nearest cities with 2005 populations exceeding 50,000 are Lincoln, Nebraska (population 239,213), approximately 60 miles west northwest of the site; Omaha, Nebraska (population 414,521), 65 miles north of CNS; and St. Joseph, Missouri (population 72,661), 60 miles southeast of the site [USCB 2006a; USCB 2006b].

Over 99 percent of the acreage in Nemaha County is used for agriculture and farming. Farming is the major activity for the rest of the area within a 50-mile radius as well. Over the past century, Atchison County has experienced significant population decline. In 1900 the population was approximately 16,501. The population declined during most of the 1900s and was just 6,430 by 2000. Atchison County is primarily rural. [NMRCG, p. 16]

There are no known missile sites within a ten-mile radius of the CNS plant site. Only one airport, the Auburn Municipal Airport, is located within a ten-mile radius of the CNS plant site. The location of this airport in relation to CNS is shown on Figure 2.1-2. The Auburn Municipal Airport has two turf runways with lengths of 2,800 feet and 2,200 feet, respectively. This limits the use of this airport to light single engine and partially loaded twin engine "executive" type aircraft. Landing and departure flight paths of aircraft using this airport are generally within one-half mile of the airport boundary. There are no current plans for airport expansion. [NPPD 2008b, Section II-1.5]

Station Features

The principal structures of the station are the reactor building, turbine building (including service area appendages), control building, controlled corridor, radwaste building, augmented radwaste building, intake structure, off-gas filter building, elevated release point, diesel generator building, multi-purpose facility, railroad airlock, drywell and suppression chamber, miscellaneous circulating water system structures (circulating water conduits, seal well, etc.), optimum water chemistry gas generator building, and office building [NPPD 2008b, Section XII-1.0]. Figure 3.2-1 shows the general features of the CNS site. Section 3.2 describes key features of the station, including reactor and containment systems, cooling and auxiliary water systems, radwaste systems, and transmission facilities.

The Protected Area is completely enclosed by a security fence, with access to the station controlled at a security gate. A plant security system monitors the Protected Area, as well as the buildings within the station. Normal access to the site is by a paved entrance road built across the site from Nemaha County road 648A Avenue, located on the west side of the property. Access was previously available by connection to a railroad spur line of the Burlington Northern Railroad, but this was abandoned by Burlington Northern. The Steamboat Trace Recreational Trail now runs along the previous railroad right-of-way [NPPD 2008b, Section II-1.4]. The exclusion area, as defined by 10 CFR 100.3, surrounds the site as shown in Figure 2.1-7. The nearest residences lie 0.9 miles beyond the site boundary to the northwest [NPPD 2008g, Section III].

The structures of CNS have been designed to provide a neat appearance, both from the river and from the county road that provides access to the site. The nearest point of view of the station is from the river that runs through the property. However, most traffic on the river is barge traffic. Predominant features are the reactor building, which is approximately 290 feet tall, the elevated release point (325 feet) and meteorological tower (328.8 feet). CNS is a modern, functional structure with a minimum of open steel framing. [NPPD 1971, Section IV-4.14] The facility has been landscaped with trees, shrubs, and grass native to the area. The view from the county road shows a distant plant surrounded by cultivated agricultural land. The 239 undeveloped acres on the Missouri (east) side of the river provides a wooded view from the river.

Due to the rural location of CNS and the lack of nearby residences, noise impacts on the public are negligible. In addition, there are no current activities that would create a condition such that the Occupational Safety and Health Administration (OSHA) 8-hour Time Weighted Allowance would be exceeded at the CNS property line. The greatest sources of noise would have occurred during the construction stage of CNS.

The site is located on a constructional plain bordering the west bank of the Missouri River at RM 532.5 (1960 river miles). It is situated on the first bottomland of the broad, nearly level, flood plain, which is approximately six miles wide at the site. The natural relief is about ten feet. The USACE has stabilized the channel by use of pile dikes and bank protection. Earthen levees run parallel with the Missouri River, on both sides of the river (see Figure 2.1-3). Flood protection levees were constructed in the area around 1950. This control prevents meandering of the river within the alluvial flood plain. [NPPD 2008b, Sections II-4.1 and II-5.1.1] The eastern bank of the Missouri River is chiefly a densely forested land similar to the un-farmable bluffs that run parallel to the Missouri River. To the west there are bluffs that peak at 1,100 feet, but average 1,000 feet along the stretch of river from Brownville to Nemaha [NPPD 1971, Section III-3.2]. Beyond the bluffs, the land is a gently rolling flood plain.

The station site grade level of 903 feet above mean sea level (AMSL) has been raised 13 feet above the natural grade level of 890 feet AMSL, in order to bring final grade one foot above the existing 902 feet AMSL levee constructed by the USACE. Figure 2.1-4 shows topographic features of the site and surrounding areas. The immediate station site area, excluding the switchyard west of the levee, was filled to elevation 903 feet AMSL, one foot higher than the top of the levee. This fill extends around the station buildings [NPPD 2008b, Sections II-2.1 and II-4.2.2.2]. The site slopes generally east, with surface drainage toward the Missouri River.

Both the bluff and rolling terrain shape is believed to have been exaggerated by wind deposited sediments. The Missouri site acreage is chiefly a densely forested land typical of the unarable bluffs that run parallel to the Missouri River. [NPPD 1971, Section III-3.2]

<u>Levees and Flood Control</u>

The maximum river level established by USACE studies was at 899 feet AMSL, during the flood of record in 1952, prior to the installation of the upstream river controls. The 1960, 1962, and 1967 floods developed downstream of the control dams and, consequently, only minor control was effected. The Missouri River was carrying approximately 414,000 cubic feet per second (cfs) at the peak of the flood in 1952. Had present river controls been available in 1952, the flow could have been reduced to approximately 100,000 cfs. [NPPD 2008b, Section II-4.2.2.1]

The maximum flood of record since the construction of flood controls was in 1993. The Brownville, Nebraska, gauging station (elevation 860 feet AMSL) recorded the maximum flood stage at 44.3 feet (904.3 feet AMSL) on July 24, 1993, or 12.3 feet above flood stage of 32 feet [Larson]. The flood level peaked at CNS at 900.8 feet AMSL and although the floodwaters did not rise above the station grade level, some plant structures experienced in-leakage [USNRC 1994].

The CNS property includes 239 acres on the east side of the Missouri River (see Figure 2.1-4) in Atchison County, Missouri, the most northwestern county in Missouri, bounded on the west by the Missouri River. In 1950, the federal levee system was completed along the Missouri River, protecting the valley from most flooding except for extremely high levels of flood water. The Missouri River enters Atchison County from the north at an elevation of nearly 900 feet and leaves at the south end at an elevation of approximately 865 feet.

Federal, Native American, State, and Local Lands

There are several Native American lands within a 50-mile radius of CNS as shown in Figure 2.1-6 [USCB 2000a]. These include the Sac and Fox Reservation, Iowa Reservation, and Kickapoo Reservation. There are also several local and county parks, golf courses, forest lands, wildlife areas, and other public recreation lands within a 50-mile radius of CNS. Major state, federal, and Native American lands within an approximate 6-mile and 50-mile radius of CNS are shown in Figures 2.1-5 and 2.1-6. Table 2.1-1 provides a list of all federal, Native American, state and major local lands within an approximate 50-mile radius of the site.

Table 2.1-1
Federal, Native American, State, and Local Lands Within 50-miles of CNS

Parks	Direction and Distance from CNS	Nearest City	County
Nebraska			
Steamboat Trace Trail	Along W side of CNS	Brownville, NE	Nemaha County
Langdon Bend (USACE)	SSE, 1 mile	Nemaha, NE	Nemaha County
Brownville State Recreation Area	N, 2 miles	Brownville, NE	Nemaha County
Aspinwall Bend WMA	SSW, 3 miles	Nemaha, NE	Nemaha County
Coryell Park	WNW, 17 miles	Johnson, NE	Nemaha County
Kansas Bend (USACE)	NNW, 12 miles	Peru, NE	Otoe & Nemaha Counties
Hamburg Bend (USACE)	NNW, 17 miles	Nebraska City, NE	Otoe County
Riverview Marina State Park	NW, 25 miles	Nebraska City, NE	Otoe County
Arbor Lodge State Historical Park	NW, 25 miles	Nebraska City, NE	Otoe County
Riverview SRA	NNW, 25 miles	Nebraska City, NE	Otoe County

Table 2.1-1 (Continued)
Federal, Native American, State, and Local Lands Within 50-miles of CNS

Parks	Direction and Distance from CNS	Nearest City	County
Wilson Creek WMA	NW, 32 miles	Syracuse, NE	Otoe County
Triple Creek WMA	WNW, 45 miles	Syracuse, NE	Otoe County
Indian Cave State Park	S, 3 miles	Barada, NE	Richardson County
Verdon State Recreation Area	SSW, 15 miles	Verdon, NE	Richardson County
Kirkman Recreation Area Park	WSW, 21 miles	Humboldt, NE	Richardson County
Margrave WMA	SSE, 26 miles	Rulo, NE	Richardson County
Four Mile Creek WMA	SSW, 27 miles	Dubois, NE	Richardson County
Kinter's Ford WMA	SW, 28 miles	Dubois, NE	Richardson County
Rulo Bluffs Preserve	SSE, 28 miles	Rulo, NE	Richardson County
Rakes Creek WMA	NNW, 38 miles	Union, NE	Cass County
Tobacco Island (USACE)	NNW, 43 miles	Plattsmouth, NE	Cass County
Schilling WMA	NNW, 48 miles	Plattsmouth, NE	Cass County
Rhoden WMA	NNW, 48 miles	Plattsmouth, NE	Cass County
Twin Oaks WMA	W, 26 miles	Tecumseh, NE	Johnson County
Osage WMA	WNW, 30 miles	Tecumseh, NE	Johnson County
Hickory Ridge WMA	W, 38 miles	Tecumseh, NE	Johnson County
Table Rock WMA	SW, 25 miles	Table Rock, NE	Pawnee County
Taylor's Branch WMA	SW, 30 miles	Pawnee City, NE	Pawnee County
Prairie Knoll WMA	SSW, 31 miles	Dubois, NE	Pawnee County
Iron Horse Trail Lake	SW, 32 miles	Dubois, NE	Pawnee County
Lores Branch WMA	SW, 32 miles	Dubois, NE	Pawnee County
Bowwood WMA	SW, 34 miles	Pawnee City, NE	Pawnee County
Burchard Lake WMA	SW, 37 miles	Burchard, NE	Pawnee County
Mayberry WMA	WSW, 38 miles	Lewiston, NE	Pawnee County

Table 2.1-1 (Continued)
Federal, Native American, State, and Local Lands Within 50-miles of CNS

Parks	Direction and Distance from CNS	Nearest City	County
Pawnee Prairie WMA	SW, 43 miles	Summerfield, KS	Pawnee County
Iowa			
O.S. Wing WMA	N, 15 miles	Hamburg, IA	Fremont County
Lower Hamburg Bend (USACE)	NNW, 15 miles	Hamburg, IA	Fremont County
Waubonsie State Park	N, 20.5 miles	Sidney, IA	Fremont County
Riverton WMA	NNE, 21 miles	Riverton, IA	Fremont County
Fremont County RA	N, 25 miles	Sydney, IA	Fremont County
Manti Park	NE, 26.25 miles	Shenandoah, IA	Fremont County
Copeland Bend (USACE)	NNW, 29 miles	Percival, IA	Fremont County
Percival I-29 WMA	NNW, 30 miles	Percival, IA	Fremont County
Shawtee Lake WMA	NNE, 32 miles	Anderson, IA	Fremont County
McPaul I-29 WMA	NNW, 33 miles	Thurman, IA	Fremont County
Forney Lake WMA	NNW, 35 miles	Thurman, IA	Fremont County
Scott I-29 WMA	NNW, 36 miles	Bartlett, IA	Fremont County
Auldon Bar (USACE)	NNW, 36 miles	Bartlett, IA	Fremont County
Pinky's Glen WMA	N, 37 miles	Tabor, IA	Fremont County
Bartlett I-29 WMA	NNW, 38 miles	Bartlett, IA	Fremont County
Grove Cemetery RA	NE, 32 miles	College Springs, IA	Page County
Pioneer County Park	NE, 33.5 miles	Yorktown, IA	Page County
Pierce RA	NNE, 36 miles	Essex, IA	Page County
Ross Park	ENE, 40 miles	Braddyville, IA	Page County
Nodaway Valley County Park	NE, 42.5 miles	Clarinda, IA	Page County
Palmquist Prairie WMA	NE, 43 miles	Hepburn, IA	Page County

Table 2.1-1 (Continued)
Federal, Native American, State, and Local Lands Within 50-miles of CNS

Parks	Direction and Distance from CNS	Nearest City	County
Hawleyville Cemetery RA	NE, 47 miles	Hawleyville, IA	Page County
Siam Tract WMA	ENE, 43 miles	Siam, IA	Taylor County
Windmill Lake County Park	NE, 49 miles	New Market, IA	Taylor County
Noddleman Island (USACE)	NNW, 39 miles	Bartlett, IA	Mills County
Nottleman Island WMA	NNW, 39 miles	Bartlett, IA	Mills County
Keg Creek I-29 WMA	NNW, 44 miles	Pacific Junction, IA	Mills County
Pony Creek Park RA	N, 50 miles	Glenwood, IA	Mills County
St. Mary's Island WMA	NNW, 50 miles	Pacific City, IA	Mills County
Anderson Park	NE, 51 miles	Stanton, IA	Montgomery County
Viking Lake State Park	NE, 51 miles	Stanton, IA	Montgomery County
Missouri			
Brickyard Loess Mound	SSW, 8 miles	Watson, MO	Atchison County
Deroin Bend CA	SE, 8 miles	Nishnabotna, MO	Atchison County
Deroin Bend (USACE)	SE, 8 miles	Nishnabotna, MO	Atchison and Holt Counties
Brickyard Hill Wildlife Conservation Area	N, 9 miles	Watson, MO	Atchison County
Nishnabotna (USACE)	NNW, 9 miles	Nishnabotna, MO	Atchison County
Star School Hill Prairie CA	N, 14 Miles	Hamburg, IA	Atchison County
Lower Hamburg Bend (USACE)	NNW, 15 miles	Hamburg, IA	Atchison and Fremont Counties
Tarkio Prairie CA	NE, 24 miles	Westboro, MO	Atchison County
Corning (USACE)	SE, 12 miles	Corning, MO	Holt County
Thurnau (USACE)	SE, 15 miles	Craig, MO	Holt County

Table 2.1-1 (Continued)
Federal, Native American, State, and Local Lands Within 50-miles of CNS

Parks	Direction and Distance from CNS	Nearest City	County
Thurnau CA	SE, 16 miles	Craig, MO	Holt County
Rush Bottom Bend (USACE)	SE, 22 miles	Rulo, NE	Holt County
Big Lake State Park	SE, 23.5 miles	Fortescue, MO	Holt County
Squaw Creek National Wildlife Refuge	SE, 28 miles	Mound City, MO	Holt County
McCormick Loess Mound	SE, 30 miles	Mound City, MO	Holt County
Jamerson C. McCormick CA	SE, 30 miles	Mound City, MO	Holt County
Bob Brown CA	SE, 33 miles	Forest City, MO	Holt County
Nodaway Valley CA	ESE, 35 miles	Maitland, MO	Holt County
Riverbreaks CA	SE 39 miles	Oregon, MO	Holt County
Monkey Mountain CA	SE, 44 miles	Nodaway, MO	Holt County
Bilby Ranch Lake CA	E, 25 miles	Quitman, MO	Nodaway County
Nodaway County Community Lake	ENE, 42 miles	Pickering, MO	Nodaway County
Mozingo Lake	ENE, 45 miles	Maryville, MO	Nodaway County
Honey Creek CA	SE, 44 miles	Nodaway, MO	Andrew County
Davis Memorial CA	ESE, 48 miles	Rosendale, MO	Andrew County
Christie CA	ESE, 48 miles	Rosendale, MO	Andrew County
Kansas			
Brown State Fishing Lake	SSE, 38 miles	Hiawatha, KS	Brown County
Native American Lands			
Sac and Fox Reservation	SSE, 23 miles	Rulo, NE	Richardson County, NE and Brown County, KS
Iowa Reservation	SSE, 26 miles	Rulo, NE	Richardson County, NE and Brown County, KS

Table 2.1-1 (Continued)
Federal, Native American, State, and Local Lands Within 50-miles of CNS

Parks	Direction and Distance from CNS	Nearest City	County
Kickapoo Reservation	S, 40 miles	Horton, KS	Brown County, KS

Distances are approximate.
SRA - State Recreation Area; RA - Recreation Area; CA - Conservation Area; WMA - Wildlife Management Area; USACE - USACE Mitigation Project
References: IDNR; KDWP; LBBNRD; MDC; MDNR 2008c; NGPC 2008d; NWF; USACE 2004a

2.2 Aquatic and Riparian Ecological Communities

2.2.1 Physical and Chemical Environment

The Missouri River

CNS is located on the Missouri River at RM 532.5, referred to by the USACE as the Lower Brownville Bend. The Missouri River is the longest river in the contiguous United States, extending 2,341 miles from southwest Montana to the Mississippi River near St. Louis, Missouri. Its drainage basin covers nearly one-sixth of the lower 48 states and is largely semi-arid, resulting in a low discharge relative to basin area [Galat and Lipkin, p. 30]. The Missouri River Basin drains approximately 529,350 square miles, including 9,700 square miles in Canada; all of Nebraska; most of Montana, Wyoming, North Dakota, and South Dakota; approximately half of Kansas and Missouri; and smaller parts of Iowa, Colorado, and Minnesota [OPPD, Section 2.2.1].

Main tributaries include the Yellowstone, Marias, Niobrara, James, Platte, and Kansas rivers [OPPD, Section 2.2.1]. The Yellowstone River flows 675 miles through Montana to its confluence with the Missouri River at the North Dakota border (Figure 2.2-1). The unregulated Bad River empties into the Missouri River at Fort Pierre in central South Dakota just upstream of Lake Sharpe. The Platte River enters the Missouri River at RM 595 near Plattsmouth, Nebraska approximately 63 miles north of CNS. The Kansas River confluence with the Missouri River is downstream from CNS and the flow is heavily regulated by dams on its mainstem (Figure 2.2-1). [NAS, pp. 69-71]

While the Platte's upper tributaries (South and North Platte rivers) are highly regulated and used for irrigation water, the lack of storage reservoirs on the Platte River itself allows considerable amounts of sediment, ranging in grain sizes from coarse to fine sand, to enter the Missouri River at the confluence. This sizeable increase in the Missouri River's bedload increases the potential for in-channel bar formation and alluviation on the floodplain during floods. [NAS, p. 71]

In the vicinity of CNS, on average the Missouri River is approximately 800 feet wide and 28 feet deep [NPPD 2006a, p. 4]. Under the present flow regulation, a minimum Nebraska City flow of 31,000 cfs is maintained for navigational purposes beginning in March and extending through

November. During the winter months, a minimum flow of 3,000 cfs is required for sanitary purposes; however, the actual winter flow in recent years has been maintained at 6,000 cfs or more. Since the establishment of present flow regulation, the lowest flow at Nebraska City to date (16 year record) was 4,320 cfs [1,939,000 gallons per minute (gpm)] in January 1957. Should a prolonged drought occur such that water is not available to maintain the above required flows, the navigational season will be shortened so that the minimum sanitary flows can always be maintained. [NPPD 2008b, Section II-4.2.1]

Flow of the Missouri River at CNS is largely controlled by the Gavins Point Dam located about 200 miles upstream in Yankton, South Dakota. The flow is highly channelized with swift flows and heavy sediment transport. To minimize the effects of sedimentation on the CNS intake, turning vanes and a low sheetpile wall are located in front of the intake bays. Wing dams are located on the Missouri side of the river near CNS to force the flow into a central channel. The water levels in the river range from a maximum at elevation 899.0 feet to a minimum at elevation 874.5 feet, with a normal level at elevation 880.0 feet. The annual mean river flow is 38,251 cfs (1930-2001) at the United States Geological Survey (USGS) gauging station at Nebraska City, Nebraska, which is located approximately 30 river miles north of CNS. [NPPD 2006a, pp. 4 and 14]

Missouri River Controls

Flow regulation of the Missouri River began in the 1930s with the construction of Fort Peck Dam in Montana, but regulation achieved significance with the closure of the Missouri River Reservoir System in 1954. This system, consisting of six mainstem dams regulated by the USACE, is now the largest water management system in the United States. This system is managed for multiple purposes, including maintenance of navigation flows, flood control, hydropower, public water supply, recreation, and fish and wildlife resources. [Jacobsen and Galat, p. 252]

There are seven dams upstream of the plant site that control flow in the Missouri River (see Figure 2.2-1 and Table 2.2-1). There are no dams or similar structures on the Missouri River downstream of the plant site [NPPD 2008b, Section II-4.1]. Before the majority of the Missouri River was impounded and channelized (1925–1948), it is estimated that at Omaha, Nebraska, the river had an average annual peak flow rate of approximately 77,692 cfs, whereas post-alteration (1967–1996) the same average annual peak flow rate was approximately 51,206 cfs [Pegg et al]. Historical river velocities were usually 0.98–2.62 feet per second (fps), but downstream from Gavins Point Dam velocities between 2.62 fps and 4.27 fps occur more frequently than they did historically [Berry et al., p. 6]. Pre- and post-alteration records of mean annual discharge also reflect the changes in the Missouri River's hydrograph. At the Nebraska City, Nebraska, USGS sampling station, the pre-alteration mean annual discharge was 32,267 cfs, whereas the post-alteration mean annual discharge is 42,159 cfs, a 30.6 percent change [Galat and Lipkin, p. 33].

Table 2.2-1
Missouri River Dams Upstream of CNS

Name	Location	River Mile	Year Completed
Gavins Point (Lewis and Clark Lake)	Yankton, SD	811	1957
Fort Randall (Lake Francis Case)	Lake Andes, SD	880	1956
Big Bend (Lake Sharpe)	Chamberlin, SD	987	1966
Oahe (Lake Oahe)	Pierre, SD	1,072	1963
Garrison (Lake Sakakawea)	Bismarck, ND	1,389	1960
Fort Peck (Fort Peck Lake)	Glasgow, MT	1,771	1940
Canyon Ferry (Canyon Ferry Lake)	Helena, MT	~2,290	1954

References: NAS, p. 45; NPPD 2008b, Section II-4.2.2.1, Table II-4-1

The USACE constructed and operates six of the seven mainstem dams on the Missouri River; the U.S. Bureau of Reclamation operates the seventh, Canyon Ferry Dam, east of Helena, Montana. When the USACE constructed five of the Missouri River mainstem dams in the 1950s and 1960s after passage of the Pick-Sloan Plan, goals for dam and reservoir operations were to reduce flood damages, enhance navigation, generate hydroelectric power, and store water for irrigation. [NAS, p. 8]

Ecological Changes

The Missouri River ecosystem experienced a marked ecological transformation during the twentieth century. At the beginning of the century, the Missouri River was notorious for large floods, massive sediment transport, and a sinuous and meandering river channel that moved freely across its floodplain. By the end of the twentieth century, the Missouri River bore little resemblance to the previously wild, free-flowing river. The river has historically been managed for multiple purposes such as flood control, barge traffic, and hydro-electric power generation. To enable this management, seven mainstem dams have been built, banks have been rip-rapped, and channels confined. Management practices have been expanded to include construction of endangered species habitats, recreation, and municipal water supplies.

The National Academy of Science (NAS) published an extensive review of the Missouri River ecosystem in 2002 that summarizes the significant changes that the river has undergone to its fundamental natural processes: loss of natural flood pulses, loss of natural low flows, straightening of stream meanders, elimination of cut and fill alluviation, losses of natural riparian vegetation, reductions in water temperature variation, introduction of nonnative species, extensive bank stabilization, and stream channelization. [NAS, Executive Summary] Specific examples of twentieth-century changes in the Missouri River ecosystem include the following.

- Nearly three million acres of natural riverine and floodplain habitat (bluff to bluff along the Missouri River's mainstem) have been altered through land-use changes, inundation, channelization, and levee building.

- Sediment transport, the hallmark of the pre-regulation Missouri River (which was thus nicknamed "The Big Muddy"), has been dramatically reduced. Sediment transport and deposition were critical to maintaining the river system's form and dynamics. For example, before the 1950s, the Missouri River carried an average of roughly 142 million tons of sediment per year past Sioux City, Iowa; after closure of the dams, an average of roughly 4 million tons per year moved past the same location.

- Damming and channelization have occurred on most of the Missouri River Basin's numerous tributary streams, where at least 75 dams have been constructed.

- The amplitude and the frequency of the Missouri River's natural peak flows have been sharply reduced. With the occasional exception of downstream sections in the State of Missouri, the Missouri River no longer experiences natural spring and summer rises and ecologically beneficial low flows at other times of the year.

- Cropland expansion and reservoir impoundment have caused reductions in natural vegetation communities. These vegetation communities continue to shrink with the additional clearing of floodplain lands. The remaining remnant areas will be critical in any efforts to repopulate the floodplain ecosystem.

- Reproduction of cottonwoods, historically the most abundant and ecologically important species on the river's extensive floodplain, has largely ceased along the Missouri River, except in downstream reaches that were flooded in the 1990s and in upstream reaches above the large dams.

- Production of benthic invertebrates (e.g., species of caddis fly and mayfly) has been reduced by approximately 70 percent in remnant unchannelized river reaches. Benthic invertebrates are an important food source for the river's native fishes and an important component of the river's food web.

- Of the 67 native fish species living along the mainstem, 51 are now listed as rare, uncommon, and/or decreasing across all or part of their ranges. One of these fishes (pallid sturgeon) and two avian species (least tern and piping plover) are on the federal Endangered Species List.

- In many reaches of the river, nonnative sport fishes exist in greater abundance than native fish species. The nonnative fishes are often more tolerant of altered conditions of temperature, turbidity, and habitat. Although some nonnative fish produce substantial economic benefits, nonnative species may also contribute to the declining abundance of native fish.
  [NAS, pp. 1-10]

The cross-sectional shape of the Missouri River's channelized portion (735 miles or about one-third of the river's length) is approximately trapezoidal. Prior to channelization, the river's flow had been swift only in its thalweg (a line connecting the deepest points of the river channel), as the river contained sloughs, sandbars, and side channels. But today the river runs swiftly throughout the entire channelized, uniform cross-section. The reduction in width, along with a decrease in flow resistance because of the uniform cross-section and the clearing of snags and sand bars, has caused an increase in flow velocity, which today measures roughly three miles per hour at usual levels of river discharge. [NAS, p. 65]

The only free-flowing reach of the Missouri River lies in Montana, upstream of the mainstem dams. This reach without storage reservoirs extends from the Missouri River source near Three Forks, Montana, downstream to Canyon Ferry Reservoir, a distance of about 30 miles. However, the much longer reach from Canyon Ferry Dam to Fort Peck Lake is only mildly regulated because of the comparatively small storage capacity of Canyon Ferry Reservoir relative to total river flow and the long distance between Canyon Ferry Dam and the next downstream reservoir (Fort Peck). Contributions from small mountain streams and springs help retain some of the natural flow and temperature patterns in this reach as well. [NAS, p. 71]

Remnant floodplain sub-units occur between reservoirs (Figure 2.2-1). The length of these reaches varies considerably. In some cases, the headwaters of the mainstem reservoirs extend nearly to the tailwaters of the next upstream dam; there are few remnant floodplains from Lake Oahe downstream to Fort Randall Dam. In other cases, reservoirs are separated by large stretches of river (e.g., section 3, from Fort Peck Dam downstream to Williston, North Dakota). These latter sub-units have retained a natural appearance, with a sinuous channel and a wide floodplain often with oxbow lakes, sand dunes, and interspersed patches of natural forest vegetation and agricultural fields. The natural appearance, however, masks fundamentally altered hydrologic and sediment regimes. Nonetheless, many of these sub-units are not physically static, and undergo natural degradation and sedimentation processes as altered by flows and releases from upstream dams and tributary inflows. Many of these segments are now incised, which has caused the loss of adjacent wetlands and secondary channels. [NAS, p. 72]

The lack of overbank flooding in remnant reaches, except on the lowest terraces during extreme wet periods, may have ecological consequences. Moreover, the reduced post-regulation peaks in Missouri River discharge have been insufficient to cause lateral meandering of the channel that is needed for pioneer forest communities dominated by cottonwood and willow recruitment sites. This diverse community type is in serious decline in much of the Great Plains due to river regulation and land management practices (grazing). [NAS, p. 72]

Downstream of Gavins Point Dam (RM 811), upstream of CNS, the Missouri River has been channelized (narrowed and deepened in a relatively fixed position) from Sioux City, Iowa, to its mouth to permit navigation by boats and barges, and its banks were stabilized to enhance utilization of the bankline adjacent to the channel (sections 14–19 in Figure 2.2-1). In addition, chutes and side channels have been blocked and diverted, converting the once structurally complex channels and in-stream islands into a single thread of deep, fast-moving water. Levees have been constructed on both banks along much of the lower river to protect crops and settlements behind them; these levees constrain overbank flows to a narrow zone of the floodplain. The Missouri River's lower reaches (especially downstream of the Platte River confluence at RM 595) have aggraded. [NAS, p. 74]

Transportation has had a major effect on the Missouri River. Morphological alterations to the Missouri River began earlier than the hydrologic alteration. Clearing and stabilization of the river began in the early 1800s to improve conditions for steamboat navigation. The riverbanks have been stabilized with wing dikes and revetments, which in turn have narrowed and focused the thalweg to maintain a self-dredging navigation channel from St. Louis, Missouri, upstream to Sioux City, Iowa. The result is a narrow, swift, and deep channel from what was historically a shallow, shifting, braided river [Jacobsen and Galat, p. 253].

Improved navigation was a major feature of the mid-twentieth century vision of the 1944 Pick-Sloan Plan, as navigation's future economic benefits were assumed to be substantial. However, the 1950s projections for commercial waterway traffic were overly optimistic; commercial towboat traffic on the Missouri River peaked in 1977 (below projected levels) and has fallen slowly and steadily since then. Missouri River navigation is conducted on the river's 735-mile channelized stretch between Sioux City, Iowa and St. Louis, Missouri. [NAS, p. 6]

There are numerous natural and anthropogenic factors since the 1804-1806 Lewis and Clark Expedition that have changed and influenced the taxa found in the aquatic and riparian communities, including the six dams of the mainstem reservoir system, channelization, stream bank stabilization, wing dikes, flood control measures, irrigation, hydropower, water supply, recreation, and flood and drought events [Jorgensen]. The changes and effects of bank stabilization, channelization, and the reservoirs have been large and well documented. Estimates of the physical changes include the following:

- 8 percent reduction in channel length,
- 27 percent reduction in bank-to-bank channel area,
- 50 percent reduction in original surface area,
- 98 percent reduction in surface area of islands,
- 89 percent reduction in the number of islands, and

- 97 percent reduction in area of sandbars.
  [Jorgensen, p. 13]

More specifically, reduction in natural riparian communities ranging from a 41 percent reduction in deciduous vegetation and a 12 percent reduction in grasslands to a 39 percent reduction in wetlands was reported. Other important changes include land use, the largest of which was the change from riparian and prairie vegetation to agriculture, urban, and industrial uses. [Jorgensen, pp. 16-17]

Engineered changes in the nation's rivers have enhanced competition, predation, and other detrimental interactions between native and nonnative species, which has contributed to the demise of native species. Missouri River reservoirs and river segments presently contain populations of exotic fishes, including cisco, several salmon and trout species, and several Asian carp species. Some of these species have contributed to the development of economically important recreational fisheries. [NAS, p. 16]

The net effect of dams on the tributaries of the Missouri River is the removal of large areas of shallow water habitat used by native fish for spawning and the rearing of young of the year, e.g., sturgeon, yellow perch, flathead chub. These alterations to the Missouri River and their associated effects (changes in water temperature, sediment and organic matter input and transport, floodplain inundation, and decrease of cover for fishes) have caused an estimated loss of 216 million kg of fish production annually. Commercial fish harvest has been reduced 80 percent and approximately one-fifth of native species are listed as imperiled. [Berry et al., p. 6]

<u>Missouri River Fish Species</u>

Currently, there are approximately 150 fish species known to occur in the Missouri River Basin.[1] Fifty-four percent are classified as "big river" species, residing primarily in the main channel. Populations of 17 species are increasing, of which 53 percent are introduced. Twenty-three of 24 species, whose populations are decreasing, are native. [Galat et al. 2005, p. 2] The most economically important sport fishes in the Missouri River include walleye (*Stizostedion vitreum*), sauger (*Stizostedion canadense*), yellow perch (*Perca flavescens*), channel catfish (*Ictalurus punctatus*), paddlefish (*Polyodon spathula*), shovelnose sturgeon (*Scaphirhynchus platorhynchus*), and northern pike (*Esox lucius*) [Berry et al., p. 6].

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1. A significant body of research on Missouri River fish communities is discussed in the various sections of this ER. Various researchers cite numbers of fish species in the Missouri River which are based on studies performed at specific times, in specific segments of the Missouri River, using a variety of sampling or analysis methodologies. Some may indicate available information related to native and non-native species combined, while others are relevant only to species in a specific segment of the Missouri (e.g., Galat et. al. 2005 report of 136 fish species from 25 families; Berry et. al. reports 150 species in the lower Missouri River basin; Hesse 1982 report of 57 fish in the vicinity of CNS and FCS; NAS report of 67 species in the mainstem Missouri; and USACE 2003 reports that 91 fish species are currently found in the Lower Missouri River). These numbers of species reflect the studies cited, and accurately cite the number of species discussed in the specific analysis.

Changes that have occurred in the Missouri River and floodplain ecosystem are believed to be significant in the decline of three federally listed threatened or endangered species. These are the interior least tern (*Sternula antillarum*), piping plover (*Charadrius melodus*), and the pallid sturgeon (*Scaphirhynchus albus*).

Missouri River Restoration Efforts

In 1989, the USACE and the U.S. Fish and Wildlife Service (USFWS) began a series of consultations mandated by the Endangered Species Act. In 1990 and 1994, the USFWS issued biological opinions indicating that actions proposed by the USACE would place certain species in jeopardy. On receipt of these opinions, the USACE continued to develop alternative approaches to system operations. In April 2000, the USACE requested the USFWS to formally consult on the operations of the Missouri River mainstem system, related operations of the Kansas River tributary reservoirs, and on the operations and maintenance of the Missouri River Bank Stabilization and Navigation Project. The USFWS concluded that continuation of current operations on the Missouri River was likely to jeopardize the continued existence of several listed species (i.e., pallid sturgeon, interior least tern, and piping plover). In November 2000, the USACE Northwestern Division Engineer discussed the USACE position on the biological opinions of the USFWS and determined there is significant agreement between the USACE and USFWS on the known biological attributes necessary to recover the listed species. However, the USACE noted in its assessment that elements of the biological opinion slightly increase the risk of flooding and are detrimental to navigation. The USACE has continued to evaluate the impact of the reasonable and prudent alternative on these and other project purposes. It is possible that the USACE will propose an alternative that meets the biological objectives with reduced impacts in other areas. [NAS, p. 51]

The USACE is implementing the Missouri River Fish and Wildlife Mitigation Project (Mitigation Project) to mitigate, or compensate, for fish and wildlife habitat losses that resulted from past channelization efforts on the Missouri River. The Mitigation Project extends from Sioux City, Iowa to the mouth of the Missouri River near St. Louis, a length of 735 river miles. Current plans are to develop approximately 166,750 acres of land in separate locations along the river in Nebraska, Iowa, Kansas, and Missouri. Implementation of the Mitigation Project includes returning some historic river features to original conditions; preserving existing fish and wildlife habitat; or creating improved shallow water habitat and new wildlife areas. Individual project sites are completed utilizing many different methods including dredging filled-in areas, reopening historic chutes, bank stabilizations, dike notching, pumping water, dike/levee construction, vegetative plantings, vegetation and land management and others. As of 2004, 36 mitigation sites were cited by the USACE along the length of the Mitigation Project. [USACE 2007b]

The USACE sets the water release schedules for the Missouri River mainstem dams. Guidance for mainstem dam water release priorities is established in the USACE's Missouri River Mainstem Reservoir System Reservoir Regulation Manual, also known as the "Master Manual." Decisions regarding water release schedules from the Missouri River mainstem reservoirs ultimately determine the distribution of the river's benefits. [NAS, p. 9]

The Master Manual, which has been subject to revisions, prescribes implementation protocols for Reservoir System storage and release functions to accommodate the multiple purposes it serves. Although hydropower and water supply provide about 70 percent of the economic benefits, the release criteria for Gavins Point Dam are currently influenced most by navigation considerations. The navigation considerations are overridden by the need to either cut back releases for downstream flood control or to evacuate flood-control storage space in the reservoirs. [USNRC 2003]

The USFWS issued a Biological Opinion that includes recommendations for changing the flow regime in the Missouri River [USFWS 2000]. These and other changes since the Main Stem Reservoir System was first authorized prompted the USACE to undertake a review and update of the Master Manual. The objectives of the revision were to determine what best meets the current needs of the basin and to incorporate controls to appropriately meet those needs. These activities, which began in 1989, included the development of an EIS. In a revised draft EIS issued in August 2001, the USFWS examined the impact of six alternatives for regulating flows in the Reservoir System. [USNRC 2003]

Specifically proposed actions include flow modifications in the lower river to restore and maintain nesting and foraging habitat for the least tern and piping plover and to trigger spawning and enhance nursery habitat for the pallid sturgeon and other native fish species. The flow scenario specified by USFWS as a starting point includes lowering target flows below Gavins Point Dam to 25,000 cfs from June 21 to July 15; 21,000 cfs from July 15 to August 15; and 25,000 cfs from August 15 to September 1. [OPPD, Section 2.2.3]

In 2004, the USACE released a Record of Decision on the Final Environmental Impact Statement on the operation of the Missouri River dams and reservoirs, a new Master Water Control Manual, and a final 2004 Annual Operating Plan. The Corps retains its commitment to flood control and power generation. The dams protect 1.4 million acres of farmland and 40,000 residential and non-residential buildings along the river from Montana to the Mississippi River. This benefit averages more than $410 million annually. They also provide average annual hydropower benefits in the range of $670 million. The new Master Manual complies with the Endangered Species Act. The USACE and USFWS have been working together to address plans to develop shallow water habitat for the pallid sturgeon, construct sand bars for the piping plover and interior least tern, and provide for "spring pulse" to meet the needs for endangered species, while also meeting other USACE objectives. [USACE 2004b]

There are many beneficial uses of the Missouri River. The Missouri River provides water supply benefits for power plants, municipal and other public water supplies, irrigation, commercial/ industrial use, and domestic water use as long as daily flows exceed minimum elevation requirements for their intakes. The USACE's Missouri River operating plan assures that daily flows will exceed the minimum elevation as much of the time as is feasible. The greatest numbers of intakes are above Gavins Point Dam for all types of use, except power plants. Of 25 power plants using river water, 18 are below Gavins Point and accounted for 73 percent of total generating capacity (see Figure 2.2-1). By far the largest numbers of intakes overall are for irrigation (891) and domestic (579) supplies. There are 57 municipal intakes serving 3.1 million people. Of these, 2.9 million persons are served below Gavins Point by 19 supply intakes. The Missouri River, and especially its reservoir system, also provides recreational benefits. It is estimated that more than 60 million recreational visitor hours per year are provided along the river. [NAS, p. 93]

The potential for flow reduction prompted several power generation companies below the Gavins Point Dam to evaluate the potential impact flow reduction might have on Missouri River electric power generation plants. The University of Missouri's Food and Agricultural Policy Research Institute (FAPRI) completed a study of the implications of alternative flows noting that there are nine power companies that operate eighteen power plants using water from the Missouri River for cooling purposes [FAPRI, p. 2]. CNS was included in the list of power plants. Table 2.2-2 lists power plants below Gavins Point Dam using the Missouri River for cooling water supply.

Much of current discussion of Missouri River flows is focused on changes in the summer flows. For this reason, the primary focus of the 2003-2004 FAPRI study was the summer flow period, which was defined as June–September. Summer river flows are particularly relevant for power plants because the summer period corresponds to a peak demand period for electrical power. A total summer generation capacity of 11,253.8 MWe is supplied by power plants that use the Missouri River for cooling water across the states of Iowa, Nebraska, Kansas, and Missouri. These plants represent about 25 percent of total power generation capacity in the four states. Lower flow rates will reduce the amount of water available for compliance with thermal effluent limitations and will generally result in higher ambient river temperatures. Extreme low flows may also result in water accessibility problems for individual power plants. Water access problems occur when a plant simply cannot pump sufficient quantities of water to support full operation. Water access problems may force a plant to reduce load or completely shut down. [FAPRI, pp. 3 and 5]

The study noted that power plants are not uniformly affected by flow rate and river water temperature. In addition, each plant has a different set of regulations depending on its state and the specific profile of the Missouri River at its location. The FAPRI study evaluated potential generation de-rating caused by reduced cooling water supply or problems in meeting Clean Water Act thermal discharge requirements. One scenario proposed by USFWS includes a spring rise of 20,000 cubic feet per second (cfs) over navigation requirements for the May 15–June 15 period, a flat 25,000 cfs release over the June 16–July 15 period, a flat 21,000 cfs release over the July 16–August 15 period, and a 25,000 cfs release over the August 16–September 1 period. The exceptions to policy occur when the system is in a flood control mode or when there has been a severe drought in the upper reservoirs that might reduce flows over the May 15 to July 15 period. Conservative economic impacts were evaluated with the conclusion that flow reductions in the Missouri River as proposed by the USFWS could result in an annual summer economic loss of approximately $46 million. [FAPRI, pp. 11-12]

The Nebraska Power Association (NPA) also evaluated the impacts of Missouri River flow alterations in 2003. An analysis of the expanded intrastate and interstate regional impact of reduced summer flows was considered for the generating units on the Missouri River that use the river water for cooling. These units represent about 22 percent of the generation capacity and 30 percent of the energy requirements for the four state region (NE, IA, MO, and KS). If generation capacity is curtailed and replacement power is unavailable or cannot be transmitted to the region, then a blackout of the entire region could result. The direct and societal cost of rolling blackouts is estimated to range from $96,000,000 to $960,000,000 per hour for the four state region. [NPA]

Water Quality

Section 303(d) of the federal Clean Water Act (CWA) requires states to identify and establish a priority ranking for waterbodies in which technology-based effluent limitations are not stringent enough to attain and maintain applicable water quality standards. States are required to periodically submit a list of impaired waterbodies and assign beneficial uses to all surface waterbodies. Beneficial uses for Nebraska waterbodies are defined in Title 117 - Nebraska Surface Water Quality Standards, Chapter 4. [NDEQ 2004]

The Missouri Tributaries Basin upstream of the Platte River includes 136 designated stream segments and 27 designated lakes (MT1-10000, from the Big Sioux River to the Platte River). The middle Missouri River in the vicinity of CNS lies within the Nemaha Basin. The Nemaha Basin has 326 designated stream segments and 33 designated lakes. These streams and lakes affect the water quality of the Missouri River. The Nebraska Department of Environmental Quality (NDEQ) designates surface waters for beneficial use for primary contact recreation, aquatic life, water supply, and aesthetics. The NDEQ has determined the Missouri River in both the Missouri Tributaries Basin and the Nemaha Basin, including the Missouri River segment NE1-10000, from the Platte River to the Nebraska-Kansas border, is impaired for primary contact recreation and aquatic life use due to the presence of fecal coliform and PCBs/Deildrin. [NDEQ 2004] Beneficial uses supported by existing water quality for the Missouri River segment in the vicinity of CNS are for agricultural water supply and industrial water supply.

Available water quality data were collected by the USACE for low flow studies for the update of the Missouri River Master Water Control Manual, July 1994. The point of data collection nearest to Barney Bend (Hamburg Bend) was at the mouth of the Nishnabotna River (approximate RM 542). Temperature, pH, dissolved oxygen, and total suspended solids were measured twice over a two-week period in August and September 1990. Temperature ranged from 27.5 degrees Celsius (°C) to 25°C; pH was 8.1 to 8.3; dissolved oxygen was 6.0 milligrams per liter (mg/l) to 7.4 mg/l; and total suspended solids were measured at 539 mg/l and 75 mg/l. These results were fairly consistent with those from other collection points along the Missouri River; however, there was no explanation provided for the large differences in total suspended solids between the two sampling events at this particular location. These parameters have an effect on the fisheries in the Missouri River. High temperatures decrease the amount of dissolved oxygen. The temperature for the Missouri River in Missouri must not be above 32.2°C and the dissolved oxygen concentration must not be below 5.0 mg/l based on federally approved water quality standards. [USACE 2007a, p. 3-11]

2.2.2 Plankton Communities

Plankton is composed of microscopic free-living forms of plants (phytoplankton) and animals (zooplankton). Planktonic algae use energy from the sun to convert carbon dioxide, minerals, and water into organic compounds used to sustain it. As primary producers, these organisms provide the base for aquatic system food webs. Phytoplankton, along with organic detritus, bacteria, and protozoans, provides a source of nutrition for microscopic animal life (zooplankton), which are then utilized as food by most young fish. [NPPD 1971, Section III-3.9.3.2] Whereas much is known about plankton dynamics in fresh water lakes and reservoirs, limited research has focused on plankton dynamics of rivers [Basu et al., p. 1572].

Dominant phytoplankton found in the Missouri River at the CNS site included green algae, blue-green algae, and diatoms. Of these, diatoms were the most abundant during all seasons, with over 180 species identified. Blue-green algae and zooplankton were the least abundant. Blue-green algae may occur at certain times each year near the discharge canal of CNS and along the shoreline of the river for up to one-half mile below the outfall. Periphyton (attached algae) is not abundant in the Missouri River due to changing water levels and heavy silt loads but may be found along the banks of the river or in stagnant water behind dikes.

Stomach contents of local fish showed that zooplankton constitute an important food base for several species of fish. [USAEC, Section II.E.2.a] Most zooplankton found near CNS between 1972 and 1977 were derived from upstream reservoir discharges. Because zooplankton species are concentrated in the reservoirs of the Missouri River, the diversity of zooplankton species encountered during 1972 and 1977 reflects the large size and extent of reservoirs along the Missouri River. [Repsys, p. 127]

Aquatic plants and phytoplankton are produced within the river from sunlight. Although reservoirs have reduced turbidity in the mainstem, sunlight remains a limiting factor to plankton and periphyton production. However, when turbidity decreases in rivers, some riverine fish species are replaced by sight-feeding planktivores and piscivores adapted to lentic habitats and clear water. Such changes were apparent by 1974 in the lower Missouri River. On the other hand, man-made channel structures provide habitat for aufwuchs (periphyton) colonization and reservoirs release tons of plankton that partly offset the loss of production from natural habitat. Algae, detritus, phytoplankton, and periphyton are consumed by many fish species in the riverine portions of the Missouri River. [Berry et al., p. 5]

The phytoplankton community in the vicinity of CNS during 1982 was comprised of seven algal divisions, including diatoms, green algae, blue-green algae, cryptophytes, chrysophytes, euglenoids, and dinoflagellates. The chysophytes, euglenoids, and dinoflagellates were present, but were not common. [Reetz, p. 73]

More recent description of plankton communities indicates the two most common plankton in the lower Missouri River are Fragilaria and Pediastrum, comprising 23 and 26 percent of the total plankton. Nematodes make up about 16 percent of total plankton. Common zooplankton includes rotifers and nauplii. Within the Missouri River, the areas most productive of a true benthos are near the steep banks, which average 2.17 pounds per acre. Areas downstream of pile dikes support about 1.27 pounds per acre. The most common organisms in the benthos include Diptera larvae and Chironomidae larvae. [USACE 2007a, pp. 3-5]

2.2.3 Macroinvertebrate Communities

An important component of the aquatic environment is the population of macroinvertebrates—small animals without backbones that can be seen with the naked eye (retained on a 0.6 mm mesh sieve) (i.e., aquatic insects, crustaceans, worms, clams, and mollusks). They are typically found within all strata of the water column, especially in association with the bottom, banks and aquatic vegetation. Macroinvertebrates are an essential trophic component of any aquatic system, providing a food source for many fish species while concurrently influencing macronutrient levels through foraging.

Little was known about the quantitative aspects of the macroinvertebrate communities in the Missouri River at the time of the original CNS license application. Studies completed from 1969 through 1975 at CNS were discussed in the original 316(a) and 316(b) report for the plant. In the channelized river, macroinvertebrate production was reported to be primarily confined to the thin bands along either bank where solid substrates of the channelization structures and accumulations of soft muddy sediments provide suitable habitats for colonization. The macroinvertebrate fauna is directly dependent upon conditions within these narrow bands of suitable habitats and only indirectly on conditions in the mainstream of the river. Substantial aufwuchs and benthic communities develop on and around the wing dikes, trail dikes, and other navigational structures maintained by the USACE along both banks of the river. High population densities of some taxa were reported during some months such as *Dugesia*, *Caenis*, *Hydropsychidae*, and *Rheotanytarsus*. *Tubificidae* (worms) and *Chironornidae* (midges) numerically dominated the benthic macroinvertebrate community upstream and downstream of the station. Heat tolerant taxa such as *Branchiuria sowerbyi*, *Limnodrilus hoffmeisteri*, and *Glyptotendipes* were identified in the vicinity of CNS. [Nalco, Section 4.4.1.5]

The Missouri River Ecosystem report, prepared in 2002, presented a list of macroinvertebrates identified in the river, provided in Tables 2.2-3a and 2.2-3b [NAS, Appendix A, Tables 1 and 2]. Macroinvertebrates found in the section of the Missouri River in the vicinity of CNS RM 532.5 are typically benthic organisms associated with substrates found along the banks of the main channel and backwaters. Common macroinvertebrate fauna identified near CNS include members of phyla *Platyhelminthes*, *Oligochaeta*, *Nematoda*, *Mollusca*, and *Insecta.* Extensive current speed (0.8–2.0 m/s [2.62–6.56 fps]), turbidity, and subsequent scouring due to channelization of the river bed, along with fluctuations in water level, help determine macroinvertebrate community composition within the Missouri River. [Poulton et al.; Carter et al.]

For example, river current velocity of 1–3 m/s and shifting substrates probably reduce benthic macroinvertebrate production, whereas flow constancy probably helps benthic invertebrate and aufwuchs communities. [Berry et al., p. 5]

In 2005 macroinvertebrate communities along the Missouri River were sampled using rock baskets, kick nets, and ponar sampling techniques at 18 locations. Sampling points in the vicinity of CNS (RM 532.5) included Langdon, Nebraska (RM 534), and Nodaway, Missouri (RM 463.7). Overall taxa richness was reported as 23.8 and 24.2 for Langdon, Nebraska, and Nodaway, Missouri, respectively. These values are among the highest (third and second, respectively) reported taxa richness values for the study; therefore, aquatic life status in the vicinity of CNS was determined to be slightly impaired based on a score relative to theoretical reference river. [Poulton et al.] Slightly impaired was the best designation applied to any of the 18 locations sampled. In addition, the slightly impaired designation was applied to all sampling locations from DeSoto, Nebraska (north of Omaha) to Nodaway, Kansas (north of St. Joseph, Missouri), indicating any potential impact on macroinvertebrate communities were unrelated to CNS.

Oligochaete density was reported to be 7,302/m^2 and 6,674/m^2 above (Langdon, Missouri) and below (Nodaway, Missouri) CNS, respectively [Poulton et al.]. These values are the second and third highest reported values for *oligochaeta* along the entire sampling span of the Missouri River. *Oligochaete* worms are bottom-dwelling organisms that usually burrow into muddy regions of the river or backwater reaches and play an important role in nutrient recycling and turnover [Poulton et al.]. *Oligochaetes* are found primarily downstream from shoreline structures, where they are afforded more protection from overall impacts of substrate instability [Carter et al.].

Mayflies (*Ephemeroptera*), stoneflies (*Plecoptera*), and caddisflies (*Tichoptera*) are scavengers/ herbivores, shredders, and grazers, respectively. They are found in aquatic systems during the larval life stages, where they are integral to aquatic food webs. All are typically intolerant of pollution and therefore indicators of river ecosystem health [Poulton et al.]. These taxa are more prevalent along the shoreline in the vicinity of riprap and dike structures [Carter et al.]. Mayfly/ stonefly density near the plant was 14,850/m^2 and 18,360/m^2 and richness was 11.6 and 11.4 thousand/m^2 for Langdon and Nodaway, respectively [Poulton et al.]. These values are the third and fourth highest among the 18 study sampling locations.

Non-biting midges (*Chironomidae*) are members of family Diptera. They are detritus feeders and therefore play an important role in nutrient recycling in aquatic systems. Similar to other insect groups mentioned above, *Chironomidae* are found in the river during their larval stages in proximity to riprapped and diked areas [Poulton et al.; Carter et al.]. *Chironomidae* densities were reported at 629/m^2 and 258/m^2 at Langdon and Nodaway, respectively [Poulton et al.].

A single taxa of mollusca (Spaerium-pill clams) was present at both Langdon and Nodaway sampling sites [Poulton et al.]. However, Hoke studied the unionid mollusks of the nearby (down-river from CNS) Big and Little Nemaha Rivers and verified the presence of 27 taxa of mollusks within these two rivers. However, most of the presence determination was via shells and only one taxa (*Ligumia subrostrata*) was collected alive in the Big Nemaha River. [Hoke] Mollusks are highly sedentary filter feeders and are therefore very susceptible to channelization and siltation. It is conceivable that many mollusks could still exist within the Missouri River around CNS.

A single zebra mussel (*Dreissena polymorpha*) was reported in the Missouri River near Sioux City, Iowa, in 1999, where it was suspected to have arrived via barge traffic [USFWS 1999]. However, no reports of adult populations of the invasive zebra mussels have been made within the vicinity of CNS [USFWS 2007d]. A colony of Asian clams (*Corbicula fluminea*), another nonnative mussel, does occur at CNS. The Asian clam is a small bivalve that can alter the benthic substrate and competes with native species [USGS 2007b]. It can cause biofouling, especially of complex power plant and industrial water systems. As a result, NPPD performs a macrofouling monitoring program at the site to identify the presence of the freshwater bivalve zebra mussels and Asian clams [CNS 2005b]. This program consists of the following monitoring activities:

- diver inspection of intake bays conducted during refueling outages to identify and remove any accumulations of macroscopic biological fouling organisms;
- ponar dredge samples taken during semiannual radiological fish collection activities (summer and fall) with samples processed by sifting the sediment through a 1/8" (Number 30) mesh sieve to collect any macroscopic biological organisms;
- heat exchanger service water inlet water box inspections; and
- artificial substrate sampling performed monthly (except during ice-up) when the circulating water inlet temperature averages more than 53.6ºF for two weeks, with monitoring typically ceasing when circulating water inlet temperature averages 53.42ºF or below for two weeks. [CNS 2005b]

This monitoring program allows NPPD to identify the presence of bivalves in the CNS area that could potentially present a fouling problem in plant systems, as well as monitor the effectiveness of the program to prevent fouling.

2.2.4 Vascular Aquatic Plants

While the vascular aquatic plants of the CNS site have not been identified, data from Attachment 6 (An Annotated Checklist of the Plants of Indian Cave State Park) of the CNS Operating License Stage ER provides a record of plants that are likely to be found at CNS. Based on this record, the dominant vascular aquatic plant species found within the CNS site boundaries would include a combination of grasses, sedges, and broad-leaved plants. Common plants found along the Missouri River at Indian Cave State Park include teal lovegrass (*Eragrostis hypnoides*), sedges (*Cyperus inflexus* and *Hemicarpha micrantha*), and marsh purselane (*Ludwigia palustris* var. *Americana*). [NPPD 1971, Appendix C, Section 6] Due to the proximity of Indian Cave State Park, these same plants are also likely to be found along the Missouri River at CNS.

2.2.5 Fish Communities

<u>*Community Impacts*</u>

Approximately 150 native fish species are known to exist in the Missouri River Basin. The USFWS (1999) developed a list of 91 fish native species that are currently found in the Lower Missouri River, which includes the CNS location (see Table 2.2-4). [USACE 2003, Section 3.3.4]

As discussed in previous sections, the Missouri River fish community has been under habitat and water quality stress for much of the past century. The loss of habitat due to mainstem dams and extensive channelization have combined to severely reduce fish species diversity and have degraded the river in general since the early 1900s. A number of factors have contributed collectively to deteriorated fisheries in the Missouri River: the loss of surface area and fish habitat due to the draining of sloughs, chutes and connected oxbow lakes; the management of the channel to remove snags, trees, and other channel obstructions; and increased current velocities, fluctuating water levels, siltation, and a scoured bottom with a shifting sand bottom. Over-fishing of sport and commercial fish populations during the 1900s, including lake sturgeon, paddlefish, flathead, and channel catfish, also contributed to the fishery decline. [NPPD 2006a, Section 4.1]

Additional impacts to fish communities along the Missouri River have included introduction of nonnative fish species beginning in the late 1800s and navigation enhancement beginning in the early 1900s. Production of benthic invertebrates (e.g., species of caddisfly and mayfly) has been reduced by approximately 70 percent in remnant unchannelized river reaches. Benthic invertebrates are an important food source for the river's native fishes and an important component of the river's food web. [NAS, Executive Summary]

Community Studies (1970-2004)

Limited fisheries studies are available to document the abundance and richness of fish in the Missouri River prior to its initial channelization, navigation enhancement, and flood control programs implemented on the river. The Missouri Conservation Commission in cooperation with the University of Missouri conducted a fisheries and limnological survey to obtain information on fish and aquatic life in the Missouri section of the river prior to further impoundment in 1945. Sixty species of fish were taken in a survey conducted from April through October of 1945 along the Missouri River from Watson, Missouri (RM 558–559), in Atchison County to the confluence with the Mississippi River. The plains minnow (*Hybognathus placita*) comprised 41.6 percent of the total catch (TC) from 11 collection stations downstream from CNS. The common carp (*Cyprinus carpio*) accounted for 16.2 percent, 16 percent of the catch were flathead chub (*Hybopsis gracilis*), 11.5 percent of the TC were silvery minnow (*Hybognathus nuchalis*), and channel catfish accounted for 7.9 percent of the TC. Eight paddlefish, nine shovelnose sturgeon, and four pallid sturgeon were captured. [Fisher]

NPPD conducted numerous historical studies of the aquatic ecology of the Missouri River in the vicinity of CNS, beginning with preoperational studies in 1970. Twenty-five species of fish were identified in sampling surveys in May, July, and October 1970 in the section of the Missouri River near CNS. Based on the 1970 surveys and additional sampling surveys completed in 1971 using different sampling methodologies, a total of 47 different species of fish were identified from collections surveys in the vicinity of CNS. Dominant fish species were reported as river carpsucker (*Carpiodes carpio*), freshwater drum (*Aplodinotus grunniens*), silvery minnow, emerald shiner (*Notropis atherinoides*), and gizzard shad (*Dorosoma cepedianum*). [USAEC, Section II.E.2.e] Pre-operational fish collections using electrofishing and various net collection techniques were completed in the vicinity of CNS and continued for several years after CNS became operational. The dominant species collected by electrofishing were gizzard shad, carp, river carpsucker, and goldeye (*Hiodon alosides*). The dominant fish species collected by bag seining were members of the genus *Hybognathus* (silvery minnow, western silvery minnow, and plains minnow). The silver chub, emerald shiner, river shiner, and red shiner (*Cyprinella lutrensis*) also were represented abundantly in the seining collections. [NPPD 2006a, Section 4.1.1]

Annual impingement sampling efforts were conducted by NPPD at CNS from 1974 to 1978 as a component of on-going NRC operational environmental studies. The dominant fish species consistently collected during the CNS impingement studies was gizzard shad. Freshwater drum and river carpsucker were the next most frequently collected species. An unidentified cyprinid minnow was the third most frequently collected taxa in 1978. Most of the fish collected were young-of-the-year (YOY), ranging from 70 to 85% of the total number impinged. Evaluation of the diurnal differences in impingement rates indicated that more fish were collected at night, and an evaluation of the seasonal differences in catch rates showed the highest rates in the summer and fall sampling periods, due primarily to the impingement of each year's YOY gizzard shad. [NPPD 2006a, Section 4.1.2]

Hesse et al. reported on pre-operational (1971–1973) and post-operational (1974–1977) benthic fish relative abundances to assess fish community composition from Sioux City, Iowa (approximately RM 732), to Rulo, Nebraska (RM 498). The pre-operational fish community was dominated by silvery minnow (27.4% TC), river carpsucker (14.7% TC), gizzard shad (13.4% TC), and emerald shiner (8.3% TC). Post-operational fish collections were dominated by common carp (14.6% TC), river carpsucker (14.5% TC), river shiner (*Notropis blennius*) (12.5% TC), gizzard shad (9.5% TC), and silvery minnow (8.0% TC). Overall, the studies collected over 90,000 fish belonging to 57 species in the vicinities of CNS and Fort Calhoun Nuclear Station (FCS), RM 846, in the seven years of the study. Of the 57 species of fish caught, 17.8 percent were game species, 33.9 percent were non-game species, and 48.3 percent were forage species. [Hesse et al. 1982, pp. 232-233]

Ichthyoplankton abundance was assessed from sample collections completed from 1974 to 1978 in the vicinity of CNS and FCS. Yolk-sac and post yolk-sac larve dominated ichthyoplankton collected in the river near FCS and CNS. Juvenile fishes were uncommon in the drift, comprising less than one percent of the total ichthyoplankton catch, and fish eggs comprised less than two percent of the TC. Hergenrader reported the eggs of most Missouri River fishes are adhesive and/or demersal which would account for their low abundance in the drift. Only goldeye and freshwater drum eggs were collected, with goldeye accounting for over 90 percent of the eggs sampled. Eggs of both species are semi-buoyant. The larger size and increased swimming ability of juveniles may have contributed to their low catch. Juveniles could have avoided the plankton nets or they may not be in the drift, as their swimming ability would allow them to seek protective habitats. In addition, mortality reduces the abundance of larval fish before they reach juvenile status, thereby decreasing the TC. The larval fish assemblage in the Missouri River was dominated by freshwater drum, catostomids, cyprinids, and carp. Differences in relative abundance between the FCS and CNS study sites were generally related to lower densities of freshwater drum near CNS. Larval fish abundance at CNS was reported to range from less than 0.5 larvae/m^3 to 7 larvae/m^3 (mid-June 1977), although the mean density at CNS was reported to range from 0.24 larvae/m^3 (mid-channel 1976) to 1.75 larvae/m^3 (cutting bank 1977). [Hergenrader et al., Table 8.4 and Figure 8.1] Larval fish in Missouri River drift were common from early May through July, but rare prior to May, and absent by mid-August. [Hergenrader et al., Chapter 8]

Recent fish studies along the Missouri River include extensive work by Hesse and others published in 1993 and 1994. Hesse and Mestl, studied numerous fish species within the Nebraska reaches of the Missouri River from 1971 to 1992. These studies reported declines in all 13 species of fish studied within the Missouri River. Five species are considered game species: channel catfish, flathead catfish (*Pylodictis olivari*), blue catfish (*I. furcatus*), sauger, and paddlefish. The other eight are considered non-game: burbot (*Lota lota*), sicklefin chub (*Macrohybopsis meeki*), sturgeon chub (*M. gelida*), silver chub (*M. storeriana*), speckled chub (*M. aestivalis*), flathead chub (*Platygobio gracilis*), plains minnow, and western silvery minnow (*H. argyritis*). All species are large river species and declines are predominantly attributed to habitat loss due to river channelization and altered flow regimes. [USNRC 2003, Section 2.2.5]

A 2004 report by Berry estimated that almost 150 fish species occur in the channelized zone of the Missouri River near CNS. They found 26 native benthic species in surveys along this stretch from 1996–1999. The five most numerous species caught were gizzard shad (31.7% TC), emerald shiners (31.6% TC), river carpsucker (9.8% TC), channel catfish (4.5% TC), and freckled madtom (*Noturus nocturnes*) (4.4% TC). [Berry et al., p. 19, Table 7]

The impacts to the Missouri River ecosystem have been reviewed as part of negotiations between the USACE and USFWS to develop measures to restore some river habitat. In 2003, the USACE issued a Final Environmental Impact Statement (FEIS) as part of its Missouri River Fish and Wildlife Mitigation project. In the channelized reaches of the river, fish are associated with revetments and dikes. Side channels yield the greatest species richness and greatest numbers of fish; however, few natural side channels remain. Sport fish include channel catfish, crappie (*Pomoxis* spp.), sauger, flathead catfish (*Pylodictus olivaris*), white bass (*Morone chrysops*), largemouth bass (*Micropterus salmoides*), bluegill (*Lepomis macrochirus*), walleye (*Stizostedion vitreum*), northern pike (*Esox lucius*), and paddlefish. Species important to the commercial fishery on the Lower Missouri River include buffalo (*Ictiobus* spp.), carp, carpsucker, freshwater drum, and catfish. However, a moratorium on the commercial harvest of catfish due to overfishing is currently in effect for the Lower Missouri River. Fish listed as occurring in the Lower Missouri River are cited in Table 2.2-4. [USACE 2003, Section 3.3.4]

Bighead and silver carp are large Asian species that escaped in the early nineties from fish culture operations and are expanding in range and numbers in the Mississippi and Missouri River drainages. Both species can reach weights that exceed fifty pounds. Asian carp are probably the most abundant large fish (greater than 5 pounds) in the lower Missouri River. Like the zebra mussel, these highly invasive carps feed by filtering zooplankton and phytoplankton from the water. The Asian carps compete for food directly with the paddlefish, a native fish, and with most fish in the early stages of life that feed on zooplankton. These carp are incapable of traveling upstream over large dams, and thus have not yet been found in the large reservoirs on the Missouri River or its tributaries. However, fishermen may transfer the species. Asian carp are expected to live very well in North American reservoirs, with potentially disastrous consequences to native fish populations. [USGS 2003]

Federal and State Listed Threatened or Endangered Species

Six federal or state listed threatened or endangered fish species potentially occur in proximity to CNS [MNHP 2007a; NGPC 2007; USFWS 2007f; USFWS 2007g]. The only federally endangered fish species in the area is the pallid sturgeon which is known to occur within the reaches of the Missouri River along the Nebraska-Missouri state border. Other species of interest in the Missouri River include the following state listed species: lake sturgeon, blue sucker, flathead chub, sturgeon chub, and sicklefin chub. [Galat et al.; Berry et al.; Hesse et al. 1982; Fisher]

The pallid sturgeon was originally listed as endangered throughout its entire range by the USFWS in 1990 due to a rapidly declining population [USFWS 1990]. This species continues to decline and is nearly extirpated from large segments of its former range and is only occasionally observed [USFWS 2000, p. 99]. The species' current distribution extends from the Missouri River in Montana to the lower Yellowstone River and the Mississippi River downstream from its junction with the Missouri River [USFWS 2007e]. Currently, the Missouri River turbidity levels are 78 percent lower and flow rates are 2–3 times greater than historic rates [Jorgensen]. These changes potentially have had a detrimental impact to pallid sturgeon levels within the Missouri River. Pallid sturgeon require large, turbid, free-flowing river habitat with strong current over firm gravel or sandy substrate. It is generally believed that the Missouri River near CNS does not provide suitable habitat for the pallid sturgeon due to human activities, which have modified or eliminated most of the habitat and ecosystem conditions in the Missouri River to which the pallid sturgeon is adapted. [USFWS 2000] The pre-operational and post-operational studies conducted from 1970 to 1979 supported this belief as no pallid sturgeon were collected near CNS. [Hazleton 1979; Nalco]

Sample collection results of sampling completed between 1196 to 1998 reported a catch of only nine blue suckers, seven sturgeon chubs, one flathead chub, and one sicklefin chub from over 7,000 fish sampled near CNS [Berry et al.]. A 1994 status survey for the sicklefin, sturgeon, and flathead chubs in the Missouri River found only one sicklefin chub and one sturgeon chub at a site above CNS (Brownville, Nebraska) and one sicklefin chub and seven sturgeon chubs below CNS (Rulo, Nebraska). No flathead chubs were sampled at either location. According to this MDC Fish and Wildlife study, the results of this 1994 survey do not suggest a decline in the distribution and abundance of sicklefin chubs and sturgeon chubs in the Missouri River. However, they do suggest a further decline in the distribution and abundance of flathead chubs, plains minnows, and western silvery minnows. The causes of the decline were not discussed by the MDC study. [Gelwicks et al.] Due to the low overall numbers of sicklefin, sturgeon, and flathead chubs in the Missouri River adjacent to the Nebraska state line, these three chubs are considered functionally extirpated from the region. Suggested reasons for the decline are the alteration of sediment dynamics due to dam construction, the elimination of bankful discharge, and the elimination of habitats such as sandbars and off-channel areas. [Hesse 1994, p. 99 and 103]

Heat or Cold Shock Events

Based on review of condition reports from 2003-2007 and routine observations conducted by site personnel, there have been no instances of "fish kill" events due to heat or cold shock as a result of the heated effluent from CNS.

Summary

Overall reduction in native benthic fish fauna has been attributed to numerous sources [Galat et al. 2005; USFWS 2001; Hesse 1994]. Anthropogenic disturbances have dramatically altered the river ecosystem throughout a majority of the Missouri River drainage. Thirty-six percent of the river mainstem has been dammed, over 40 percent has been channelized, and 24 percent experiences altered flow regimes [USFWS 2001, p. 42]. Historic flows in the Missouri River were reported to be 0.3–0.8 m/s versus current velocities between 0.8–1.3 m/s below Gavins Point Dam [Berry et al., p. 6]. Concomitant with these changes is the introduction of exotic and non-indigenous species which functionally out-compete or prey upon native species. All of these factors are compounding, which results in a reduction in the native benthic community.

Table 2.2-2
Missouri River Power Plants Below Gavins Point Dam as of 2004

Company	Plant Name	Approximate Net Capacity (MWe)
Nebraska		
Nebraska Public Power District	Cooper Nuclear Station	758*
Omaha Public Power District	Fort Calhoun Nuclear Station	476
Omaha Public Power District	Nebraska City	646
Omaha Public Power District	North Omaha	662
Iowa		
MidAmerican Energy Co.	Council Bluffs	806
MidAmerican Energy Co	George Neal North	950
MidAmerican Energy Co	Neal South	644
Missouri		
Central Electric Power Coop	Chamois	66
Ameren UE	Labadie	2,421
Ameren UE	Callaway	1,143
Kansas City Power & Light Co	Hawthorn	865
Kansas City Power & Light Co	Iatan	670
UtiliCorp United Inc	Lake Road	97
UtiliCorp United Inc	Sibley	523
City of Independence	Missouri City	38
Kansas		
Kansas City Board of Public Utilities	Nearman Creek	225
Kansas City Board of Public Utilities	Kaw	55
Kansas City Board of Public Utilities	Quindaro	208

* All ratings are as of 2002. Current rating at CNS is approximately 830 gross MWe at 0.85 pf.
Reference: FAPRI, Table 1

Table 2.2-3a
Macroinvertebrates—Aquatic Insects

Taxa	Trophic group	Habitat
Ephemeroptera		
Family Ephemeridae		
Hexagenia	Collector-gatherer	Backup, chute, soft
Ephemera	Collector-gatherer-predator	Backup, marsh
Pentagenia	Collector-gatherer	Chute, channel, hard
Family Polymitarcyidae		
Ephoron	Collector-gatherer	Chute, channel, clay
Tortopus	*	Channel border, clay
Family Oligoneuriidae		
Homoeoneuria	Collector-filterer	Channel, sandbar
Family Tricorythidae		
Tricorythodes	Collector-gatherer	Channel, chute, sand
Family Caenidae		
Caenis	Collector-gatherer-scraper	Chute, channel border
Brachycercus	Collector-gatherer	Channel, chute, sand
Family Heptageniidae		
Heptagenia	Scraper-collector-gatherer	Channel border, chute
Pseudiron	Predator-engulfer	Channel sandbars
Stenonema	Scraper-collector-gatherer	Chute, backup, pools
Stenocron	Scraper-collector-gatherer	Channel border, chute
Anepeorus	Predator	Channel, chute, borders
Family Leptophlebiidae		
Leptophlebia	Collector-gatherer	Backup, marsh, pool
Paraleptophlebia	Shredder-detritivore	Channel, chute, backup
Family Siphlonuridae		
Isonychia	Collector	Channel, channel border

Table 2.2-3a (Continued)
Macroinvertebrates—Aquatic Insects

Taxa	Trophic group	Habitat
Family Baetidae		
Baetis	Collector-gatherer-scraper	Channel, chute, sandbar
Pseudocleon	Scraper	Channel, chute, sandbar
Centroptilum	Collector-gatherer-scraper	Pool, backup, sandbar
Family Baetidae		
Heterocloeon	Scraper	Channel, channel border
Callibaetis	Collector-gatherer	Backup, marsh, puddle
Dactylobaetis	Scraper	Backup, marsh, sand
Family Baetiscidae		
Baetisca	Collector-gatherer-scraper	Chute, border, sandbar
Family Emhemerellidae		
Ephemerella	Collector-gatherer-scraper	Chute, backup, marsh
Trichoptera		
Family Hydropsychidae		
Hydropsyche	Collector-filterer	Chute, channel borders
Potamyia	Collector-filterer	Chute, channel borders
Cheumatopsyche	Collector-filterer	Chute, channel borders
Family Polycentropodidae		
Neuroclipsis	Shredder-herbivore	Chute, backup, marsh
Nyctiophylax	Predator-collector-filterer	Off channel habitat
Cyrnellus	Collector-filterer	Off channel habitat
Family Hydroptilidae		
Mayatrichia	Scraper	*
Hydroptila	Piercer-herbivore	Backwater borders
Agraylea	Piercer-herbivore	Backwater borders

Table 2.2-3a (Continued)
Macroinvertebrates—Aquatic Insects

Taxa	Trophic group	Habitat
Family Leptoceridae		
Ceraclea	Collector-gatherer	All aquatic habitat
Nectopsyche	Shredder-herbivore	Chute, backup, borders
Triaenodes	Shredder-herbivore	Backup, marsh, puddle
Family Limnephilidae		
Pycnopsyche	Shredder-detritivore	Chute, backup, puddle
Family Philiopotamidae		
Wormaldia	Collector-filterer	Channel, chute
Family Brachycentridae		
Brachycentrus	Collector-filterer	Channel, chute
Diptera		
Family Chironomidae	Collector-gatherer-filter	All aquatic habitats
Family Tipulidae	Shredder-detritivore	All aquatic habitats
Family Tephritidae	*	*
Family Tabanidae	Predator	Backup, marsh, puddle
Family Chaobordiae	Predator-engulfer	Backup, marsh, puddle
Family Culicidae	Collector-filterer-gatherer	Backup, marsh, puddle
Family Simuliidae	Collector-filterer	Chute, channel
Family Mycetophilidae	*	*
Family Ceratopogonidae	Predator-gatherer	Backup, marsh, puddle
Family Muscidae	Predator	All aquatic habitats
Family Tachinidae	*	*
Family Stratiomiyidae	Collector-gatherer	Backup, marsh, puddle
Family Agromyzidae	*	*
Family Cecidomyidae	*	*
Family Empididae	Predator	Off channel habitat

Table 2.2-3a (Continued)
Macroinvertebrates—Aquatic Insects

Taxa	Trophic group	Habitat
Family Sciaridae	*	*
Family Dolichopodidae	*	*
Family Psychodidae	Collector-gatherer	Backup, marsh, puddle
Family Ephydridae	Collector-gatherer	Backup, marsh, puddle
Family Phoridae	Predator	*
Plecoptera		
Family Perlidae		
Acroneuria	Predator	Channel, chute, borders
Family Perlodidae		
Isoperla	Predator	Channel, chute, borders
Perlinella	*	*
Perlesta	*	*
Family Taeniopterygidae	Shredder-detritivore	Channel, chute, borders
Odonata		
Family Coenagrionidae		
Argia	Predator	Off channel habitat
Ischnura	Predator	Chute, backup, marsh
Coenagrion	Predator	Off channel habitat
Agrion	Predator	Off channel habitat
Enallagma	Predator	Backup, marsh, puddle
Family Gomphidae		
Gomphus	Predator	Backup, marsh, puddle
Family Libellulidae	Predator	Oxbow, puddle
Family Lestidae		
Lestes	Predator	Backup, marsh, puddle
Family Aeshinidae	Predator	Backup, marsh, puddle

Table 2.2-3a (Continued)
Macroinvertebrates—Aquatic Insects

Taxa	Trophic group	Habitat
Family Calopterygidae		
Agrion	Predator	Chute
Coleoptera		
Family Halipidae	Shredder-herbivore	Backup, marsh, puddle
Family Dytiscidae	Predator	Backup, marsh, puddle
Family Gyrinidae	Predator	Off channel habitat
Family Dryopidae	Scraper-collector-gatherer	Chute, channel, sandbar
Family Curculionidae	Shredder-herbivore	Backup, marsh, puddle
Family Helodidae	Shredder-herbivore	Oxbow, puddle, marsh
Family Hydrophilidae	Predator	All aquatic habitats
Family Staphylinidae	Predator	Sandbar, dune
Family Elmidae	Collector-gatherer-scraper	Chute, channel, sandbar
Family Heteroceridae	Predator	Sandbar, dune
Family Carabidae	Predator	*
Family Chrysomelidae	Shredder-herbivore	Backup, marsh, puddle
Family Coccinellidae	*	*
Hemiptera		
Family Corixidae	Piercer	All aquatic habitats
Family Lygaeidae	*	*
Family Nabidae	*	*
Family Aradidae	*	*
Family Tingitidae	*	*
Family Mesoveliidae	Predator	Backup, marsh, oxbow
Family Cicadellidae	*	*
Family Coreidae	*	*
Family Naucoridae	Predator	Backup, marsh, oxbow

Table 2.2-3a (Continued)
Macroinvertebrates—Aquatic Insects

Taxa	Trophic group	Habitat
Family Pleidae	Predator	Oxbow, puddle, marsh
Family Notonectidae	Predator	Backup, marsh, oxbow
Family Saldidae	Predator	Backup, marsh, oxbow
Family Gerridae	Predator	All aquatic habitats
Family Hebridae	Predator	Backup, marsh, oxbow
Lepidoptera		
Family Pyralidae	Scraper-shredder-herbivore	Off channel habitat
Homoptera		
Family Aphididae	Herbivore	Terrestrial-incidental
Family Cicadellidae	Herbivore	Terrestrial-incidental
Family Ceropidae	Herbivore	Terrestrial-incidental
Family Delphacidae	Herbivore	Terrestrial-incidental
Family Aleyrodidae	Herbivore	Terrestrial-incidental
Hymenoptera		
Family Formicidae	Parasitic	Terrestrial-incidental
Family Eurytomidae	Parasitic	Terrestrial-incidental
Family Pteromalidae	Parasitic	Terrestrial-incidental
Family Braconidae	Parasitic	Terrestrial-incidental

* Information not provided from source document.
Reference: NAS, Appendix A, Table 1

Table 2.2-3b
Macroinvertebrates—Unionid Mollusks

Platte River	Missouri River
Anodonta imbecillis	*Anodonta g. grandis*
Anodonta g. grandis	*Anodonta g. corpulenta*
Anodontoides ferussacianus	*Anodonta suborbiculata*
Strophitus u. undulatus	*Lasmigona complanata*
Lasmigona complanata	*Tritogonia verrucosa*
Quadrula quadrula	*Quadrula quadrula*
Quadrula p. pustulosa	*Truncilla truncata*
Fusconaia flava	*Leptodea fragilis*
Uniomerus tetralasmus	*Leptodea leptodon*
Leptodea fragilis	*Potamilus ohiensis*
Potamilus alatus	*Lampsilis teres f. teres*
Potamilus ohiensis	
Toxolasma parvus	
Ligumia subrostrata	
Lampsilis teres f. teres	
Lampsilis radiata luteola	
Lampsilis ventricosa	
Corbicula fluminea	
Elliptio dilatata	

Reference: NAS, Appendix A, Table 2
Note: The NAS list does not include the invasive Asian clam (*corbicula fluminea*) or zebra mussel (*Dreissena polymorpha*).

Table 2.2-4
Fish Species in the Lower Missouri River

Chestnut lamprey (*Icthyomyzon castaneus)*	Western silvery minnow (*Hybognathus argyritis)*
Lake sturgeon (*Acipenser fulvescens)*	Plains minnow (*Hybognathus placitus)*
Shovelnose sturgeon (*Scaphirhyncus platorynchus)*	Brassy minnow (*Hybognathus hankinsoni)*
Pallid sturgeon (*Scaphirhyncus alba)*	Bluntnose minnow (*Pimephales notatus)*
Paddlefish (*Polyodon spathula)*	Fathead minnow (*Pimephales promelas)*
Shortnose gar (*Lepisosteus platostomus)*	Central stoneroller (*Campostoma anomalum)*
Longnose gar (*Lepisosteus osseus)*	Blue sucker (*Cycleptus elongates)*
Bowfin (*Amia calva)*	Bigmouth buffalo (*Ictiobus cyprinellus)*
American eel (*Anguilla rostrata)*	Black buffalo (*Ictiobus niger)*
Rainbow smelt (*Osmerus mordax)*	Smallmouth buffalo (*Ictiobus bubalus)*
Skipjack herring (*Alosa chrysochloris)*	River carpsucker (*Carpiodes carpio)*
Alabama shad (*Alosa alabamae)*	Quillback (*Carpiodes cyprinus)*
Gizzard shad (*Dorosoma cepedianum)*	White sucker (*Catostomus commersoni)*
Goldeye (*Hiodon alosoides)*	Golden redhorse (*Moxostoma erythrurum)*
Mooneye (*Hiodon tergisus)*	Shorthead redhorse (*Moxostoma macrolepidotum)*
Northern pike (*Esox lucius)*	Black bullhead (*Ameiurus melas)*
Carp (*Cyprinus carpio)*	Yellow bullhead (*Ameiurus natalis)*
Goldfish (*Carassius auratus)*	Channel catfish (*Ictalurus punctatus)*
Grass carp (*Ctenopharyngodon idella)*	Blue catfish (*Ictalurus furcatus)*
Bighead carp (*Hypophthalmicthys nobilis)*	Freckled madtom (*Noturus flavus)*
Silver carp (*Hypophthalmicthys molitrix)*	Flathead catfish (*Pylodictus olivaris)*
Golden shiner (*Notemigonus crysoleucas)*	Stonecat (*Noturus flavus)*
Creek chub (*Semotilus atromaculatus)*	Burbot (*Lota lota)*
Silver chub (*Hybopsis storeriana)*	Plains killifish (*Fundulus kansae)*
Gravel chub (*Hybopsis x-punctata)*	Mosquitofish (*Gambusia affinis)*

Table 2.2-4 (Continued)
Fish Species in the Lower Missouri River

Speckled chub (*Hybopsis aestivalis)*	Brook silverside (*Labidesthes sicculus)*
Flathead chub (*Hybopsis gracilis)*	White bass (*Morone chrysops)*
Sicklefin chub (*Macrhybopsis meeki)*	Striped bass (*Morone saxatilis)*
Sturgeon chub (*Macrhybopsis gelida)*	Hybrid striped bass (*Morone chrysops x saxatilis)*
Suckermouth minnow (*Phenacobius mirabilis)*	Largemouth bass (*Micropterus salmoides)*
Emerald shiner (*Notropis atherinoides)*	Spotted bass (*Micropterus punctulatus)*
Silverband shiner (*Notropis shumardi)*	Green sunfish (*Lepomis cyanellus)*
Redfin shiner (*Notropis umbratilis)*	Orangespotted sunfish (*Lepomis humilis)*
Common shiner (*Notropis cornutus)*	Longear sunfish (*Lepomis megalotis)*
Striped shiner (*Notropis chrysocephalus)*	Bluegill (*Lepomis macrochirus)*
River shiner (*Notropis blennius)*	Rock bass (*Ambloplites rupestris)*
Bigmouth shiner (*Notropis dorsalis)*	White crappie (*Pomoxis annularis)*
Bigeye shiner (*Notropis boops)*	Black crappie (*Pomoxis nigromaculatus)*
Spotfin shiner (*Notropis spilopterus)*	Walleye (*Stizostedion vitreum)*
Red shiner (*Notropis lutrensis)*	Sauger (*Stizostedion canadense)*
Sand shiner (*Notropis stramineus)*	Slenderhead darter (*Percina phoxocephala)*
Mimic shiner (*Notropis v.volucellus)*	Logperch (*Percina caprodes)*
Ghost shiner (*Notropis buchanani)*	Johnny darter (*Etheostoma nigrum)*
Rosyface shiner (*Notropis rubellus)*	Orangethroat darter (*Etheostoma spectabile)*
Channel shiner (*Notropis v. wickliffi)*	Freshwater drum (*Aplodinotus grunniens)*
Central silvery minnow (*Hybognathus nuchalis)*	

Reference: USACE 2003, Table 3.3-2

2.3 Groundwater Resources

The site is located on an alluvial plain bordering the west bank of the Missouri River at RM 532.5 (1960 river miles). This portion of the Missouri River is referred to as the Lower Brownville Bend. It is situated on the first bottomland of the broad, nearly level, flood plain which is approximately six miles wide at the site. The natural relief is about ten feet. The USACE has stabilized the channel by use of pile dikes and bank protection. This control prevents meandering of the river within the alluvial flood plain. [NPPD 2008b, Sections II-4.1 and II-5.1.1] The eastern bank of the Missouri River is chiefly a densely forested land typical of the unarable bluffs that run parallel to the Missouri River. To the west there are bluffs that peak at 1,100 feet, but average 1,000 feet along the stretch of river from Brownville to Nemaha [NPPD 1971, Section III-3.2]. Beyond the bluffs the land is gently rolling farmlands.

The station site grade level of 903 feet AMSL has been raised 13 feet above the natural grade level of 890 feet AMSL, in order to bring final grade one foot above the existing 902 feet AMSL levee constructed by the USACE. The immediate station site area, excluding the switchyard, which is west of the levee, was filled to elevation 903 feet AMSL, one foot higher than the top of the levee. This fill extends around the station buildings. [NPPD 2008b, Sections II-2.1 and II-4.2.2.2] The site slopes generally east, with surface drainage toward the Missouri River.

2.3.1 Geology

The OL ER described the regional and local geology in detail. In southeastern Nebraska, northeastern Kansas, northwestern Missouri, and southwestern Iowa, the early Paleozoic era was characterized by long marine invasions, evidenced by thick beds of limestone, dolomite, sandstone, and shale. In later Paleozoic time during the Permian, Pennsylvanian, and Mississippian periods, short, frequent, alternating cycles of marine and continental deposition occurred. Thin beds of coal, numerous layers of limestone and shale, and some layers of impure sandstone resulted from these changes in depositional environment. [NPPD 1971, Section III-3.7.1]

In the structural development of the midcontinent, a major change occurred in the late Mississippian or early Pennsylvanian when the Nemaha Anticline (arch of stratified rock), broadly folded in earlier geologic time, was upfaulted. By the end of the Paleozoic, probably all structural development had ceased in the four state area bordering the Missouri River valley. This is evidenced by the relatively undisturbed beds of the Dakota formation of the Cretaceous period, indicating little tectonic or deforming activity since the end of the Permian. [NPPD 1971, Section III-3.7.1]

The granite basement rock controls the major geologic structures of the area, which are the Nemaha Anticline, the Redfield Anticline, and the Forest City Basin. Associated with the anticlines are two faults, the Humboldt Fault and the Thurman-Wilson Fault. The Nemaha Anticline developed mountainous relief late in the Paleozoic era and was subsequently buried. The Nemaha Anticline trends southward from Omaha, through Nebraska, across Kansas, and into northern Oklahoma. The Humboldt Fault, about twenty miles from the site at its closest point, has apparently ceased in major techtonic activity since Permian time; however, it is believed that deep seated adjustments are still continuing and are the cause of earthquakes along the Nemaha Anticline. The Forest City Basin, east of the Humboldt Fault, underlies the site and consists of approximately 3,500 feet of sedimentary rocks. Geologic survey and subsurface exploration did not give any evidence of faulting at the site. [NPPD 1971, Section III-3.7.2]

During the Pleistocene period, four different ice sheets covered the central interior of North America, including the valleys of the Missouri River. The first two ice sheets, the Nebraskan and Kansan, extended south into northern Kansas, leveling the terrain and depositing till and glacio-fluvial materials. These were followed by the third and fourth, the Illinoian and Wisconsin ice sheets. The four ice sheets, accompanied by inter-glacial stages, created the geologic make-up of the Missouri River valleys. The valleys were first filled during the advance of the Nebraskan, partially reopened during the Aftonian interglacial stage, filled again by the Kansan, partially reopened during the Yarmouth inter-glacial stage, and again partially refilled with alluvium during the Illinoian. Near the end of the Wisconsin glaciation, the melt waters removed much of the material in the valleys. Before all the material was removed, arid conditions prevailed and the Permian loess was deposited on the uplands adjacent to the valleys. [NPPD 1971, Section III-3.7.1]

The principal geologic strata in the region in order of increasing depth are soil deposits, sedimentary rocks, and deep basement igneous rocks. The soil deposits consist of loess and till in the uplands, and either stratified or heterogeneous alluvium in the flood plains. Thickness of deposits varies from a few feet to about 100 feet for loess, none to several feet for till, and less than 10 feet to more than 100 feet for alluvium. The rock strata are gently dipping sedimentary rocks mainly Paleozoic in age. Alternating beds of shale, limestone, sandstone, and occasional thin beds of coal are present. The total thickness near the site is over 3,500 feet. The deep basement igneous rocks are Precambrian in origin, chiefly primary granite or granitoid rocks. [NPPD 2008b, Section II-5.1.3]

The site stratigraphy is best represented by a section through the bluffs along the western boundary of the site. It shows Peorian loess, Kansas till, limestone and shale of the Permian system, and limestone, shale, sandstone, and occasional thin beds of coal of the Pennsylvanian system. The contact between the two systems is unconformable and occurs in the bluff at approximately elevation 930 feet AMSL. [NPPD 2008b, Section II-5-39] A generalized columnar section is shown in Figure 2.3-1.

Locally, four principal types of soils are found, each of different geologic origin: loess and till in the bluffs and alluvial and glacial deposits in the flood plains. The loess are wind blown silts and have created the bluffs to the west of CNS. The topography of the loess reflects the surface configuration of the underlying till or rock. Its ability to maintain steep faces is responsible for the near vertical slopes in the upper portion of the bluffs. [NPPD 2008b, Section II-5.1.4]

The Kansan till underlies the loess. It is a heterogeneous mixture of clay, silt, sand, gravel, cobble, and boulder, and is five to ten feet thick. In an unleached and unoxidized condition, it is commonly dark gray silty clay which contains erratics and locally derived cobbles and boulders.

Sand lenses are distributed throughout the deposit. Complete removal of calcareous minerals in the upper limits of the till produces the highly tenacious gumbotil. The alluvial deposits in the flood plain at the site vary in thickness from 62 to 71 feet. Two major subtypes of different geologic origin are present: the surficial fine grained soils and the underlying sands. [NPPD 2008b, Section II-5.1.4]

The surficial fine grained soils are recent alluvial deposits derived from the meandering Missouri River and consist of meander belt and back swamp deposits, ranging in thickness from 10 to 25 feet. For the most part, these deposits are silty sand, silty clay, and clay, and may be encountered in localized pockets or in complex combinations. The underlying sands appear to be either fluvial or glacial outwash deposits, or both. The amount of silt and clay size particles is generally small. The particles grade from fine to coarse with increasing depth. Lenses of clay, coarse sand, and fine gravel are distributed irregularly throughout the deposit. [NPPD 1971, Section III-3.7.3]

2.3.2 Regional Groundwater

The Western Interior Plains Aquifer System lies deep beneath the CNS site, but is not used as a source of groundwater. The Western Interior Plains aquifer system, which is illustrated in the United States Geological Survey (USGS) Ground Water Atlas of the United States, underlies most of Kansas, the eastern and southern parts of Nebraska, and a small area in west-central Missouri [USGS 1997, Fig. 118]. The aquifer system consists of water-yielding dolomite, limestone, and sandstone that are stratigraphically equivalent to aquifers of the Ozark Plateaus aquifer system. However, in contrast to the Ozark Plateaus system, the Western Interior Plains aquifer system contains no freshwater. The Western Interior Plains aquifer system consists of lower aquifer units in rocks of Ordovician and Cambrian age, a shale confining unit of Mississippian and Devonian age, and an upper aquifer unit of Mississippian limestone. The thickness of the aquifer system (including the confining unit) ranges from less than 500 feet to more than 3,000 feet. Dissolved-solids concentrations of water in the Western Interior Plains aquifer system are greater than 1,000 mg/l everywhere. In thick, deeply-buried parts of the aquifer system, dissolved-solids concentrations of more than 200,000 mg/l have been reported. Little water is withdrawn from the Western Interior Plains aquifer system because the aquifer system is deeply-buried and contains highly mineralized water. [USGS 1997]

The CNS site overlies a surficial freshwater aquifer system consisting of alluvial deposits of the Missouri River stream valley aquifer and glacial deposits of the Glacial Drift Aquifer. The groundwater aquifers surrounding the site are illustrated by Figure 2.3-2. These aquifers are hydraulically connected in some places. For example, many of the glacial-drift aquifers in northern Missouri, northeastern Kansas, and eastern Nebraska occupy ancient stream channels that have been eroded into bedrock. At locations where modern streams follow the ancient drainage patterns, the alluvial deposits of sand and gravel that compose a stream-valley aquifer may lie directly on glacial outwash that also consists of sand and gravel. Much of the sand and gravel of the stream-valley aquifers in Missouri and eastern Kansas and Nebraska has been reworked from older glacial-drift deposits and, therefore, may be difficult to distinguish from glacial outwash. Most of the water in the surficial aquifer system is under unconfined conditions. [USGS 1997]

Glacial Drift Aquifer

CNS lies within the Missouri River Stream Valley aquifer, described below. According to several sources, including the USGS, the Glacial Drift Aquifer is indistinguishable from the stream-valley aquifers in some locations. A more detailed description is available in the USGS Groundwater Atlas of the United States.

The maximum southern extent of glacial ice and glacial-drift deposits was about the present location of the Missouri River in Missouri and just south of the Kansas River in northeastern Kansas (Figure 2.3-2). The glacial deposits are pre-Illinoian and thus are older than deposits in states to the north and east. Some of the drift might be of late Pliocene age, whereas most glacial deposits in North America are considered to be Pleistocene. [USGS 1997]

Although deposits of glacial drift extend over wide areas, most were laid down directly by the ice; are fine grained, poorly sorted, or both; and, therefore, yield only small amounts of water to wells. The thickness of glacial drift generally is 100 to 200 feet, but locally is greater than 400 feet in western Missouri and northeastern Kansas. In southeastern Nebraska, local drift thicknesses of more than 350 feet have been reported. Melt-water created an extensive stream network in front of the advancing ice, and the streams deposited gravel, sand, and finer sediments as alluvium along the courses of pre-glacial bedrock valleys. [USGS 1997]

Complex inter-bedding of fine- and coarse-grained material is characteristic of the glacial deposits. The lens-like shape of some of the beds is the result of meandering of the melt-water streams across their valley floors and of periodic changes in stream-channel locations. Yields of wells completed in the glacial-drift aquifers are highly variable and range from less than 10 to about 1,000 gpm. Large diameter wells that penetrate several thick, saturated, highly permeable sand beds yield the most water. Even in places where wells penetrate only one thin sand bed in the glacial-drift deposits, yields are generally larger than those of wells completed in the underlying bedrock. Transmissivity values that range from 200 to 13,000 feet squared per day have been reported from aquifer tests in glacial-drift aquifers in Kansas. The larger transmissivity values represent places where several thick sand beds were encountered by wells; the smaller values indicate that thin sand beds with low permeability were penetrated. [USGS 1997]

Movement of water in the glacial-drift aquifers is from recharge areas to discharge areas along major modern streams. Much of the water moves along short flow paths to the nearest surface-water body, where it discharges. A small amount of the water percolates downward and enters underlying bedrock aquifers. [USGS 1997]

Missouri River Stream Valley

Alluvial deposits along the Missouri River form an important stream-valley aquifer from the Iowa-Missouri State line to the junction of the Missouri and the Mississippi Rivers; small areas of similar deposits in eastern Nebraska compose local aquifers. The deposits partly fill an entrenched bedrock valley that ranges from about 2 to 10 miles wide. In many places in northern Missouri, the bedrock contains slightly saline to saline water, and the stream-valley aquifers, along with aquifers in glacial drift, are the only sources of fresh ground water. [USGS 1997]

The part of the stream-valley aquifer along the Missouri River between St. Charles and Jefferson City, Missouri, described in USGS literature, appears to be generally representative of the segment near CNS as well.

The stream-valley aquifer consists of clay, silt, sand, and gravel. Gravel and sand generally are most common in the lower parts of the aquifer. Poorly permeable silt and clay are prominent in the upper part of the aquifer and locally create confined conditions. Sandstone, limestone, dolomite, and shale of Pennsylvanian and Mississippian age mostly compose the bedrock that underlies the stream-valley aquifer in western Missouri. [USGS 1997]

The alluvial material of the stream-valley aquifer between St. Charles and Jefferson City, Missouri, averages about 90 feet in thickness, but is locally as much as 160 feet thick. The saturated thickness of the aquifer averages about 80 feet. Reported yields of wells completed in the aquifer range from less than 100 to about 3,000 gpm. [USGS 1997]

As noted above, the alluvial deposits in the floodplain at the site vary in thickness from 62 to 71 feet [NPPD 2008b, Section II-5.1.4]. The saturated thickness of these deposits appears to be approximately 50 feet, based on review of registered well records at the site. [NDNR 2008]

Recharge to the stream-valley aquifer is by infiltration of precipitation, seepage of water from the Missouri River to the aquifer during periods of high streamflow, and inflow from bedrock aquifers. Discharge from the aquifer is by evapotranspiration, withdrawals by wells, and seepage to the Missouri River during periods of low streamflow. The general direction of water movement in the stream-valley aquifer is downstream and toward the river. [USGS 1997]

2.3.3 Local Groundwater

Groundwater at the site occurring near the river is primarily taken from the sand and gravels in the alluvium over the bedrock. Although the unconsolidated sediments are mostly sand, some silt and clay seams, probably discontinuous, are found in the upper 15 feet of the deposit and in discontinuous lenses at a depth of about 40 feet. Over 90 percent of the deposit is loose to medium dense, fine to coarse, sand. From the hydrologic point of view, the sand deposits constitute an open hydraulic system with the Missouri River. This means that, with respect to the river, ground water will seasonally discharge to the river or be recharged by the river depending on river stage. [NPPD 2008b, Section II-4.4.1]

As noted above the alluvial deposits in the flood plain at the site are of two major subtypes: the surficial fine grained soils and the underlying sands. The surficial fine grained soils are recent alluvial deposits derived from the meandering Missouri River. The surficial soils consist of meander belt and back swamp deposits, ranging in thickness from 10 to 25 feet. For the most part, these deposits are silty sand, sandy silt, silty clay, and clay, and may be encountered in localized pockets or in complex combinations. The underlying sands appear to be either fluvial or glacial outwash deposits or both. The amount of silt and clay size particles is generally small. They grade from fine to coarse with increasing depth. Lenses of clay, coarse sand, and fine gravel are distributed irregularly throughout the deposit. [NPPD 2008b, Section II-5.1.4]

The average rainfall in the area is about 30 inches per year. Essentially all of the precipitation falling on the flood plain is infiltrated into the subsurface, where it is consumed in support of crops. The excess over transpiration and pellicular requirements filters down to the water table (879 feet AMSL) about 10 feet below the original surface at the plant site. A higher percentage of water falling on the uplands west of the bluff line goes into run off. Most of this is discharged into drainage ditches located between the site and the bluff line. [NPPD 2008b, Section II-4.4.1]

In the general area of the site, ground water flow has a component parallel to and a component perpendicular to the Missouri River. A study of groundwater elevations showed that the groundwater level is governed by the elevation of the river since the unconsolidated surficial sediments in the site area constitute an open hydraulic system with the river. The flow is generally toward the river from the northwest on the Nebraska side and toward the river from the northeast on the Missouri side. The maximum rate of flow is approximately 3.5 feet per day. During the early site field investigations, groundwater levels varied between approximately 878 and 890 feet AMSL. [USAEC, p. II-24]

2.3.4 Groundwater Use

CNS lies within the Nemaha River Basin in Nebraska, which is under the management of the Nemaha Natural Resources District (NNRD) (see Figure 2.3-3). The Nemaha River Basin (Basin) in Nebraska is defined as the areas of Nebraska south of the Platte River Basin that drain directly into the Missouri River and includes the Missouri River below its confluence with the Platte River. Major streams in the Basin include Weeping Water Creek, the Little Nemaha River, the Big Nemaha River, and the Missouri River. The total area of the Basin is approximately 2,800 square miles and includes all of Johnson, Nemaha, Otoe, and Richardson Counties and portions of Cass, Gage, Lancaster, and Pawnee Counties. [NDNR 2006, p. N-1]

Groundwater in the Basin is used for a variety of purposes: domestic, industrial, livestock, irrigation, and others. There are 1,400 registered groundwater wells within the Basin as of October 1, 2005, according to the Nebraska Department of Natural Resources (NDNR) registered groundwater wells database. Not all wells are registered in the NDNR database, especially stock and domestic wells, which are not required to be registered if drilled prior to 1993. Certain dewatering and other temporary wells are also not required to be registered. Irrigation is the largest consumer of ground water, with approximately 46,000 acres being supplied with water from approximately 400 wells as of October 1, 2005. [NDNR 2006, p. N-3]

A search of the NDNR website identified registered water wells within the Station vicinity. The water well database includes all irrigation wells installed since 1953 and all water wells since 1993. The database search revealed 351 water wells within Nemaha County [NDNR 2008]. Ten of the 351 recorded water wells are owned by NPPD or Consumers Public Power District (CPPD) (predecessor of NPPD). Two of the ten wells registered to NPPD are shown as having been decommissioned and were replaced by two new wells with the same registration numbers (G-100339 and G-100340). Three water wells have recently been installed by the Nebraska Game and Parks Commission (NGPC) (Registration Numbers: G-146401A, G-146401B, and G-146401C) between approximately 1.5 and 1.8 miles to the south southwest. The City of Auburn, Nebraska, has an inactive observation well located approximately 1.9 miles south of CNS. (G-142071). [NDNR 2008]

A search performed and provided by the Missouri Department of Natural Resources did not identify any registered wells within two miles of the site in Atchison County, Missouri [MDNR 2008a, MDNR 2008b]. Since the direction of groundwater flow in Atchison County is toward the Missouri River, which lies between pumping wells at CNS and Missouri groundwater users, it would not be expected that groundwater use at CNS would have any impact on any Atchison County users [USGS 1997].

Section 2.10.1 describes the public water systems within 10 miles of CNS. These community water systems in Nemaha County include the City of Auburn, the City of Nemaha, Nemaha County Rural Water District No. 1 (RWD #1), Nemaha County RWD #2, and the City of Peru.

The closest community water system to CNS is the Nemaha Municipal Water System, whose wellhead protection area eastern boundary is located approximately 1.65 miles southeast of CNS [NDEQ 2008]. The Nemaha Municipal Water System serves the Village of Nemaha and is supplied by two wells with an average depth of 60 feet at a rated capacity of 216,000 gpd. Average capacity is 17,500 gpd, and a peak demand of 30,000 gpd. Treatment is not required. [NPPD 2008c] Nemaha's public water system serves a residential population of 188, with 82 residential connections and three commercial connections [NDHHS 2008d].

The Nemaha County Rural Water District No. 1 wellhead protection area is located immediately west of the Nemaha Municipal Water System wellhead protection area, and approximately 2.25 miles west southwest of CNS at its closest point [NDEQ 2008]. The Nemaha County Rural Water District No. 1 is supplied by two active wells. The Nemaha County RWD #1 public water system serves a residential population of 800, with approximately 200 residential connections and 50 commercial connections. [NDHHS 2008e] Nemaha RWD#1 serves rural Nemaha County including the Village of Brownville, Nebraska.

The Auburn Board of Public Works operates the Auburn Municipal Water System. All of the Auburn water supply is provided by groundwater. Eleven wells can deliver up to 1,728,000 gpd of high quality, filtered, disinfected, and fluoridated water to all Auburn residences. Tight soil formations yield extremely pure water. The water system continues to meet all state and federal regulations. [Auburn] Auburn's system has an average capacity of 700,000 gpd, with a peak demand of 1,181,700 gpd, and storage capacity of 1,650,000 gallons. Auburn's treatment plant's reported capacity is approximately 1,200 gpm. Auburn is reported to have available capacity for additional industrial development, indicating relatively stable groundwater levels in recent years. [NPPD 2008a]

The Peru Municipal Water System serves the municipality of Peru in Nemaha County. The Peru system is supplied by two wells with an average depth of 60 feet at a rated capacity of 576,000 gpd. Average capacity is 83,000 gpd, and a peak demand of 113,500 gpd. Treatment includes filtration and chlorination, with a daily capacity of 100,000 gallons. [NPPD 2008d] Peru's public water system serves a residential population of 923, with 82 residential connections and three commercial connections [NDHHS 2008f].

There are thirteen Community Wellhead Protection Areas (WHPA) in Nemaha County, Nebraska, including four within a ten-mile radius of CNS: Village of Nemaha, Nemaha County Rural Water District #1, City of Auburn, and Village of Stella. The NPPD/CNS Non-Transient Non-Community Public Water System is also included in the NDEQ database for systems with a wellhead protection area equal to 1,000 feet radius. Although NDEQ's website identifies the Village of Brownville, as having a WHPA, NDEQ's Program Coordinator has stated that Brownville is now serviced by the Nemaha County RWD #1, and Brownville's wells are no longer active or considered by NDEQ to have a WHPA. [NDEQ 2008]

There are thirty wells that have been identified within two miles of the plant site (Table 2.3-1). All but four are registered by the NDNR or the USGS. Four wells have been cited in the CNS Updated Safety Analysis Report (USAR), as follows:

(1) Farm well approximately 0.7 miles south-southwest from the reactor building, for domestic use, 1¼" casing size, pump less than 10 gpm, and static water level approximately 15 feet. Driven sand point installation will not permit drawdown measurements.

(2) Farm well approximately 0.7 miles south-southwest from the reactor building, for livestock use, seven-inch casing size, pump less than 10 gpm, static water approximately 15 feet. The domestic type installation does not include the means for drawdown measurements.

(3) Farm well approximately 0.8 miles west from the reactor building, for domestic and livestock use. The well is hand-dug, approximately 3½ feet in diameter with a rock-lined wall. Well capacity is less than 10 gpm and static water level is approximately 15 feet. Drawdown data are not available.

(4) Farm well approximately 1.0 miles west-northwest from the reactor building. This is an abandoned, hand-dug, rock-lined well on an abandoned farmstead. [CRA, Section 2.3.5]

The USGS database lists three wells within two miles of CNS (see Table 2.3-1). One well is approximately 1.8 miles northwest of the site and identified as a groundwater well used once for water level measurements in 1968. The remaining two wells identified as groundwater wells, are located approximately 1.8 miles east southeast and approximately 2.0 miles east northeast of the site. [USGS 2007a]

All of the wells within one mile of the CNS site are small farm wells that were installed to supply domestic and livestock water needs for the individual farmsteads. There are only two occupied farmsteads within a one-mile radius of the plant. For a distance of five river miles downstream, there are six Nebraska farmsteads within a mile of the river. Shallow, low capacity, hand-dug or sandpoint wells are the normal sources of water supply for these farmsteads. These wells fall into three classes: drilled and cased wells, hand-driven sand points, and hand-dug, rock- or brick-lined wells. The wells are shallow and draw their water from the same general aquifer, which yields very high solids water with high iron and manganese concentrations. Because of the private nature of these domestic wells and absence of test connections, data are not available for maximum pumping rates and water levels. However, a pumping rate of less than 10 gpm is consistent with these types of wells. [CRA, Section 2.3.5; NPPD 2008b, Section II-4.4.2].

The site uses two wells, registered with the NDNR as G-030088 and G-030089, for supplying potable water to the facility [NDNR 2008]. They are approximately 150 feet apart, located on a north-south line approximately 860 feet west and 250 feet north of the reactor building. Both wells are over 60 feet deep and currently each have a registered capacity of approximately 500 gpm. However, current total pumping capacity is 250 gpm for both wells. The normal pumping rate is anticipated to be 125 gpm, with one well in service at a time. Maximum short-term plant demand is approximately 250 gpm which is the capacity of the plant Makeup Water Treatment System. [NPPD 2008b, Section II-4.4.2] A third site well (NDNR Registration No. G-040718) was installed in 1973 and is currently used by the CNS Fire Protection personnel for training exercises. Maximum registered capacity of this well was reported to be approximately 750 gpm with a depth of 73 feet. [NDNR 2008]

River Wells A and B are industrial wells that supply water for pump seals (G-100339 and G-100340). Available well construction and survey data for the River Wells are listed in Table 2.3-1. According to a review of CNS engineering drawings, the River Wells A and B have been relocated and redrilled at their current locations.

Existing monitoring wells at the Station include three decomissioned piezometers (G-143738A, G-143738B, and G-143738C). These three piezometers were installed during the soil boring investigation program associated with the Independent Spent Fuel Storage Installation (ISFSI) project. The primary purpose for the installation of these piezometers was to obtain groundwater levels/gradients across the Station property. [NDNR 2008]

The passage of LB 962 in Nebraska in 2004 is anticipated to have a major impact on water in Nebraska. It requires that the NDNR evaluate every river basin in Nebraska and make a determination whether a basin is fully appropriated or over-appropriated. NDNR announced in 2005 that after reviewing the best available data, the Nemaha River Basin will not be declared fully appropriated. This means there will be no restrictions on the drilling of new wells and the State will continue to issue surface water permits as long as flows are present. [NDNR 2006; NNRD 2005]

At this time, there are restrictions on the installation of additional wells in the NNRD. The limited restriction is a temporary moratorium on large capacity wells, for which a potential new well owner can apply for a waiver. Contact with a representative with the NNRD indicated there have been no groundwater use conflicts in the Missouri River Valley alluvial aquifer around Cooper [NNRD 2008].

NEI 07-07 (August 2007) was developed to describe the industry's Groundwater Protection Initiative (GPI). The GPI identifies actions to improve utilities' management and response to instances where the inadvertent release of radioactive substances may result in low, but detectable levels of plant-related materials in subsurface soils and water. As part of this GPI, NPPD routinely collects and analyzes onsite groundwater samples to monitor for potential radioactive releases via ground water pathways at the site in accordance with site procedures [CNS 2008a]. Additional wells that were installed as part of the NEI GPI to supplement an already existing onsite groundwater sampling program included wells G-149001A through G-149001K (see Table 2.3-1). Currently no levels above background have been recorded.

Table 2.3-1 provides the location and available information regarding known registered and currently identified wells, including inactive, abandoned, and decommissioned wells within two miles of CNS.

Table 2.3-1
Identified Wells Within Two Miles of CNS

Registered Well ID	Well Depth (ft.)	Approximate Distance to Site	Status	Capacity (gpm)	Primary Use
G-030088[a]	62	On site	Active	503	Potable Water
G-030089[a]	62	On site	Active	530	Potable Water
G-040718[a]	73	On site	Active	750	Fire Protection Training
G-100340[a]	75	On site	Active	150	River well
G-100339[a]	71	On site	Active	150	River well
G-142071[a]	62	1.9 mi S	Inactive	N/A	Observation
G-143738A[a]	25	On site	Decommissioned	N/A	Observation
G-143738B[a]	25	On site	Decommissioned	N/A	Observation
G-143738C[a]	25	On site	Decommissioned	N/A	Observation
G-146401A[a]	59	1.6 mi SW	Active	N/A	Other
G-146401B[a]	58	1.4 mi SW	Active	N/A	Other
G-146401C[a]	56.5	1.7 mi SSW	Active	N/A	Other
G-149001B[b]	40	On site	Active	N/A	Observation
G-149001C[b]	90	On site	Active	N/A	Observation
G-149001D[b]	41	On site	Active	N/A	Observation
G-149001A[b]	41	On site	Active	N/A	Observation

Table 2.3-1 (Continued)
Identified Wells Within Two Miles of CNS

Registered Well ID	Well Depth (ft.)	Approximate Distance to Site	Status	Capacity (gpm)	Primary Use
G-149001E[b]	38	On site	Active	N/A	Observation
G-149001F[b]	80	On site	Active	N/A	Observation
G-149001G[b]	41	On site	Active	N/A	Observation
G-149001H[b]	42	On site	Active	N/A	Observation
G-149001I[b]	40	On site	Active	N/A	Observation
G-149001J[b]	99	On site	Active	N/A	Observation
G-149001K[b]	45	On site	Active	N/A	Observation
Farm well[c]	N/A	0.7 mi SSW	Active	10	Domestic
Farm well[c]	N/A	0.7 mi SSW	Active	10	Farm
Farm well[c]	N/A	0.8 mi W	Active	10	Farm
Farm well[c]	N/A	1.0 mi WNW	Abandoned	N/A	N/A
USGS 402236095401301[d]	80	1.8 mi NW	N/A	N/A	Observation
USGS 402113095355901[d]	N/A	1.8 mi ESE	N/A	N/A	Observation
USGS 402215095355001[d]	N/A	2.0 mi ENE	N/A	N/A	Observation

N/A - Information not available

a. NDNR 2008
b. NPPD 2008f
c. NPPD 2008b, Section II-4.4.2
d. USGS 2007a

2.4 Critical and Important Terrestrial Habitats

The site and its associated transmission system lie within the Missouri Alluvial Plains level IV ecoregion. The transmission lines included within the scope of license renewal are discussed in Section 3.2. This ecoregion is described as a glaciated, level floodplain of alluvium with elevation ranging from 800 to 1,200 feet above sea level. Within this ecoregion, the dominant vegetation includes a combination of northern floodplain forest with cottonwood (*Populus deltoides*), green ash (*Fraxinus pennsylvanica*), boxelder (*Acer negundo*), elm (*Ulmus* spp.), lowland tallgrass prairie with big bluestem (*Andropogon gerardii*), prairie cordgrass (*Spartina pectinata*), switchgrass (*Panicum virgatum*), and various sedges. The majority of land within this ecoregion is intensively farmed for corn and soybeans and is a transportation corridor with most areas drained by surface ditches, land grading, or protected by dams or levees. [Chapman et al.]

Table 2.4-1 provides cover types and approximate percentage of each area within the 1,359 acre site with site land use illustrated in Figure 2.4-1. Areas along the west side of the Missouri River, in Nemaha County, Nebraska, where the CNS site is located are composed primarily of alluvial bottomland with some rolling floodplain atop bluffs. A stand of ash, elm, cottonwood, and scattered eastern red cedar (*Juniperus virginiana*) is found on the bluffs bordering the west side of the station property [USAEC, Section II.E.1]. The majority of bottomland in Nemaha County is farmed. On the east side of the Missouri River in Atchison County, Missouri, the 239 acres of CNS is comprised primarily of forested riparian bottomland. The site is dominated by native bottomland plant species including cottonwood, sycamore (*Platanus occidentalis*), silver maple (*Acer saccharrinum*), black willow (*Salix nigra*), boxelder, button bush (*Cephalanthus occidentalis*), and false indigo (*Amorpha fruticosa*). There are also invasive plant species at this site along the Missouri River, both exotic and native. The exotic invasive species include reed canary grass (*Phalaris arundinacea*) and purple loosestrife (*Lythrum salicaria*). The one native species at the site that tends to be invasive is the eastern red cedar. [NRCS 2007] The invasive common reed (*Phragmites austrailis*) is a non-native species recently added to the state's noxious weed list by the Nebraska Department of Agriculture, and may be found along the Missouri River in the vicinity of CNS [NDA].

Table 2.4-1
CNS Land Cover Types

Description	**Nebraska Percent[a]**	**Missouri Percent[b]**
Industrial	8.3	0
Cropland / Pasture	81	16
Deciduous Forest	10	82.8
Streams / Canals	0.7	1.2
Totals	100.0	100.0

a. UNL 2008
b. MSDIS

Within the site boundary of CNS there are three mapped federal jurisdictional wetlands (see Figure 2.4-2). Within a 6-mile radius of CNS there are more than 700 wetlands included in the USFWS wetlands inventory database [includes USACE jurisdictional and non-jurisdictional wetlands (see Figure 2.4-3)] [USFWS 2007a].

Mammals common to the area around CNS and potentially found within the transmission line right-of-way include white-tailed deer (*Odocoileus virginiana*), raccoon (*Procyon lotor*), coyote (*Canis latrans*), eastern cottontail rabbit (*Sylvilagus floridanus*), eastern fox squirrel (*Sciurus niger*), muskrat (*Ondatra zibethicus*), beaver (*Castor canadensis*), mink (*Mustela vison*), bobcat (*Lynx rufus*), and various mice and other small mammals. [Bailey]

Resident and migratory bird species common to the CNS area and potentially found within the transmission line right-of-way include the northern bobwhite quail (*Colinus virginianus*), ring necked pheasant (*Phasianus colchicus*), greater prairie chicken (*Tympanuchus cupido*), American kestrel (*Falco sparverius*), cliff swallow (*Petrochelidon pyrrhonota*), wild turkey (*Meleagris gallopavo*), the turkey vulture (*Cathartes aura*), and a large variety of neo-tropical migratory or passerine birds [Bailey; UNSM 2007b]. American bald eagles (*Haliaeetus leucocephalus*) are also found throughout the CNS area.

Amphibian and reptile species common to the CNS area and potentially found within the transmission line right-of-way include northern leopard frog (*Rana pipiens*), bullfrog (*Rana catesbeiana*), Woodhouse's toad (*Bufo woodhousii*), northern cricket frog (*Acris crepitans*), Cope's gray treefrog (*Hyla chrysoscelis*), eastern rat snake (*Elaphe obsoleta*), two species of garter snake (*Thamnophis* spp.), ringneck snake (*Diadophis punctatus*), prairie kingsnake (*Lampropeltis calligaster*), common snapping turtle (*Chelydra serpentina*), and painted turtle (*Chrysemys picta*). [UNSM 2007a]

CNS is located on the eastern boundary of the Central North American migratory bird flyway and the western boundary of the Mississippi River flyway. The CNS Operating License Stage Environmental Report noted that sixteen duck species follow the Missouri River during spring and fall flights. Snow, blue, Canada, and white-fronted geese pass through the area, with the blue and snow geese being the most numerous. [NPPD 1971, Section III-3.9.1]

The DeSoto National Wildlife Refuge, Schilling Wildlife Management Area, and Squaw Creek National Wildlife Refuge provide feeding and resting habitat for waterfowl and migratory birds that pass through the area. The DeSoto Refuge, located approximately 85 miles north of CNS in Iowa on the east bank of the Missouri River east of FCS, has recorded 240 bird species sited within the refuge, with snow geese, mallard ducks, ring-neck pheasants, mourning dove, red-winged black bird, eastern kingbird, certain woodpeckers, and certain sparrows as being abundant during different seasons; and 11 waterfowl species (such as Canada geese, teals, wood ducks, northern pintails, and common mergansers) and nearly 60 other species (including, but not limited to, bald eagles, pied-billed Grebe, and black terns) being common on the refuge at times. [USGS 2006] Snow geese and mallard counts on the DeSoto National Wildlife Refuge between September 2005 to April 2006 peaked at 30,000 and 18,000, respectively, as the most abundant migratory bird species in November 2005. [USFWS 2005a]

Squaw Creek Refuge, located approximately 25 miles southeast of CNS (three miles south of Mound City, Missouri) is home to a variety of animal species. Wildlife recordings show more than 30 species of mammals, almost 40 species of reptiles and amphibians, and more than 300 species of birds have been found using the refuge. The diversity of animal species results from the diversity of habitats within the refuge. Woodland slopes covered by mature oak-hickory trees are where the towhees, robins, nuthatches, chickadees, woodpeckers, and tanagers can be seen during the summer. The woodlands provide resting and feeding perches for hawks and bald eagles. White-tailed deer and turkey are also common in the woodlands, and bobwhite quail and pheasants are found in the grassy edge near the woodlands. Squaw Creek Refuge's wetlands can attract as many as 400,000 snow geese, if conditions are correct during spring and fall migrations. Fall and winter waterfowl migration can peak with 100,000 ducks. Wetlands range from open pools and mud flats to flooded woodlands and cattail-filled marshes. An abundant population of muskrats is evident from the number of muskrat houses dotting the large wetlands. These dome-shaped houses make handy perches for bald eagles, double-crested cormorants, and Canada geese. Eagle numbers can peak with 300 birds or more in early December. [USFWS 2007c]

Although no definable trend has been identified by CNS, approximately five bird death incidents have been noted at the site from 2003–2007 as summarized below.

- In 2003, a great horned owl flew into the razor wire at Security Microwave Zone 8 and eventually died. [CNS 2003]
- In 2004, a dead bird was observed at the main transformer yard fence and another at the southeast corner of the maintenance shop. [CNS 2004a; CNS 2004b]
- In 2005, dead birds were observed at the main transformer yard. [CNS 2005a]
- In 2006, a dead bird was discovered on the turbine building upper roof. [CNS 2006a]

Although the cause of death for the 2003 incident was known and triggered an offsite agency notification, the cause of deaths for the remaining incidents were not known and did not trigger any offsite regulatory notifications.

In addition, in July 2006 an injured juvenile bald eagle was rescued offsite near CNS. The NGPC was contacted and the bird was taken to a rehabilitation center. The bird had made a successful recovery from its injuries and was scheduled to be released when the eagle unexpectedly fell ill at the rehabilitation center. It was later determined that the eagle had been infected with the West Nile virus which ultimately caused its death. [King]

On the Missouri River side of the site, there is an established bald eagle nest with a breeding pair of bald eagles. This pair has produced multiple bald eagle chicks over several years. Although the bald eagle is no longer protected under the Endangered Species Act, it is still protected by the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act. Special care is taken to ensure that the eagles are not harassed by the infrequent site activities on the Missouri River side of the site.

There are no other known special, threatened, or endangered species on-site, although they could potentially transit the site. For activities which may involve brush removal activities around wetlands or the shoreline of the Missouri River on the CNS site or along transmission line right-of-ways, NPPD has procedural controls in place to ensure that environmentally sensitive areas, if present, are adequately protected during site operations and project planning [CNS 2007; NPPD 2007d]. These controls would ensure that appropriate local, state, and/or federal permits are obtained or modified as necessary, that threatened or endangered species are protected if present, and that other regulatory issues are adequately addressed if necessary.

NPPD also has a corporate program on the use, application, and documentation for applying restrictive- and nonrestrictive-use pesticides. NPPD personnel applying restricted-use pesticides are certified licensed personnel through the Nebraska Department of Agriculture. NPPD also occasionally hires contract licensed personnel to apply restrictive use pesticides on NPPD property. [NPPD 2007c]

Other than terrestrial monitoring associated with the sites' radiological environmental monitoring program described in the CNS Offsite Dose Assessment Manual (ODAM), there are no other terrestrial monitoring programs conducted at the site.

2.4.1 State-Listed Critical or Important Habitats

NPPD's review identified no state-listed critical or important habitats in the vicinity of the site or along the associated transmission lines. The Missouri Natural Heritage Program and the NGPC were contacted (see Attachment A) regarding state-listed critical or important habitats within the vicinity (6-mile radius) of CNS and along the associated transmission lines within the scope of license renewal (As of the time of the submittal of this ER, neither agency had responded to this request for information). Critical and important habitats are those areas that are managed by a state for species that are listed at the state level as endangered, threatened, or of concern. Even though state-listed rare species are known to occur in Nemaha County, Nebraska, no state-listed critical or important habitats are designated within a 6-mile radius of CNS or along the associated transmission lines [MNHP 2007b; NGPC 2007].

2.4.2 Federal-Listed Critical or Important Habitats

As addressed in Section 2.5, eight federally listed threatened or endangered species are potentially encountered within the vicinity (6-mile radius) of CNS or along the associated transmission lines within the scope of license renewal. NPPD's review identified no designated critical habitat for these species within a 6-mile radius of CNS or along the associated transmission lines based on the USFWS Critical Habitat portal [USFWS 2007b]. USFWS regional offices in Nebraska and Missouri were contacted (see Attachment A) regarding federally listed critical or important habitats within the vicinity of CNS and along the associated transmission lines within the scope of license renewal (At the time of the submittal of this ER, neither agency had responded to this request for information).

2.5 Threatened or Endangered Species

Five species currently protected under the Federal Endangered Species Act have geographic ranges which could possibly include the CNS site. Federally protected species potentially represented include one fish, two birds, one mammal, and one plant. They are the pallid sturgeon, Indiana bat, piping plover, interior least tern, and western prairie fringed orchid. Of these species, the pallid sturgeon, Indiana bat, and interior least tern are listed as endangered and the piping plover and western prairie fringed orchid are listed as threatened. [USFWS 2007f; USFWS 2007g]

In addition to the western prairie fringed orchid, three additional federally protected species were identified as potentially present along the transmission lines corridor. Federally protected species not already listed above are the black-footed ferret (*Mustela nigripes*), the whooping crane (*Grus Americana)*, and the Salt Creek tiger beetle (*Cicindela nevadica lincolniana*). All three are listed as endangered. [USFWS 2007f]

Cooper Nuclear Station

The pallid sturgeon is endangered throughout its historic range. Today floodplain habitats and much of the once naturally functioning ecosystem have been altered by construction of dams and channelization that have caused changes in the morphology, hydrology, temperature regime, cover, and sediment/organic matter transport necessary for the species survival [USFWS 1993]. They are only occasionally found in a few selected areas. Since 1980, reports of most frequent occurrences are from the Missouri River: (1) between the Marias River and Fort Peck Reservoir in Montana; (2) between Fort Peck Dam and Lake Sakakawea (near Williston, North Dakota); (3) within the lower 70 mi (113 km) of the Yellowstone River downstream of Fallon, Montana; (4) in the headwaters of Lake Sharpe in South Dakota; (5) near the mouth of the Platte River near Plattsmouth, Nebraska; and (6) below RM 218 to the mouth in the State of Missouri [USFWS 2000, p. 99]. Population estimates for pallid sturgeon in the Missouri River below Gavins Point Dam are considered subjective due to lack of mark and recapture data. Population estimates of pallid sturgeon based on frequency of sightings give an estimate of one to five pallid sturgeon per kilometer of river, or 1,303 to 6,516 individuals downstream of Gavins Point Dam to the Mississippi River. A total of 511 pallid sturgeons were stocked in the Platte River in 1997, 1998, and 1999 to augment the existing population [USFWS 2000, p. 157, Table 11].

The apparent decline of the pallid sturgeon in the Missouri River is generally considered to be due to habitat changes, most significantly those caused by USACE management of the river (e.g., mainstem dams, channelization, and flow management as discussed above) [USFWS 2000; Jorgensen]. This has led to the USFWS Biological Opinion concluding that a mitigation plan is necessary that would mitigate impacts on the pallid sturgeon, piping plover, and interior least tern [USFWS 2000; USACE 2003]. The exact causes of the decline of pallid sturgeon remain unknown and subject to controversy. Jorgensen contradicts the widely held hypothesis that mainstem management of the Missouri River is the main reason the pallid sturgeon (and interior least tern and piping plover) is endangered. Jorgensen contends it has not been established if the changing of habitat or flow conditions are the critical or dominant factors in the apparent decline of the pallid sturgeon and other native fish. The pallid sturgeon has always been rare, and available information suggests that the undeveloped Missouri River may not have been a 'friendly' river for the pallid sturgeon. Even in the Platte River (where pallid sturgeon have been identified near its confluence with the Missouri River), which may be more like the pre-development Missouri River, the pallid sturgeon is rare. [Jorgensen]

Missouri River studies have indicated the pallid sturgeon abundance may also be affected by its hybridization with other sturgeon species. The pallid sturgeon hybridizes with the more common population of shovelnose sturgeon [Berry et al., p. 82]. The USFWS formal consultation Biological Opinion in 2000 notes "the populations of pallid sturgeon in the lower Missouri River and the Mississippi River appear to have much hybridization, thus complicating identities. Detecting hybrids through use of morphological and meristic characteristics has many shortcomings and can only provide circumstantial evidence of hybridization. If hybridization has proceeded beyond the first generation, distinguishing individuals of mixed ancestry is often impossible" [USFWS 2000, p. 96]. The USFWS species profile notes that hybridization (of pallid sturgeon) with the more common shovelnose sturgeon is a threat to the species and may be attributed to the modifications occurring to the habitats used by both species [USFWS 2007e].

Piping plovers have been reported within the counties and watershed areas immediately adjacent to CNS [NatureServe]. Piping plovers are breeding residents along the Missouri River in close proximity to CNS. Habitat requirements for breeding include large expanses of gravel bars and sparsely vegetated river banks and islands which are not found at CNS. Threats to piping plovers include habitat modification/loss due to channelization, nest disturbance, and predation [NatureServe; Haig and Elliot-Smith, Section 12]. Critical habitat has been designated for the piping plover, along the Nebraska-South Dakota border, but does not include the section of the Missouri River adjacent to CNS [USFWS 2002].

Interior least terns have also been reported along the Platte River [NatureServe, p. 29]. Nesting habitat use is similar to that of piping plovers. Threats to the interior least tern include loss of nesting habitat along rivers due to channelization and other modifications to the hydrology flow regimes [NatureServe; Thompson et al., Section 12]. However, the interior least tern is not indicated as being present in Nemaha County, Nebraska [USFWS 2007f, p. 57653].

The Indiana bat is quite small, weighing only one-quarter of an ounce (about the weight of three pennies). In flight, it has a wingspan of 9 to 11 inches. The fur is dark-brown to black. The Indiana bat is similar in appearance to many other related species. Indiana bats hibernate during winter in caves or, occasionally, in abandoned mines. For hibernation, they require cool, humid caves with stable temperatures, under 50°F, but above freezing. Very few caves within the range of the species have these conditions. After hibernation, Indiana bats migrate to their summer habitat in wooded areas where they usually roost under loose tree bark on dead or dying trees. During summer, males roost alone or in small groups, while females roost in larger groups of up to 100 bats or more. Indiana bats also forage in or along the edges of forested areas. Indiana bats are found over most of the eastern half of the United States. The USFWS estimates a Missouri Indiana bat population of approximately 65,000. [USFWS 2006] While the Indiana bat is included in the USFWS' Missouri endangered species list, it is not included on the USFWS Nebraska list. [USFWS 2007f] The Indiana bat is not believed to be present on CNS property or in Nemaha County.

The western prairie fringed orchid is a perennial belonging to the family Orchidaceae. The western prairie fringed orchid is distributed throughout lowland, damp tallgrass prairies in Iowa, Kansas, Minnesota, Missouri, Nebraska, and North Dakota [USFWS 1992]. However, the western prairie fringed orchid is not indicated to be present in Nemaha County, Nebraska [USFWS 2007f]. Habitat modification by loss or conversion of native prairie, woody encroachment, and fire suppression are some causes of its decline [USFWS 1992].

Transmission Lines

Four federally endangered species were identified that may potentially be found along the corridors of the transmission lines that originally connected CNS to the electric grid. These are the black-footed ferret, the whooping crane, the western prairie fringed orchid, and the Salt Creek tiger beetle [USFWS 2007f].

The black-footed ferret has been considered to be the most endangered mammal in North America for many years. They are primarily nocturnal, with most daytime activity limited to the first few hours following sunrise. They spend most of their time in underground burrows, typically spending only a few minutes above ground each day. Finally, ferrets occur in areas with low human densities, which makes observation difficult. Although it was probably never abundant, historically the ferret occurred throughout the Great Plains in 12 states and two Canadian provinces, from the foothills of the Rocky Mountains east to Nebraska and from southern Canada south to Texas. The range of the black-footed ferret coincides closely with that of three species of prairie dogs on which the ferret depends for food and habitat. As the plains were settled and large tracts of prairie were plowed for farmland, prairie dog and ferret habitat was destroyed. Poisoning campaigns eliminated vast acreages of prairie dogs that were competing with livestock for forage. [NGPC 2008a] The black-footed ferret has the potential to be present near the in-scope transmission lines.

The Whooping Crane in Nebraska is found along the Platte Valley, with its wide slow moving river and associated sandbars and islands. Nearby wet meadows, croplands, and marshlands are important for foraging. It is an occasional spring and fall migrant along Platte Valley. Ninety percent of sightings are within 30 miles of Platte River, and eighty percent occurred between Lexington and Grand Island. [NGPC 2008b] In the early 1940s, only 21 Whooping Cranes remained. Probably never very abundant, this larger cousin of the Sandhill Crane came perilously close to extinction as plume and market hunters, egg collectors, and habitat loss took its toll at the turn of the 20th century. The tallest of North American birds, Whooping Crane numbers have slowly climbed to nearly 200 wild individuals. [NGPC 2008c] Based on NPPD observations, there is a potential for the Whooping Crane to be present near the in-scope transmission lines.

The Little Salt Creek wetlands contain the world's only known populations of the Salt Creek tiger beetle. This species is state endangered and received federal listing in 2005. Several protected areas occur within this landscape including Arbor Lake WMA, Little Salt Creek WMA, Jack Sinn WMA, the City of Lincoln's Shoemaker Marsh, Anderson Tract, and King Tract, the Lower Platte South NRD's Lincoln Saline Wetland Nature Center and Warner Wetland, and The Nature

Conservancy's Little Salt Fork Marsh. The Salt Creek tiger beetle is found only in Lancaster County, Nebraska. However, in-scope transmission lines are near its identified habitat, above. [NGPC 2005; USFWS 2005b]

As discussed above, the western prairie fringed orchid in not indicated as being present in Nemaha County, Nebraska. However, it is distributed in other counties that could potentially be near the in-scope transmission lines, including Lancaster, Saline, and Hall County.

State Protected Species

The States of Missouri and Nebraska also protect additional species as endangered, threatened, or species of special concern. State-listed species that have the potential to occur in Nemaha and Richardson Counties, Nebraska, and Atchison County, Missouri, which are in the vicinity of CNS, include 35 animal species and 16 plant species. These animal species include nine fish, 11 birds, eight reptiles and amphibians, seven mammals, and one invertebrate (Table 2.5-1). [MNHP 2007a; NGPC 2007; USFWS 2007f; USFWS 2007g] None of these state-listed species have been observed to date at CNS and are therefore not discussed in detail in this ER.

Two small mammals listed as state protected species that occur in Nemaha County, Nebraska, are the southern flying squirrel (*Glaucomus volans*) and woodland vole (*Microtus pinetorum*) [NatureServe]. On the CNS site in Atchison County, Missouri, state protected mammals potentially occurring include the plains spotted skunk (*Spilogale putorius interrupta*), Franklin's ground squirrel (*Spermophilus franklinii*), and plains pocket mouse (*Perognathus flavescens*) [MNHP 2007a; NatureServe].

State protected bird species that occur in Nemaha County, Nebraska, and Atchison County, Missouri, include ruffed grouse (*Bonasa umbellus*), bald eagle, peregrine falcon (*Falco peregrinus*), barred owl (*Strix varia*), whip-poor-will (*Caprimulgus vociferus*), Carolina wren (*Thryothorus ludovicianus*), and blue-gray gnatcatcher (*Polioptila caerulea*) [MNHP 2007a; NatureServe].

State protected reptiles and amphibians known to occur in Nemaha County, Nebraska, include the smallmouth salamander (*Ambystoma texanum*), western wormsnake (*Carphophis vermis*), yellow-bellied kingsnake (*Lampropeltis calligaster*), and smooth green snake (*Liochlorophis vernalis*) [NatureServe]. State protected reptiles known to occur in Atchison County, Missouri, include the northern leopard frog (*Rana pipiens*), the plains spotted skunk (*Spilogale putorius interrupta*), and the western fox snake (*Elaphe vulpina*) [MNHP 2007a].

Table 2.5-1
Federal and State Protected Species

Scientific Name	Common Name	Federal Status	State Status
Reptiles and Amphibians			
Ambystoma texanum	Smallmouth salamander	-	SC (NE)
Carphophis vermis	Western wormsnake	-	SC (NE)
Elaphe vulpina vulpine	Western fox snake	-	E (MO)
Eumeces obsoletus	Great plains skink	-	SC (MO)
Lampropeltis calligaster	Yellow-bellied kingsnake	-	SC (NE)
Liochlorophis vernalis	Smooth green snake	-	SC (NE)
Rana pipiens	Northern leopard frog	-	SC (MO)
Sistrurs catenatus	Massasauga rattlesnake	-	T (NE) E (MO)
Birds			
Bonasa umbellus	Ruffed grouse	-	SC (NE)
Caprimulgus vociferus	Whip-poor-will	-	SC (NE)
Charadrius melodus	Piping plover[a]	T	T (NE)
Falco peregrinus	Peregrine falcon	-	E (MO)
Grus americana	Whooping crane[b]	E	E (NE)
Haliaeetus leucocephalus	Bald eagle	-	T (NE)* E (MO)
Lanius ludovicianus	Loggerhead shrike	-	SC (MO)
Polioptila caerulea	Blue-gray gnatcatcher	-	SC (NE)
Sterna antillarum athalassos	Interior least tern[a]	E	E
Strix varia	Barred owl	-	SC (NE)
Thryothorus ludovicianus	Carolina wren	-	SC (NE)
Mammals			
Glaucomys volans	Southern flying squirrel	-	T (NE)
Microtus pinetorum	Woodland vole	-	SC (NE)

Table 2.5-1 (Continued)
Federal and State Protected Species

Scientific Name	Common Name	Federal Status	State Status
Mustela nigripes	Black-footed ferret[b]	E	E (NE)
Perognathus flavescens	Plains pocket mouse	-	SC (MO)
Spermophilus franklinii	Franklin's ground squirrel	-	SC (MO)
Spilogale putorius interrupta	Plains spotted skunk	-	E (MO)
Myotis sodalis	Indiana bat[a]	E	E (MO)
Fish			
Acipenser fulvescens	Lake sturgeon	-	T (NE)
Cycleptus elongates	Blue sucker	-	T (NE)
Fundulus zebrinus	Plains killifish	-	SC (MO)
Hybognathus argyritis	Western silvery minnow	-	SC (MO)
Hybognathus placitus	Plains minnow	-	SC (MO)
Macrhybopsis meeki	Sicklefin chub	-	T (NE)
Macrhybopsis gelida	Sturgeon chub	-	E (NE)
Platygobio gracilis	Flathead chub	-	E (MO)
Scaphirhyncus albus	Pallid sturgeon[a]	E	E
Insects			
Cincindela nevadica lincolnaina	Salt Creek tiger beetle[b]	E	SC (NE)
Invertebrates			
Melanoplus packardii	Packard's grasshopper	-	SC (MO)
Plants			
Anemone cylindrica	Thimbleweed	-	SC (MO)
Astragalus lotiflorus	Low milk vetch	-	SC (MO)
Bouteloua gracilis	Blue grama	-	SC (MO)
Bouteloua hirsuta var. *hirsuta*	Hairy grama	-	SC (MO)
Buchloe dactyloides	Buffalo grass	-	SC (MO)
Carex sprengelii	Longbeak sedge	-	SC (MO)

Table 2.5-1 (Continued)
Federal and State Protected Species

Scientific Name	Common Name	Federal Status	State Status
Castilleja sessiliflora	Downy painted cup	-	SC (MO)
Dalea enneandra	Nine-anther dalea	-	SC (MO)
Lactuca tatarica ssp. *pulchella*	Blue lettuce	-	SC (MO)
Nothocalais cuspidate	Prairie dandelion	-	SC (MO)
Oxytropis lambertii var. *lambertii*	Locoweed	-	SC (MO)
Pediomelum argophyllum	Silvery psoralea	-	SC (MO)
Penstemon grandiflorus	Large beard-tongue	-	SC (MO)
Platanthera praeclara	Western prairie fringed orchid[b]	T	T (NE) E (MO)
Symphoricarpos occidentalis	Wolfberry	-	SC (MO)
Yucca glauca	Small soapweed yucca	-	SC (MO)
E = Endangered NE = Nebraska MO = Missouri SC = Species of Concern T = Threatened			

a. Species with the potential to be present in vicinity of CNS.

b. Species with the potential to be present along transmission line ROWs (in addition to those identified in vicinity of CNS)

* In June 2008 the NGPC recommended the removal of the bald eagle from listing under the Nebraska Non-game and Endangered Species Conservation Act. This process is ongoing at the time of the submittal of this ER.

References: MNHP 2007a; NGPC 2007; USFWS 2007f; USFWS 2007g

2.6 Regional Demography

2.6.1 Regional Population

NUREG-1437 *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) presents a population characterization method that is based on two factors: "sparseness" and "proximity" [USNRC 1996, Section C.1.4]. "Sparseness" measures population density and city size within 20 miles of a site and categorizes the demographic information as follows.

Demographic Categories Based on Sparseness

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

Reference: USNRC 1996

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

Demographic Categories Based on Proximity

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

Reference: USNRC 1996

The GEIS then uses the following matrix to rank the population in the vicinity of the plant as low, medium, or high.

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

Low Population Area	Medium Population Area	High Population Area
1.1, 1.2, 2.1	1.3, 1.4, 2.2, 2.3, 2.4, 3.1, 3.2, 3.3, 4.1, 4.2	3.4, 4.3, 4.4

Reference: USNRC 1996

The 2000 census population and TIGER/Line data from the U.S. Census Bureau (USCB) were used to determine demographic characteristics in the vicinity of the site. The data were processed at the state, county, and census block levels using ESRI ArcView® [ESRI 2000].

The 2000 census data indicate that approximately 18,318 people live within a 20-mile radius of the site, which equates to a population density of 15 persons per square mile [ESRI 2000]. According to the GEIS sparseness index, the site is classified as Category 1: Most Sparse.

The 2000 census data indicate that approximately 160,211 people live within a 50-mile radius of the site, which equates to a population density of 20 persons per square mile. According to the GEIS proximity index, the site is classified as Category 1: Not in Close Proximity [ESRI 2000].

According to the GEIS sparseness and proximity matrix, the combination of "sparseness" Category 1 and "proximity" Category 1 results in the conclusion that the site is located in a "low" population area.

The area within a 50-mile radius of the site includes twenty-four counties from four states that are totally or partially included within the 50-mile radius (see Table 2.6-1). According to the 2000 census, the total permanent population (not including transient populations) of these counties was approximately 638,824, as shown in Table 2.6-1 [ESRI 2000]. By 2034, which is the end of the proposed license renewal period, the total whole county population (not including transient populations) is projected to be approximately 937,618. The total population (including transient populations) within a 50-mile radius of the site is projected to be 179,865 in 2034. [UNBBR; Woods & Poole; Eklund; MCDC].

Table 2.6-1
County Population by State Totally or Partially Included in the 50-Mile Radius of CNS

State and County	2000 Population	2034 Projected Permanent Population
Iowa (5 counties)	**58,262**	**61,922**
Fremont	8,010	7,664
Mills	14,547	20,566
Montgomery	11,771	11,102
Page	16,976	16,180
Taylor	6,958	6,410
Kansas (6 counties)	**70,086**	**74,304**
Atchison	16,774	15,749
Brown	10,724	10,431
Doniphan	8,249	7,648
Jackson	12,657	18,699
Marshall	10,965	11,373
Nemaha	10,717	10,404
Missouri (4 counties)	**50,185**	**49,369**
Andrew	16,492	18,957
Atchison	6,430	6,007
Holt	5,351	4,946
Nodaway	21,912	19,459
Nebraska (9 counties)	**460,291**	**752,023**
Cass	24,334	38,211
Gage	22,993	27,137

**Table 2.6-1 (Continued)
County Population by State Totally or Partially Included
in the 50-Mile Radius of CNS**

State and County	2000 Population	2034 Projected Permanent Population
Johnson	4,488	4,947
Lancaster	250,291	438,655
Nemaha	7,576	7,088
Otoe	15,396	23,281
Pawnee	3,087	2,640
Richardson	9,531	8,656
Sarpy	122,595	201,408
TOTAL POPULATION	**638,824**	**937,618**
References: ESRI 2000; UNBBR; Woods & Poole; Eklund; MCDC		

CNS is located in rural Nemaha County, Nebraska, and according to the 2000 census has a population of 7,576. Villages and cities within the county include Brownville, Nemaha, Peru, and Auburn. The 2000 census populations of these communities were 146, 178, 569, and 3,350, respectively. By 2005, the population of Brownville was 137; Nemaha was 177; Peru was 778; and Auburn was 3,076. [USCB 2006a]

The site is located on the state border with Missouri. According to 2000 census data, the neighboring county to the site is Atchison County, Missouri (population 6,430). Within Atchison County, the cities with the largest populations are Tarkio with a 2000 population of 1,935 and Rock Port with a 2000 population of 1,395. The City of Maryville, MO (Nodaway County) is the largest city within the 50-mile radius of the site and had a 2000 census population of 10,581. By 2005 the estimated population of Tarkio was 1,866; Rock Port was 1,343, and Maryville was 10,567. [USCB 2006b]

Estimated total projected populations and average annual growth rates for the six counties included within the 20-mile radius of the site are shown in Table 2.6-2 [ESRI 2000]. These include Nemaha, Otoe, and Richardson counties in Nebraska, the counties of Atchison and Holt in Missouri, and Fremont County in Iowa. These counties are of special significance in evaluation of demographic impacts because of their proximity to the site and ease of accessibility for employees living in the vicinity and region.

Of the six counties, only Otoe County in Nebraska (located north of Nemaha County and the site) shows consistent increase in projected population between the years 1990 and 2034 (see Table 2.6-2). Otoe County has the closest proximity to the largest urban centers in the state, Lincoln and Omaha. The other five counties listed in Table 2.6-2 show an overall decline in projected population, which is expected to continue through 2034. Based on 2000–2034 population projections, an annual growth rate of approximately 1.13 percent is anticipated for population in the 24 counties wholly or partially located within the 50-mile radius of the site. [ESRI 2000]

Table 2.6-2
Nemaha (NE), Otoe (NE), Richardson (NE), Atchison (MO), Holt (MO), and Fremont (IA) County Population Growth, 1990–2034

Year	Nemaha (NE)[a]	Average Annual Growth %	Otoe (NE)[a]	Average Annual Growth %	Richardson (NE)[a]	Average Annual Growth %	Atchison (MO)[a]	Average Annual Growth %	Holt (MO)[a]	Average Annual Growth %	Fremont (IA)[a]	Average Annual Growth %
1990	7980	--	14252	--	9937	--	7457	--	6034	--	8226	--
2000	7576	-0.52	15396	0.78	9531	-0.42	6430	-1.47	5351	-1.19	8010	-0.27
2005	6965	-1.67	15509	0.15	8732	-1.74	6246	-0.58	5081	-1.03	7759	-0.63
2015	7135	0.24	17967	1.48	9039	0.35	6017	-0.37	4974	-0.21	7664	-0.12
2025	7088	-0.07	20378	1.27	8656	-0.43	6007	-0.02	4946	-0.06	7664	0.00
2034[b]	7088	0.00	23281	1.49	8656	0.00	6007	0.00	4946	0.00	7664	0.00

a. References: USCB 1990; USCB 2000b; USCB 2000c; USCB 2000d; USCB 2000e.
b. Except for Otoe County, actual estimated population between 2025-2034 is projected to decline. To be conservative, population figures were held constant.

2.6.2 Minority and Low-Income Populations

2.6.2.1 Background

The NRC performs environmental justice analyses utilizing a 50-mile radius around the plant as the environmental "impact area." The four states included within the 50-mile radius, used individually for comparative analysis, comprise the "geographic area." This approach is presented below. Since the site is also located in close proximity to Iowa, Missouri, and Kansas, an alternative approach is addressed, which uses a combined geographic area of Nebraska, Iowa, Missouri, and Kansas. Both approaches were used for assessing minority and low-income population criteria.

NRC guidance suggests using the most recent USCB decennial census data. The 2000 census population data and TIGER/Line data for Nebraska, Iowa, Missouri, and Kansas were obtained from the USCB web site and processed using ESRI ArcView® GIS software [ESRI 2000]. Census population data were used to identify the minority and low-income populations within a 50-mile radius of the site. Minority and low-income populations in the geographic area were analyzed based on 2000 census block information. A total of 22,289 census blocks were identified as it relates to minority population area, with 192 census block groups identified in the low-income population area. The results were compiled and maps were produced showing the geographic location of minority and low-income populations in relation to the site. Information for both groups was then reviewed with respect to the Nuclear Reactor Regulation criteria for minority and low-income populations [USNRC 2004].

2.6.2.2 Minority Populations

The NRC Procedural Guidance for Performing Environmental Assessments and Considering Environmental Issues defines a "minority" population as American Indian or Alaskan Native, Asian, Native Hawaiian or Pacific Islander, Black, other, two or more races, the aggregate of all minority races, Hispanic ethnicity, and the aggregate of all minority races and Hispanic ethnicity [USNRC 2004, page D-8]. The guidance indicates that a minority population is considered to be present if either of the two following conditions exists:

(1) the minority population in the census block exceeds 50 percent, or

(2) the minority population percentage is more than 20 percentage points greater in the census block than the minority percentage of the geographic area chosen for the comparative analysis.

To establish minimum thresholds for each minority category, the non-white minority population total for each state was divided by the total population in the state. This process was repeated with the combined four-state total minority population and four-state total population. As described in the second criteria, 20 percent was added to the minority percentage values for the geographic area. The lower of the two NRC conditions for a minority population was selected as defining a minority area (i.e., census block minority population exceeds 50 percent, or minority population is more than 20 percent greater than the minority population of the geographic area, state or four-state area). Any census block with a percentage that exceeded this value was considered to be a minority population. Minority percentages for Nebraska, Iowa, Missouri, Kansas, and the four-state area, along with corresponding thresholds, are shown in Table 2.6-3b.

The 2000 census indicates 10.4 percent of the population in Nebraska and 12.21 percent of the population for the four-state area were included in the minority category All Races Combined, as shown in Table 2.6-3b. Using the second criteria listed above for identification of the presence of a minority population, when Nebraska is used as the geographic area, any census block group with a combined minority population equal to or greater than 30.4 percent would be considered a "minority population." Since 30.4 percent does not exceed the criteria of 50 percent, the second criteria (30.4 percent) would be used by default. When the four-state area is used as the geographic area, any census block with a combined minority population exceeding 32.21 percent would be considered a "minority population area."

For CNS, the four-state area was evaluated for minority populations within census blocks because the area within a 50-mile radius of the site includes portions of Nebraska, Iowa, Missouri, and Kansas. Populations within each state were considered individually and as a four-state geographic area. A combined or aggregate population of the four-state area was calculated based on these state populations. Finally, an additional evaluation was completed to identify the percentage of the population where all racial categories were combined and added to the Hispanic population counts for each state geographical area and for the four-state geographical area as a whole. Figures 2.6-1 through 2.6-18 reveal the areas within block groups within the 50-mile radius that exceed the criteria percentages for race categories defined in Table 2.6-3b. The nearest minority population designated by this analysis is located approximately 10 miles west of CNS, near Nemaha.

Because Hispanic is not considered to be a race by the USCB, Hispanics are already represented in the census defined race categories. Because Hispanics can be represented in the any race category, some white Hispanics not otherwise considered as minorities then become classified as a minority when categorized in the All Races Combined plus Hispanics category. Also, Hispanics that are of non-white racial background are included in both the racial group and the Hispanic group, and thereby double counted. The All Race Combined plus Hispanics category, however, results in the greatest chance of consideration of populations within a block group to be classified as minority.

The number of census blocks contributing to the minority population count was evaluated using the criteria shown in Table 2.6-3b and summarized in Table 2.6-3a. The results of the evaluation are census blocks that are either flagged as not having a minority population or flagged as having a minority population(s). The resulting maps, Figures 2.6-1 through 2.6-18, depict the location of minority population census blocks flagged accordingly for each category.

As shown in Table 2.6-3a, the percentage of census blocks exceeding the All Races Combined minority population criteria was 1.35 percent when a four-state geographic area was used or 1.37 percent when each individual state was used as the geographic area. For the All Races Combined plus Hispanic category, 1.7 percent of the census blocks within the four-state geographic area contained a minority population, and 1.67 percent of the blocks within a 50-mile radius contained minority populations when each individual state was used (see Table 2.6-3a). The minority population values of the block groups were significantly reduced when races are analyzed individually.

The location of several American Indian minority populations correspond with three Native American lands located within the 50-mile radius of the site. Straddling the border of Nebraska (Richardson County) and Kansas (Brown and Doniphan counties) are neighboring lands for the Iowa tribe and the Sac and Fox tribe. The Kickapoo Indian lands are also located within the 50-mile radius in Brown County, Kansas.

Table 2.6-3a
Minority Census Block Counts within 50-Mile Radius

	Four-State Combined Method		Individual State Method	
	Number of Blocks with Identified Racial Category	**% of Blocks within 50 miles**	**Number of Blocks with Identified Racial Category**	**% of Blocks within 50 miles**
Black	44	0.2	43	0.19
American Indian/Alaska Native	134	0.6	134	0.6
Asian	53	0.24	53	0.24
Native Hawaiian/other Pacific Islander	1	0	1	0
Two or More Races Combined	113	0.51	112	0.5
Other	69	0.31	72	0.32
All Races Combined	300	1.35	305	1.37
Hispanic	156	0.7	167	0.75
All Races Combined and Hispanic	378	1.7	373	1.67

Reference: ESRI 2000

Table 2.6-3b
Minority Populations Evaluated Against Criterion

Geographic Area	Iowa			Kansas			Missouri			Nebraska			Four-State Area		
	Total Population			Total Population			Total Population			Total Population			Total Population		
	2,926,324			2,688,418			5,595,211			1,711,263			12,921,216		
	Count	%	Crit.	Count	%	Crit.	Count	%	Crit.	Count	%	Crit.	Count	%	Crit.
Black	61,853	2.11	22.11	154,198	5.74	25.74	629,391	11.25	31.25	68,541	4.01	24.01	913,983	7.07	27.07
American Indian/Alaska Native	8,989	0.31	20.31	24,936	0.93	20.93	25,076	0.45	20.45	14,896	0.87	20.87	73,897	0.57	20.57
Asian	36,635	1.25	21.25	46,806	1.74	21.74	61,595	1.1	21.1	21,931	1.28	21.28	166,967	1.29	21.29
Native Hawaiian/ other Pacific Islander	1,009	0.03	20.03	1,313	0.05	20.05	3,178	0.06	20.06	836	0.05	20.05	6,336	0.05	20.05
Two or More Races	31,778	1.09	21.09	56,496	2.1	22.1	82,061	1.47	21.47	23,953	1.4	21.4	194,288	1.5	21.5
Other	37,420	1.28	21.28	90,725	3.37	23.37	45,827	0.82	20.82	47,845	2.8	22.8	221,817	1.72	21.72
All Races Combined	177,684	6.07	26.07	374,474	13.93	33.93	847,128	15.14	35.14	178,002	10.4	30.4	1,577,288	12.21	32.21
Hispanic	82,473	2.82	22.82	188,252	7	27	118,592	2.12	22.12	94,425	5.52	25.52	483,742	3.74	23.74
All Races Combined and Hispanic	260,157	8.89	28.89	562,726	20.93	40.93	965,720	17.26	37.26	272,427	15.92	35.92	2,061,030	15.95	35.95

Reference: ESRI 2000

2.6.2.3 Low-Income Populations

NRC guidance defines "low-income" using USCB statistical poverty thresholds [USNRC 2004, p. D-8]. As addressed above with minority populations, two alternative geographic areas (Nebraska, Iowa, Kansas, and Missouri individually and then all four states combined) were used in this analysis.

The guidance indicates that a low-income population is considered to be present if either of the two following conditions exists:

(1) the low-income population in the census block group exceeds 50 percent, or

(2) the percentage of households below the poverty level in a block group is significantly greater (typically at least 20 percentage points) than the low-income population percentage of the geographic area chosen for the comparative analysis (i.e., individual state and four-state combined average).

The 2000 census data indicate that 8.8 percent of the population of Iowa, 9.6 percent of the population of Kansas, 11.4 percent of the population of Missouri, 9.4 percent of the population of Nebraska, and 10.2 percent of the population within the four-state area was composed of low-income individuals (see Table 2.6-4). When Nebraska is used as the geographic area, any census block group within a 50-mile radius of the site with low-income population equal to or greater than 29.4 percent of the total block group population would be considered a "low-income population". Using these criteria for each state, three of the 192 census block groups (1.6 percent) within a 50-mile radius of the site have low-income population percentages which meet or exceed the percentages in Table 2.6-4. These census block groups are located in Page County, Iowa, and Nodaway County, Missouri, as illustrated in Figure 2.6-19.

When the four-state combined area is used as the geographic area, any census block group within a 50-mile radius of the site with low-income populations equal to or greater than 30.2 percent of the total block group population would be considered a "low-income population." Using these criteria, the same 3 out of the 192 census block groups (1.6 percent) were identified within a 50-mile radius of the site, as shown in Figure 2.6-20. Overall, low-income populations within the 50-mile radius "impact site" were a small percentage of the overall population.

Table 2.6-4
Low-Income Population Criteria Using Two Geographic Areas

Geographic Area	Total Population	Number of Persons Below Poverty Level	Percentage of Persons Below Poverty Level	Percentage of Low-Income Criterion
Iowa	2,926,324	258,008	8.8%	28.8%
Kansas	2,688,418	257,829	9.6%	29.6%
Missouri	5,595,211	637,891	11.4%	31.4%
Nebraska	1,711,263	161,269	9.4%	29.4%
Four-state area	12,921,216	1,314,997	10.2%	30.2%

Reference: ESRI 2000

2.7 Taxes

NPPD is Nebraska's largest electric generating utility, with a chartered territory including all or parts of 91 of the state's 93 counties. NPPD uses a mix of generating facilities to meet the needs of its customers. This includes a nuclear plant (Cooper Nuclear Station); two coal-fired plants (Gerald Gentleman Station and Sheldon Station); one combined cycle (Beatrice Power Station); one gas/oil plant (Canaday Station); one wind facility in partnership with the Nebraska Distributed Wind Generation Project (Springview); one totally-owned wind project (Ainsworth); nine hydro facilities; nineteen diesel plants and three peaking units. NPPD also purchases hydro power from the Western Area Power Administration (WAPA), which is operated by the federal government. [NPPD 2007a]

The average mix of fuel to supply NPPD's customers is approximately 59 percent from coal and 23 percent from nuclear with the remaining power supplied from a variety of hydro, oil/gas and wind. As a not-for-profit public corporation and political subdivision of the state of Nebraska, NPPD is exempt from income or property taxes. Instead, in lieu of tax and other payments are made to state, county, and local governments. [NPPD 2007a]

Payment In lieu of Taxes

NPPD pays monies in lieu of taxes (in lieu of property taxes) to the counties in which it provides retail electric power. As part of NPPD's generation capacity, in lieu of tax payments and payments to retail communities may be attributed to CNS.

The Nebraska State Constitution Article VIII, Section 11 (1958), stipulates:

> Every public corporation and political subdivision organized primarily to provide electricity or irrigation and electricity shall annually make the same payments in lieu of

> taxes as it made in 1957, which payments shall be allocated in the same proportion to the same public bodies or their successors as they were in 1957. The legislature may require each such public corporation to pay to the treasurer of any county in which may be located any incorporated city or village, within the limits of which such public corporation sells electricity at retail, a sum equivalent to five (5) per cent of the annual gross revenue of such public corporation derived from retail sales of electricity within such city or village, less an amount equivalent to the 1957 payments in lieu of taxes made by such public corporation with respect to property or operations in any such city or village. The payments in lieu of tax as made in 1957, together with any payments made as authorized in this section shall be in lieu of all other taxes, payments in lieu of taxes, franchise payments, occupation and excise taxes, but shall not be in lieu of motor vehicle licenses and wheel taxes, permit fees, gasoline tax and other such excise taxes or general sales taxes levied against the public generally. So much of such five (5) per cent as is in excess of an amount equivalent to the amount paid by such public corporation in lieu of taxes in 1957 shall be distributed in each year to the city or village, the school districts located in such city or village, the county in which such city or village is located, and the State of Nebraska, in the proportion that their respective property tax mill levies in each such year bear to the total of such mill levies. [Nebraska State Constitution]

NPPD paid $6.589 million in 2006 and $6.966 million in 2007 in lieu of taxes to the 91 counties in which NPPD is chartered [NPPD 2006b; NPPD 2007b]. Each county receives 5 percent of the total gross revenues NPPD receives from electricity sales within the county. The actual in lieu of tax allocation attributable to CNS is not recorded by NPPD. NPPD's power generation units provide power to the grid, and county retail sales are then from the grid. However, CNS represents approximately 23 percent of NPPD's power generation capacity. Based on its 23 percent generation, the payments in lieu of tax attribution to CNS is approximately $1.515 million in 2006 and $1.602 million in 2007 (see Table 2.7-1).

It should be noted that since NPPD's charter is to produce and distribute electricity to its customers throughout the state, these payments in lieu of taxes would likely be paid by NPPD regardless of the operation of CNS.

<u>Payments to Retail Communities</u>

The District serves the total wholesale power requirements of 52 municipalities and 25 public power districts and cooperatives. NPPD also serves 80 municipalities at retail totaling nearly 88,000 customers. More than 5,000 miles of transmission lines make up the NPPD electrical grid system. NPPD uses a mix of generating facilities to meet the needs of its customers. NPPD also purchases electricity from the Western Area Power Administration, which is operated by the federal government. [NPPD 2006b]

As part of its agreements with its retail communities, NPPD also pays 12 percent of its total gross revenues from those retail communities to which it supplies power back to those communities, which amounted to $17.48 million in 2006 and $18.32 million in 2007 [NPPD 2006b; NPPD

2007b]. Based on its 23 percent of NPPD's total generation capacity, CNS's contribution back to those retail communities was $4.02 million in 2006 and $4.21 million in 2007 (see Table 2.7-1).

As noted above, however, NPPD's charter is to produce and distribute electricity to its customers throughout the state. Therefore, these payments to the retail communities would likely be paid by NPPD regardless of the operation of CNS.

Miscellaneous Taxes

Sales/use taxes are paid on purchases made by CNS. Nebraska sales tax is imposed upon the gross receipts from all sales, leases, or rentals of tangible personal property made at retail in this state and upon the gross receipts of selected services; gross receipts of every person engaged as a public utility or as a community antenna television service operator; the gross receipts from the sale of admissions in the state; the gross receipts of persons selling, leasing, or otherwise providing intellectual or entertainment property; and the gross receipts from the sale of warranties, guarantees, service agreements, or maintenance agreements when the items covered are subject to tax [NEDOR]. As shown in Table 2.7-1, CNS paid $943,020 in sales/use taxes in 2007; $1,353,435 in 2006. City sales taxes are paid to the town of Auburn, Nebraska. NPPD also pays a special assessment for the Brownville-Nemaha Levee District that is paid to the county treasurer, but distributed back to that District.

Table 2.7-1
CNS Estimated Tax Distribution, 2005–2007 ($)

Tax	2005	2006	2007
Nebraska State Sales/Use Tax	1,082,780	1,353,435	943,020
City of Auburn, NE Sales/Use Tax	240	455	40
Special Assessment on Brownville-Nemaha Levee Paid to Nemaha County	5,090	5,090	5,090
Nemaha County, NE Real Estate Taxes	10,865	10,980	11,140
Atchison County, Missouri Real Estate Taxes	145	145	140
Nebraska In Lieu of Taxes to Counties with NPPD Retail Electric Sales Attributed to CNS	1,526,280	1,515,470	1,602,180
Payments to Retail Communities Attributed to CNS	4,053,060	4,020,400	4,212,910
Total	6,678,460	6,905,975	6,774,520

References: NPPD 2005a; NPPD 2006b; NPPD 2007b

Therefore, as shown in Table 2.7-1, the total taxes and payments to the state, counties, and retail communities attributable in 2006 was approximately $6.9 million, and $6.8 million in 2007.

2.8 Land Use Planning

Land use planning focuses on Nemaha, Otoe, and Richardson counties in Nebraska and Atchison County in Missouri, because the operation of CNS is important to the economy of these counties as a result of the 750 people employed at CNS.

2.8.1 Existing Land Use Trends

The four-county area near CNS is rural in character and largely unincorporated. Less than half of the population in the four-county area lives in incorporated towns and villages [NDED 2007]. Agricultural, forest, and open land are the largest land use components in the four-county area (See Table 2.8-1). Little land in the area is developed for residential, commercial, or industrial purposes. Much of the native grasslands and forests have been converted to agricultural uses. Remaining forested areas are generally limited to narrow areas along streams and rivers and steep hilly areas that are unsuitable for agriculture.

Nemaha County occupies approximately 409 square miles (261,950 acres) [USCB 2000b]. The county is relatively flat; however the western portion has more hills than the eastern area that borders the Missouri River. Approximately 255,360 acres, or 97 percent, of the land in Nemaha County was used for agricultural uses in 2002. The county had 483 farms with most of the agricultural land devoted to cropland (81.4 percent) and pasture (10.7 percent). Major crops produced in the county include: soybeans (85,682 acres or approximately 34 percent of agricultural land), corn (79,320 acres, or 31 percent), forage crops (7,763 acres, or 3 percent) wheat (3,442 acres, or 1 percent). Major livestock commodities are cattle and hogs. [USDA] Other than agriculture, the U.S. Census does not provide land uses within the counties. The USGS National Land Cover Database provides land use information, including, but not limited to, commercial/industrial and residential land use. Other land uses are provided from the most recent (1992 for Nebraska) USGS database for Nemaha County in Table 2.8-1. As reflected in Table 2.8-1, developed open land areas cover approximately 4.21 percent of the 261,760 acres in Nemaha County. [USGS 1992]

Richardson County occupies roughly 553 square miles (354,085 acres) [USCB 2000c]. The largest category of land use, approximately 320,785 acres or 91 percent, is devoted to agriculture in Richardson County, with 732 farms. Approximately 76 percent (243,795 acres) of the agricultural land is in cropland, with approximately 14 percent (44,910 acres) devoted to pasture. Major crops produced in the county include: soybeans (91,266 acres or approximately 28 percent of agricultural land), corn (86,095 acres, or 27 percent), forage crops (11,539 acres, or 4 percent) wheat (3,403 acres, or 1 percent), and sorghum (1 percent). Major livestock commodities are cattle, dairy products, and hogs. [USDA] Other land uses are provided from the most recent USGS database for Richardson County in Table 2.8-1. As reflected in Table 2.8-1, developed open land covers approximately 3.93 percent of the county. [USGS 1992]

Otoe County occupies roughly 616 square miles (394,040 acres) [USCB 2000d]. The largest category of land use, approximately 342,520 acres or 87 percent, is devoted to agriculture in Otoe County, with 797 farms in 2002. Approximately 81 percent (277,440 acres) of the agricultural land is in cropland, with approximately 10 percent (34,250 acres) devoted to pasture.

Major crops produced in the county include: soybeans (109,331 acres or approximately 32 percent of agricultural land), corn (102,211 acres or 30 percent), forage crops (13,712 acres or 4 percent) wheat (4,312 acres or 1 percent), and corn for silage (1 percent). Major livestock commodities are hogs and pigs, followed by cattle and calves, and dairy products. [USDA] Other land uses are provided from the most recent USGS database for Otoe County in Table 2.8-1. As reflected in Table 2.8-1, developed open land covers approximately 5.42 percent of the total county land. [USGS 1992]

Atchison County, Missouri occupies approximately 545 square miles (348,620 acres) [USCB 2000e]. Approximately 91 percent of Atchison County land is used for agricultural purposes. In 2002, the county had 465 farms consisting of 317,650 acres. Major agricultural uses consist of croplands (87 percent or 257,295 acres), with the remainder being other uses. The primary crop commodities include: corn (122,047 acres or 38 percent of all agricultural land), soybeans (121,857 acres or 38 percent), forage (9,781 acres or 3 percent), and popcorn and corn for silage. Major livestock commodities include cattle and calves, and hogs and pigs. [USDA] Other land uses provided from the most recent USGS database in Table 2.8-1 reveals developed open land accounts for 4.02 percent of the total land area [USGS 1992].

Nemaha, Richardson, and Atchison Counties have all seen a steady decline in total population over the past 50 years as more residents leave farms for employment in larger cities and towns. Most towns and villages located within a 50-mile radius of CNS are small and primarily support the agricultural community. The closest developed community to CNS is the Village of Brownville, located approximately two miles northwest of CNS. The population of Brownville in 2000 was 146. The town occupies 0.6 square miles (384 acres) and land use is primarily residential [City-Data 2008a]. The next closest town is Nemaha with a population of 178. Land use is predominately residential zoning within the 0.31 square miles (198 acres) the town encompasses [City-Data 2008b]. Industrial developments in the four-county area are classified as "light" and are located in the larger communities of Auburn and Nebraska City, Nebraska and Marysville, Missouri. Major land uses for the four-county area are shown in Table 2.8-1.

Table 2.8-1
Percent Land Use in Nemaha County (NE), Otoe County (NE), Richardson County (NE), and Atchison County (MO) in 1992

Description	Nemaha	Otoe	Richardson	Atchison
Open Water	1.33	0.59	1.45	1.35
Developed, open space	4.21	5.42	3.93	4.02
Developed, low intensity	0.68	0.56	0.76	1.23
Developed, medium intensity	0.09	0.13	0.07	0.24
Developed, high intensity	0.04	0.01	0.03	0.06
Barren land	0.00	0.00	0.00	0.00
Deciduous forest	8.75	4.64	8.51	5.83
Evergreen forest	0.05	0.01	0.02	0.03
Mixed forest	0.01	0.00	0.01	0.02
Scrub/shrub	0.04	0.00	0.09	0.06
Grassland/herbaceous	11.07	4.20	10.66	16.87
Pasture/hay	7.05	10.43	10.82	6.27
Cultivated crops	63.08	72.81	60.58	62.08
Woody wetlands	3.15	0.78	2.87	1.84
Emergent herbaceous wetland	0.45	0.42	0.20	0.10
Total Percent	**100**	**100**	**100**	**100**

Reference: USGS 1992

2.8.2 Future Land Use Trends

As discussed in Section 2.6, Nemaha, Richardson, and Atchison Counties have all seen a steady decline in total population over the past 50 years as more residents leave farms for employment in larger cities and towns. Most towns and villages located within a 50-mile radius of CNS are small and primarily support the agricultural community. Population density in the entire four-county area is very low.

Agricultural is the primary land use within Nemaha, Otoe, Richardson, and Atchison counties and no significant change in land use is anticipated for the future. Land use trends reflect a slow, but steady overall decline in population in the region. Limited commercial and urban development in the area centers on small urban areas where public services and utilities are available. No significant changes in future agricultural acreage, farm size, and land uses are anticipated for the four-county region near CNS.

Nebraska statute §23-114.03 authorizes a county to regulate, restrict, or prohibit the erection, construction, reconstruction, alteration, or use of nonfarm buildings or structures and the use, conditions of use, and/or occupancy of land. Most Nebraska counties have developed planning and zoning regulations. However, neither Nemaha or Richardson County have enacted zoning regulations, although the City of Auburn in Nemaha County and Falls City in Richardson County have local zoning regulations.

Otoe County has adopted land use planning regulations, such as zoning, to manage future growth and development [Schmitz]. The regulations, outlined in the county Comprehensive Plan, were adopted to assure adequate provisions for transportation, water flowage, water supply, drainage, sanitation, recreation, soil fertility, food supply, and other public requirements. The regulations apply to both urban and non-urban areas within the unincorporated area of the county.

The State of Missouri zoning statutes are defined in the Missouri Revised Statutes, Chapter 89 Section 89.030. Atchison County is part of the Northwest Missouri Regional Council of governments, which developed an Overall Economic Development Plan (OEDP) in 1992. The OEDP outlines objectives and goals for the area, in addition to assessing the region's economic progress. Furthermore, Comprehensive Economic Development Strategy (CEDS) plan updates to the OEDP serve as a long-term guide for economic and community development for the region. Although no zoning laws were identified at the county level, the 2001 CEDS recommends development of land for a more holistic community development approach. [NMRCG]

2.9 Housing

As of January 2008, CNS has a permanent staff of approximately 750 employees (see Table 3.5-1). The nearest four counties with employee residences are Nemaha, Richardson, and Otoe Counties in Nebraska and Atchison County in Missouri. Approximately 48 percent or nearly half of the CNS employees reside in Nemaha County, and approximately 90 percent reside within the four-county area of Nemaha, Richardson, and Otoe Counties in Nebraska and Atchison County in Missouri. The remaining employees live in outlying counties, including some who live in Kansas, Iowa, and several other states.

Between 1990 and 2000, the total population of the four counties near the CNS site has generally decreased (see Table 2.6-2). The population decreased from 7,980 to 7,576 in Nemaha County, from 9,937 to 9,531 in Richardson County, and from 7,457 to 6,430 in Atchison County, Missouri. The population increased in Otoe County from 14,252 to 15,396 [USCB 1990; USCB 2000d]. During the same period, the number of housing units changed little in the four-county area (see Table 2.9-1). Total housing units increased slightly from 3,432 to 3,439 in Nemaha County, increased from 6,137 to 6,567 in Otoe County, decreased from 4,704 to 4,560 in Richardson County, and decreased from 3,298 to 3,103 in Atchison County, Missouri. [USCB 1990; USCB 2000h]

The vacancy rates in the four counties have changed slightly from 1990 to 2000 as shown in Table 2.9-1. Richardson County had the highest vacancy rate of approximately 12.4 percent in 2000. The vacancy rate in Nemaha County decreased from 11.5 percent to 11.4 percent, Otoe County decreased from 10.4 percent to 7.7 percent, and Atchison County, Missouri, increased from 11.5 percent to 12.3 percent. [USCB 1990; USCB 2000h]

The median home values for the four-county area increased between 1990 and 2000 as shown in Table 2.9-1. Values increased 42.4 percent in Nemaha County, 36.2 percent in Richardson County, 51.2 percent in Otoe County, and 42.2 percent in Atchison County. In the 10-year period, the median monthly rent (contracted) also increased in the four-county area. Median monthly rent increased 49.1 percent in Nemaha County, 51.3 percent Richardson County, 52.1 percent in Otoe County, and 51.7 percent in Atchison County, Missouri. [USCB 1990; USCB 2000h]

Between 1990 and 2000, vacancy rates have generally remained about the same and the total number of new housing units has kept pace with the low growth in the area population. In all four of the nearest counties, home values and rental rates have shown moderate increases. However, there has been minimal growth in the housing market.

Table 2.9-1
Nemaha County (NE), Richardson County (NE), Otoe County (NE), Atchison County (MO) Housing Statistics, 1990-2000

	1990[a]	2000[b]	% Change
Nemaha County, NE			
Total Housing Units	3,432	3,439	0.2
Occupied Units	3,079	3,047	(1.0)
Vacant Units	353	392	9.9
Vacancy Rate	11.5	11.4	(0.9)
Median House Value ($)	33,500	58,200	42.4
Median Rent ($/month)	183	360	49.1
Richardson County, NE			
Total Housing Units	4,704	4,560	(3.1)
Occupied Units	4,120	3,993	(3.0)
Vacant Units	584	567	(2.9)
Vacancy Rate	12.0	12.4	3.2
Median House Value ($)	24,800	38,900	36.2
Median Rent ($/month)	145	298	51.3

Table 2.9-1 (Continued)
Nemaha County (NE), Richardson County (NE), Otoe County (NE), Atchison County (MO) Housing Statistics, 1990-2000

	1990[a]	2000[b]	% Change
Otoe County, NE			
Total Housing Units	6,137	6,567	6.5
Occupied Units	5,657	6,060	6.6
Vacant Units	480	507	5.3
Vacancy Rate	10.4	7.7	(25.9)
Median House Value ($)	38,800	78,000	51.2
Median Rent ($/month)	208	434	52.1
Atchison County, MO			
Total Housing Units	3,298	3,103	(5.9)
Occupied Units	2,961	2,722	(8.1)
Vacant Units	337	381	11.5
Vacancy Rate	11.5	12.3	6.5
Median House Value ($)	28,800	49,800	42.2
Median Rent ($/month)	153	317	51.7

a. USCB 1990
b. USCB 2000b; USCB 2000c; USCB 2000d; USCB 2000e; USCB 2000h

2.10 Social Services and Public Facilities

2.10.1 Public Water Supply

CNS utilizes an onsite Non-transient Non-community Public Water System for the plant potable water. CNS does not, however, utilize any Community Public Water System for potable, cooling, or process water systems. The site relies on groundwater and surface water from the Missouri River for all of its water supplies (see Section 2.3). The site uses two wells to supply potable water to the facility. Both wells are registered as being approximately 62 feet deep with a capacity of over 500 gpm, although they are currently pumped at a maximum of 250 gpm [NDNR 2008]. The two potable water wells are approximately 150 feet apart, located on a north-south line approximately 860 feet west and 250 feet north of the reactor building (see Figure 4.5-1). The normal pumping rate is anticipated to be 125 gpm, with one well in service at a time. Maximum short-term plant demand is approximately 250 gpm which is the capacity of the plant Makeup Water Treatment System. [NPPD 2008b, Section II-4.4.2]

For the purposes of this discussion, only water systems within 10 miles of the CNS site are discussed. Public water supply systems (community and rural) in the counties around CNS include systems within Nemaha and Richardson counties in Nebraska, and Atchison County, Missouri as shown in Table 2.10-1. Each of these water systems is supplied by shallow groundwater wells ranging in depth from approximately 45 to 90 feet in depth [NDHHS 2008a; NDHHS 20008b; NDHHS 2008c].

Community water systems in Nemaha County as discussed below include the City of Auburn, the City of Nemaha, Nemaha County Rural Water District No. 1 (RWD #1), Nemaha County RWD #2, and the City of Peru. The Village of Brownville no longer uses its own supply wells, but is connected to Nemaha County RWD #1.

The Auburn Board of Public Works operates the Auburn Municipal Water System. All of the Auburn water supply is provided by groundwater. Eleven wells can deliver up to 1,728,000 gpd of high quality, filtered, disinfected, and fluoridated water to all Auburn residences. Tight soil formations yield extremely pure water. The water system continues to meet all state and federal regulations. [Auburn] Auburn's system has an average capacity of 700,000 gpd, with a peak demand of 1,181,000 gpd, and storage capacity of 1,650,000 gallons. Auburn is reported to have available capacity for additional industrial development, indicating relatively stable groundwater levels in recent years. [NPPD 2008a]

The Nemaha Municipal Water System serves the Village of Nemaha and is supplied by two wells with an average depth of 60 feet at a rated capacity of 216,000 gpd. Average capacity is 17,500 gpd, with a peak demand of 30,000 gpd. Treatment is not required. [NPPD 2008c] Nemaha's public water system serves a residential population of 188, with 82 residential connections and three commercial connections [NDHHS 2008d].

The Nemaha County RWD #1 is supplied by two active wells with a rated capacity of 100,000 gpd and a peak demand of 90,000 gpd. The Nemaha County RWD #1 public water system serves a residential population of 800, with approximately 200 residential connections and 50 commercial connections. [NDHHS 2008e] Nemaha RWD #1 serves rural Nemaha County including the Village of Brownville, Nebraska.

The Nemaha County RWD #2 is supplied by four active wells with a reported average demand of 206,300 gpd. The Nemaha County RWD #2 storage capacity is reported to be 230,000 gallons and serves a population of 1,315, with approximately 408 residential connections, 69 commercial connections, and four industrial connections. [NDHHS 2008b].

The Peru Municipal Water System serves the municipality of Peru in Nemaha County. The Peru system is supplied by two wells with an average depth of 60 feet at a rated capacity of 576,000 gpd. Average capacity is 83,000 gpd, with a peak demand of 113,500 gpd. Treatment includes filtration and chlorination, with a daily capacity of 100,000 gallons. [NPPD 2008d] Peru's public water system serves a residential population of 923, with 82 residential connections and three commercial connections [NDHHS 2008f].

Richardson County obtains its public and private water supplies from groundwater wells. Only the Richardson County RWD #1 and the Village of Shubert have community water systems in Richardson County within ten miles of CNS. The Richardson County RWD #1 system has two wells which are reported to have a capacity of 230,000 gpd with a demand of 100,000 gpd from a population of 805, with 260 residential connections [Enercon]. The Village of Shubert operates a municipal water system supplied by two wells serving a population of 240. These wells can deliver up to 204,000 gpd, with a peak demand of 22,800 gpd.

Almost all potable water use within Atchison County is from groundwater supplied from wells, with the exception of Westboro, Missouri which purchases from a surface water source [MDNR 2007a]. The Rock Port Municipal Water System provides drinking water to the City of Rock Port, Atchison County, Missouri. The water system consists of three wells. Peak demand is approximately 300,000 gpd with a system capacity of approximately 720,000 gpd. [MDNR 2007a]

In summary, groundwater is the primary source of both community and non-community water supply systems and serves virtually the entire population in the area. A majority of areas of Nemaha, Atchison, and Richardson Counties are not served by community water supplies. Private groundwater wells supply much of the water to residents in the area. The groundwater in this area is generally good; however, agricultural contamination is known to occur in some areas.

As discussed in Section 2.3.4, there are four wellhead protection areas within 10 miles of CNS: Village of Nemaha, Nemaha County RWD #1, City of Auburn, and Village of Stella. The Village of Brownville obtains water from wells supplied from the Nemaha County RWD #1. [NDEQ 2008]

In addition, there are several USGS registered wells within counties surrounding the site; however, none are located within a 1-mile radius of the site [USGS 2007a]. These wells range in depth from 13 ft to over 3,000 ft below the surface and are listed as unused, domestic use, and commercial use wells.

Table 2.10-1
Major Community Water Supply Systems Near CNS

Public Water System (PWS)	Source	Number of Wells	Population Served	Capacity (gpd)	Demand (gpd)[a]
CNS Non-Transient Non-Community System					
CNS	Groundwater	2	825	360,000	180,000
Nemaha County					
Auburn	Groundwater	11	3,217	1,728,000	1,181,000
Nemaha	Groundwater	2	188	216,000	30,000
Peru	Groundwater	2	923	576,000	113,500
Nemaha Co. RWD #1	Groundwater	2	800	100,000	90,000
Nemaha Co. RWD #2	Groundwater	4	1,315	230,000	206,300
Richardson County					
Richardson Co. RWD #1	Groundwater	2	805	230,000	100,000
Shubert	Groundwater	2	240	204,000	22,800
Atchison County					
Rock Port	Groundwater	3	726	720,000	300,000
Atchison Co. PWSD #1	Purchased groundwater from Rock Port	0	831	N/A	46,000

a. Average daily demand.

Reference: Enercon

2.10.2 Transportation

The area within a 6-mile radius of CNS is bisected by the Missouri River, with portions of the site located in Nemaha County, Nebraska on the west side of the river and Atchison County, Missouri on the east side. Otoe County is located to the north of Nemaha County, with Richardson County to the south in Nebraska. CNS lies within 50 miles of portions of Iowa to the northeast on the east side of the river (and north of Atchison County, Missouri), and Kansas south of Richardson

County, Nebraska (see Figure 2.1-2). Several major highways serve as transportation corridors on both sides of the Missouri River. These highways generally have a Level of Service (LOS) designation of A or B due to the rural nature of the area surrounding the site. The discussion of transportation below primarily addresses the site vicinity, which is limited to Nemaha County, Nebraska and Atchison County, Missouri where the majority of CNS employees reside. A brief summary is also provided for Otoe and Richardson counties in Nebraska where additional CNS employees reside.

2.10.2.1 Nemaha and Atchison Counties

Several major and minor highway routes serve as transportation corridors within Nemaha and Atchison counties. The primary highways in Nemaha County include US Highways 75 and 136 and Nebraska State Highways 62, 67, and 105 (Figures 2.1-2 and 2.1-1). Normal access to the site is by a paved entrance road built across the site from Nemaha County Road 648A Avenue located on the west side of the property. County Road 648A Avenue intersects US Highway 136 which runs east to west, north of CNS at Brownville, Nebraska. State Highway 67 traverses Nemaha County north to south to the west of CNS. US Highway 75 bisects Nemaha County running north to south, while US Highway 136 bisects the county east to west.

The primary highways in Atchison County, Missouri on the east side of the Missouri River include Interstate 29 (I-29), US Highways 136, 59, and 275, Missouri State Highways 46 and 111, and County Roads B, M, and T. I-29 runs north to south through Atchison County roughly parallel to the river in between Council Bluffs, Iowa northeast of CNS and St. Joseph, Missouri, southeast of CNS. CNS employees who reside in Missouri can access the site by using either US Highways 136 or 159, which cross the Missouri River at Brownville and Rulo, Nebraska (in Richardson County), respectively. US Highway 136 bisects Atchison County in Missouri, similar to how it bisects Nemaha County on the west side of the river. Atchison County is also bisected by US Highway 59 which runs north to south through the central portion of the county.

2.10.2.2 Richardson and Otoe Counties

Primary highways in Richardson County include US Highways 73, 75, and 159 and State Highways 8, 62, 67, and 105. US Highway 75 intersects both Nemaha and Richardson Counties, running north to south. US Highway 159 crosses the river downstream of CNS at Rulo, Nebraska, crossing into Holt County, Missouri.

The primary highways in Otoe County include US Highways 50 and 75 and Nebraska State Highways 2, 43, 66A, 67, and 128. Otoe County is bisected north to south by US Highway 50 and Nebraska State Highway 2. Access to Otoe County directly from CNS is primarily from Nebraska State Highway 67 and US Highway 75.

2.10.2.3 Traffic Counts

The Nebraska Department of Roads (NDOR) and Missouri Department of Transportation (MODOT) provide traffic counts for major highways [NDOR; MODOT]. A summary of NDOR and MODOT estimates for average annual daily traffic counts near the site is shown in Table 2.10-2.

Table 2.10-2
Traffic Counts Near Site 1998-2007

Average Annual Daily Traffic Counts Near Site, 1998-2004				
Location	**1998**	**2000**	**2002**	**2004**
US Highway 136 at Brownville (NE)	2,290	2,370	2,030	2,435
US Highway 59 at Hwy 136 Intersection (NE)	1,035	1,015	900	925
US Highway 59 at Nemaha (NE)	1,035	1,125	915	895
State Highway 67 south of Site (NE)	275	145	240	160
State Highway 67 at Peru (NE)	1,410	1,340	1,220	1,355
US Highway 136 west of I-29 (MO)	NA	2,470	2,596	2,494
Interstate 29 just north of US 136 (MO)	NA	12,945	13,825	10,033
State Highway 111 near Nishnabotna, MO	NA	166	164	117

Average Annual Daily Traffic Counts Near Site, 2006		
Location	**Total Vehicles**	**Heavy Commercial Vehicles**
US Hwy 136 at Brownville (NE)	2,615	425
US Highway 67 and US Highway 136 (NE)	960	89
US Highway 67 at Nemaha (NE)	770	65
State Highway 67 south of Site (NE)	625	65
State Highway 67 at Peru (NE)	1,025	35

Daily Traffic Count, Nemaha, NE 2007		
Location	**Total Count**	**Trucks Only**
US Hwy 67 and Washington Street	683	62
US Hwy 136 and Main Street	1,938	41
US Hwy 136 and 1st Street	1,487	403

References: MODOT; NDOR

Level of Service

The U.S. Transportation Research Board has developed a commonly used indicator, called level of service (LOS), to measure roadway traffic volume. LOS is a qualitative assessment of traffic flow and how much delay the average vehicle might encounter during peak hours. Table 2.10-3 presents the LOS definitions used by local and state agencies, as well as by the NRC in the GEIS [USNRC 1996, Section 3.7.4.2].

Table 2.10-3
Level of Service Definitions

Level of Service	Conditions
A	Free flow of the traffic stream; users are unaffected by the presence of others.
B	Stable flow in which the freedom to select speed is unaffected, but the freedom to maneuver is slightly diminished.
C	Stable flow that marks the beginning of the range of flow in which the operation of individual users is significantly affected by interactions with the traffic stream.
D	High-density, stable flow in which speed and freedom to maneuver are severely restricted; small increases in traffic will generally cause operational problems.
E	Operating conditions at or near capacity level causing low, but uniform, speeds and extremely difficult maneuvering that is accomplished by forcing another vehicle to give way; small increases in flow or minor perturbations will cause breakdowns.
F	Defines forced or breakdown flow that occurs wherever the amount of traffic approaching a point exceeds the amount that can traverse the point. This situation causes the formation of queues characterized by stop-and-go waves and extreme instability.

The Nebraska Department of Roads estimates that State Highway 67 carries an LOS designation of A, based on 2007 data [NDOR]. Highway US-136 in the vicinity of CNS includes an LOS designation of B, while Avenue 648 near CNS carries an LOS designation of A. Therefore, since the LOS designations of roads in the vicinity of CNS are A and B, no delays in traffic volume are occurring and improvements to existing roads are not needed at this time.

2.10.3 Education

The State of Nebraska is divided into numerous school districts. Nemaha County is generally covered by four school districts: Auburn Public Schools, Johnson-Brock Public Schools, Locust

Grove Public Schools, and Southeast Nebraska Consolidated Schools. CNS lies near the district boundary between Auburn Public Schools and Southeast Nebraska Consolidated Schools.

Auburn Public Schools is a Class III district comprised of the towns of Auburn, Brownville, Howe, Julian, Peru, and the surrounding rural areas in southeast Nebraska. Auburn Public Schools is a rural district with 860 students in grades K-12. The most recent financial data were obtained from the Nebraska Department of Education. Total receipts from local, county, state, federal, and other sources amounted to approximately $7.003 million for the 2004–2005 school year, with approximately 45 and 44 percent each coming from local and state revenue sources, respectively. Approximately 62 percent, or $4.307 million, was spent for instruction. [NDOE] The Auburn High School was reported to have approximately 15 students per teacher [Public School Review].

Southeast Nebraska Consolidated Schools is a K–12 district located in southeast Nemaha County with a student population of 155. Total receipts from local, county, state, federal, and other sources amounted to approximately $2.042 million for the 2004–2005 school year, with approximately 78 and 13 percent each coming from local and state revenue sources, respectively. Approximately 51 percent, or $1.047 million, was spent for instruction. [NDOE]

Johnson-Brock Public Schools is a K–12 school district located in rural western Nemaha County, Nebraska, with an enrollment of 250. Total receipts from local, county, state, federal, and other sources amounted to approximately $2.142 million for the 2004–2005 school year, with approximately 78 and 12 percent each coming from local and state revenue sources, respectively. Approximately 54 percent, or $1.142 million, was spent for instruction. [NDOE]

The Locust Grove Public School is a K–12 district located east of Auburn and west of Brownville, Nebraska, with seven students during the 2005–2006 school year. Total receipts from local, county, state, and federal sources amounted to approximately $135,268 for the 2004–2005 school year, with approximately 51 and 48 percent coming from local and state revenue sources, respectively. Approximately 80 percent, or $93,526, was spent for instruction. [NDOE]

2.10.4 Transient Population

State tourism agencies were contacted to obtain the most recent tourist (transient) information (see Table 2.10-4). Tourist information for 2005 was not available for Kansas; therefore, 2004 data were incorporated and were assumed to remain constant for 2005. State level tourist data were used because finer resolution data are not available for the region. State tourist numbers, estimated at the county level population, were developed by multiplying the permanent county population by this ratio. The ratio was then used to estimate transient population numbers in Table 2.10-5.

Table 2.10-4
State Tourism Offices and Reported Visitor Numbers

State	Department	Data Year	Reporting Visitor Numbers
Iowa	Iowa Department of Economic Development Tourism Office	2005	29,600,000
Kansas	Kansas Department of Commerce, Travel and Tourism Division	2004	35,000,000
Missouri	Missouri Division of Tourism	2005	38,800,000
Nebraska	Nebraska Department of Economic Development	2005	19,600,000

References: Global Insight; IDED; Kaylen; NDED 2006

Table 2.10-5
2005 Transient/Permanent Ratio for 24 Reporting Counties

State/County	2005 Estimated Population	2005 Person Visits (per day)	Transient/ Permanent Ratio (per day)
Iowa			
Fremont	7,759	212	0.027
Mills	15,284	418	0.027
Montgomery	11,313	309	0.027
Page	16,253	444	0.027
Taylor	6,614	181	0.027
Kansas[a]			
Atchison	16,804	589	0.035
Brown	10,239	359	0.035
Doniphan	7,816	274	0.035
Jackson	13,535	475	0.035
Marshall	10,405	365	0.035
Nemaha	10,443	366	0.035

Table 2.10-5 (Continued)
2005 Transient/Permanent Ratio for 24 Reporting Counties

State/County	2005 Estimated Population	2005 Person Visits (per day)	Transient/ Permanent Ratio (per day)
Missouri			
Andrew	16,899	310	0.018
Atchison	6,246	114	0.018
Holt	5,081	93	0.018
Nodaway	21,710	398	0.018
Nebraska			
Cass	25,734	786	0.031
Gage	23,306	712	0.031
Johnson	4,695	143	0.031
Lancaster	264,814	8,085	0.031
Nemaha	6,965	213	0.031
Otoe	15,509	474	0.031
Pawnee	2,878	88	0.031
Richardson	8,732	267	0.031
Sarpy	139,371	4,255	0.031

a. Data for Kansas based on 2004, but assumed to be constant for 2005.

References: ESRI 2000; Global Insight; IDED; Kaylen; NDED 2006

2.10.5 Migrant Farm Labor

Migrant farm labor was reviewed using the U.S. Department of Agriculture's National Agricultural Statistics Service (NASS) data for 2002. NASS only began reporting such data in 2002, which is the most recent year with available data. Actual migrant worker numbers are not directly reported. County level data on hired farm labor from NASS reported that in 2002, none of 142 farms in Nemaha County, 178 farms in Otoe County, and 228 farms in Richardson County, Nebraska, hired migrant farm labor. A similar condition was reported for Atchison County, Missouri. [USDA]

2.10.6 Employment

The four counties most affected by CNS operations are those counties immediately surrounding the plant where the majority of employees reside. These four counties are Nemaha County, wherein lies the plant, Otoe County, Richardson County, and Atchison County, Missouri. As noted in Section 2.6, excluding the more heavily populated portions of Otoe County outside the 50-mile radius from CNS, the populations of these counties are generally in decline, which has a significant impact on the local economies. The trend of population decline has occurred for much of the past 100 years. Generally, unemployment is between three to six percent, but that may be affected by eligible labor emigrating from the area [USCB 2000f].

The employed population in Nemaha County, Nebraska, in 2000 was 3,687 with management, professional, and related occupations dominating total employment in the county at almost 34 percent (approximately 1,234 people employed) [USCB 2000f]. The largest employer in Nemaha County is NPPD at CNS with approximately 750 employees. The largest employers, after CNS, within Nemaha County are Ariens, Armstrong Cabinets (162 employees) and Peru State College (160 employees). [NPPD 2008c] Employment in the educational, health, and social services industry sector was the highest of all sectors in Nemaha County at 797 workers, or 22 percent of total employment. Transportation, warehousing, and utilities employed 636 people, or 17 percent. All other sectors of industry, including retail trade, agriculture, manufacturing, and food services, each employed less than 10 percent of the civilian labor force. Construction and maintenance employment in 2000 was 343 people, or 9.3 percent of the labor force. The annual payroll in Nemaha County was reported to be approximately $47.9 million in 2005. [USCB 2005] In 2000, per capita personal income was $17,004 and unemployment was approximately six percent. [USCB 2000f]

The employed population in Otoe County, Nebraska, in 2000 was 7,593 with management, professional, and related occupations dominating total employment in the county at more than 30 percent (approximately 2,321 people employed) [USCB 2000f]. Based on available information, the largest employer in Otoe County is American Meter Company with approximately 700 employees. After American Meter, the largest employers in Otoe County are Cargill Meat Solutions (550 employees), Arbor Day Farms (approximately 280 employees), and Nebraska City Public Schools (197 employees). [NPPD 2008e] Employment in the educational, health, and social services industry sector was the highest of all sectors in Otoe County at 1,443 workers, or 19 percent of total employment. The manufacturing industry employed 1,124 workers, or 15 percent, and retail trade workers accounted for 925 workers, or 12 percent of the labor force. All other sectors of industry, including agriculture, transportation, warehousing, utilities, and food services, each employed less than 10 percent of the civilian labor force. Construction and maintenance employment in 2000 was 638 people, or 8.3 percent of the labor force. In 2000, per capita personal income was $17,752 and unemployment was approximately four percent. [USCB 2000f]

The employed population in Richardson County, Nebraska, in 2000 was 4,343 with management, professional, and related occupations dominating total employment in the county at almost 29 percent (approximately 1,244 people employed). Employment in the educational, health, and social services industry sector was the highest of all sectors in Richardson County at 957 workers, or 22 percent of total employment. The manufacturing industry employed 584 workers, or 13 percent, and agriculture accounted for 448, or 10 percent of the labor force. Transportation, warehousing, and utilities employed 430 or nearly 10 percent. All other sectors of industry, including retail trade workers and food services, employed less than 10 percent of the civilian labor force each. Construction and maintenance employment in 2000 was 289 people, or 6.7 percent of the labor force. In 2000, per capita personal income was $16,460 and unemployment was approximately five percent. [USCB 2000f]

The employed population in Atchison County, Missouri, in 2000 was 3,025 with management, professional, and related occupations dominating total employment in the county at more than 32 percent (approximately 971 people employed) [USCB 2000g]. Based on available information, the largest employer in Atchison County is Community Hospital Fairfax with approximately 115 employees [Atchison County]. Employment in the educational, health, and social services industry sector was the highest of all sectors in Atchison County at 658 workers, or 22 percent of total employment. The manufacturing industry employed 388 workers, or 13 percent, and both agriculture and retail trade workers accounted for approximately 355 workers each, or 12 percent of the labor force, each. The transportation, warehousing, and utilities sector employed approximately 300 workers, or 10 percent of the civilian labor force. All other sectors of industry employed less than 10 percent each of the civilian labor force. Construction and maintenance employment in 2000 was 152 people, or five percent of the labor force. In 2000, per capita personal income was $16,956 in 2000 and unemployment was approximately 3.7 percent. [USCB 2000g]

2.11 Meteorology and Air Quality

The two closest locations to CNS where meteorological data are monitored are Lincoln and Omaha, Nebraska [NPPD 2008b, Section II-3.1].

Lincoln is near the center of Lancaster County in southeastern Nebraska. The surrounding area is gently rolling prairie. The western edge of the city is in the flat valley of Salt Creek, which receives a number of tributaries in or near the city and flows northeastward to the lower Platte River. The terrain slopes upward to the west and is sufficient to cause instability in moist easterly winds in the Lincoln area. Precipitation with westerly winds is infrequent since these winds move downslope. The upward slope to the west is a part of the general rise in elevation that begins at the Missouri River 45 miles east of Lincoln and culminates in the Continental Divide about 575 miles to the west. The Chinook (or foehn) effect often produces rapid rises in temperature here during the winter with a westerly shift of the wind [NPPD 2008b, Section II-3.1].

Omaha is situated on the west bank of the Missouri River. The river level at Omaha is approximately 965 feet above sea level and the rolling hills in and around Omaha rise to approximately 1,300 feet above sea level. The climate is typical continental with relatively warm summers and cold, dry winters. It is situated midway between two distinctive climatic zones, the humid east and the dry west. Fluctuations between these two zones produce weather conditions for periods that are characteristic of either zone, or combinations of both. Omaha is also affected by most storms or "lows" that cross the country. This causes periodic and rapid changes in weather, especially during the winter months [NPPD 2008b, Section II-3.1].

Sunshine is fairly abundant, ranging from approximately 50 percent of the maximum possible in the winter to 75 percent of the maximum possible in the summer. The temperature has exceeded 110°F on five separate occasions since the beginning of record-keeping in 1888. However, all five cases occurred in the period 1934-1939, which was a period of remarkable droughts. Hot winds, combining unusual wind force and high temperatures, occasionally cause serious injury to crops. [NPPD 2008b, Section II-3.1.1]

The majority of winter outbreaks of severely cold air from northwestern Canada move over the Lincoln area. However, the centers of some of these cold air masses move southward and far enough to the east that their full effect is not felt here. The average frost-free date in the spring is April 14 and the first autumn frost occurrence of 32°F or lower is October 20. The longest freeze-free period on record is 219 days in 1924 and the shortest period is 152 days in 1885. [NPPD 2008b, Section II-3.1.1]

General information on temperature inversions in the central plains obtained from the U.S. Weather Bureau indicates that the mid-section of the country has a pronounced continental type climate, and as such, has inversion frequencies closely related to the diurnal cycle. That is, there is a definite tendency for nocturnal stabilization and daytime instability in the lower levels. In general, inversions occur 20 to 30 percent of the time during the spring and summer, while during the fall and winter months inversions may be expected about 30 to 45 percent of the time [NPPD 2008b, Section II-3.1.1].

Most of the higher winds are caused by deep low pressure systems of great intensity, but are a rare occurrence. In the summer the higher winds are associated with thunderstorms. There is much sunshine, averaging 64 percent of the possible duration. Moderate to low humidity prevails except for short periods during the summer when warm, moist, tropical air occasionally reaches this area [NPPD 2008b, Section II-3.1.2].

Since 1950 there have been 2,457 tornadoes recorded in Nebraska for an average of 49 tornadoes in the state of Nebraska every year. The most recent five years between March 31, 2002 and March 31, 2007 were somewhat more active, with approximately 61 tornadoes per year [USDOC 2007a]. On average, 69 percent of all tornadoes are considered weak, with winds less than 110 miles per hour; 29 percent are considered strong, with winds of 111-205 miles per hour; and only 2 percent are considered violent, with winds above 206 miles per hour [NSSL]. According to the National Climatic Data Center, Nemaha County has had a total of 13 tornadoes since 1950, eight of which have been F1 or less and one of which was an F3 (April 1963) [USDOC 2007b]. This means that there is an average of one tornado in Nemaha County every four years. Based upon this, the probability of a tornado striking the site is small.

Tornadoes are most prevalent during May and June. About 87 percent of all tornadoes come from a westerly direction. Nearly 60 percent approach from the southwest, and 82 percent of all tornadoes are recorded as having occurred between noon and midnight. Almost 42 percent occur between 3 and 7 pm with more tornadoes occurring between 4 and 6 pm than during any other hours [NPPD 2008b, Section II-3.1.2].

During the crop season in Nebraska, April through September, over three-fourths of the annual precipitation is received. Nighttime thundershowers are predominant in the summer months, so that needed moisture is received during much of the growing season at a time of least interference with outdoor work. Since 1884 the annual precipitation has exceeded 40 inches on five occasions and dropped below 20 inches ten times. The largest annual rainfall amount recorded was 41.33 inches in 1965, the least was 14.09 inches in 1936 [NPPD 2008b, Section II-3.1.3].

Snowfall is about 25 inches in an average season. The largest recorded amount is the 59.4 inches that fell during the 1914–15 season. Much of the snow is light and melts rapidly. However, at times a considerable amount accumulates on the ground, the greatest recorded depth being 21 inches in February 1965 [NPPD 2008b, Section II-3.1.3].

Most of the precipitation in Omaha falls during showers or thunderstorms. Of the total precipitation, about 75 percent falls during the six month period of April to September, mostly as evening or nighttime showers and thunderstorms. Although winters are relatively cold, precipitation is light, with only 10 percent of the total annual precipitation falling during the winter months [NPPD 2008b, Section II-3.1.3].

During recent years, Nebraska has suffered through an extended period of below average rainfall. During the period of January 1, 1999, through August 31, 2006, Eppley Airfield in Omaha received only 95.2 percent of normal average rainfall, which is 30 inches per year. From January 1, 1999–August 31, 2006 there was an 11.15-inch rainfall deficit compared to normal. [UNL]

The Lincoln and Omaha annual climatological data give the total number of days of heavy fog/ year plus the three months during which the most snow fell, the day on which the most snow fell and the total amount of snow for that year for the years 1952–1971 [NPPD 2008b, Section II-3.2.1, Tables II-3-1 and II-3-2].

With regards to rainfall within the site vicinity, data from the U.S. Department of Commerce Weather Bureau, climatological summary from 1931 to 1960 for the Falls City, Nebraska, area (28 miles south of the plant) indicate a maximum 24 hour rainfall total of 6.00 inches. Values obtained from similar reports for the Omaha and Lincoln, Nebraska, areas substantiate this value. Omaha and Lincoln are north and west of the plant site respectively [NPPD 2008b, Section II-3.1.3].

From the aforementioned reports, which are summaries of recorded rainfall rates, a rainfall intensity of three inches per hour is indicated as being appropriate for this area. The following documents were also reviewed to determine the rainfall rate [NPPD 2008b, Section II-3.1.3].

- National Standard Plumbing Code as suggested by National Association of Plumbing Heating Cooling Contractors, 1971 edition, Table A indicates that the maximum rate of rainfall for the Lincoln and Omaha, Nebraska, areas is 7.0 inches/hour for a five-minute duration for a ten-year return period. Converting this value to a rate equivalent to that used in the design of drainage facilities yields 3.1 inches per hour for a 60 minute duration and a ten-year return period [NPPD 2008b, Section II-3.1.3].

- U.S. Department of Commerce Weather Bureau and U.S. Department of the Army, Corps of Engineers, Hydrometeorological Report No. 33 dated April 1956, from which it was determined that the "probable maximum precipitation" for the site area is 23.5 inches total rainfall for a 24 hour period. This value has been determined from Figure 17 (August) of the aforementioned report. Converting this value to a rate equivalent to a one hour rainfall, by using the Civil Engineering Bulletin No. 528, revised March 1965, published by the Department of the Army, office of the Chief of Engineers, which determines a rainfall rate per hour from a 24 hour period, the "probable maximum precipitation" for the site area was conservatively determined to be 3.56 inches per hour for a ten-year return period [NPPD 2008b, Section II-3.1.3].

The States of Nebraska, Missouri, Kansas, and Iowa are located within 50 miles of the CNS plant site. A review of state and federal regulatory agency websites indicates that there are no counties in non-attainment status for any of the listed priority pollutants (particulates, including PM_{10} and $PM_{2.5}$; nitrogen oxides; sulfur oxides; carbon monoxide) or criteria pollutants (lead and ozone). The only counties in these four states that are in a non-attainment status are located in eastern Missouri, more than 250 miles southeast of CNS. These counties are located in the St. Louis Standard Metropolitan Statistical Area and are in non-attainment status for at least one of the following: ozone, $PM_{2.5}$, or lead [USEPA 2006a].

Class I areas, as defined in the Clean Air Act, are the following areas that were in existence as of August 7, 1977: national parks over 6,000 acres, national wilderness areas and national memorial parks over 5,000 acres, and international parks. There are no Mandatory Class I Areas located within 50 miles of CNS. [USEPA 2006b]

2.11.1 Meteorological System

The current CNS meteorological system consists of two monitoring sites located at a grade level of approximately 889 feet AMSL. A 100-meter tower and an auxiliary 10-meter tower, located approximately 3,230 feet and 1,597 feet, respectively, from the northwest corner of the reactor building are used to gather the meteorological data. In 2008, a new 100-meter tower is being erected and fully instrumented approximately 2,000 feet northwest of the original 100-meter meteorological tower erected in 1981. The equipment and monitoring system for the new 100-meter tower is nearly identical to that currently operational on the original 100-meter tower. The meteorological monitoring system associated with the new 100-meter tower is to become fully operational in April 2009 and is described below.

The 100-meter tower is fully instrumented with independent dual sensors (Systems A and B) for wind speed, wind direction, and temperature at three levels: 10m, 60m, and 100m. System A contains Met One sonic sensors for measuring wind speed and wind direction, and Climatronics temperature sensors. A Climatronics relative humidity sensor is mounted at the 10m level and a Climatronics tipping bucket rain gauge with Alter wind shield is mounted at the base of the 100m tower. System A also includes a Climatronics Station Pressure Sensor mounted inside the main shelter at the base of the tower. Three differential temperatures are calculated from the temperature sensors for 100m-10m, 100m-60m, and 60m-10m. Identical to System A, System B contains Met One sonic sensors for measuring wind speed and wind direction and Climatronics temperature sensors. Three differential temperatures are calculated from the temperature sensors for 100m-10m, 100m-60m, and 60m-10m. The wiring for each system is run through separate conduit from the tower base to each measurement level. Two independent elevators are mounted on different tower faces with two electric winches that carry the six instrument carriages up and down the tower for maintenance and calibration. To minimize tower interference, System A is mounted on the south face in the direction of the mean wind, and System B is mounted on the northwest face in the direction of the secondary peak in the mean wind.

The signals from the tower instrumentation are interfaced with the meteorological shelter equipment, including six Campbell Scientific, Inc., CR3000 Data Loggers and two off-the-shelf heavy-duty-grade personal computers (PCs). Three of the dataloggers serve as interfaces between the tower and Climatronics temperature system. All of the data loggers are programmed to receive meteorological data from both the A and B sensors on the tower. Three of these data loggers are programmed to produce and store 15-minute and hourly averaged values for all parameters, i.e., wind, temperature, dew point, precipitation, etc. Two of these data loggers are each hard wired into an independent PC, where data from each of the A and B sensors are stored.

Two of the dataloggers serve as redundancy in the event of a single failure while a third is set up with a modem connection and telephone line to access the data remotely in the event the line from the 100m shelter to the CNS Plant Computer (PMIS) is interrupted or fails. These 15-minute and hourly averages are transmitted from the two main dataloggers to two PCs in the 100m shelter. Data validation software, based on CNS site-specific meteorological criteria, is then run on each 15-minute and hourly averaged data. Data that fail specific tolerance and/or meteorological checks are flagged and color coded before being transmitted each 15 minutes and hourly to the PMIS using line drivers. A validated 15-minute and hourly data string that represents the best data from both the A and B systems is also generated and transmitted to PMIS from the 100m shelter PCs.

Backup meteorological data may be obtained from the National Weather Service Office located in Valley, Nebraska, which offers projected wind speed, wind direction, and temperature up to the 10,000-foot level. Information can be obtained by telephone or by the National Warning System. [CNS 2008c, Section 7.5.2]

2.11.2 Radiological Environmental Monitoring Program Air Sampling Program

Continuous air sampling is performed at 11 locations using continuous air samplers mounted in louvered enclosures similar to U.S. Weather Bureau instrument shelters. Air sampling consists of continuous 7-day samples collected by drawing air through membrane filters, and where applicable through charcoal cartridges, at a uniform rate of 1 cubic foot per minute. The filter housings are six feet above ground level to reduce dust loading of the filters and minimize the influence on sample activity of radon and its daughters emitting from the soil. All filters are changed weekly. Volume of air sampled is computed from elapsed running time and calibrated air flow rate. Gross beta analysis is performed on each particulate filter. The particulate filters are also composited quarterly by location and analyzed for gamma-emitting radionuclides. Charcoal cartridges are analyzed for radioiodine using gamma spectral analysis.

As a note, Table D4.1-1 of the CNS ODAM requires only five locations for the collection of airborne particulates and Iodine samples. However, NPPD is currently collecting air samples at a total of 11 locations to help ensure that at least five stations are operational at all times.

2.12 Historic and Archaeological Resources

The Nebraska and Missouri State Historic Preservation Offices (SHPO) Environmental Review programs are a planning process that helps protect Nebraska and Missouri historic and cultural resources from the potential impacts of projects that are funded, licensed, or approved by state or federal agencies. Under Section 106 of the National Historic Preservation Act (NHPA), the SHPO's role in the review process is to ensure that effects or impacts on eligible or listed properties are considered and avoided or mitigated during the project planning process. Nebraska's and Missouri's programs include:

- Section 106 of the NHPA of 1966. The Nebraska SHPO and Missouri SHPO review projects when a federal agency is involved with the project. It is the federal agency's responsibility to seek comments about the project from the SHPO.

- The Nebraska SHPO implements Section 106 of the NHPA in the State of Nebraska. It is the responsibility of the Nebraska SHPO under the NHPA of 1966 (as amended) to prepare and implement a comprehensive statewide historic preservation plan (Section 101), and conduct review and compliance activities (Section 106) with federal agencies which have projects in the state of Nebraska.

- Missouri Revised Statutes Chapter 253 Section 408-412 (State Historic Preservation Act). The State Historic Preservation Office is located in the Department of Natural Resources and is responsible for establishing, implementing, and administering federal and state programs or plans for historic preservation, and developing a comprehensive statewide survey of historic, archaeological, architectural, and cultural properties and maintain inventories of such properties.

The Nebraska SHPO is the primary contact for the two historic registers that track Nebraska's historic resources; the Missouri SHPO is the primary contact for the historic registers that track Missouri historic resources. The National Register of Historic Places (NRHP) is the official federal listing of significant historic, architectural, and archaeological resources.

2.12.1 Prehistoric Era

There are five major subdivisions in regional chronologies, based primarily on differences in lifeways and conditions. These include the Paleo-Indian, Archaic, Woodland, Plains Village, and Historical periods. The First Arrivals period is being added as an introduction to the Paleo-Indian period and is not a formally recognized archeological period. [Adair]

First Arrivals

CNS is situated on the eastern edge of the Central Great Plains and northwest edge of the Missouri Prairie-Timberlands in the Missouri River Valley. The area is a broad valley between loess bluffs with extremely deep sediments of Holocene and Pleistocene age. At some point near the end of the Pleistocene, the first people began filtering into the region. Who these people were or where they came from remains unknown. There is, however, a growing body of evidence that indicates a "First Arrivals" archeological period that precedes the Paleo-Indian period. A handful of sites in the Central Plains date between about 13,000 and 17,000 years ago [Hofman, pp. 41-45]. Most of these sites have circumstantial evidence for human occupation. At La Sena (Southwestern Nebraska), a dismembered mammoth showed percussion-like fractures on long bones such as would result from smashing the bones to extract the rich marrow inside [Holen, pp. 88-89]. Acceptance of archeological remains older than the long accepted Clovis Culture remains controversial [Hofman; Holen].

Paleo-Indian Period

The Clovis Culture, around 11,500 years ago, is the earliest dated and accepted group in the New World. The culture was the oldest of the Paleo-Indian or Big Game Hunters Period which existed at the end of the last Ice Age. Conditions at the time were colder and wetter than today and the eastern edge of the Central Plains was a broad open grassland occupied by great herds of now extinct animals. Small nomadic bands, probably extended family groups of a dozen or less followed the large herds and subsisted off the occasional kill of a mammoth or other large animal, and foraging for local plant and smaller game resources. Distinctive point styles and variations in other tool types defined the Clovis, Folsom, Midland, and later Paleo-Indian groups. [Hofman, pp. 47-78] Period camp and kill sites are generally found in areas where deposits of the right age are exposed. No early sites are known from the Missouri Valley in Nemaha or Atchison Counties, but such resources may exist as deeply buried deposits along relic terraces.

Archaic Period

Around 8,000 years ago, the Paleo-Indian period was replaced by the Archaic period. The Archaic period began as a slow transition from nomadic wandering to a more systematic exploitation of particular areas. The Dalton Culture (circa 8,500 to 7,500 years ago) is seen by many as the last of the Paleo-Indian peoples, and by others as the first of the Archaic peoples. Earlier Paleo-Indian influences appear to have come from the Plains to the west. Dalton Culture influence appears to have originated in the Woodlands to the east, marking a transition between the two cultures/periods. [O'Brien and Wood, pp. 51-52] The Archaic period is subdivided into the Early Archaic Logan Creek Complex (circa 7,500 to 6,000 years ago), Middle Archaic

Jacomo Complex (circa 5,500 to 5,000 years ago) and Late Archaic Nebo Hill Complex (circa 4,500 to 2,500 years ago) [Nelson, pp. 16-17]. Archaic foragers appear to have begun exploiting a wider range of more localized resources with a wider range of tool forms. Climatic conditions entered a warmer/dryer period that reached a thermal maximum (also known as the Hypsithermal) around 5,500 years ago. Conditions during the Hypsithermal were extremely arid and people retreated to the east, rarely venturing out onto the open plains. By 3,000 years ago, conditions had ameliorated and the Nebo Hill Culture (centered around the Kansas City area) had begun to expand up the Missouri Valley. Larger semi-permanent warm weather villages were located along the higher terraces along the valley margins. Winter encampments were located along smaller order streams in the uplands. Fiber tempered pottery found at some sites shows clear influences from the developing Woodland cultures to the east. Period sites identified in the CNS area are generally lithic scatters with various dart points (or lacking diagnostics) identified as "Archaic" by the recording archeologist. [Nelson, p. 16]

Plains Woodland Period

The Woodland or Early Ceramic period (circa 2,500 to 1,000 years ago) was heavily influenced by the developing cultures to the east. The first signs of sedentary villages, bow and arrow technology, and elaborate ceremonialism with stone-lined graves and mounds occurred in the Woodland period. Indigenous groups began increasing in population and developed during the Middle Woodland period (circa 2,000 to 1,500 years ago) into the Valley focus. The Valley focus spread over the entire eastern half of Nebraska, western part of Iowa, and parts of South Dakota and Kansas. These people were essentially simple forager-gardeners living in small hamlets along the higher valley terraces. The Kansas City Hopewell was influenced by the Hopewell Culture developing to the east. The Kansas City Hopewell was somewhat more complex than the Valley focus through a diffusion of ideas and trade materials. Most distinctive of the Hopewell influences was the introduction of burial mounds, with grave offerings indicative of a more elaborate level of ceremonialism. [O'Brien and Wood, pp. 58-79]

A number of Middle Woodland sites have been archeologically investigated in both Nemaha and Atchison Counties. These sites are located along higher terraces at the base of the loess bluff line or along higher levee terraces across the bottoms, on either side of the river. Several probable period sites have also been recorded along old levee terraces on the Missouri side of the valley. [Sturdevant 1982; Sturdevant 1991; Sturdevant 1996]

The abandonment of the larger Middle Woodland "villages" in favor of smaller camps and individual home sites were evident in the Late Woodland sub-period Sterns creek phase (circa 1,500 to 1,100 years ago), generally in the uplands away from the river bottoms. The number of burial mounds increased dramatically. Most of the mounds were small and low with distinctive rock structures. The mounds are found throughout the bottoms and along prominent points along the loess bluff line. Most of the mounds in the bottoms have been lost to plowing, but rock structures around graves are commonly found on bottom terraces and points on both sides of the river. [Nelson, pp. 17-18]

Plains Village Period

By about 1,000 years ago, groups had coalesced into permanent villages. The Nebraska phase was the pre-contact expression in the Missouri Valley between the approximate locations of St. Joseph and Sioux City. The Nebraska phase was closely related to the Central Plains tradition cultures to the west, but was also similar to the Pomona and Steed-Kisker phases to the south, which show Mississippian influences. The Plains Village peoples were farmers and bison hunters living in larger villages along the river terraces. Smaller hamlets, hunting camps, and kill sites have been recorded in the uplands. The culture disappeared about 700 years ago for mostly unknown reasons. Conditions during the fourteenth century were becoming warmer and dryer, and drought may have forced people out of traditional garden farming areas. There was also an influx of people coming onto the Plains from the northeast and west that may have made living in the region untenable. The Plains Apache roamed and settled much of the western two-thirds of Nebraska about this time, while Siouan groups were beginning to range across the eastern portion of the region. The area was mostly unoccupied or infrequently visited by neighboring groups between the fourteenth and eighteenth centuries. [Ludwickson and Bozell, pp. 110-131; Nelson, pp. 21-22]

2.12.2 Historic Era

Historic Tribes and Fur Traders

The eighteenth and nineteenth centuries was a period of a great deal of displacement of peoples, particularly from the upper Mississippi Basin to the east. On July 13, 1804, the Lewis and Clark expedition passed the remains of a trading post said to have been where Benet of St. Louis traded with the Otoe and Pawnee for two years. A day earlier, the party passed an abandoned Kansa village. Other groups that passed through the area included the Omaha, Osage, Delaware, Pottawatomi, Sauk and Fox, Winnebago, and Miami. [Nelson, pp. 21-22]

A ten-mile radius around the CNS facility includes land primarily within Nemaha County, Nebraska, and Atchison County, Missouri, although a portion of northeastern Richardson County, Nebraska, and northwest Holt County, Missouri, are also included. The recorded history of the vicinity of CNS began with the explorations of Lewis and Clark in 1804, although French *couers de bois* were familiar with the area for the better part of the previous century. On July 15, 1804, the Lewis and Clark party encamped along a rise on the west side of the river, just below a large sand bar in the channel next to a wide flat plain on the west side of a bend. There is some dispute about the location of the actual encampment at Langdon Bend (also known as Langdon Landing) with Nebraska researchers placing the camp on the Missouri side of the present river channel and Missouri historians placing the camp roughly where the CNS facility now stands. The river has migrated westward over the past 200 years and the sand bar in the old river channel is now a levee terrace half a mile east of the river channel. The southern end of the old river bank is located on the Missouri side of the river and the encampment was potentially near the present Langdon Landing in Missouri (see Figure 2.12-1). [Plamondon, Map 57]

Historic accounts of the Lewis and Clark expedition describe a beautiful valley filled with grape vines and wild cherries, which undoubtedly attracted the first settlers to the area in the 1840s

[Plamondon]. Figure 2.12-1 provides a cartographic reconstruction of the area at the time of Lewis and Clark's expedition. Settlement of the area was gradual, but steadily spread along the eastern side of the river with Holt County being formed in 1839 [National Historical Company, p. 611]. Atchison County was separated from Holt County in 1847 with established communities at Langdon, Rock Port, Phelps City, and Watson and the County Seat at Tarkio to the east. Nebraska Territory was established by the Kansas-Nebraska Act of 1854 and Nemaha County was established a year later. Prior to 1854, a small trading post had been established in the southeast corner of what would later be Nemaha County, and several interloper families had settled on small farms in the area [Heritage]. Settlement along the river increased dramatically in the 1850s with Brownville, Nebraska, being established as a major steamboat port and shipping point. The towns of Nemaha, Brownville, and Peru continued to grow along the bluff line above the Missouri River with speculation of a coming railroad, but settlement of the interior away from the river remained low until the Nebraska Railway Company actually reached the area in 1874. The 1865 Government Land Office plat for Township 5 North, Range 16 East shows two farmsteads in the area now occupied by the CNS facility (see Figure 2.12-2).

The coming of the Nebraska Railway Company in 1874 and Missouri Pacific Railroad in 1881 spurred settlement of the interior at the expense of the bluff top towns, and Brownville rapidly lost its preeminence as the principle city in the area [Heritage, pp. 3-4]. The building of the Brownville Bridge in 1939 connected the two sides of the river but did little to alleviate the town's economic downfall. A massive fire in 1903 destroyed much of Brownville. Nemaha fared slightly better with surrounding orchards and wheat fields, but a severe freeze in 1940 killed most of the fruit trees. The Missouri communities experienced a similar fate, which culminated with the towns being by-passed by construction of Interstate 29 in the 1960s.

The region today has seen a rebirth of sorts with the development of recreational and tourist offerings on both sides of the river and the coming of the CNS facility. Attractions to the area include Arbor Day Farms at Nebraska City, Indian Cave State Park at Barada, Squaw Creek National Wildlife Refuge at Mound City, numerous wildlife conservation and public hunting areas, and restoration of the remaining portions of the town of Brownville.

CPPD was founded in 1939 to generate, and provide transmission, distribution, and sale of, electrical energy. CPPD planned and financed the construction of CNS and became NPPD on January 1, 1970. NPPD is a public corporation and political subdivision of the State of Nebraska. [NPPD 1971, Section II-2.1]

Engineering studies leading to the decision to construct a nuclear facility were initiated in early 1965. Work on the then 1,090-acre plant site near Brownville, Nebraska, began early in 1968. Excavation for the plant involved moving more than 760,000 cubic yards of earth, with construction completed in 1972.

2.12.3 Cultural Resource Properties

No prehistoric or historic sites eligible for listing on or already listed on the NRHP or the state historic registers are located on the CNS site (see Attachment B). Historic archaeological sites have been identified within a 6-mile radius of the site. Historic sites are areas of land that usually contain aboveground historic structures and objects such as old homes, barns, churches, cemeteries, business districts, and residential districts. Research of the Nebraska and Missouri SHPO records shows no eligible or listed historic sites on the CNS site, although there are historic or pre-historic sites nearby.

A great deal of archeological and historical research has been conducted in both Nemaha County, Nebraska and Atchison County, Missouri. The loess bluff line along either side of the Missouri River Valley and higher terraces along the bottoms were favored as prehistoric habitation and burial sites and also by early-day homesteaders. There are no known burial sites on the CNS property.

Based on available records, only one previous historical study has been conducted on the CNS property. The William Dawson House (Site # NH00-69), located in the southwest corner of the site near the bluff, was recorded in Nebraska historic archives but not included on the National Register of Historic Places. The Dawson House was torn down in 1970, shortly after it was recorded, according to the Nebraska SHPO. The Dawson House site, recorded in the Nebraska SHPO office files, was not revisited during the Phase 1A Literature Review and Archeological Sensitivity Assessment walkover conducted at CNS in April 2007 and March 2008.

The Whitten Archeological Site, Archeological Survey No. 25NH4, is located immediately north of the CNS property. The Whitten Site is a prehistoric mound site where graves were excavated on a bluff point.

Pre-historic and historic review of documentary sources were completed at the Nemaha County and Atchison County Historical Societies and Libraries, Nebraska Historic Preservation Office, and the Missouri Department of Natural Resources. Databases at the Nebraska SHPO and Missouri SHPO Offices in Lincoln and Jefferson City were consulted for up-to-date information on historical properties and localities within a 10-mile radius of CNS. Both historic and archeological sites are summarized in Tables 2.12-1 and 2.12-2.

Table 2.12-1
Missouri- and Nebraska-Listed Historic Sites

Site Name	Nearest City or Town	Listed NRHP
Atchison County, Missouri		
Atchison County Memorial Building	Rock Port	Yes
Bend Center School	Langdon	No
Brownville Bridge	Phelps City	Yes
Cooper School	Langdon	No
Cottonwood Grove	Rock Port	No
Excelsior School	Langdon	No
John Dickinson Dopf Mansion	Rock Port	Yes
Gibbs Site	Watson	Yes
Langdon School	Langdon	No
Mule Barn Theatre	Tarkio	Yes
Northwestern Loess Hills	Langdon	No
Phelps City School	Rock Port	No
St. Oswald's Protestant Episcopal Church	Skidmore	Yes
St. Peters Church	Langdon	No
Thompson-Campbell Farmstead	Langdon	Yes
Union School	Rock Port	No
Walnut Inn	Tarkio	Yes
Nemaha County, Nebraska		
NH00-003: McComas House	Brownville (Rural)	No
NH00-004: Furnas House and Nursery	Brownville (Rural)	No
NH00-005: Aspinwall Townsite	Nemaha (Rural)	No
NH00-007: McCandless School	Nemaha (Rural)	No

Table 2.12-1 (Continued)
Missouri- and Nebraska-Listed Historic Sites

Site Name	Nearest City or Town	Listed NRHP
NH00-009: Barn	Nemaha (Rural)	No
NH00-015: Bennet-Furnas House	Brownville (Rural)	Yes
NH00-016: Barn	Brownville (Rural)	No
NH00-022: Barn	Brownville (Rural)	No
NH00-023: Maple Grove School	Nemaha (Rural)	No
NH00-026: Farmhouse	Brownville (Rural)	No
NH00-057: Den House	Brownville (Rural)	No
NH00-059: Brick Farmhouse	Brownville (Rural)	No
NH00-069: Dawson House (On property, demolished)	Nemaha (Rural)	No
NH00-072: Barns	Brownville (Rural)	No
NH00-085: Brownville Bridge	Brownville (Rural)	Yes
NH00-103: American Foursquare Farmhouse	Nemaha (Rural)	No
NH00-104: Deroin Creek Bridge	Nemaha (Rural)	No
NH00-105: Deroin Creek Bridge	Nemaha (Rural)	No
NH00-106: Deroin Creek Bridge	Nemaha (Rural)	No
NH00-107: Farmstead with Queen Anne House	Nemaha (Rural)	No
NH00-108: Barn	Nemaha (Rural)	No
NH00-109: Front-Gabled Farmhouse	Nemaha (Rural)	No
NH00-110: Bungalow Farmhouse	Nemaha (Rural)	No
NH00-111: Nemaha Cemetery	Nemaha (Rural)	No

Table 2.12-1 (Continued)
Missouri- and Nebraska-Listed Historic Sites

Site Name	Nearest City or Town	Listed NRHP
NH00-112: Farmstead with Bungalow House	Nemaha (Rural)	No
NH00-113: Farmstead with Side-Gabled House	Nemaha (Rural)	No
NH00-114: American Foursquare Farmhouse	Nemaha (Rural)	No
00-115: Prairie Cube Farmhouse	Nemaha (Rural)	No
NH00-116: Farmstead with Bungalow House	Nemaha (Rural)	No
NH00-117: Happy Hollow Creek Bridge	Nemaha (Rural)	No
NH00-118: Bungalow Farmhouse	Nemaha (Rural)	No
NH00-119: Happy Hollow Creek Bridge	Nemaha (Rural)	No
NH00-121: Bungalow Farmhouse	Brownville (Rural)	No
NH00-122: Farmstead with Side-Gabled House	Brownville (Rural)	No
NH00-123: American Foursquare Farmhouse	Nemaha (Rural)	No
NH00-124: Bridge over Unnamed Creek	Nemaha (Rural)	No
NH00-127: Queen Anne Farmhouse	Nemaha (Rural)	No
NH00-135: Bridge over Whiskey Run	Nemaha (Rural)	No
NH00-136: American Foursquare Farmhouse	Nemaha (Rural)	No
NH00-267: Bridge over unnamed creek	Peru (Rural)	No
NH00-268: Railroad Bridge	Brownville (Rural)	No

Table 2.12-1 (Continued)
Missouri- and Nebraska-Listed Historic Sites

Site Name	Nearest City or Town	Listed NRHP
NH00-269: Front-Gabled House	Brownville (Rural)	No
NH00-270: Locust Grove District 32 School	Brownville (Rural)	No
Town of Brownville, Nebraska		
NH03-001: Anthony P. Cogswell House (C1868)	NEC 1st and Nemaha	Yes
NH03-003: Burlington Northern Depot (1874-75)	1st Street near Main	No
NH03-004: Shadley House	S side Water between 1st and Wharf	No
NH03-005: George W. Neely House (1867)	SWC Wharf and Water	No
NH03-006: Side-Gabled House	SEC 1st and Atlantic	Yes
NH03-007: Muir House (1870-72)	SEC 2nd and Atlantic	Yes
NH03-009: Side-Gabled House	NWC 3rd and Atlantic	No
NH03-010: John L. Collhapp House (1869)	N side Atlantic between 3rd and 4th	Yes
NH03-014: Bratton-Minick House (C1864)	NEC 6th and Atlantic	Yes
NH03-015: Nace House (C1874)	S side Atlantic between 6th and 7th	Yes
NH03-016: Hoover House (C1973)	SEC 6th and Nemaha	Yes
NH03-017: Frame House (ca 1873)	NEC 6th and Nemaha	No
NH03-019: Lewis Hill House (1869)	SWC 6th and Water	Yes

Table 2.12-1 (Continued)
Missouri- and Nebraska-Listed Historic Sites

Site Name	Nearest City or Town	Listed NRHP
NH03-020: Furnas House (C1868)	E side 6th Street between Richard and Water	Yes
NH03-021: Brown-Carson House (1860-1880)	SEC 3rd and Main	Yes
NH03-022: Brownville House (ca 1880)	Main between 2nd and 3rd	No
NH03-023: Opera House (ca 1880)	Main between 2nd and 3rd	No
NH03-024: Brownville Post Office	Main between 2nd and 3rd	No
NH03-025: Middleton Shop Reconstruction (1859)	SEC 2nd and Main	Yes
NH03-026: Lone Tree Saloon-Brownville Mills (C1868)	Main between 1st and 2nd	Yes
NH03-027: Masonic Building (C1870)	Main between 2nd and 3rd	Yes
NH03-028: Carson Carriage House (C1880)	E side 3rd between Water and Main	Yes
NH03-029: Steel Truss Bridge (ca 1910s)	3rd Street across Brewery Run	
NH03-030: Vernacular House (ca 1885)	Main between 3rd and 4th	Yes
NH03-031: Side-Gabled House (ca 1875)	Main between 3rd and 4th	No
NH03-033: Cyrus Polock House (1871-72)	Water between Main and Water	Yes
NH03-034: Abbot G. Gates House (1859)	4th between Main and Water	Yes
NH03-034: Gates-McLaughlin House	SWC 4th and Water	No
NH03-035: John J. Mercer House (1866-92)	SWC 4th and Water	No

Table 2.12-1 (Continued)
Missouri- and Nebraska-Listed Historic Sites

Site Name	Nearest City or Town	Listed NRHP
NH03-036: Brownville School (ca 1910s)	SWC 3rd and Water	No
NH03-037: Methodist Church (1859)	Water between 4th and 5th	Yes
NH03-039: Lewis-Wibley House (1870)	618 Main Street	Yes
NH03-040: Thompson-Lowman House (1860)	NEC 5th and Water	Yes
NH03-041: Side-Gabled House (ca 1870s)	504 Main Street	No
NH03-042: Front-Gabled House (ca 1870)	Main between 4th and 5th	No
NH03-044: Benson M. Bailey House (1877-78)	N side Main between 4th and 5th	Yes
NH03-045: Worthing-Baker House (C 1863)	SWC Main and 4th	Yes
NH03-046: Gabled Ell House (ca 1890)	NEC Main and 4th	No
NH03-047: Atkinson-Tipton House (C 1869)	S end 4th Street	Yes
NH03-048: Theodore Hill House (1860s)	NWC 1st and Allen	No
NH03-050: The Beehive (C 1864)	2nd between Water and Richard	Yes
NH03-052: Robert C. Dueser House (1860-66)	Water between 1st and 2nd	Yes
NH03-053: Village Theater-Old Christian Church (C 1903)	Water between 2nd and 3rd	Yes
NH03-055: Timothy McLaughlin House (C 1862-66)	SEC Richard and 1st	Yes
NH03-056: Steven's House (1866)	Nebraska between 1st and 2nd	Yes

Table 2.12-1 (Continued)
Missouri- and Nebraska-Listed Historic Sites

Site Name	Nearest City or Town	Listed NRHP
NH03-057: Side-Gabled House (ca 1870s)	NWC 2nd and Nemaha	No
NH03-059: Merriwether Lewis Dredge (1932)	Brownville State Recreation Area	Yes
NH03-062: Walnut Grove Cemetery (ca 1860s)	N end 7th Street	No
NH03-065: Brownville Cannon	Brownville Wheel Museum	No
NH03-066: Frame Cupola	SWC Water and 6th	No
NH03-067: Brownville Wheel Museum (ca 1920s)	Main between 2nd and 3rd	No
NH03-068: Brownville Bazar (1890s)	Main between 2nd and 3rd	No
City of Nemaha, Nebraska		
NH08-003: Christian Church	WC 3rd and Main	No
NH08-006: Nemaha United Methodist Church	1st Street between Nebraska and Otoe	No
NH08-010: Nemaha Public Library	1st Street between Main and Washington	No
NH08-011: Pyramid-Rood House	607 5th Street	No
NH08-012: Side-Gabled House	EC 3rd and Main	No
NH08-013: Nemaha Community Building	NC 1st and Main	No
NH08-014: House	NC 4th and Washington	No
NH08-015: Bungalow House	WC Main and Kansas	No
NH08-016: Queen Anne House	Kansas between Nebraska and Otoe	No
NH08-017: Store	WC 1st and Washington	No

Table 2.12-1 (Continued)
Missouri- and Nebraska-Listed Historic Sites

Site Name	Nearest City or Town	Listed NRHP
NH08-018: Front-Gabled House	715 1st Street	No

References: MDNR 2007b; NSHS

Table 2.12-2
Missouri- and Nebraska-Listed Archeological Sites

Site No.	Nearest City or Town	Listed NRHP
Atchison County, Missouri		
23AT1	Not Listed	No
23AT2	Not Listed	No
23AT3	Not Listed	No
23AT4	Rock Port	No
23AT5	Not Listed	No
23AT7	Not Listed	No
23AT8	Not Listed	No
23AT9	Not Listed	No
23AT10	Not Listed	No
23AT12	Not Listed	No
23AT20	Not Listed	No
23AT21	Rock Port	No
23AT30	Rock Port	No
23AT31	2.5 miles South of Rock Port	No
23AT32	Not Listed	No
23AT34: fs-c10	Not Listed	No
23AT35: FSAT1	Not Listed	No
23AT36	Rock Port	No
23AT37	Not Listed	No

Table 2.12-2 (Continued)
Missouri- and Nebraska-Listed Archeological Sites

Site No.	Nearest City or Town	Listed NRHP
Nemaha County, Nebraska		
NH 4: Whitten	Not Listed	No
NH 5: Osborne	Not Listed	No
NH 10: Morehead	Not Listed	No
NH 13: Hyatt Place	Not Listed	No
NH 14: Heineman	Not Listed	No
NH 19:	Not Listed	No
NH 20	Not Listed	No
NH 27: Stevenson	Not Listed	No
NH 28: Rhodes	Not Listed	No
NH 29	Not Listed	No
NH 30: Lambert	Not Listed	No
NH 31: Thomas	Not Listed	No
NH 33	Not Listed	No
NH 34: Wilson	Not Listed	No
NH 35: McAdams	Not Listed	No
NH 36: Majors	Not Listed	No
NH 39: Allen L. Coate	Not Listed	No
NH 40: W. Townsend	Not Listed	No
NH 41: Willer Mill	Not Listed	No
NH 42: Hoavers Mill	Not Listed	No
NH 43: Titus	Not Listed	No
NH 44: Tessy Cots	Not Listed	No
NH 45: John Lyon	Not Listed	No
NH 46: John W. Hall	Not Listed	No
NH 47: Brownville	Not Listed	Yes

Table 2.12-2 (Continued)
Missouri- and Nebraska-Listed Archeological Sites

Site No.	Nearest City or Town	Listed NRHP
NH 48: New John	Not Listed	No
NH 49: Trail	Not Listed	No
NH 50: Wildbee	Not Listed	No
NH 51	Not Listed	No
NH 52	Not Listed	No
NH 55	Not Listed	No
NH 56	Not Listed	No
NH 57	Not Listed	No
NH 58	Not Listed	No
NH 59	Not Listed	No
NH 60: Brownville	Not Listed	No
NH 61	Not Listed	No
NH 63	Not Listed	Eligible
NH 67: Brewery	Not Listed	No
NH 68: Johnston-Green House	Not Listed	No
NH 69: Baptist Church	Not Listed	No
NH 72	Not Listed	Eligible
NH 73	Not Listed	Eligible
NH 74	Not Listed	Eligible
NH 75	Not Listed	Eligible
NH 83	Not Listed	Eligible
NH 504	Not Listed	No
NH 505	Not Listed	No
NH 507	Not Listed	No
NH 508	Not Listed	No
NH 510	Not Listed	No

Table 2.12-2 (Continued)
Missouri- and Nebraska-Listed Archeological Sites

Site No.	Nearest City or Town	Listed NRHP
NH 511	Not Listed	No
Richardson County, Nebraska		
RH 3: Alvin Catlett Farm	Not Listed	No
RH 9	Not Listed	No
RH 10: Sailors	Not Listed	No
RH 11: Indian Cave	Not Listed	No
RH 12: Dunn	Not Listed	No
RH 13: Wixon	Not Listed	No
RH 60	Not Listed	No
RH 61	Not Listed	No

Reference: MDNR 2007b; NSHS

The proposed action upon which this ER is based is for the renewal of the CNS OL. As discussed in Section 3, NPPD does not foresee a need for refurbishment during the license renewal period, nor is any major construction planned that will result in significant land disturbance.

A Phase 1A Literature Review and Archeological Sensitivity Assessment was performed for the site property in April 2007 and March 2008. Current land use at CNS is depicted in Figure 2.4-1. The 55 acres occupied by the current operations are heavily disturbed. Eighty-one percent is under agricultural cropland use on the Nebraska side of the river and 16 percent is in agricultural use on the Missouri side of the site. Due to the sensitive archeological information contained in the Phase 1A Assessment, this report will be available for review during the site audit.

The property now occupied by CNS was mainly agricultural land where two farmsteads previously existed (see Figure 2.12-2). Construction activities at the site began in early 1968 and were completed in 1972, with excavation activities resulting in the removal of more than 760,000 cubic yards of earth. The William Dawson House (Site # NH00-69), located in the southwest corner of the site near the bluff, was torn down shortly after it was recorded, according to the Nebraska SHPO.

NPPD does not have plans for further development of these property areas in association with the application for license renewal. However, a corporate procedure is in place for management of cultural resources ahead of any future ground-disturbing activities at the plant. This procedure, which requires reviews, investigations, and consultations as needed, ensures that existing or potentially existing cultural resources are adequately protected and assists NPPD in meeting state and federal expectations. [CNS 2008b]

2.13 Related Federal Project Activities

During the preparation of this report, NPPD did not identify any known or reasonably foreseeable federal projects or other activities that could contribute to the cumulative environmental impacts of license renewal at the site.

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Figure 2.1-1
Location of CNS, 6-Mile Radius

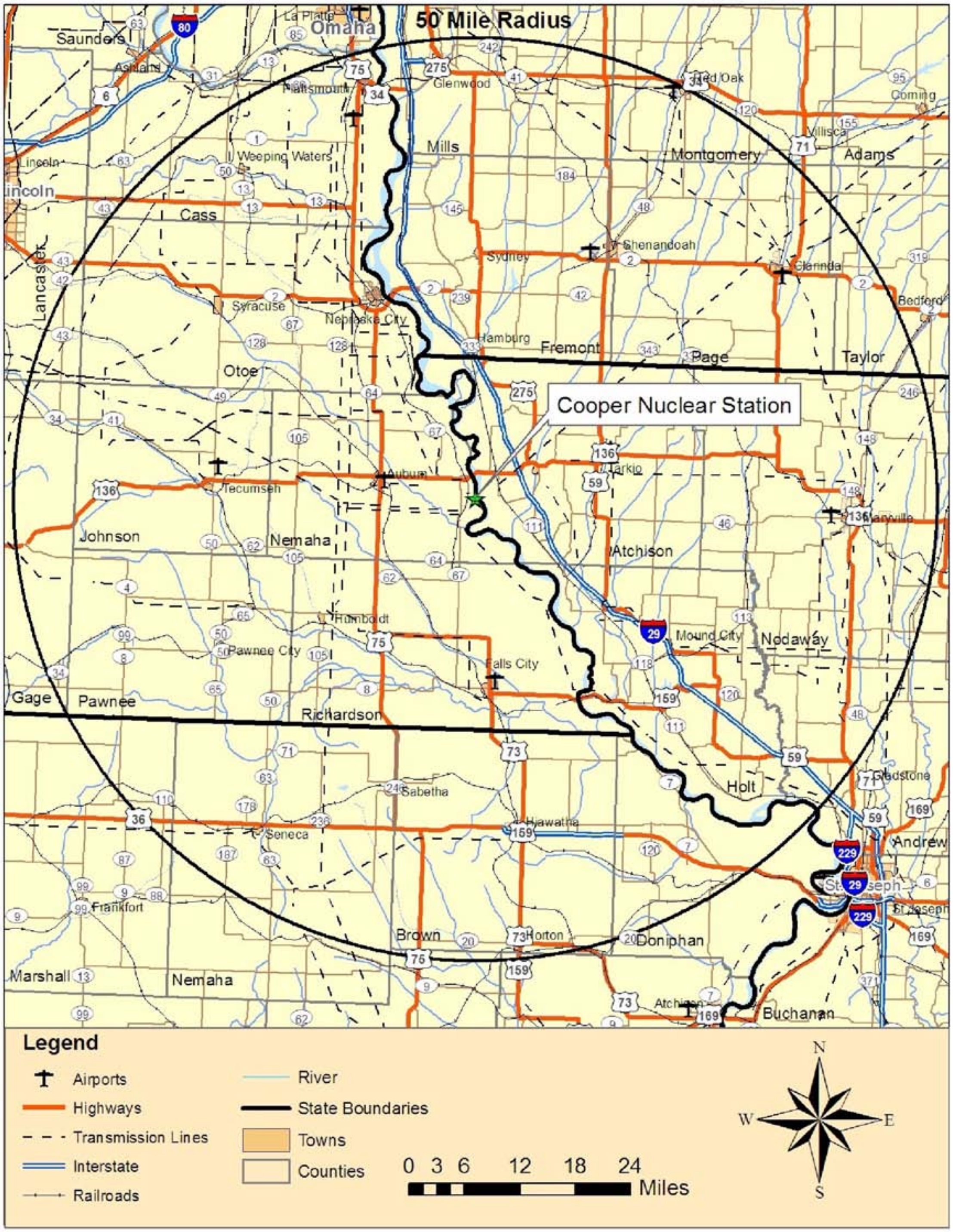

Figure 2.1-2
Location of CNS, 50-Mile Radius

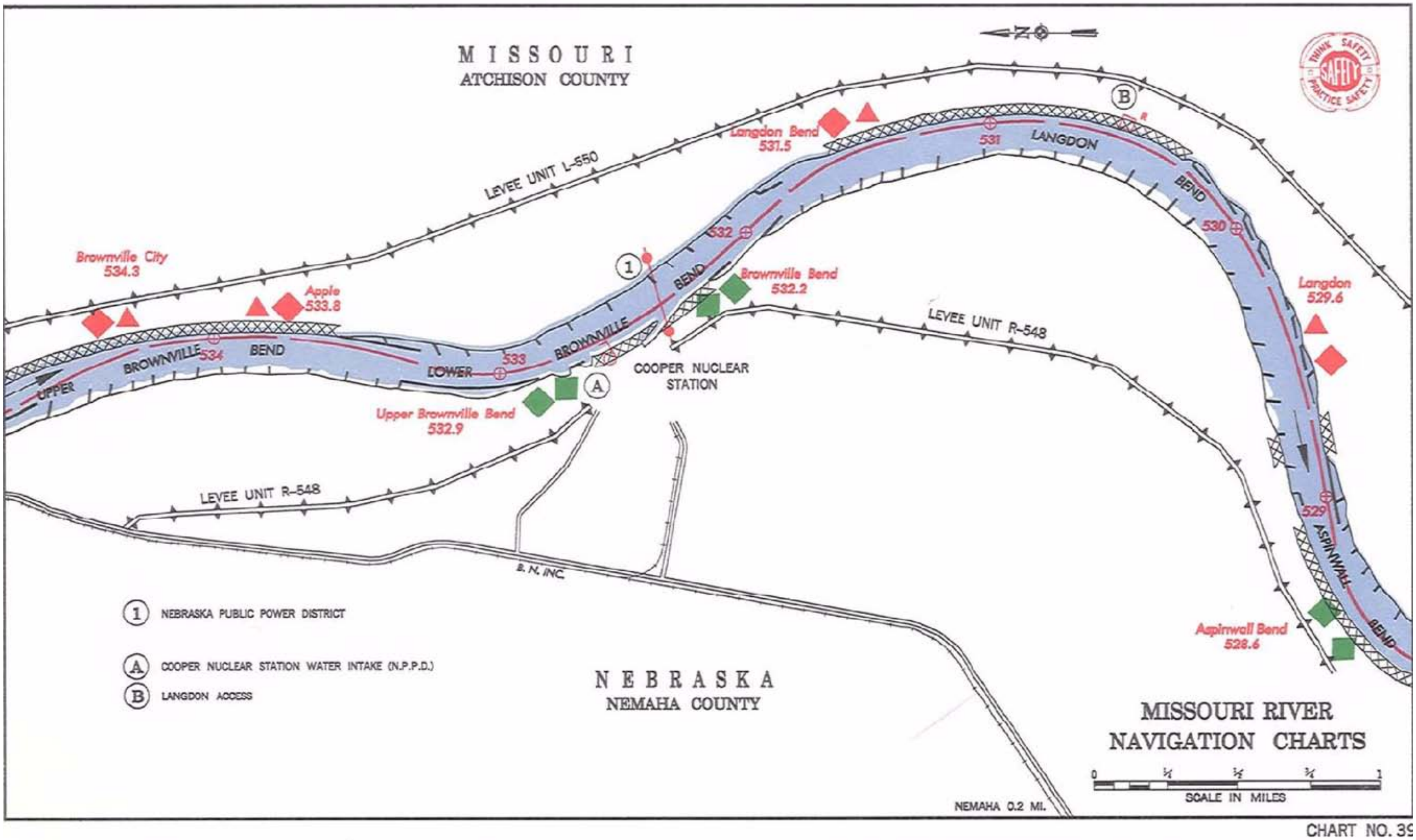

Figure 2.1-3
CNS Levee Map

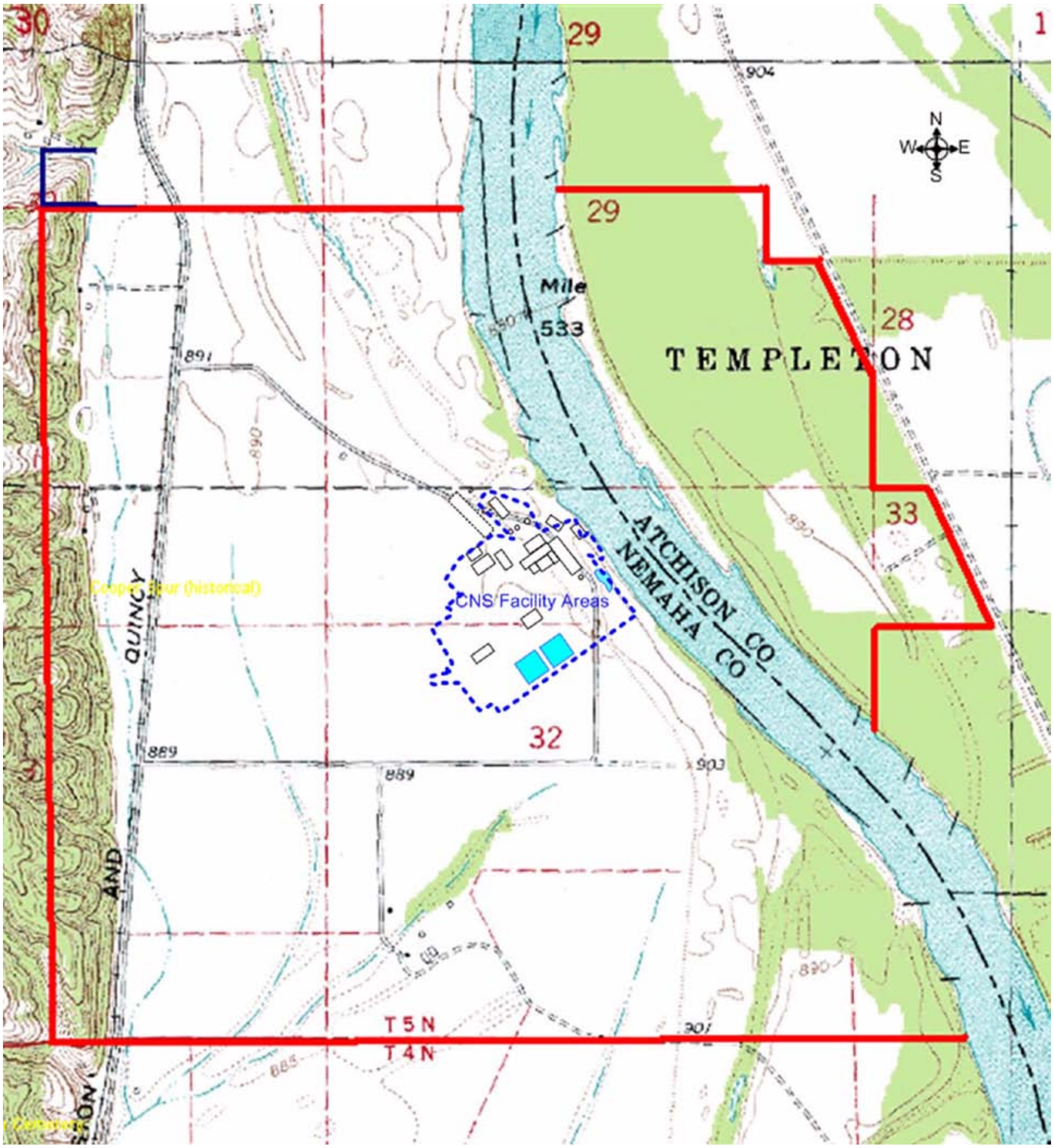

Figure 2.1-4
Topographic Map

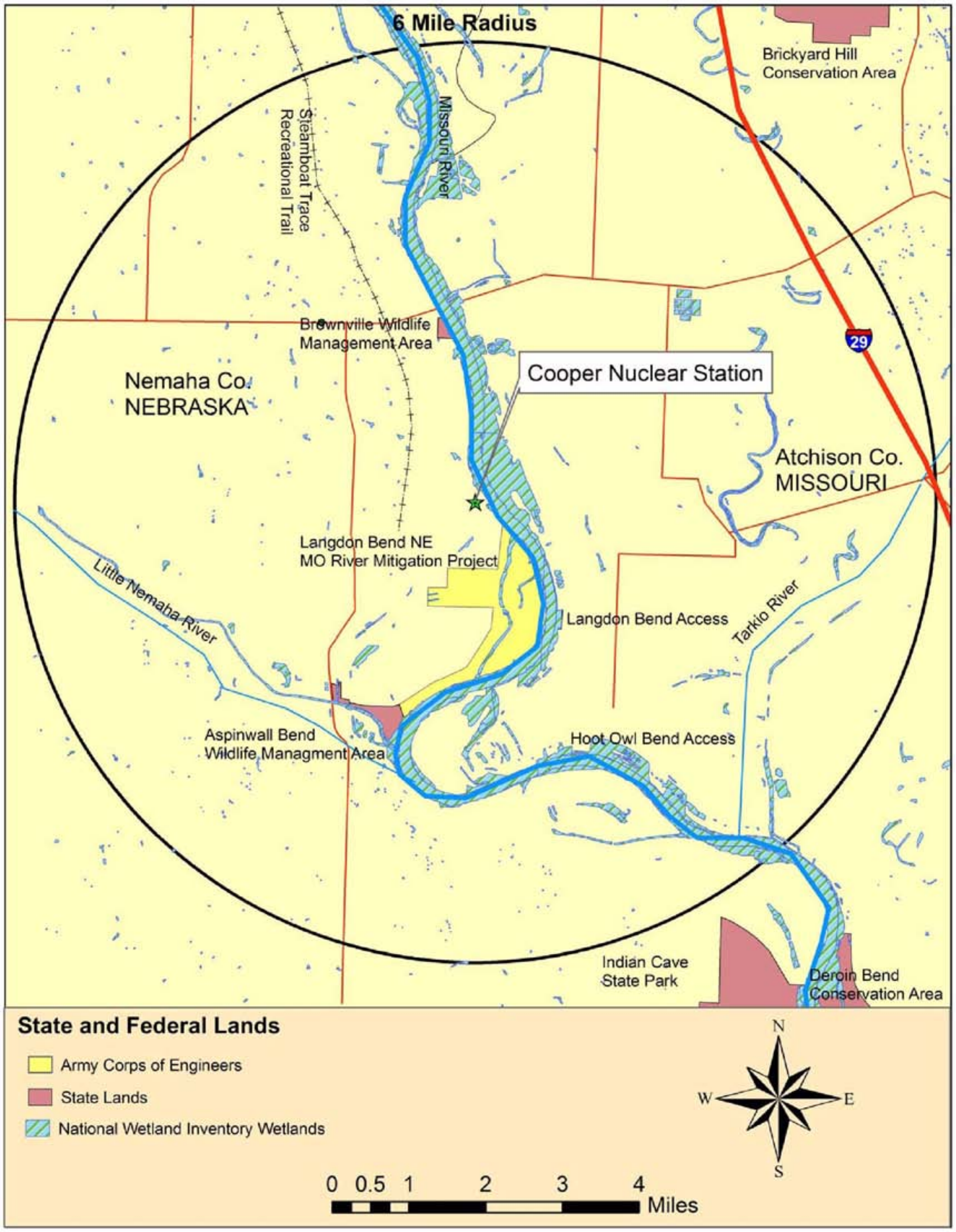

Figure 2.1-5
Major State and Federal, and Native American Lands, 6-Mile Radius

Figure 2.1-6
Major State, Federal, and Native American Lands, 50-Mile Radius

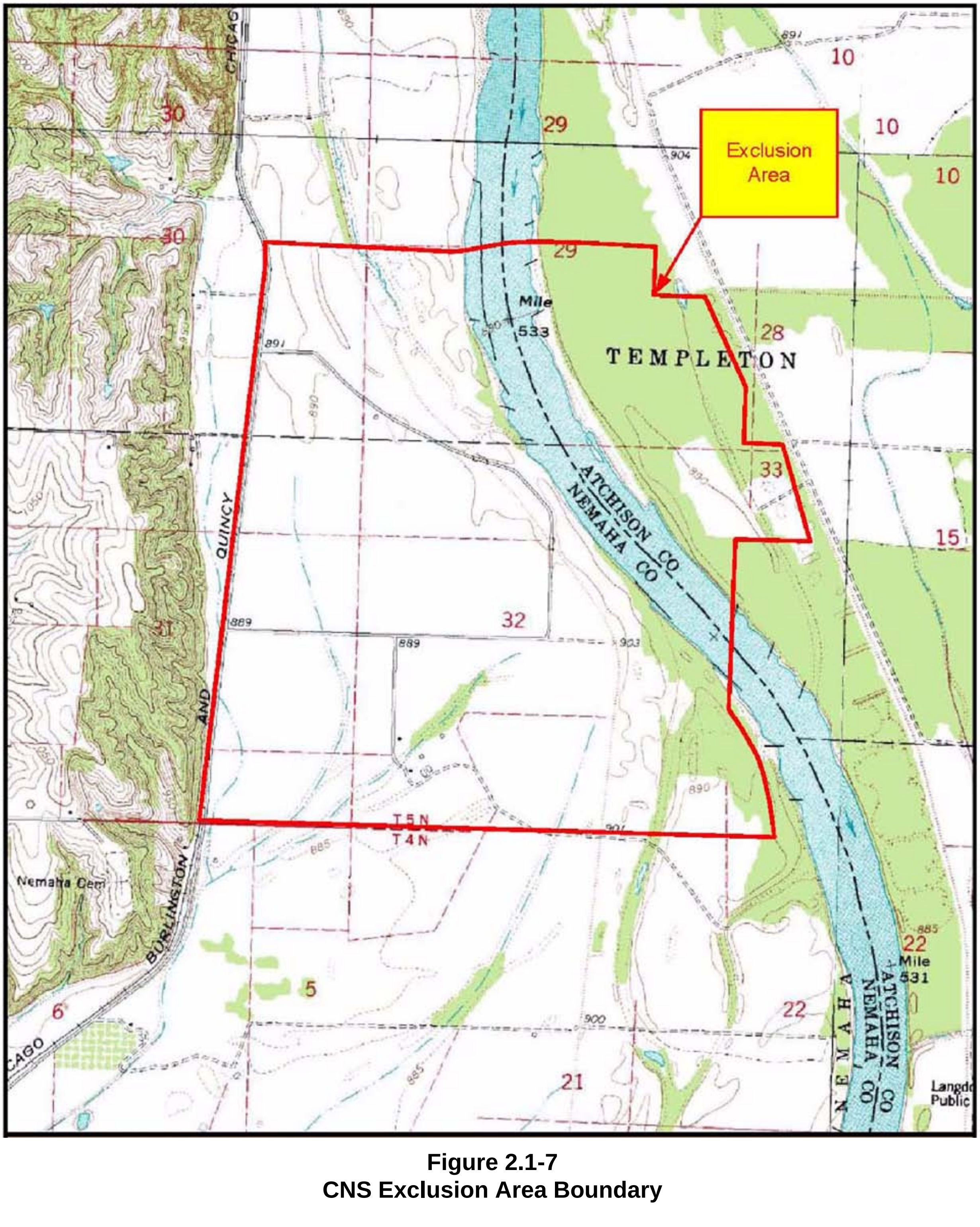

Figure 2.1-7
CNS Exclusion Area Boundary

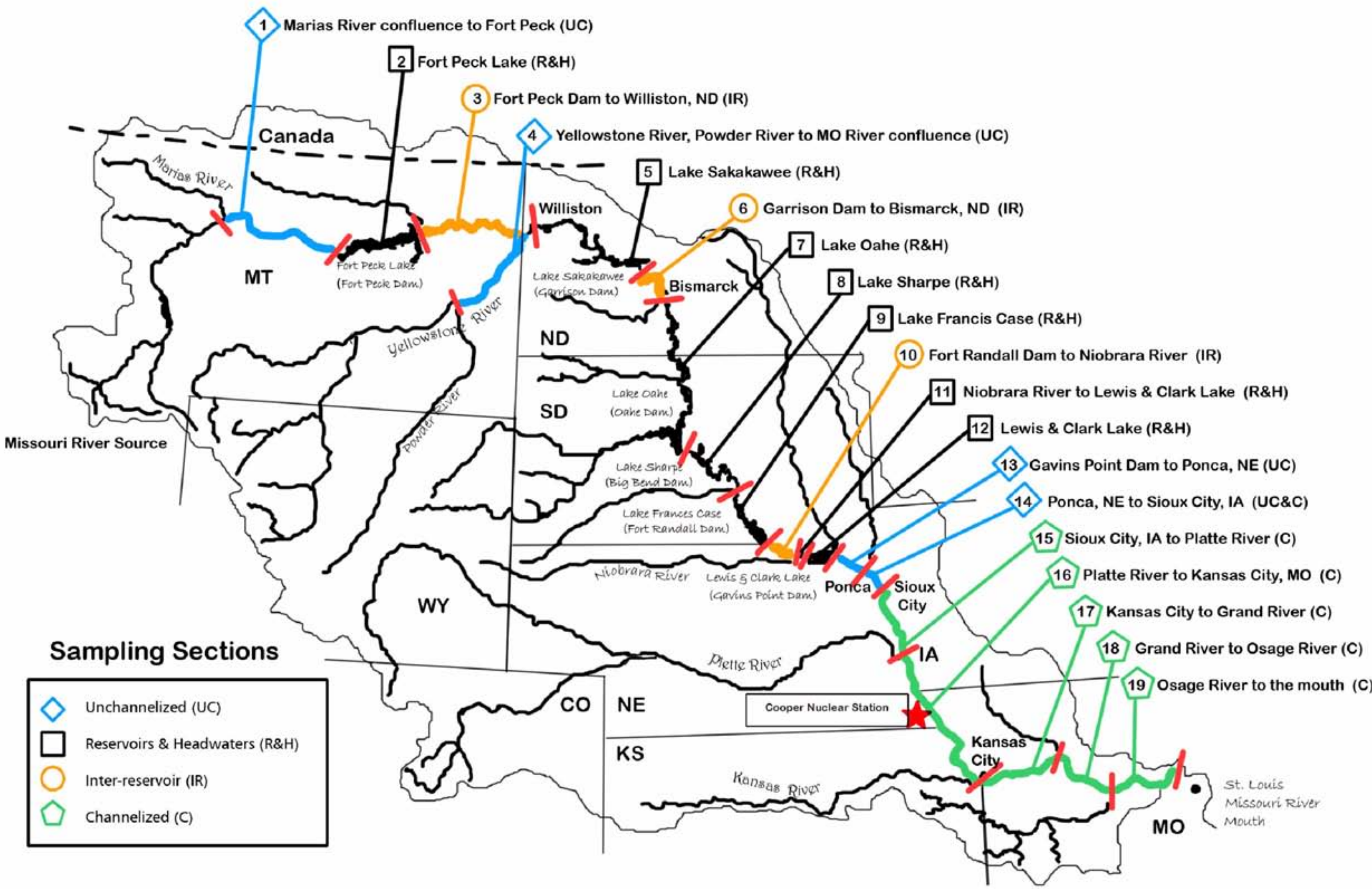

Figure 2.2-1
Missouri River Drainage

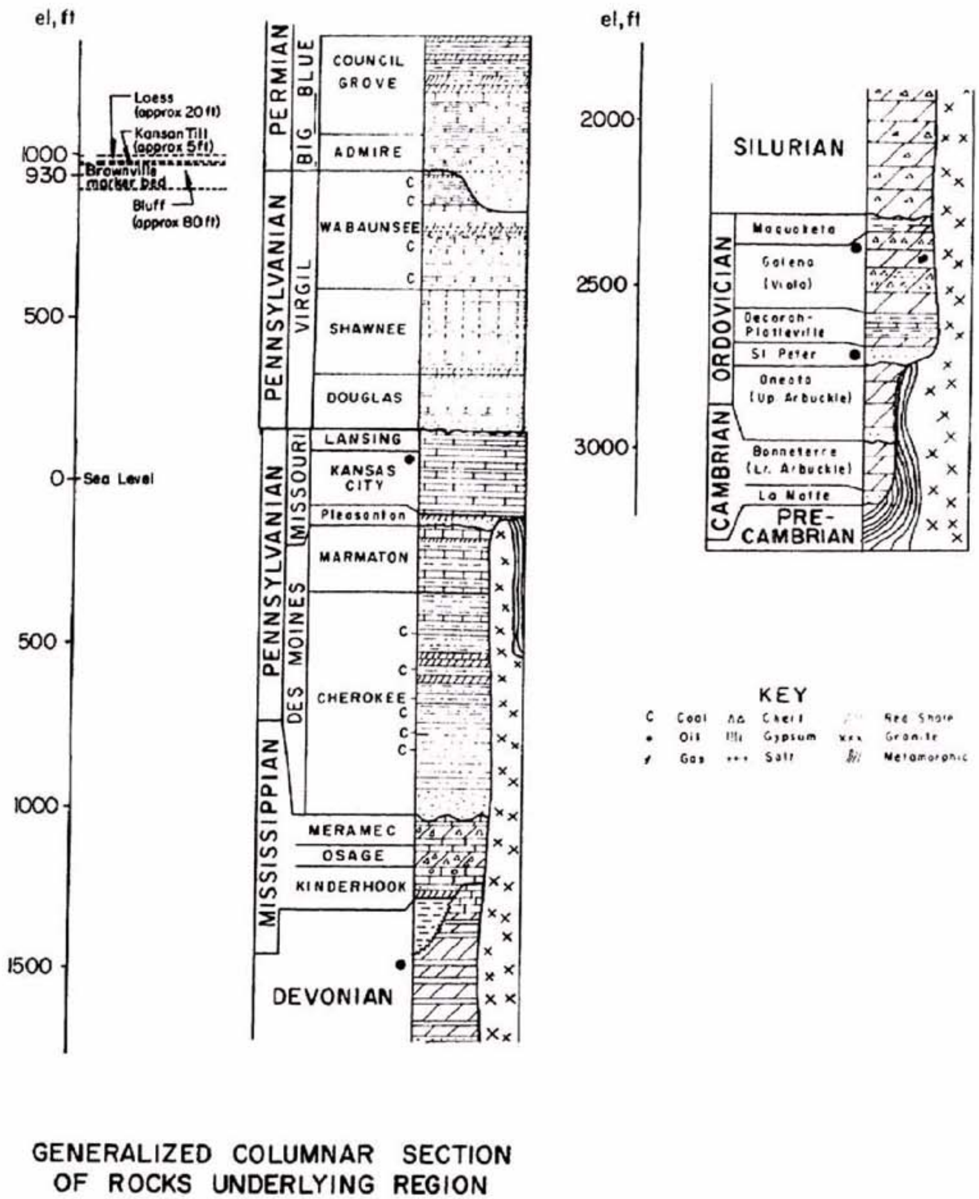

Figure 2.3-1
Stratigraphic Chart

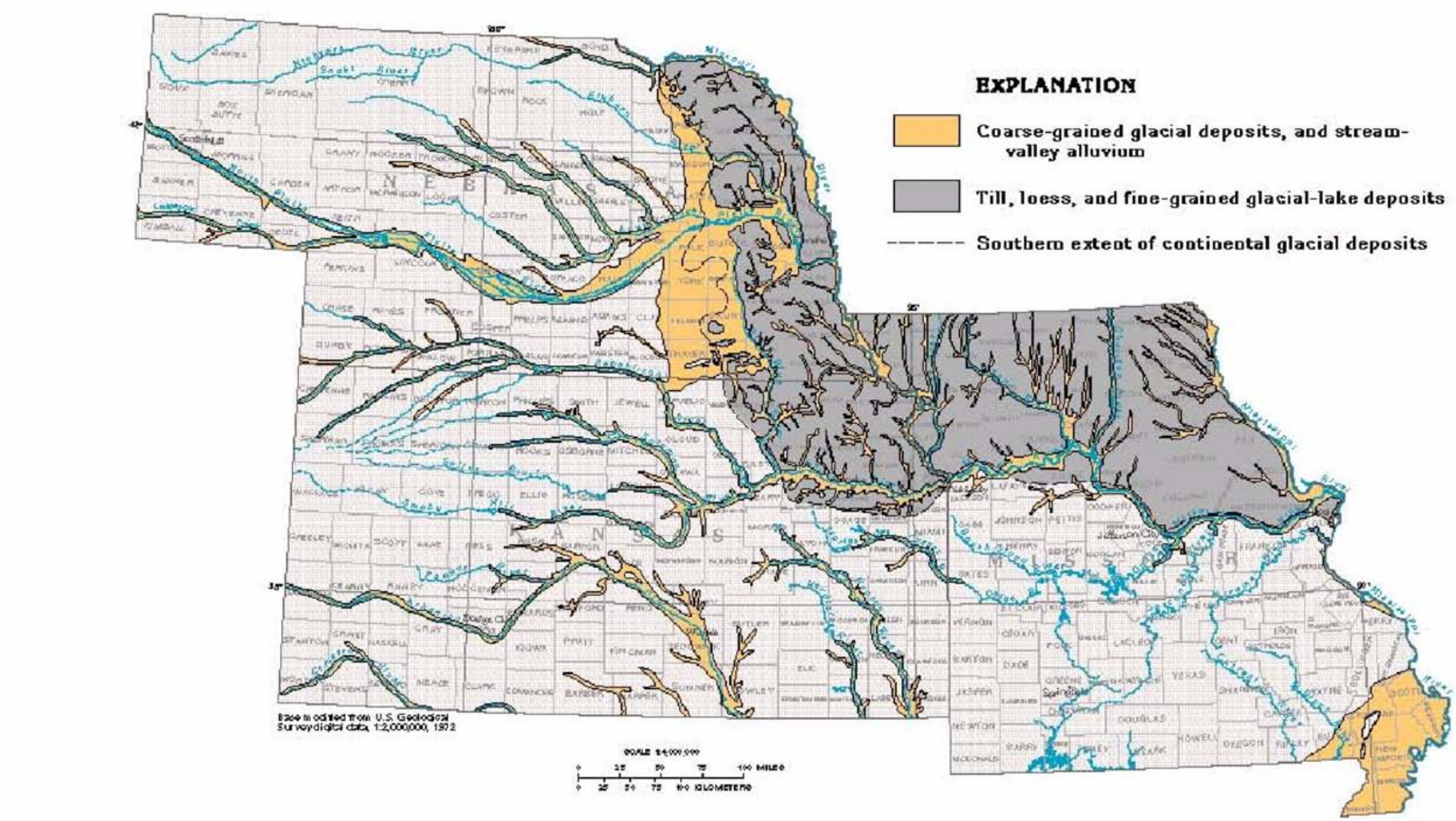

Figure 2.3-2
Surficial Aquifers

Notes for Figure 2.3-2

Coarse-grained, unconsolidated deposits, mostly of quaternary age, compose the surficial aquifer system and provide water for many shallow wells. Alluvium along major stream valleys, a broad blanket of alluvium in southeastern Missouri, and glacial outwash (buried in some places beneath fine-grained sediments) form productive aquifers. Till, loess, and fine-grained glacial-lake deposits are widespread in areas of the segment that were covered by continental glaciers; these deposits generally yield only small amounts of water and are not considered to be principal aquifers.

Modified from
American Association of Petroleum Geologists, 1984, Geological Highway Map, Northern Great Plains Region—North Dakota, South Dakota, Iowa, Nebraska, Minnesota: American Association of Petroleum Geologists, scale 1:900,000, 1 sheet.
American Association of Petroleum Geologists, 1988, Geological Highway Map, Mid-Continent Region: Kansas, Missouri, Oklahoma, Arkansas: American Association of Petroleum Geologists, scale 1:900,000, 1 sheet.
Lugn, A.L. and Wenzel, L.K., 1938, Geology and ground-water resources of south-central Nebraska: U.S. Geological Survey Water-Supply Paper 779,242P.
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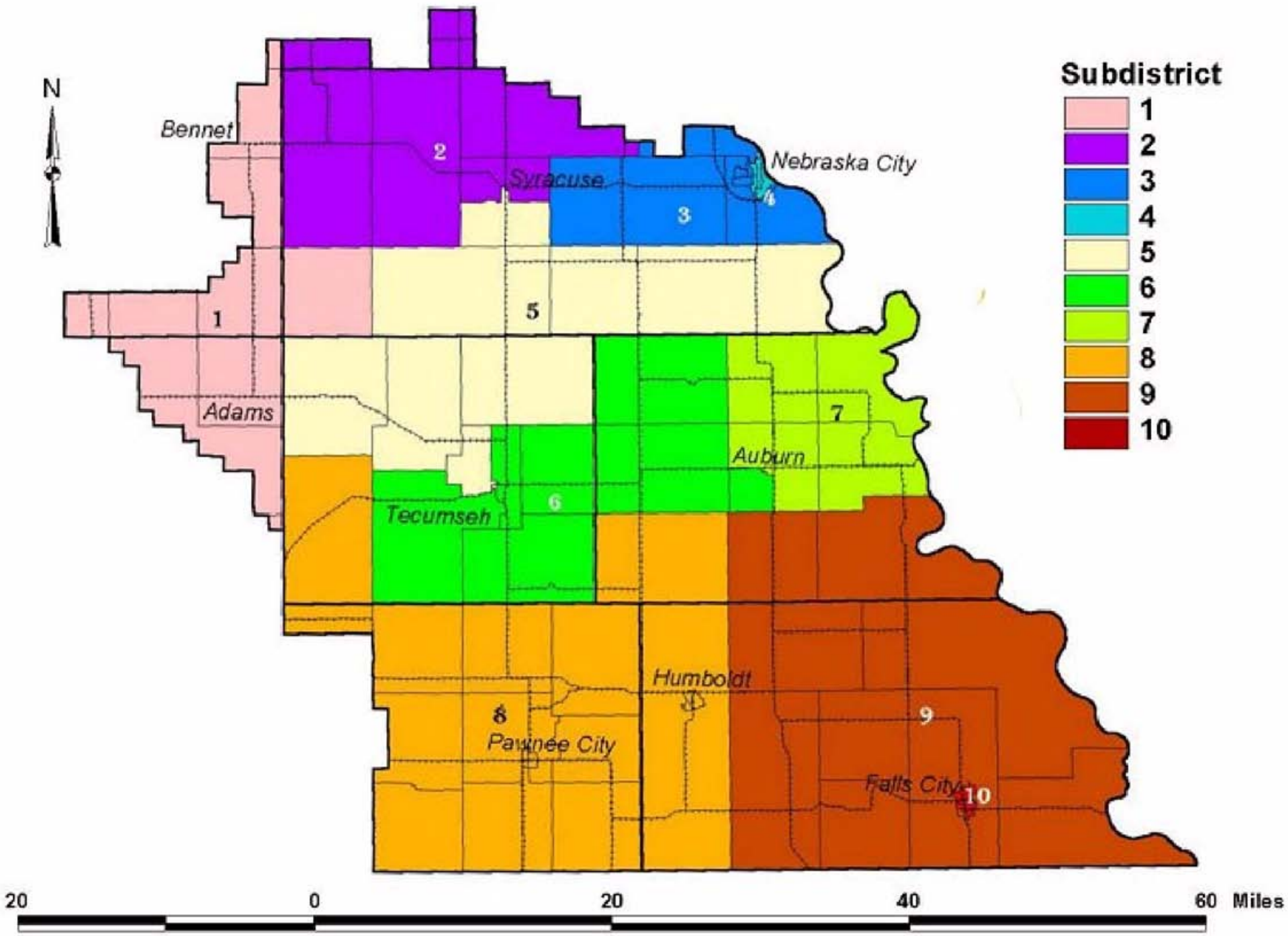

Figure 2.3-3
Nemaha Natural Resources District

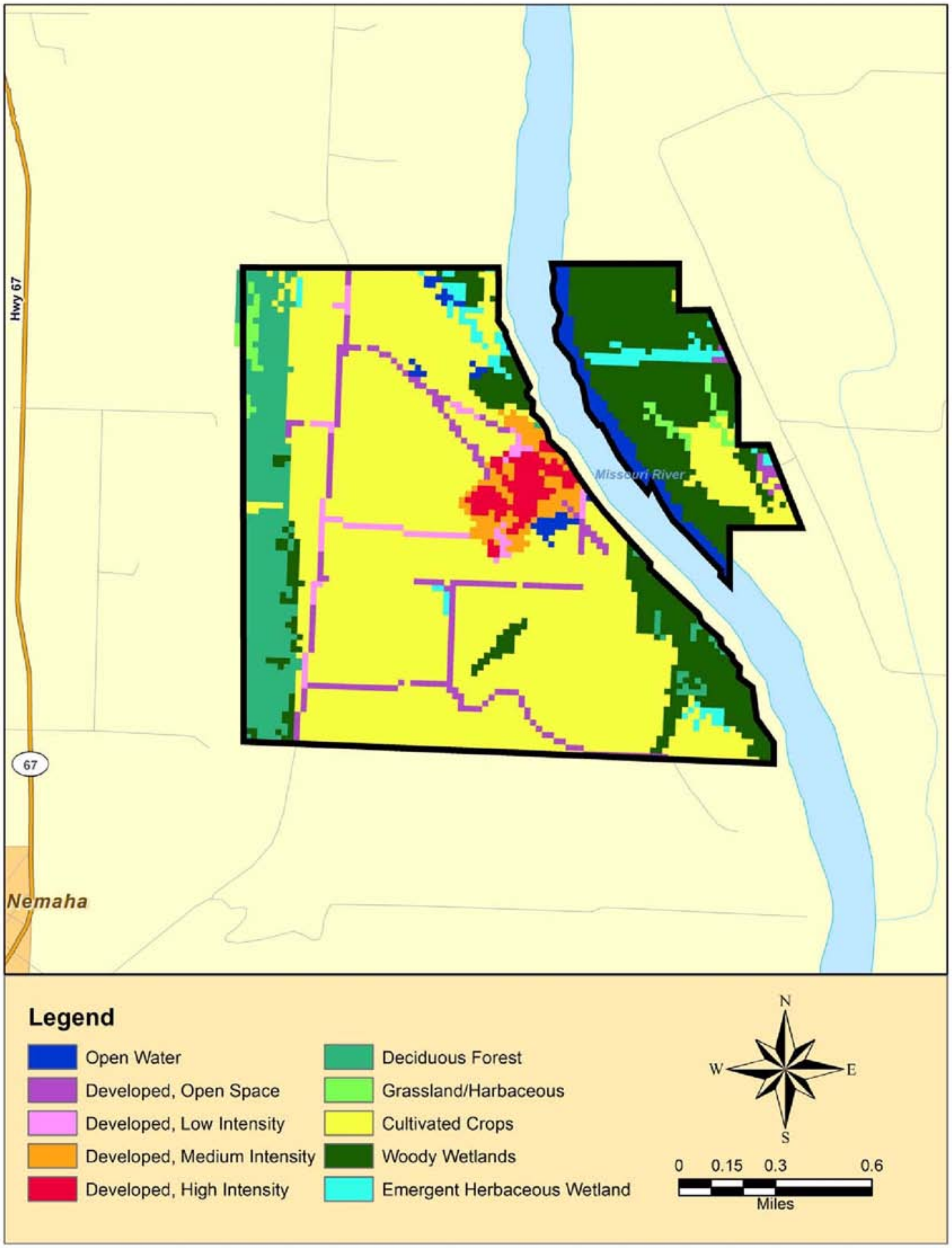

Figure 2.4-1
CNS Site Land Use

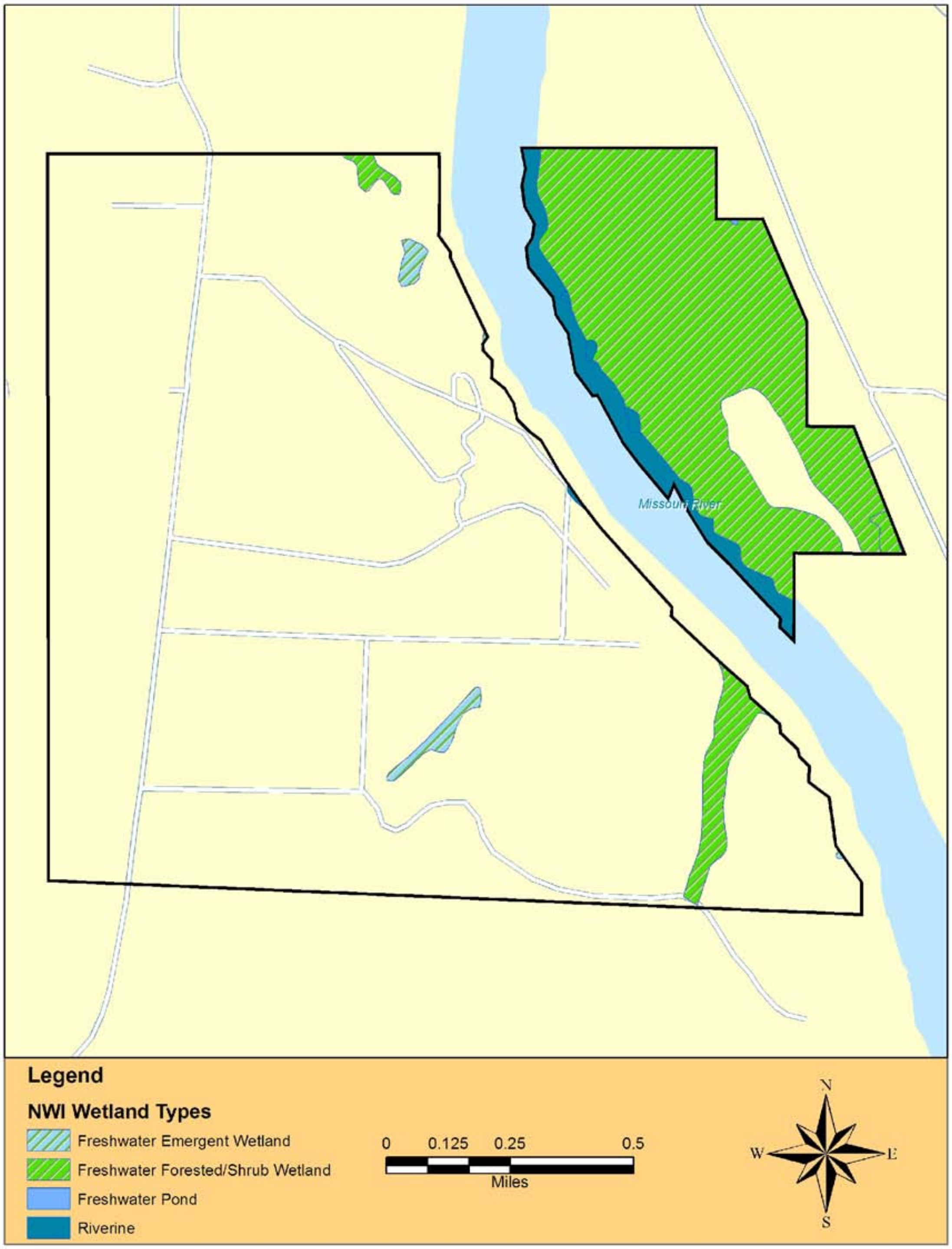

Figure 2.4-2
CNS Mapped Wetlands

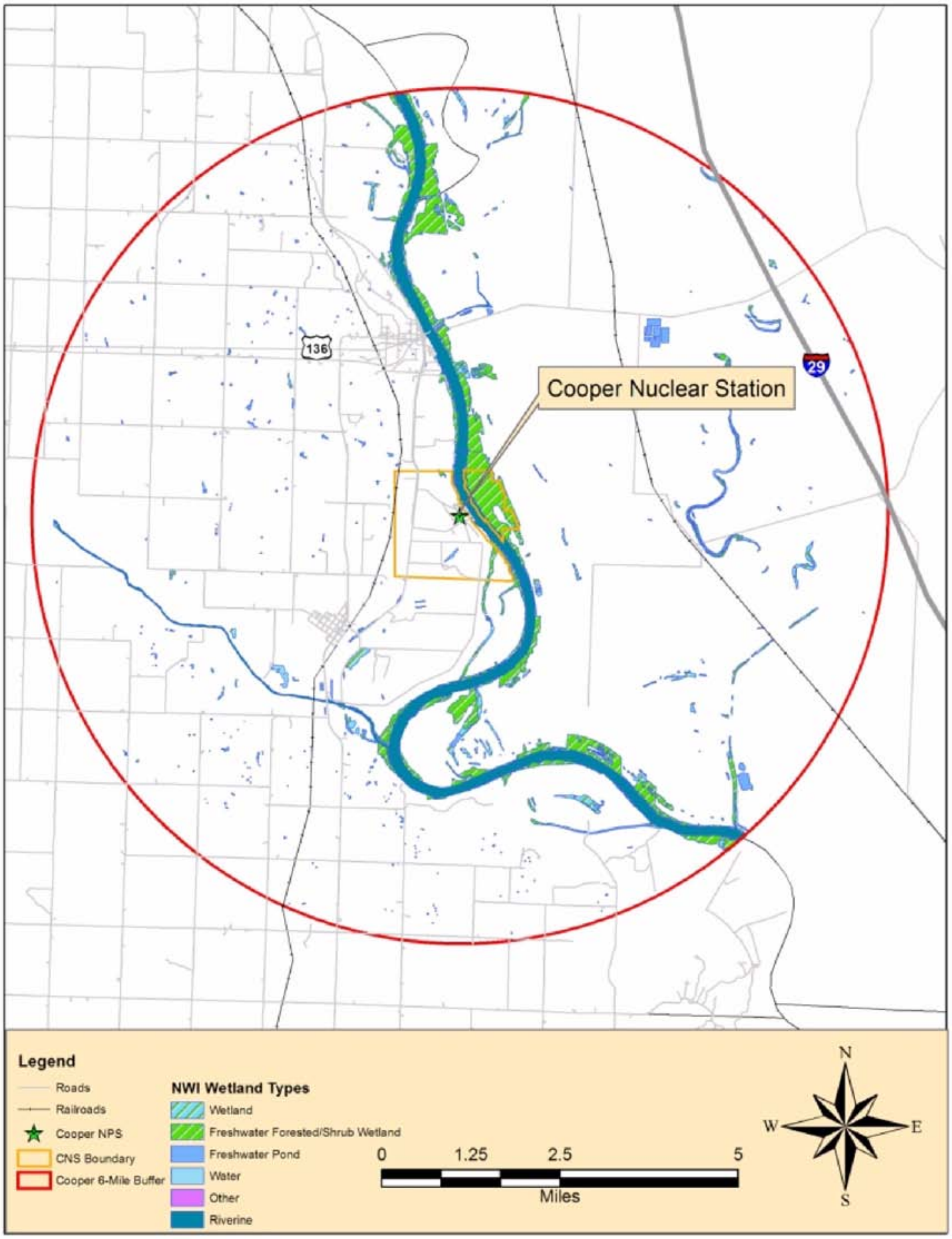

Figure 2.4-3
Cooper Six-Mile Radius—Wetlands

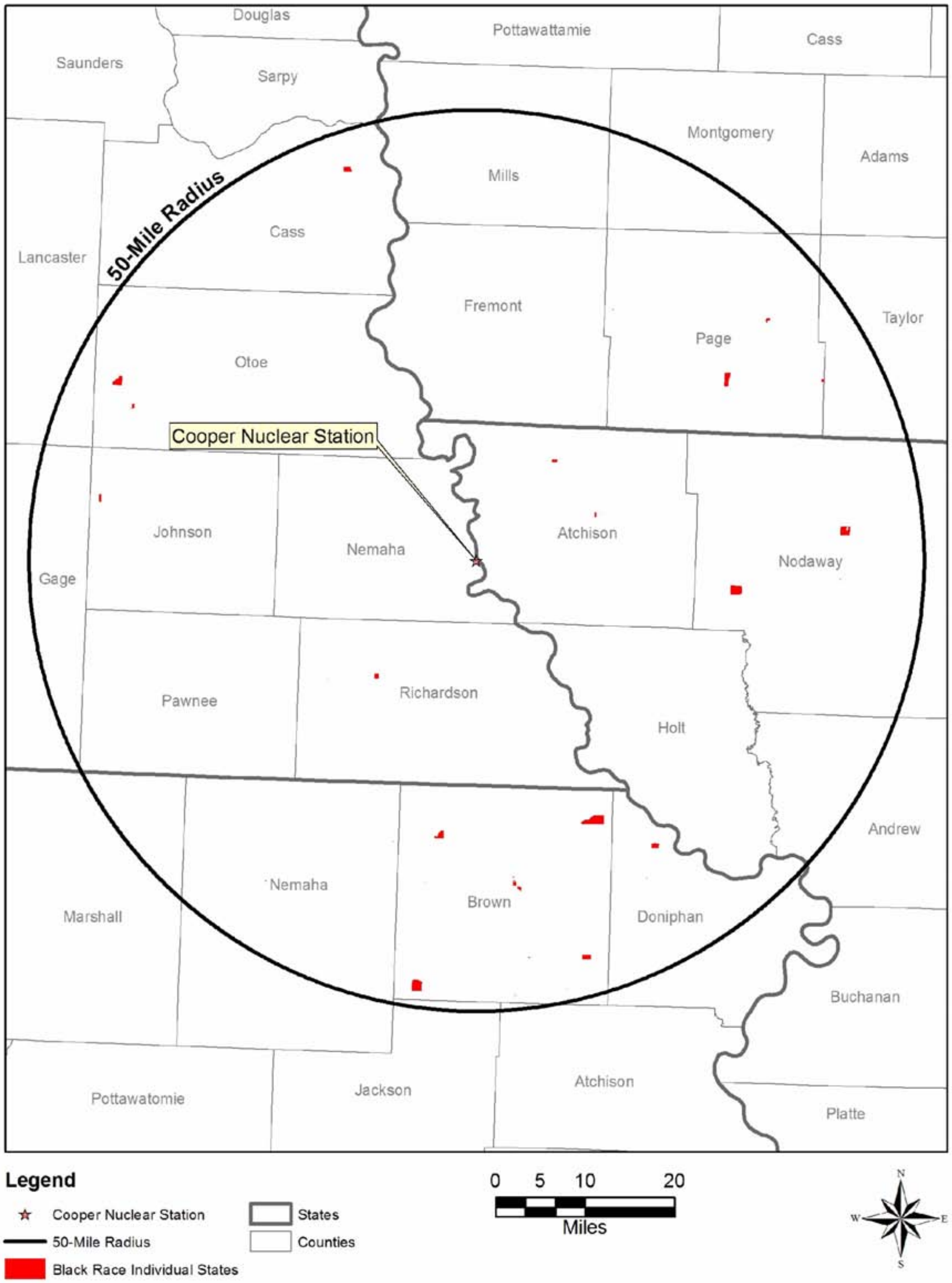

Figure 2.6-1
Census—Black Minority Population (Individual States)

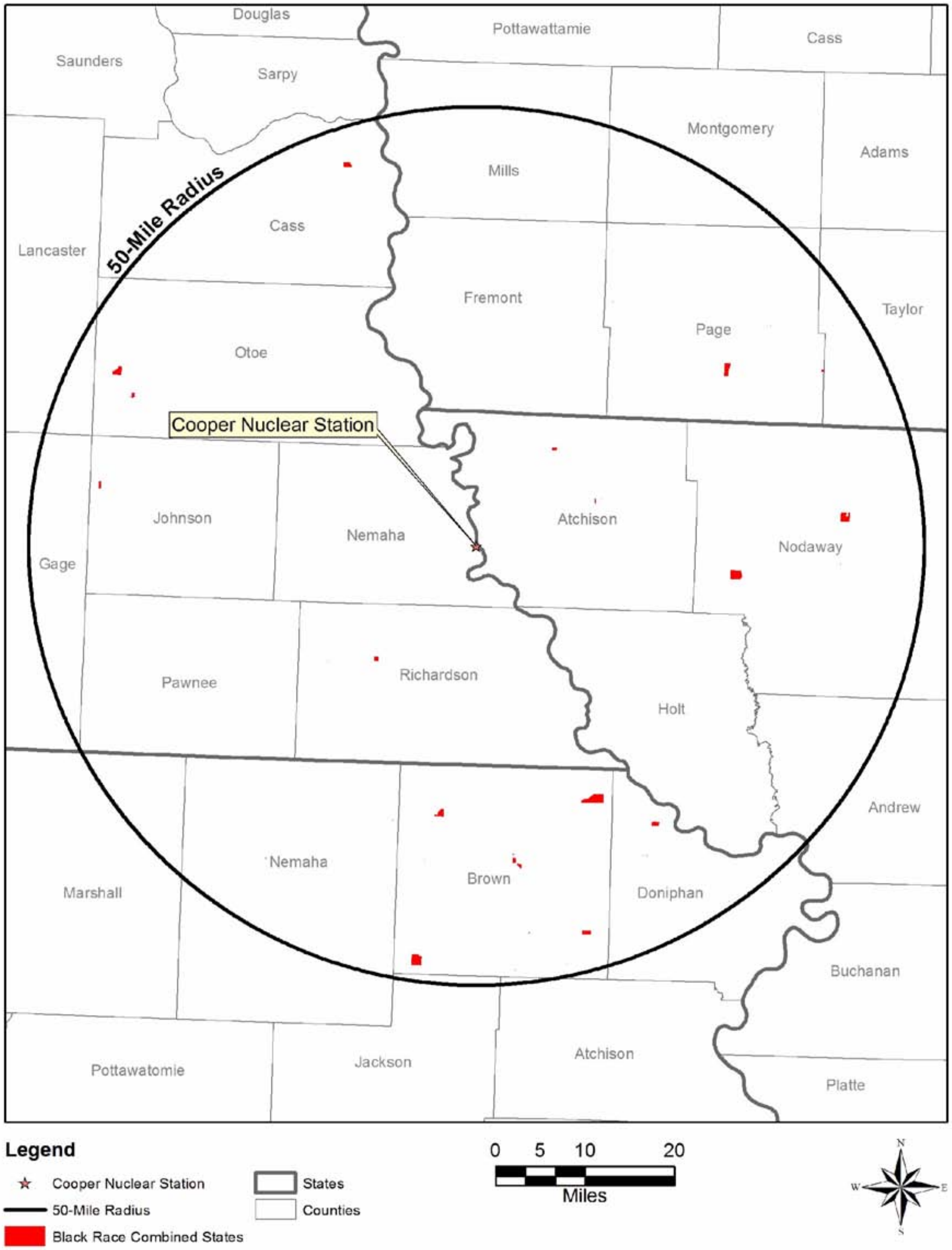

Figure 2.6-2
Census—Black (Combined States)

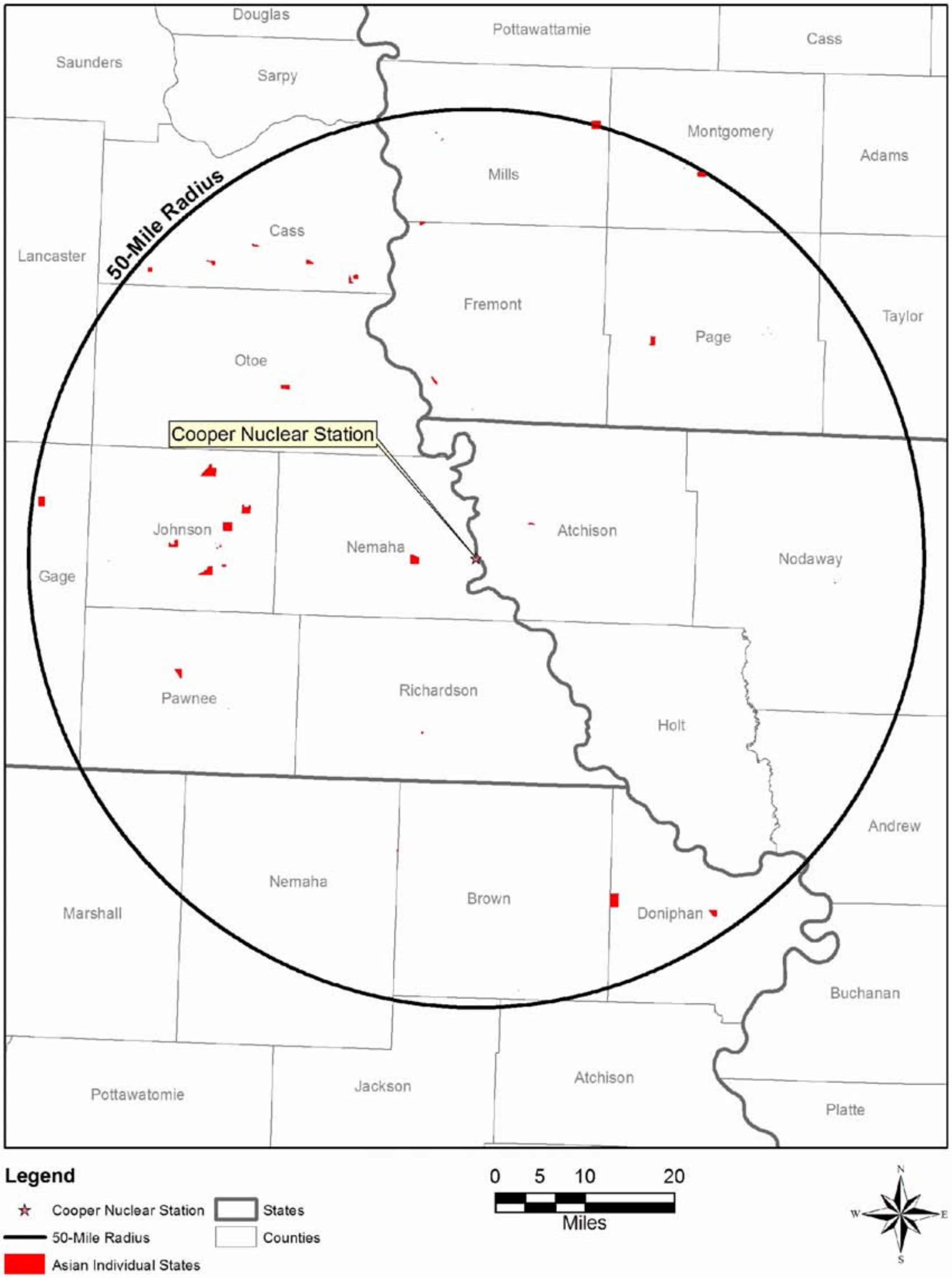

Figure 2.6-3
Census—Asian (Individual States)

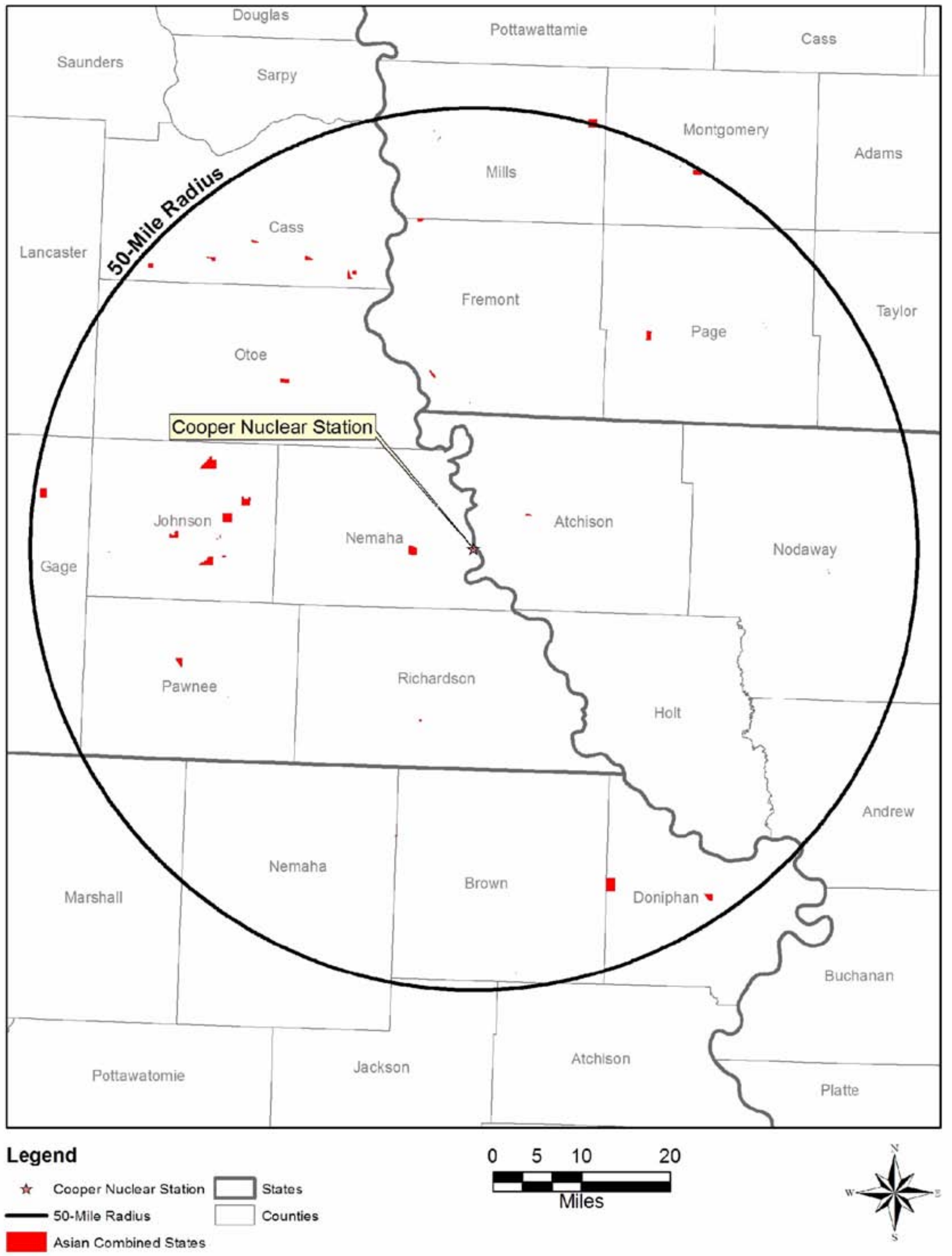

Figure 2.6-4
Census—Asian (Combined States)

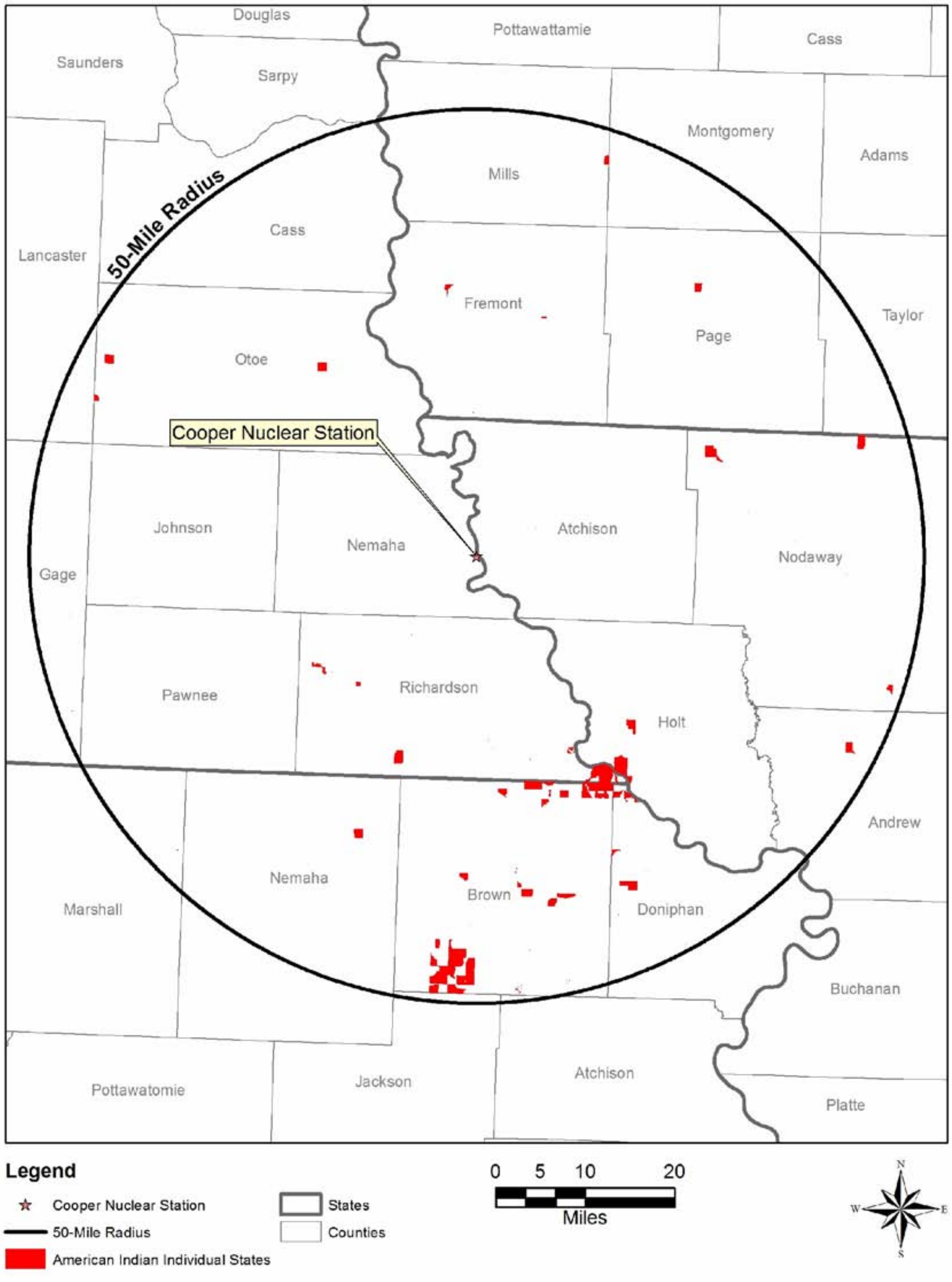

Figure 2.6-5
Census—Native American (Individual States)

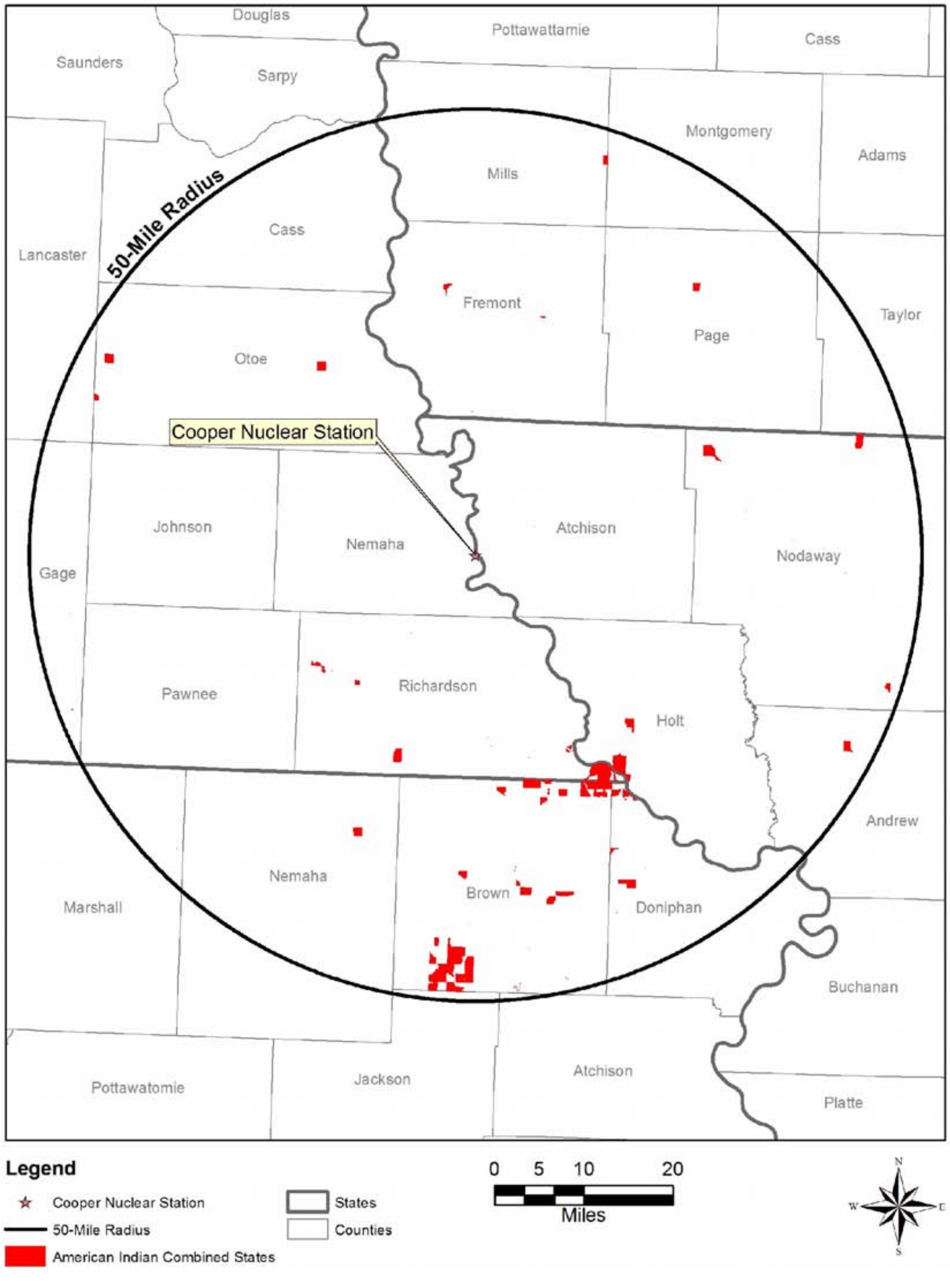

Figure 2.6-6
Census—Native American (Combined States)

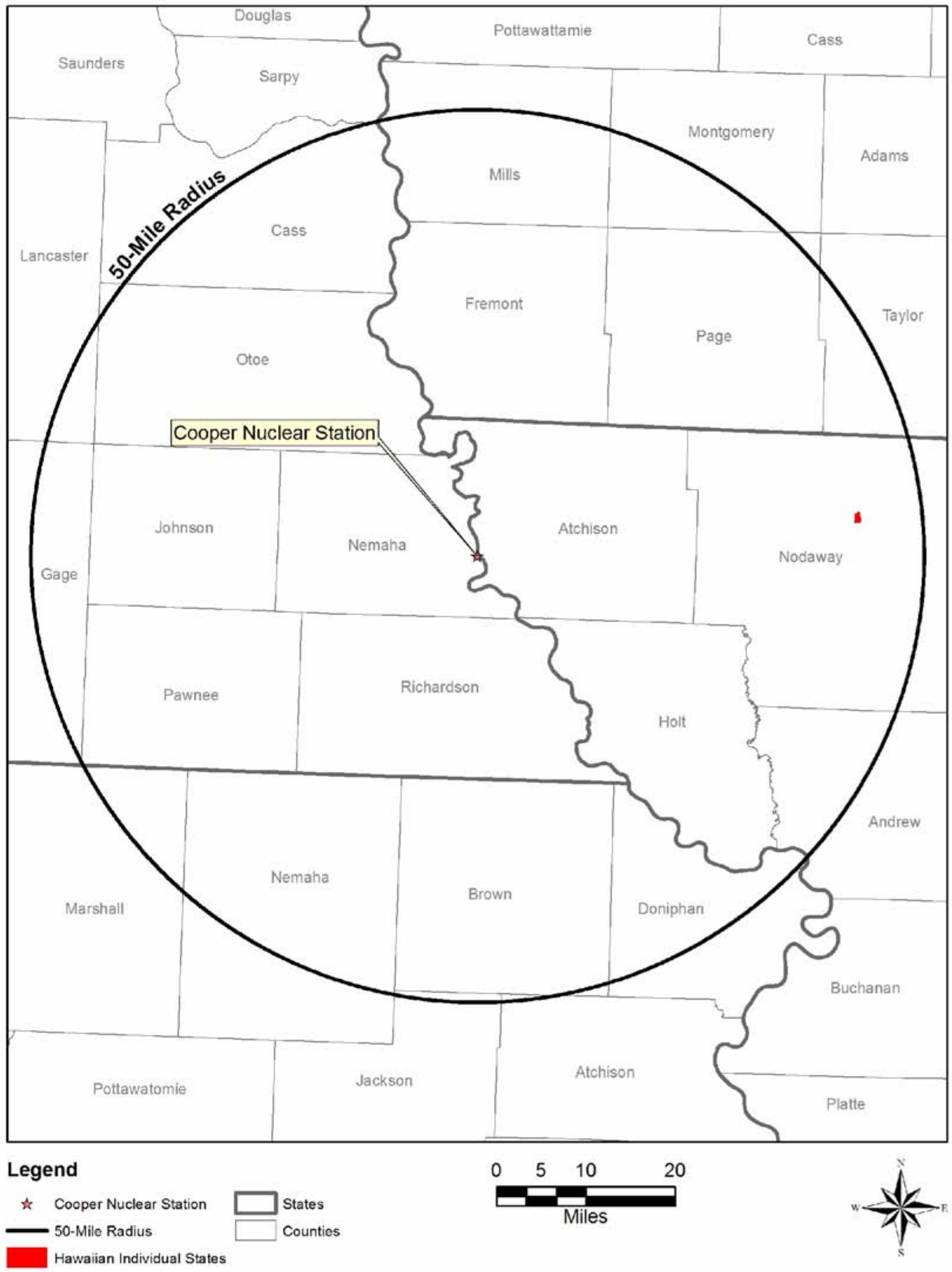

Figure 2.6-7
Census—Hawaiian (Individual States)

Figure 2.6-8
Census—Hawaiian (Combined States)

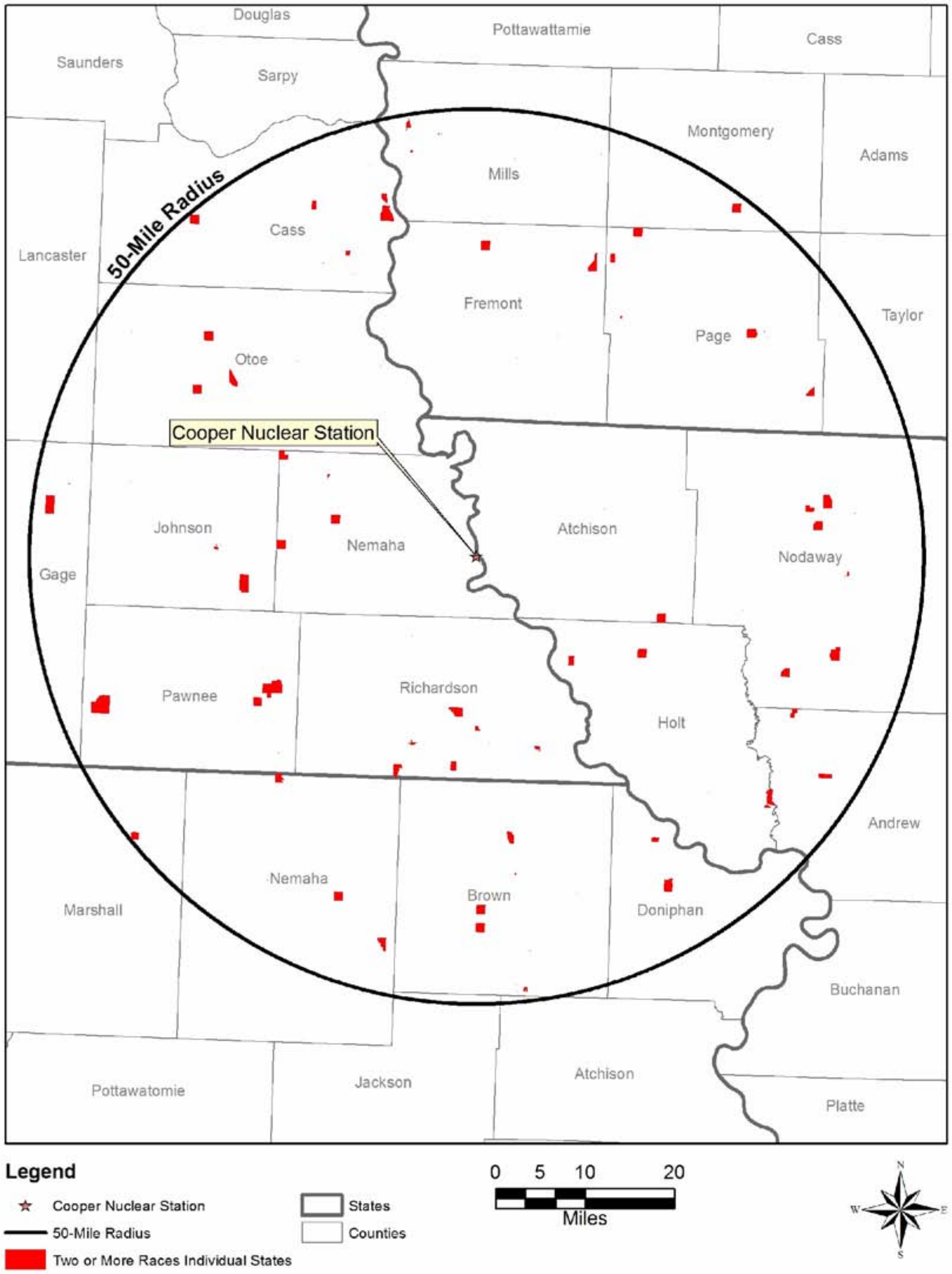

Figure 2.6-9
Census—Two or More Races (Individual States)

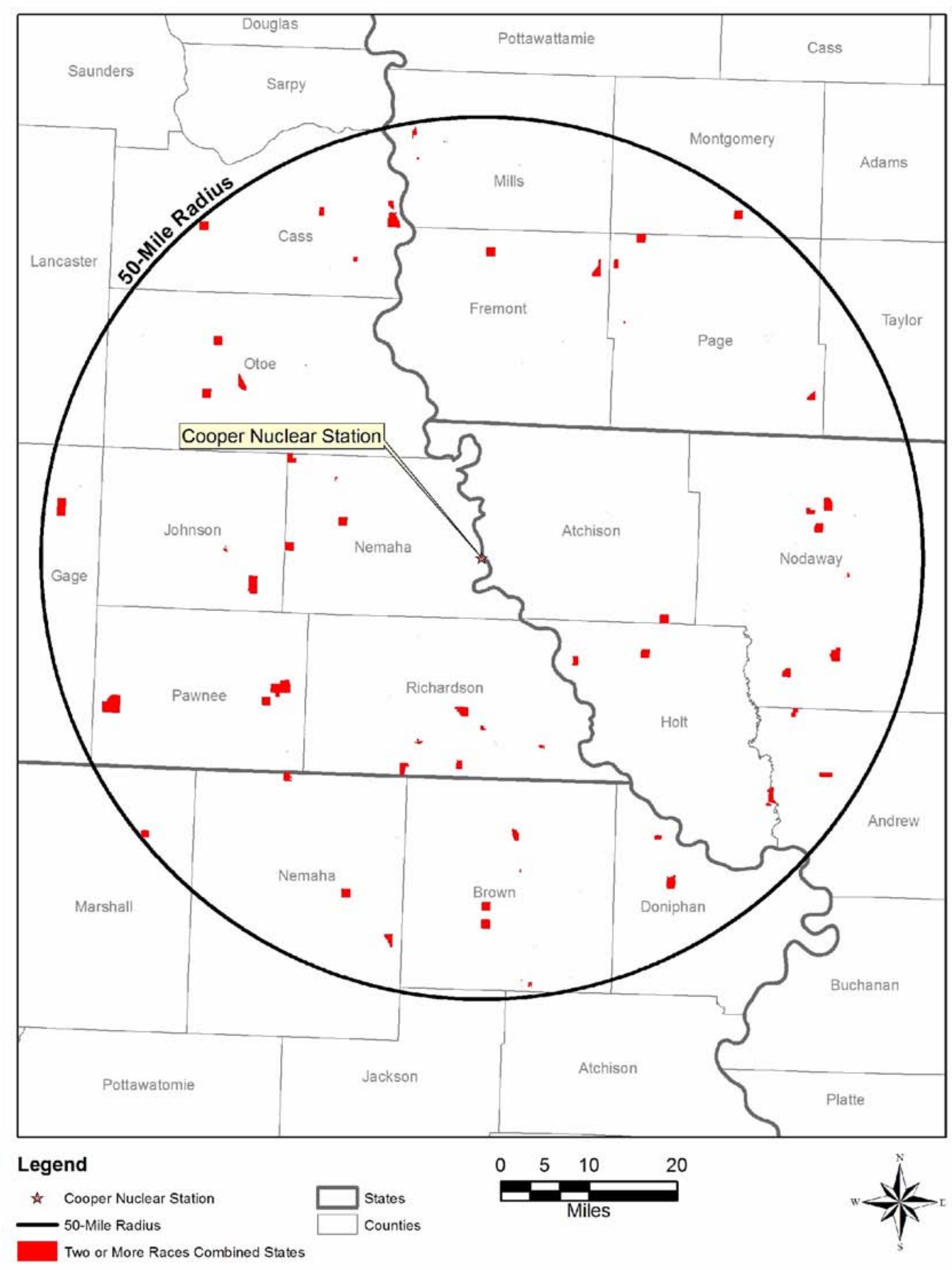

Figure 2.6-10
Census—Two or More Races (Combined States)

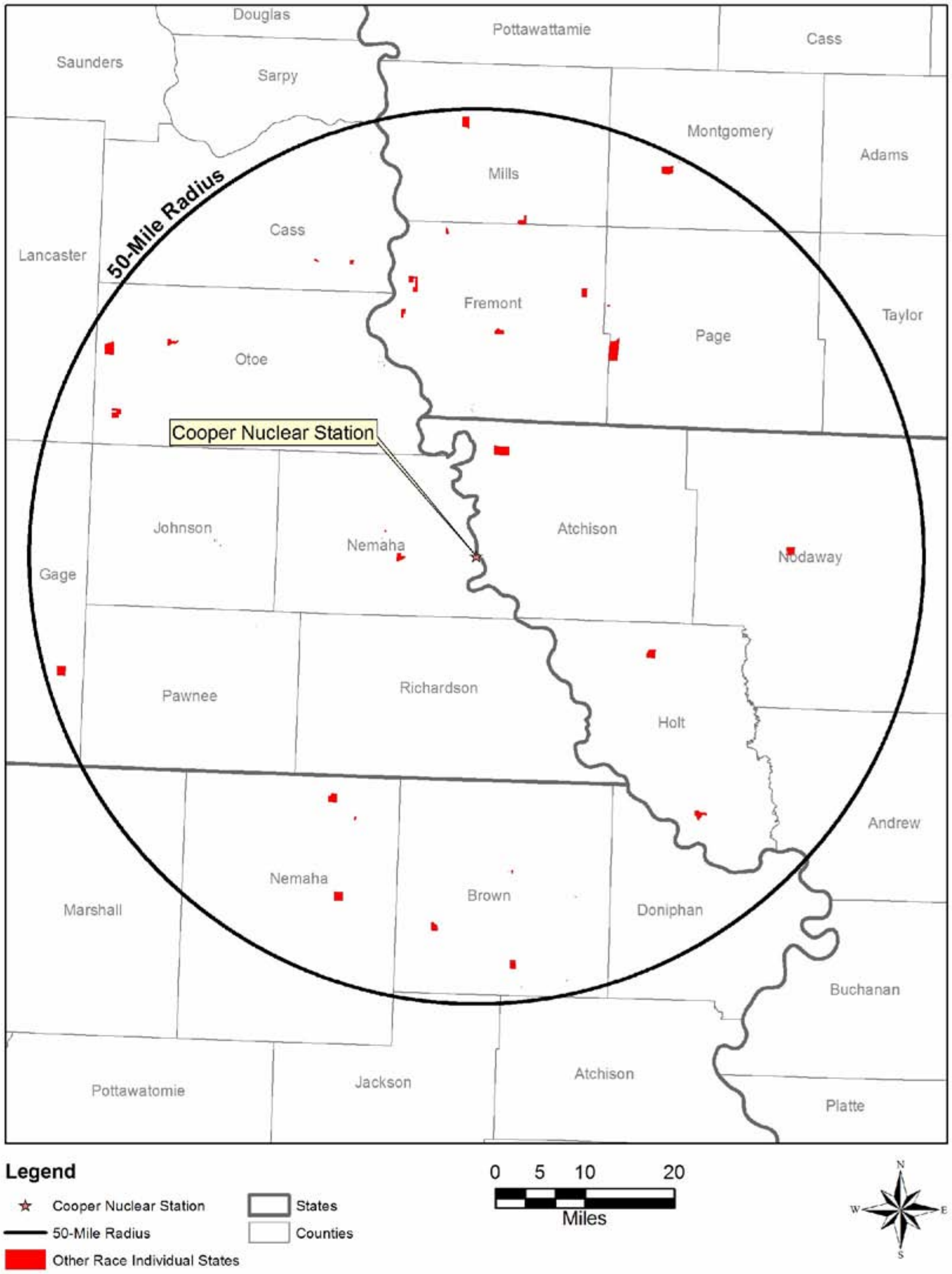

Figure 2.6-11
Census—Other Races (Individual States)

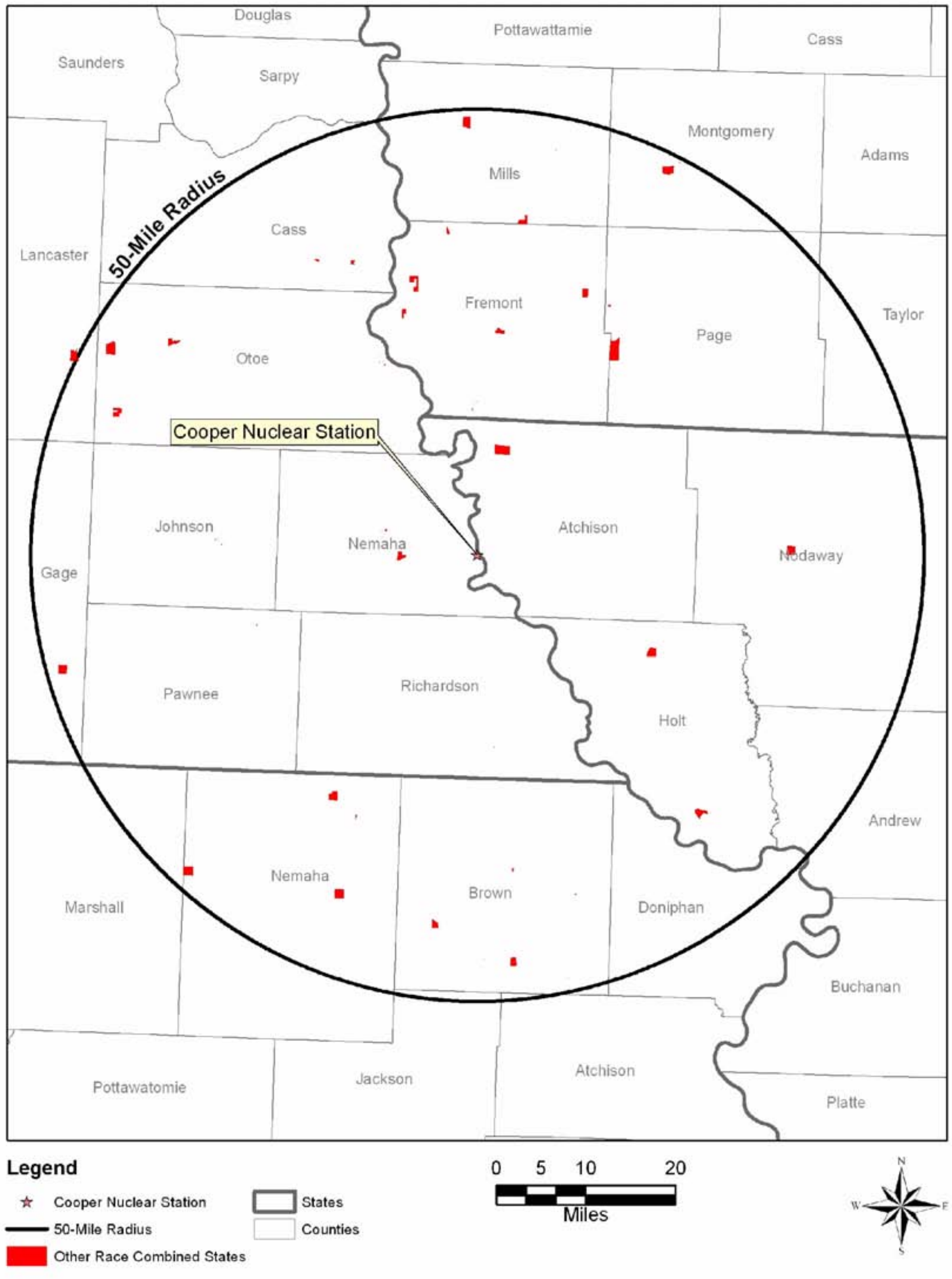

Figure 2.6-12
Census—Other Races (Combined States)

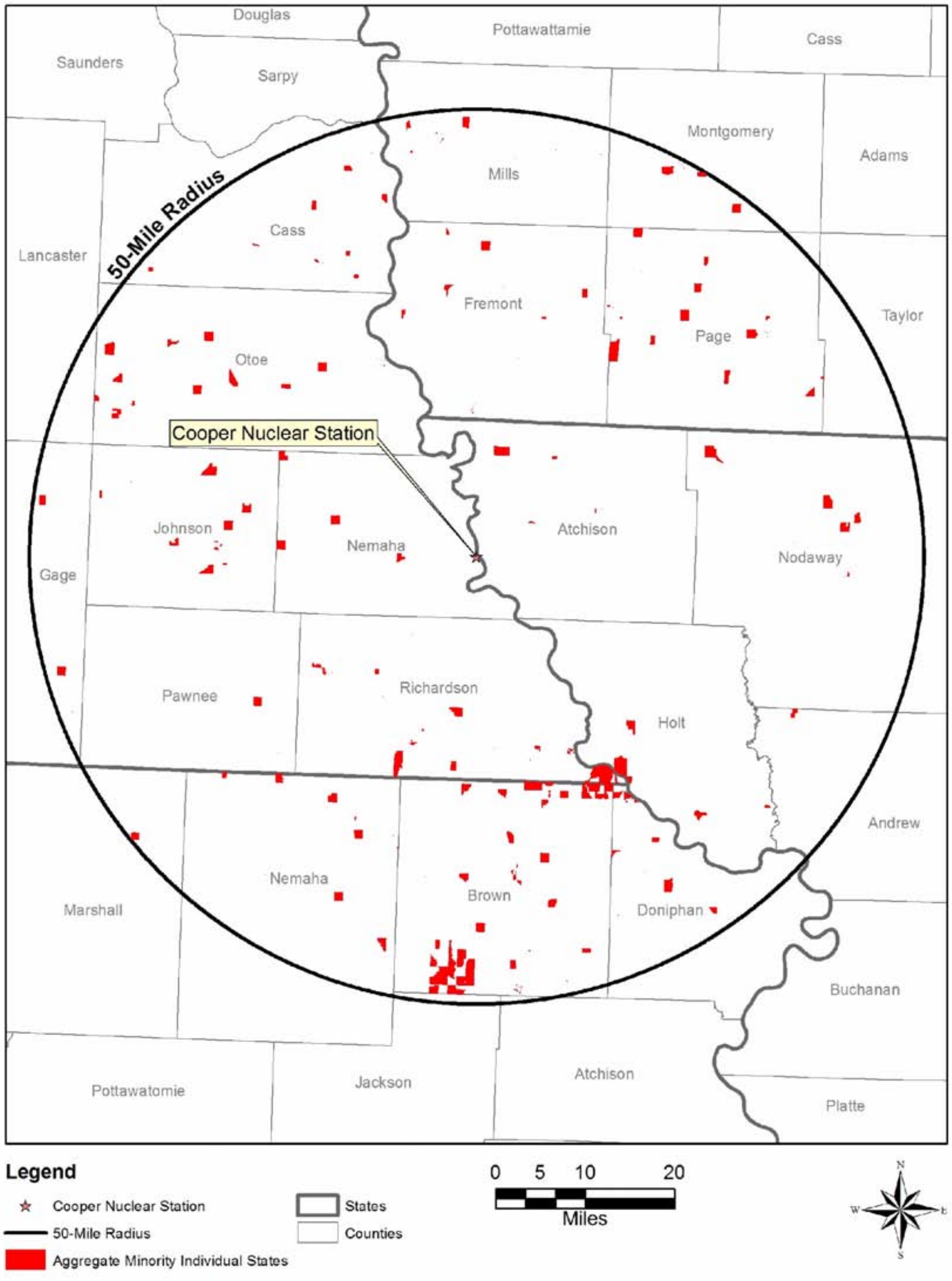

Figure 2.6-13
Census—All Races Combined (Individual States)

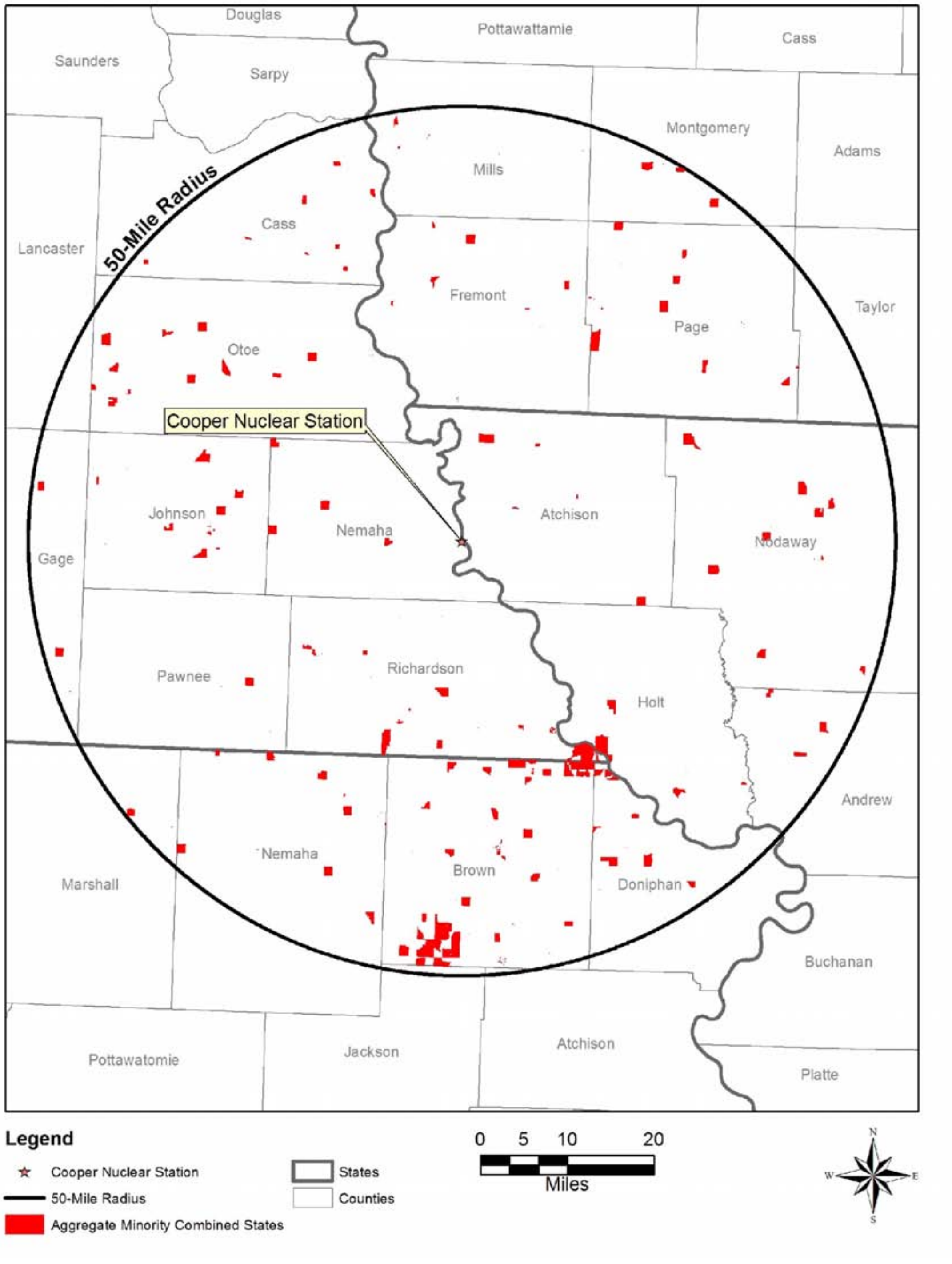

Figure 2.6-14
Census—All Races Combined (Combined States)

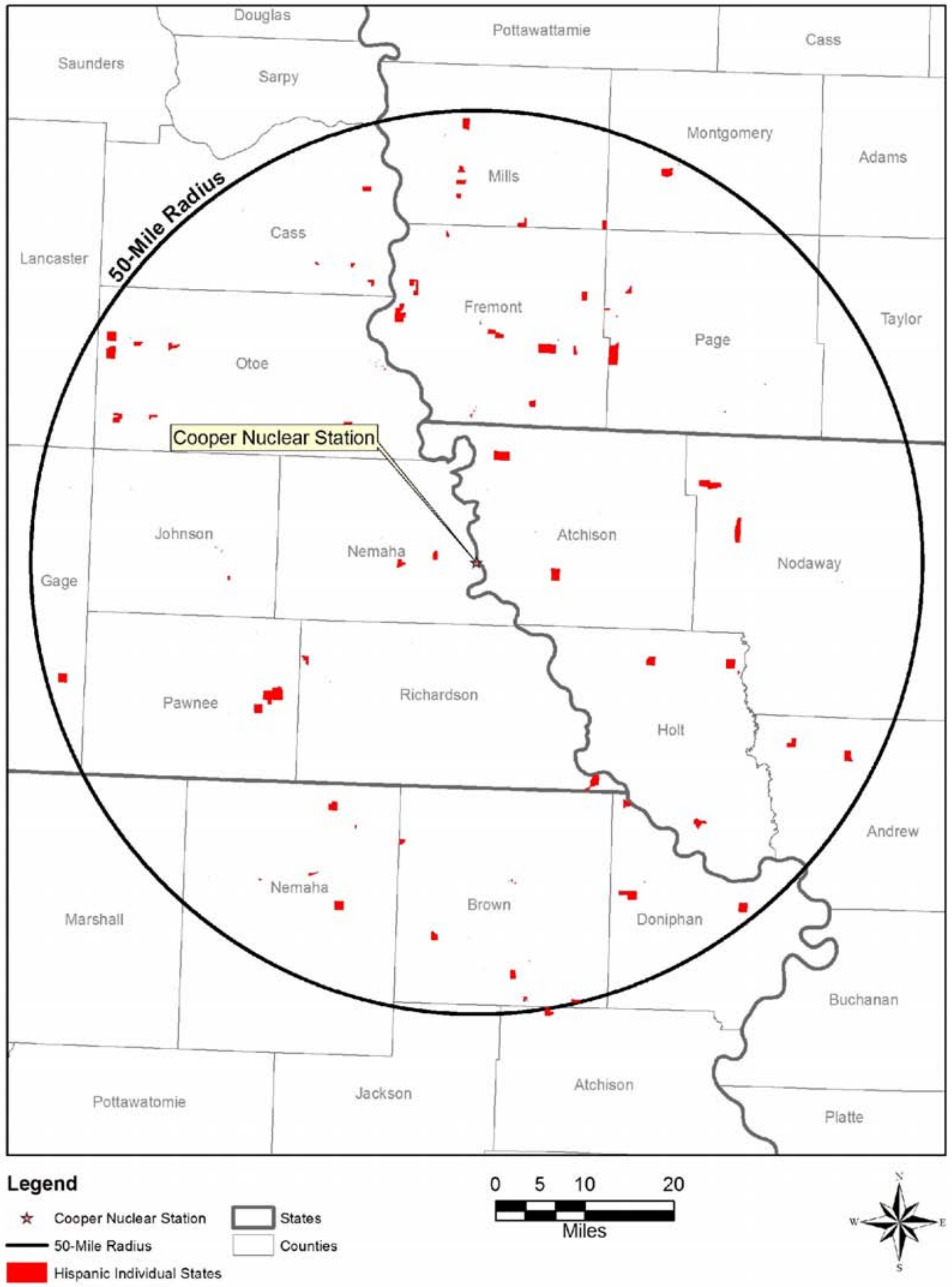

Figure 2.6-15
Census—Hispanic (Individual States)

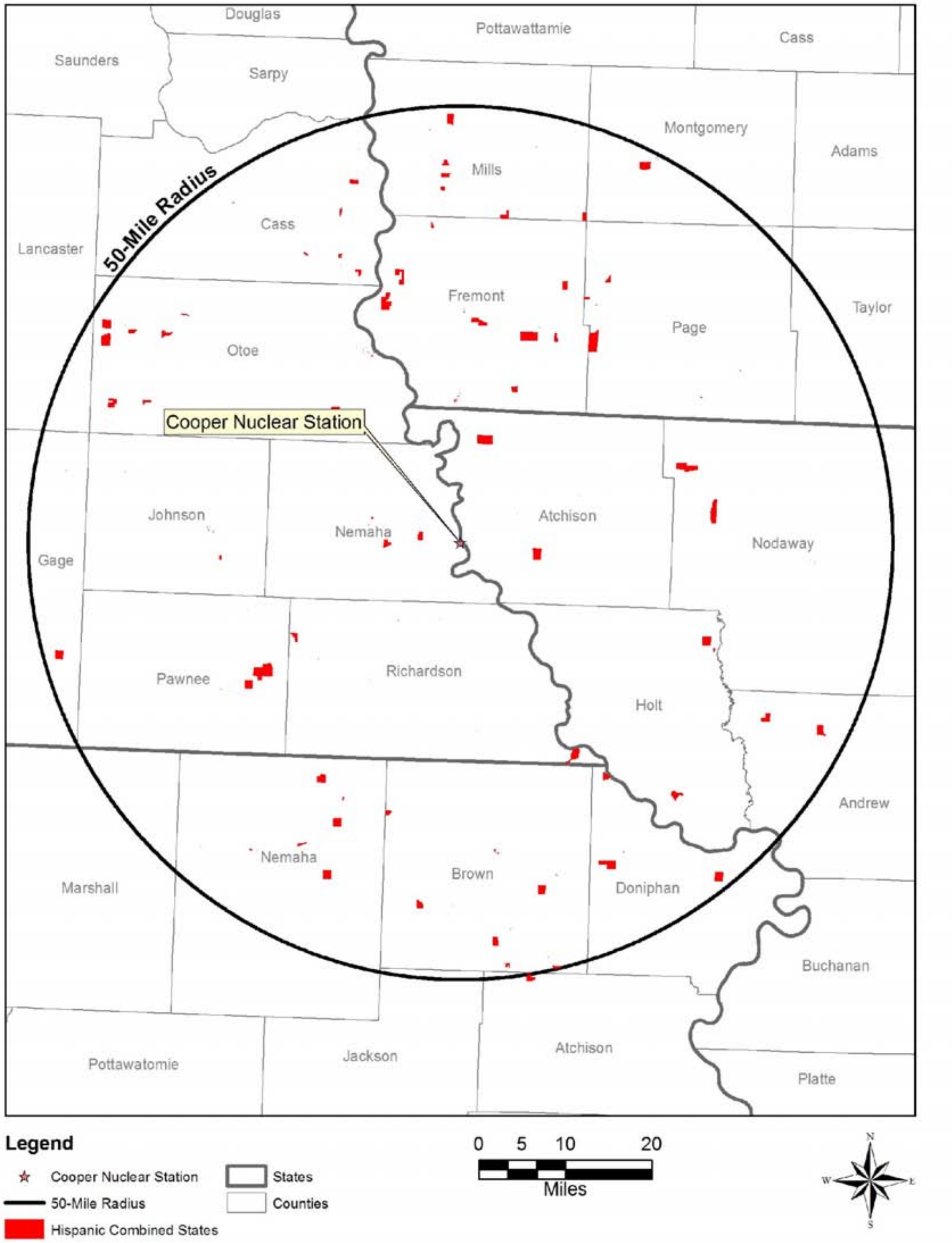

Figure 2.6-16
Census—Hispanic (Combined States)

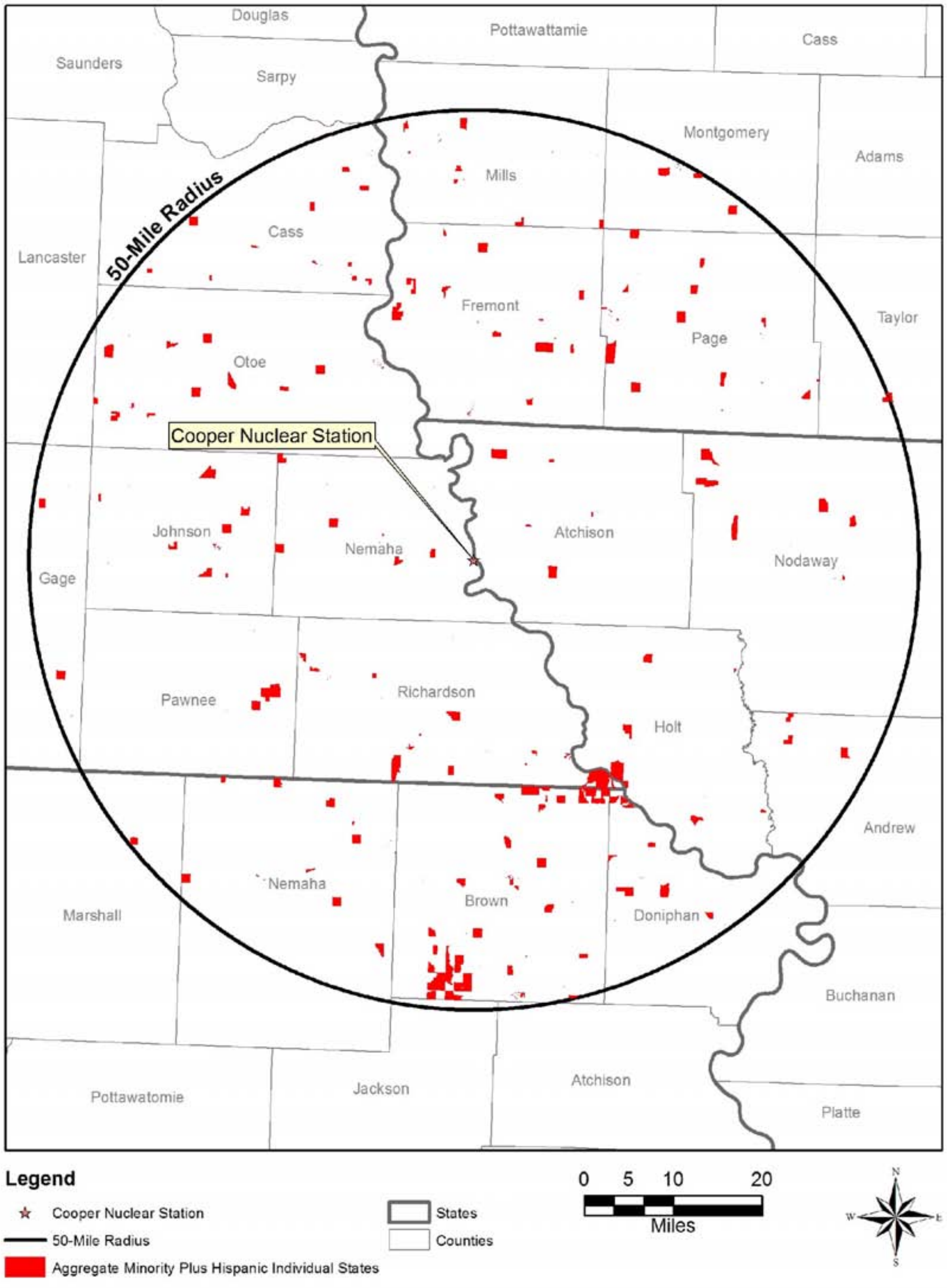

Figure 2.6-17
Census—Aggregate and Hispanic Combined (Individual States)

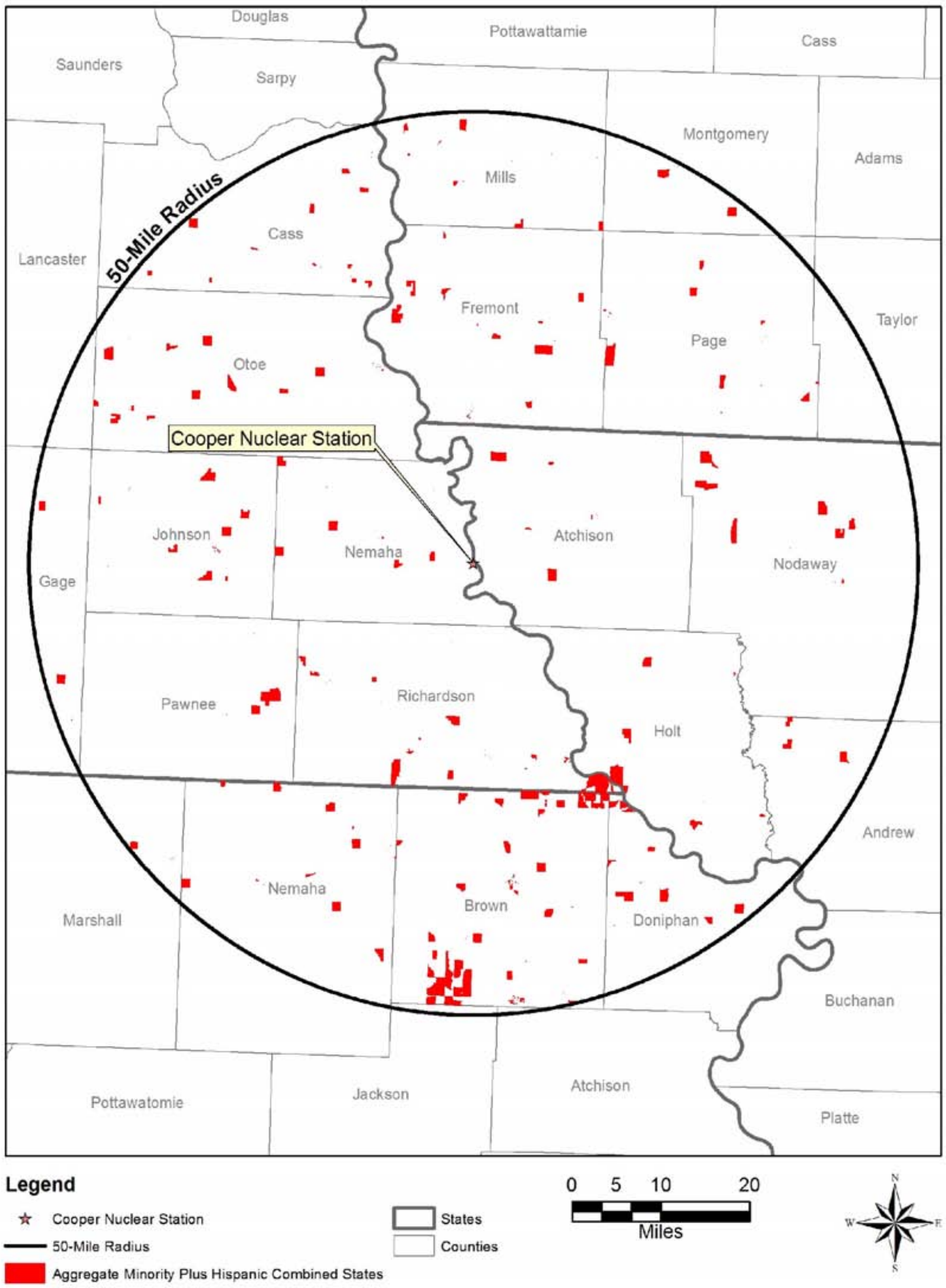

Figure 2.6-18
Census—Aggregate and Hispanic Combined (Combined States)

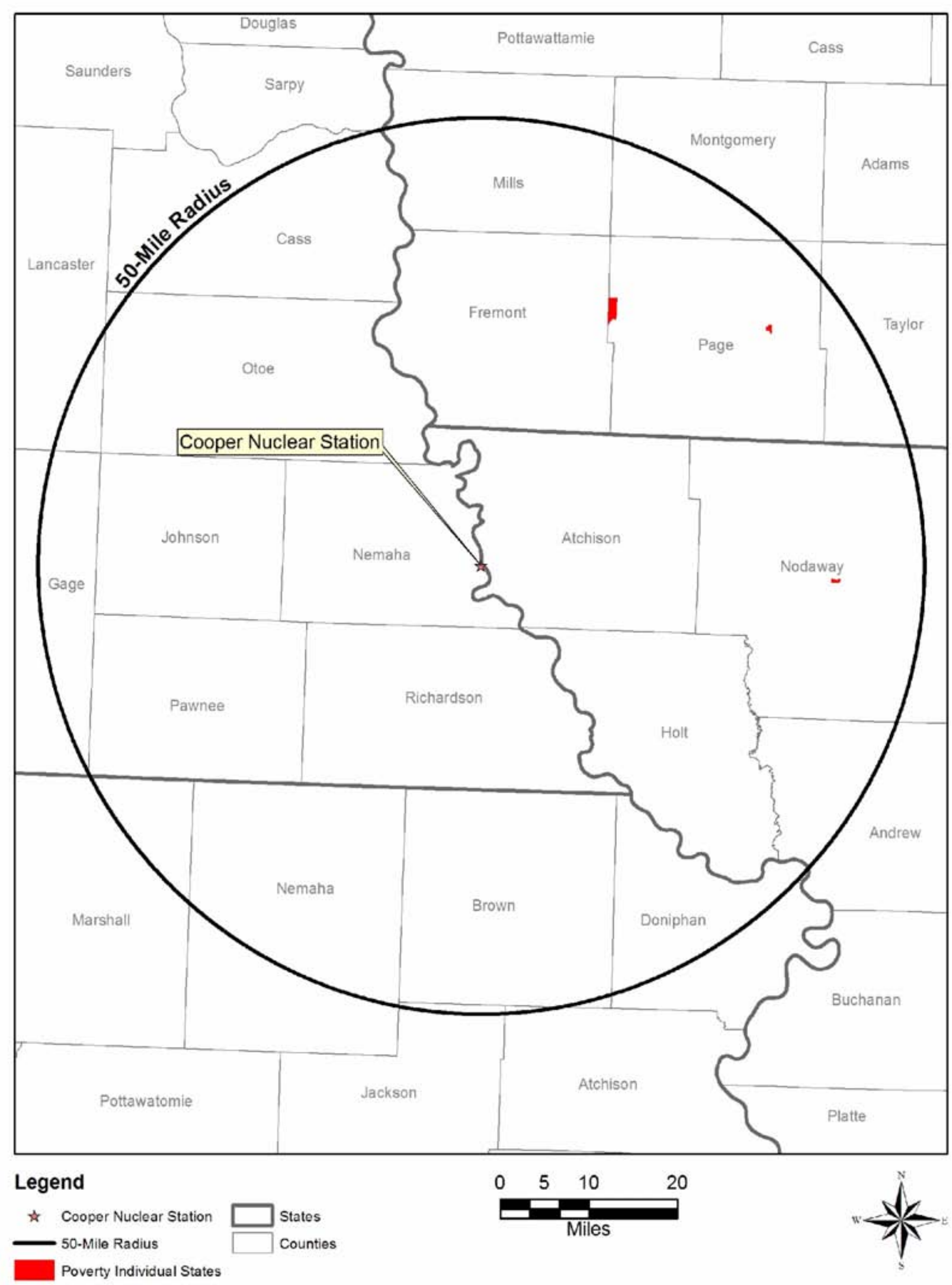

Figure 2.6-19
Census—Low Income (Individual States)

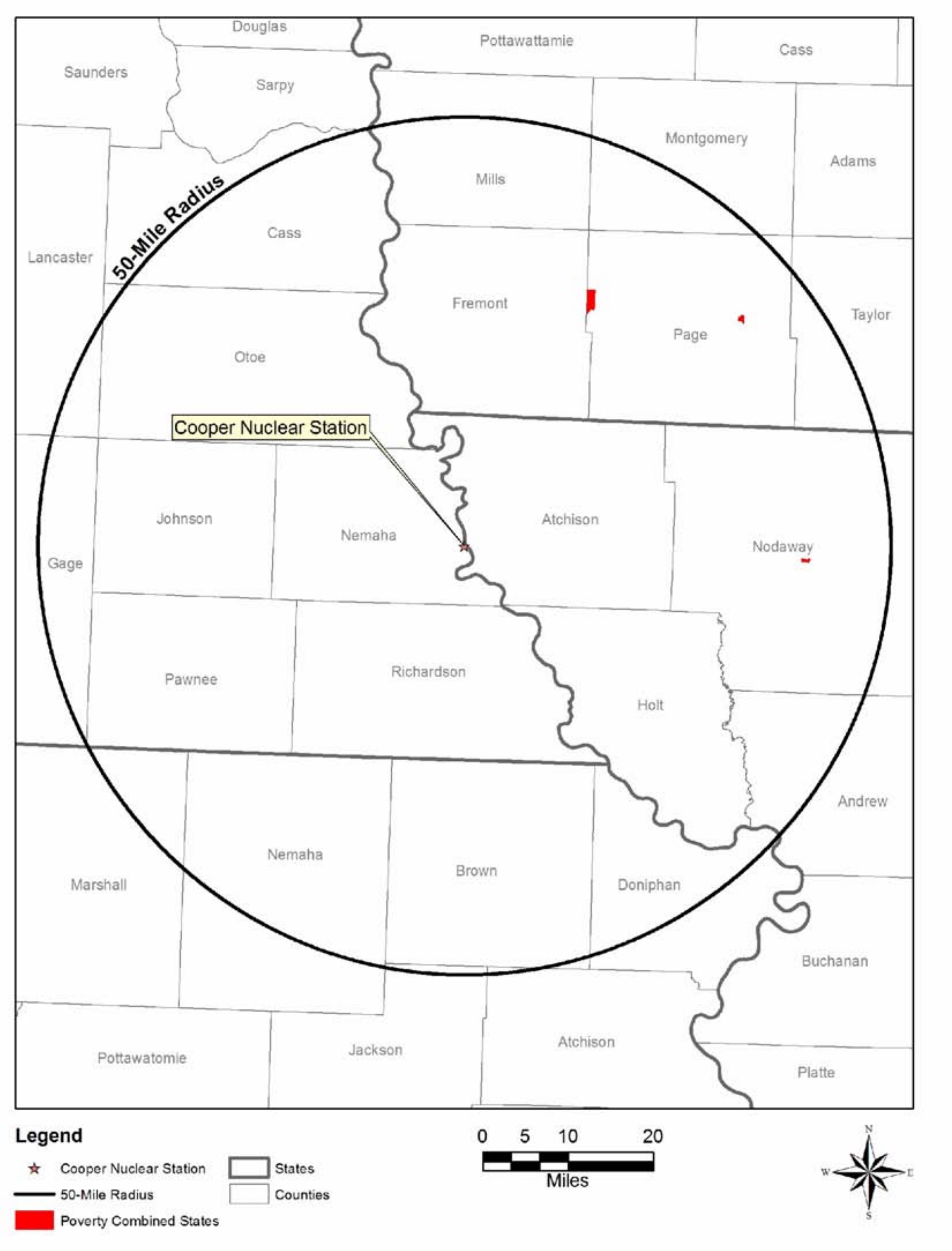

Figure 2.6-20
Census—Low Income (Combined States)

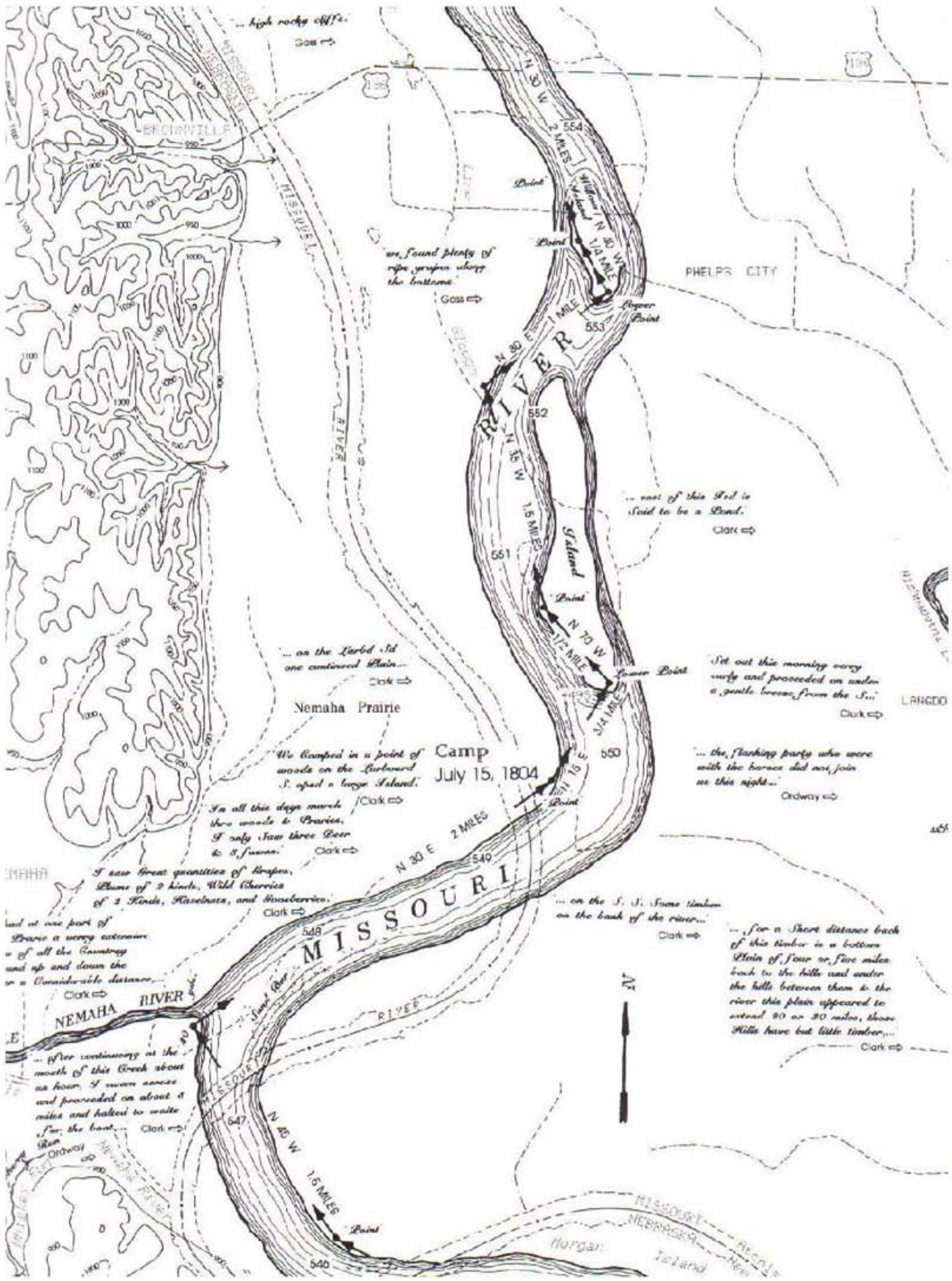

Figure 2.12-1
Cartographic Reconstruction

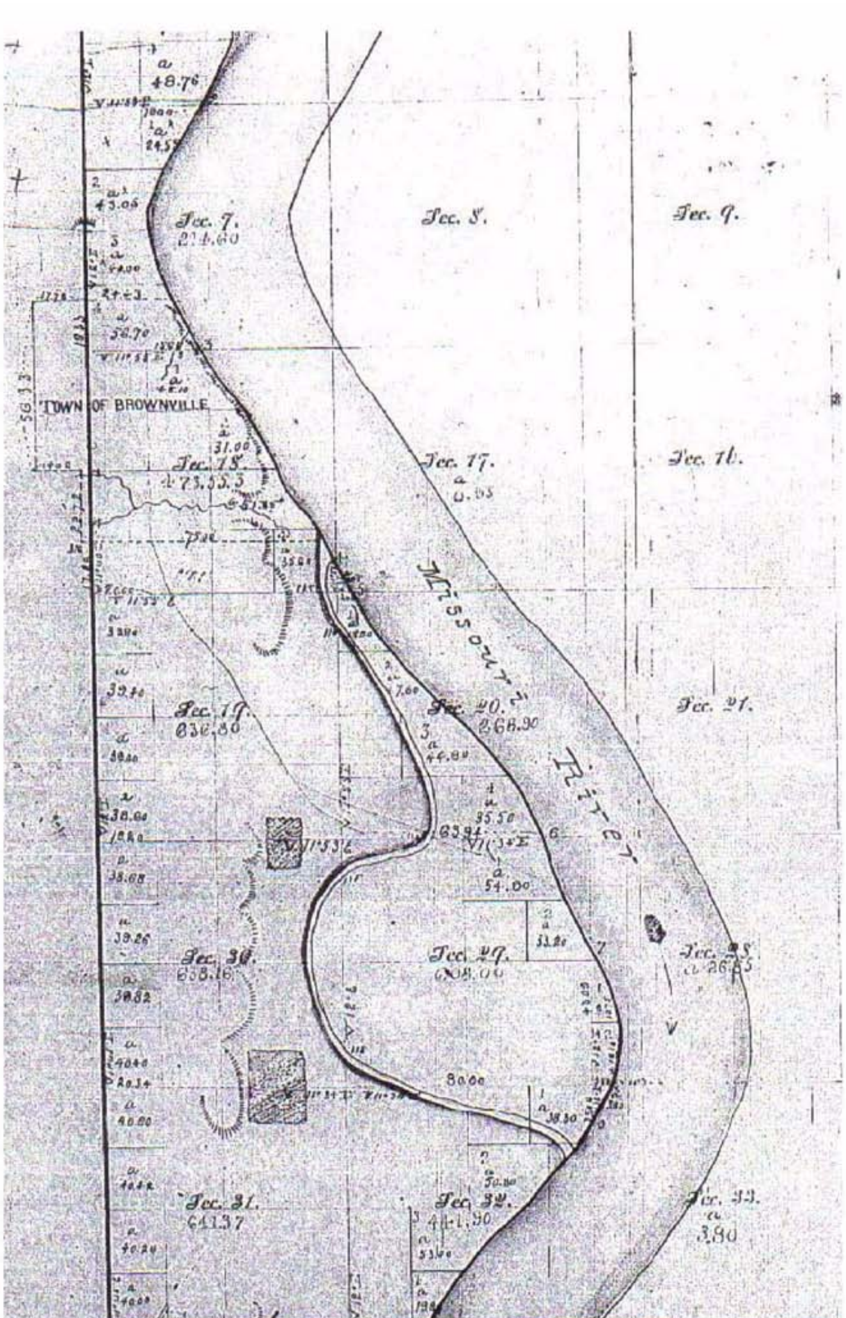

Figure 2.12-2
CNS Area 1865

3.0 THE PROPOSED ACTION

3.1 Description of the Proposed Action

The proposed action is to renew the operating license (OL) for CNS which would provide the option for NPPD to continue to operate CNS through the 20-year period of extended operation. For CNS (Facility Operating License DPR-46), the requested renewal would extend the license expiration date from midnight January 18, 2014, to midnight January 18, 2034.

In summary, as explained in this ER, there are no changes related to license renewal with respect to operation of CNS that would significantly affect the environment during the period of extended operation.

3.2 General Plant Information

The principal structures at CNS consist of the reactor building, turbine building (including service area appendages), control building, controlled corridor, radwaste building, augmented radwaste building, intake structure, off-gas filter building, elevated release point, diesel generator building, multi-purpose facility, railroad airlock, drywell and suppression chamber, miscellaneous circulating water system structures (e.g., circulating water conduits, seal well), optimum water chemistry gas generator building, and office building [NPPD 2008, Section XII-1.0]. The reactor and nuclear steam supply systems for the site, along with the mechanical and electrical systems required for the safe operation of CNS, are primarily located in the containment structure. Figure 3.2-1 shows the general features of the facility. The exclusion area boundary (EAB) is shown in Figure 2.1-7. No residences are permitted within the CNS EAB.

3.2.1 Reactor and Containment Systems

The site uses a boiling water reactor (BWR) in the nuclear steam supply system and a once-through circulating water system that withdraws cooling water from and discharges to the Missouri River. General Electric supplied the nuclear steam supply system. CNS achieved commercial operation in 1974.

CNS is a single unit plant, consisting of a nuclear steam supply system, steam and power conversion systems, and related facilities. The original licensed thermal power level was 2,381 megawatts-thermal [NPPD 2007a]. Maximum electrical power output was 815 megawatts-electrical (MWe) gross. The current licensed thermal power level is 2,419 MWt and 830 gross MWe at 0.85 pf.

A safety analysis report for a measurement uncertainty recapture (MUR) was submitted to the NRC in November 2007. The approach to achieve a higher thermal power level was to increase core flow along the established Maximum Extended Load Line Limit Analysis rod lines. This strategy allows CNS to maintain most of the existing available core flow operational flexibility while assuring that low power related issues (e.g., stability and ATWS instability) do not change because of the MUR uprate. [NPPD 2007a, p. 1-2] The MUR changes result from increased feedwater flow measurement accuracy to be achieved by utilizing high accuracy Caldon

CheckPlus Leading Edge Flow Meter ultrasonic flow measurement instrumentation. NPPD made the necessary modifications to CNS to increase the licensed core rated power by 1.62 percent from 2,381 MWt to 2,419 MWt during the April 2008 outage. [NPPD 2007a, Section 1.0]

Fuel for CNS is made of low-enrichment (less than 5 percent by weight) high-density ceramic uranium dioxide fuel pellets stacked within Zircaloy-2 cladding that is evacuated, backfilled with helium, and sealed with Zircaloy end plugs welded in each end [NPPD 2008, Section III-2.5; NPPD 2008, Section X-4.5.1.1]. Based on core design value, CNS operates at an individual rod average fuel burnup (burnup averaged over the length of a fuel rod) of no more than 62,000 MWD/MTU, which ensures that peak burnups remain within the acceptable limits specified in Appendix B to Subpart A of 10 CFR Part 51 (Table B-1) [USNRC 2006].

The primary containment system is designed, fabricated, and erected to accommodate without failure the pressures and temperatures resulting from or subsequent to the double-ended rupture or equivalent failure of any coolant pipe within the primary containment. The reactor building, encompassing the primary containment system, provides secondary containment when the primary containment is closed and in service, and provides for primary containment when the primary containment is open, as required. The two containment systems and such other associated engineered safety features as may be necessary are designed and maintained so that off-site doses resulting from postulated design basis accidents are below the values stated in 10 CFR Part 100. [NPPD 2008, Appendix F-2.2.5] The primary containment system for CNS is a reinforced concrete structure completely enclosing the reactor vessel.

3.2.2 Cooling and Auxiliary Water Systems

3.2.2.1 Circulating Water Intake Structure

The circulating water system uses water taken from the Missouri River. Water passes through trash racks and then through traveling screens. A major portion of the flow is directed to the circulating water pumps, which deliver water to the main condenser. A smaller portion of Missouri River water is used by the service water pumps. The discharge from the condenser and from the service water system is returned via the discharge channel to the river. [NPPD 2008, Section XI-6.3]

The circulating water intake structure (CWIS) is located on the west shoreline as shown in Figure 3.2-2 [NPPD 2006b, Section 2.1]. Figures 3.2-3 and 3.2-4 provide plan and cross-section views of the CWIS, respectively. In front of the CWIS is a guide wall and submerged weir constructed of steel sheet piling that runs parallel to and at distance of 14.25 feet (ft) from the face of the intake. The weir is physically attached at its upstream terminal to the circular cell that was left in place after the remaining cofferdam structure was removed following construction of the CWIS. The downstream terminal is 40 ft below the downstream corner of the CWIS. No connection is made to the shore at the downstream terminal. The top elevation of the upstream portion is El. 885 ft (all elevations for CNS refer to AMSL), which is 5 ft higher than normal summer river elevation of 880 ft. The top of the weir gradually changes from El. 885 ft at the upstream terminal to a submerged downstream-most weir section of El. 867.5 ft. [NPPD 2006b, Section 2.2]

The purpose of the guide wall and weir is to reduce the sediment input to the CWIS. It accomplishes this by forcing bed load and other material contained in the river to flow around and past the CWIS. When the level of the river is higher than El. 867.5 ft, most of the water spills over the top of the wall. The bed load, composed of heavier and larger diameter particles, is usually found in the bottom part of the river and moves along the weir wall to be directed away from the CWIS. When river level drops, a higher percentage of water goes around the weir rather than going over it. As river level drops, a higher percentage of bed load comes into the CWIS due to eddy effects at the terminal end of the weir. Therefore, during 2005 turning vanes were installed in front of the CWIS to redirect bed load away from the intake structure. [NPPD 2006b, Section 2.2] Twenty-three 10 ft long by six ft high sheet pile turning vanes were installed riverward of the weir wall with top elevations of EL. 860 ft. Installed at a 22 degree angle to the outer weir, and extending beyond the downstream terminus of the weir, these turning vanes redirect sand and gravel outward away from the weir and CWIS.

Water for the facility is drawn through five intake bays. Four of these bays provide circulating water to the generating unit while the other is used for service water. Each circulating water intake bay splits into two screen bays, while the service water intake bay narrows to a smaller screen bay. These bays are 9.7 feet in length by 5.6 feet wide, providing space for 4.2 feet wide dual flow screens. Each bay is fitted with modified dual flow traveling screens designed with fish collection baskets (see Figure 3.2-5). The modified dual flow screens operate at 90 degrees to the water flow. Fish and debris are collected on both the ascending and descending sides of the dual-flow screen which allows only filtered water to pass downstream to the pumps. Fish and debris are removed by a high pressure screen wash system and conveyed back to the river. Installation of the modified dual flow traveling screens began during 2005 and was completed in 2006, to address debris carry-over problems encountered with the original flow through traveling screens. A decision was also made by NPPD to install fish collection baskets on the dual flow screens to address future 316(b) issues. However, the present design and construction does not include installation of the low pressure spray system or a separate fish return trough and conveyance system to return fish back to the river. [NPPD 2006b, Section 2.2]

Each circulating water intake bay splits into two screen bays, while the service water intake bay narrows to a smaller screen bay. These bays are 9.7 ft long by 5.6 ft wide, providing space for 4.2 ft wide dual-flow screens. Each bay is fitted with modified dual-flow traveling screens designed with fish collection baskets (see Figure 3.2-5). The modified dual-flow screens operate at 90 degrees to the water flow. Fish and debris are currently collected on both the ascending and descending sides of the dual-flow screen, which allows only filtered water to pass downstream to the pumps. Fish and debris are removed by a high pressure screen wash system and conveyed back to the river. Modified dual-flow traveling screens were installed in 2006 to address debris carry-over problems encountered with the original flow-through traveling screens. [NPPD 2006b, Section 2.2]

Each screen has 1/8 by 1/2 in. smooth top mesh and is rotated continuously at 8.2 fpm to prevent excess debris build up. A high pressure screen backwash system providing 3,000 gpm at 30-60 psig is used to remove fish and debris from the screens. Water for the screenwash is drawn from the service water pumps. Fish and debris flushed from the screens are returned to the river via an 18 in. steel pipe. This steel pipe discharges downstream from the intake. The existing screen wash system does not have the capacity to provide the required flow to support both a low pressure fish protection spray system and the high pressure debris removal system nor is there a separate fish return trough and conveyance system to return fish back to the river. [NPPD 2006b, Section 2.2]

However, CNS is planning to augment its existing intake structure design with a dual flow conversion screen fish handling systems during the current operational term. The system currently being considered is the Brackett Green USA, Inc. Fish Handling Screen with the Advanced S.I.M.P.L.E. Process. This possible modification to the intake structure would involve the installation of inside and outside fish sprays which operate between 5-10 psi and a separate fish return trough. As raw water would pass through the existing fish baskets, floating and suspended debris larger than the mesh opening of the existing dual flow screens would be retained on the upstream side of the mesh and juvenile marine life would be captured in the hydraulically stabilized fish recovery basket. The recovered fish would then be discharged on the descending side with aid from the inside and outside fish sprays into a fish trough located above the debris trough. [Brackett]

Four circulating water pumps provide the circulating water for the facility. Each pump can draw 159,000 gpm. The pump design water level is at El. 875.0 ft, with a minimum submergence level at El. 865.0 ft. There are four service water pumps providing a combined flow of 32,000 gpm. Velocities in the intake structure are 1.1 ft/sec under the curtain wall, 0.7 ft/sec at the trash racks, and approximately 2.0 ft/sec at the traveling water screens. These velocities were calculated at low water levels (El. 874.5 ft) and maximum circulating water pump flow (159,000 gpm per pump). [NPPD 2006b, Section 2.2]

Flow of the Missouri River at CNS is largely controlled by the Gavins Point Dam located about 200 miles upstream in Yankton, South Dakota. The river is about 800 feet wide and flows in a southeasterly direction. The flow is highly channelized with swift flows and heavy sediment transport. To minimize the effects of sedimentation on the intake, turning vanes and a low sheetpile wall are located in front of the intake bays. Wing dams are located on the Missouri side of the river to force the flow into a central channel. The water levels in the river range from a maximum at El. 899.0 ft to a minimum at El. 874.5 ft, with a normal level at El. 880.0 ft. The annual mean river flow is 38,251 cfs (1930–2001) at the USGS gauging station at Nebraska City, Nebraska. This gauging station is located approximately 30 river miles north of the CNS CWIS. During the winter, ice is very common on the river. To prevent ice damage, ice deflector barges are installed during the winter months. To prevent the formation of frazzle ice, some of the main condenser discharge water (25–30 percent) is re-circulated through the ice control tunnel and released in front of the trash rack within the CWIS while the remaining water is discharged about 1,300 ft downstream of the intake via a discharge canal. [NPPD 2006b, Section 2.3]

Chlorination is typically not required because of the inherent scouring action of the sandy river water. However, a connection is provided for such a system in the event should it's be found necessary potentially needed in the future. The chlorination system connection is located on the common inlet to Screen Wash Pump A and B from the service water system. [NPPD 2008, Section XI-6.3]. Bacteria that occur naturally in the Missouri River may contribute to the growth of biological film fouling of the main condenser tubes. The station is proceeding with a study to determine if routine chemical injection (chlorine, bromine, etc.) will be effective in eliminating the microbiological film on the interior walls of the condenser tubes.

3.2.2.2 Discharge Structure

Water leaves the pumphouse and circulates through the condenser, where it is collected from the condenser section through a large manifold. It then travels through concrete tunnels to the seal well structure and the discharge canal (see Figure 3.2-1). [USAEC, Section III-C.1] At the rated circulating water flow of 631,000 gpm through the condenser and at design power on the turbine-generator, the temperature rise through the condenser is approximately 17.8°F [NPPD 2008, Section XI-6.3]. From the seal well and gate control structure, the water is directed into a discharge canal that is approximately 1,000 ft long; it then enters the river at a slight angle. The velocity of discharge is about 1 fps during average water levels of 879.4 ft AMSL and 35,000 cfs flow and increases to about 2.5 fps as the water surface elevation is reduced to 874.5 ft AMSL and flows near 11,000 cfs, the nominal control low maintained by the USACE below the confluence of the Platte. Travel times in the pumphouse-condenser-canal system will be about 20 minutes at high flow and 10 to 12 minutes at lower river flows. [USAEC, Section III-C.1] Stone rip-rap is used to prevent scours in the vicinity of the discharge structure [NPPD 2008, Section XII-2.2.7.4].

3.2.3 Radioactive Waste Treatment Processes (Gaseous, Liquid, and Solid)

The radioactive waste systems collect, treat, and dispose of radioactive and potentially radioactive wastes in a controlled and safe manner such that the operation and availability of the station is not limited. The radioactive waste system includes equipment, instrumentation, and operating procedures that ensure radioactive wastes may be safely processed and disposed of within the limits set forth in 10 CFR Part 20, 10 CFR Part 50, Appendix I, and 40 CFR Part 190. [NPPD 2008, Section IX-1.0]

The radioactive input to the radwaste systems is due primarily to (1) activation products resulting from irradiation of the reactor water and impurities therein (principally metallic corrosion products) and (2) fission products resulting from defective fuel cladding or tramp uranium contamination within the reactor system. [NPPD 2008, Section IX-1.0]

Radioactive wastes resulting from station operation are classified as liquid, gaseous, and solid. The following definitions apply to radioactive wastes.

(1) Liquid radioactive wastes: liquids directly from the reactor process and auxiliary systems or liquids which can become contaminated due to contact with these liquids from reactor process systems.

(2) Gaseous radioactive wastes: off-gases from the main condenser evacuation and turbine gland sealing systems and ventilation system exhausts from buildings

having the potential for containing radioactive materials. Gaseous radioactive wastes include noble gases, radioiodine, particulates, Carbon-14, and tritium.

(3) Solid radioactive wastes: solids from the reactor or auxiliary systems, solids in contact with reactor or auxiliary systems operations, or those materials processed through the radwaste system and solidified. [NPPD 2008, Section IX-1.0]

Storage of radioactive materials is regulated by the NRC under the Atomic Energy Act of 1954, and storage of hazardous wastes is regulated by the United States Environmental Protection Agency (EPA) under the Resource Conservation and Recovery Act of 1976.

In 2007, the site began preparation work for the installation of an ISFSI Facility on the north end of the CNS site in an area which was previously disturbed and outside the existing Protected Area. The ISFSI Facility will provide storage locations for Holtec International HI-STORM 100S(B) Casks. The site ISFSI Facility has been sized to include spent fuel assemblies to maintain spent fuel pool reserve core margin for CNS, based upon an additional 20-year license renewal term.

3.2.3.1 Liquid Waste Processing Systems and Effluent Controls

The liquid radwaste (LRW) system includes an augmented treatment subsystem that is no longer in use. The LRW system (non-augmented) is described below. [NPPD 2008, Section IX-2.0]

The LRW system for CNS was designed to accept process wastes from two nuclear units. Since CNS is only a single unit, the system is larger than would normally be necessary. The LRW system collects, processes, stores, and disposes of all radioactive liquid wastes. [NPPD 2008, Section IX-2.5.1]

Included in the LRW system are the following components and systems:

a. piping and equipment drains carrying potentially radioactive wastes;
b. floor drain systems in areas that may contain potentially radioactive wastes;
c. tanks, piping, pumps, process equipment, instrumentation, and auxiliaries necessary to collect, process, store, and dispose of potentially radioactive wastes; and
d. tanks and sumps used to collect potentially radioactive wastes. [NPPD 2008, Section IX-2.5.1]

Equipment was selected, arranged, and shielded to permit operation, inspection, and maintenance with acceptable personnel doses. For example, tanks and processing equipment that are expected to contain significant radiation sources are located behind shielding, and similarly sumps, pumps, valves, and instruments are located in radiologically controlled access rooms or shielded spaces. In addition, the radwaste equipment was selected to minimize the need for maintenance. Operation of the waste system is essentially manual start-automatic stop. [NPPD 2008, Section IX-2.5.1]

The LRW system is divided into several subsystems so that the liquid wastes from various sources can be kept segregated and processed separately. Cross connections between the subsystems provide additional flexibility for processing of the wastes by alternate methods. The liquid radwastes are classified, collected, and treated as either high purity, low purity or chemical. The terms "high" purity and "low" purity refer to chemistry purity conductivity, not radioactivity. [NPPD 2008, Section IX-2.5.1]

3.2.3.1.1 High Purity Wastes (Waste Collector Subsystem)

High purity (low conductivity) liquid wastes are collected in the waste collector tank from the following sources.

1. drywell equipment drain sump
2. reactor building equipment drain sump
3. radwaste building equipment drain sump
4. turbine building equipment drain sump
5. startup discharge from reactor water cleanup (RWCU) pumps
6. draining of residual heat removal (RHR) system
7. decantate from RWCU phase separators
8. decantate from condensate phase separators
9. fuel pool system
10. decantate from waste sludge tank
11. chemical waste sample tank
12. distillate tank
13. radwaste building sample rack IE
14. waste sample tanks
15. elevated release point sump (Z sump)

[NPPD 2008, Section IX-2.5.2]

These wastes have low conductivity with variable radioactive concentrations dependent on their area of collection. The average high purity waste collected is 16,000 gallons/day with an average activity level of 1 x 10^{-4} Ci/ml. [NPPD 2008, Section IX-2.5.2]

During treatment, the high purity wastes are filtered in the waste collector filter and then demineralized in the deep bed waste demineralizer. The expected decontamination factor (DF) for combined filtration and demineralization is at least 1,000. After processing, the waste is pumped to the waste sample tanks where it is sampled. [NPPD 2008, Section IX-2.5.2]

If the analysis of the sample reveals water of high conductivity or high turbidity, the waste is recycled to the waste collector tank for reprocessing. If the analysis of the sample reveals purity of the waste is acceptable, the waste is sent to the condensate storage tank (CST). However, if the CST inventory does not permit additional water, the waste may be sent to the waste surge tank or the waste can be discharged to the river, provided a minimum of one circulating water pump is in operation. The flow capacity is 270 gpm. [NPPD 2008, Section IX-2.5.2]

The backwash resins from the demineralizer are sent to the spent resin tank. The resins are then pumped to a high integrity container where they are dewatered using the NuPac dewatering system. [NPPD 2008, Section IX-2.5.2]

The backwash filter material from the waste collector filter is sent to the waste sludge tank. Solids treatment of the contents of this tank is similar to that for the resins. However, the tank contains a mixture of backwashes from the waste collector and floor drain filters and fuel pool demineralizer sludges. [NPPD 2008, Section IX-2.5.2]

3.2.3.1.2 Low-Purity Wastes (Floor Drain Subsystems)

Low purity (high conductivity) liquid wastes are collected in the floor drain collector tank from the following sources.

1. drywell floor drain sump
2. reactor building floor drain sumps
3. radwaste building floor drain sumps
4. turbine building floor drain sump
5. chemical waste tank
6. laboratory drain tanks
7. elevated release point sump (alternate flow path only)
8. augmented radwaste building floor drain sump
9. decantate from waste sludge tank (only when waste collector tank is full)

[NPPD 2008, Section IX-2.5.3; CNS 2007]

These wastes generally have low radioactivity concentrations; therefore, processing consists of filtration and ion exchange. [NPPD 2008, Section IX-2.5.3; CNS 2007]

If the analysis of the sample reveals that the purity of the waste is sufficient to transfer to the high purity waste system, then the waste is transferred to the waste collector tank, provided the inventory of the high purity waste system is such as to permit the additional volume. If the purity of the waste precludes processing to the waste collector subsystem, but the radioactivity concentration and purity are acceptable for discharge, the waste is discharged to the river, provided a minimum of one circulating water pump is in operation. If the waste cannot be processed to the waste collector subsystem or the river, it is recycled back to the floor drain collector tank for further processing. [NPPD 2008, Section IX-2.5.3]

Because no radium-226 or radium-228 of plant origin will be present, and because the potential concentration of iodine-129 is very low, the discharge concentration limit for an otherwise unidentified mixture of radioisotopes will not exceed the limit of 10^{-8} Ci/ml above background. If other radioisotopes are shown not to be present in significant concentrations, or if analyses are made, discharge limits may meet maximum permissible concentrations. [NPPD 2008, Section IX-2.5.3]

The average "dirty waste" (i.e., low purity wastes from the floor drain sumps) volume collected from the floor drain system is 7,000 gallons/day. In the treatment process the wastes are filtered in the floor drain collection filter with a flow capacity of 65 gpm and an expected dilution factor of 10 for filtration. [NPPD 2008, Section IX-2.5.3]

3.2.3.1.3 Chemical Wastes

Chemical wastes are collected in the chemical waste tank and laboratory drain tanks from the following sources.

1. shop decontamination solutions
2. laboratory drains
3. reactor building and radwaste building decontamination drains
4. RWCU, waste, and condensate precoat tank drains

[NPPD 2008, Section IX-2.5.4]

The chemical wastes are normally comprised of laboratory drains. Infrequently (every several years), decontamination solutions may be present due to equipment decontamination for maintenance. The multi purpose facility floor drains provide some of this solution due to decontamination of equipment in the machine shop. The maximum activity and volumes are due to the decontamination solutions. [NPPD 2008, Section IX-2.5.4]

Chemical wastes may be of such high conductivity (ionic content) as to preclude treatment by ion exchange. If necessary, wastes may be neutralized by adding an appropriate neutralizing agent. These wastes may be sent to the floor drain collector tank and processed by the low purity waste system for disposal to the river. The design capacity flow rate for the laboratory drain tanks to the floor drain collector tank is 38 gpm. The chemical waste tank wastes are transferred to the floor drain collector tank at a design capacity rate of 50 gpm. A DF of 10 is expected in passing through the floor drain collector filter. [NPPD 2008, Section IX-2.5.4]

If the radioactivity content of the waste precludes disposal to the river, the chemical wastes are processed through the floor drain demineralizer system or processed using an approved vendor method. [NPPD 2008, Section IX-2.5.4]

Corrosion of laboratory drains through the normal use of acids is minimized by re-circulating unused portions of samples to waste at the sample station. In effect, this retains the sample in the system until it is satisfactorily neutralized. Reactor water, condensate, and feedwater samples, which do not need to be neutralized, are routed to the high purity waste subsystem where the water is recovered for reuse. [NPPD 2008, Section IX-2.5.4]

3.2.3.2 Liquid Effluent Releases

Controls for limiting the release of radiological liquid effluents are described in the Offsite Dose Assessment Manual (ODAM). Controls are based on (1) concentrations of radioactive materials in liquid effluents and projected dose or (2) dose commitment to a hypothetical member of the public. Concentrations of radioactive material that may be released in liquid effluents beyond the site and EAB are limited to the concentration specified in 10 CFR 20.1302. The total concentration of dissolved or entrained noble gases in liquid releases is limited to 2×10^{-4} microcurie/ml [CNS 2004, Section D 3.1.1]. The ODAM dose limits during a calendar quarter are < 0.015 mSv (1.5 mrem) to the total body and < 0.05 mSv (5 mrem) to any organ [CNS 2004, Section D 3.1.3]. During the calendar year, the ODAM dose limits are < 0.03 mSv (3 mrem) to the total body and < 0.10 mSv (10 mrem) to any organ [CNS 2004, Section D 3.1.3]. The radioactive liquid waste sampling and analysis program specifications provided in the ODAM address the sampling frequency, minimum analysis frequency, type of activity analysis, and lower limits of detection.

3.2.3.3 Gaseous Waste Processing Systems and Effluent Controls

3.2.3.3.1 Condenser Off-Gas System

The off-gas system (non-augmented) includes the subsystems that process and dispose of the gases from the main condenser air ejectors, the startup mechanical vacuum pumps, and the gland steam condensers. The processed gases are routed to the elevated release point (ERP) for dilution and elevated release to the atmosphere. The air ejector discharge and the ERP are continuously monitored by radiation monitors. [NPPD 2008, Section IX-4.3.1.1]

Gases routed to the ERP include air ejector and gland seal off-gases and gases from the standby gas treatment system. Dilution air input to the ERP is provided to reduce the hydrogen in the air ejector off-gases to a concentration of less than four percent by volume. Dilution air is supplied by one of two full capacity fans in the off-gas filter building located near the ERP. The ERP is designed such that prompt mixing of all gas inlet streams occurs in the base to provide additional dilution of hydrogen and to allow location of the sample point as near to the base as possible. The ERP drainage is routed to the liquid radwaste system via loop seals. [NPPD 2008, Section IX-4.3.1.1]

The gaseous radwaste system is adequately shielded to minimize the dose received by station personnel. [NPPD 2008, Section IX-4.3.1.1]

3.2.3.3.1.1 Air Ejector Off-gas Subsystem

The air ejector off-gas subsystem consists of a 30-minute hold-up line, high efficiency filters, isolation valves, dilution fans, and the ERP. During normal operation, the air ejector off-gas is the major contributor to the activity in the station off-gas release. The air ejector off-gases entering this system are noncondensibles from the main condenser. These noncondensibles consist essentially of hydrogen and oxygen formed in the reactor by radiolytic decomposition of water, air in-leakage to the main condenser, water vapor, and fission gases, which are negligible in terms of volume. [NPPD 2008, Section IX-4.3.1.2]

Fission gases may arise from minor amounts of tramp uranium on the surface of the fuel element or from imperfections or perforations that might develop in the fuel cladding. The release rate of activation gases is proportional to the thermal output of the reactor and to the hold-up time provided in the system prior to release at the ERP. [NPPD 2008, Section IX-4.3.1.2]

For normal station operation, the air ejector off-gas subsystem provides a total hold-up time of 30 minutes, based on normal air in-leakage. This time period provides for decay of short-lived xenon or krypton to solid daughters to permit retention of these particulates by filters prior to off-gas vent pipe release. In addition, this holdup provides sufficient time for an operator to take appropriate action in the event that the noble gas release rate (due to fuel leaks) exceeds the instantaneous permissible release rate. [NPPD 2008, Section IX-4.3.1.2]

Valves are placed in each of the air ejector off-gas subsystems to automatically close on an isolation signal from both air ejector process radiation monitors. A signal from both channels is required to close these valves by means of a time delay of 15 minutes when the short-term release rate limit is reached. [NPPD 2008, Section IX-4.3.1.2]

From the air ejector outlet to the dilution fan outlet, the system is designed for a pressure of 350 psi to contain a possible explosion resulting from the hydrogen and oxygen present. The off-gas filter system, which is located in the off-gas filter building, consists of two parallel trains, with each train containing a moisture separator, two full-flow, high-efficiency, particulate air filters, and a filter retainer plate. Each train is sized for 100 percent air ejector off-gas capacity (one operating, one spare unit). [NPPD 2008, Section IX-4.3.1.2]

Upon possible explosion upstream of filters, the failed filter retainer plate is capable of stopping filter pieces larger than 0.15 x 0.15 mm in cross-section and can sustain explosion pressure from either direction. Both filter units are located below grade in a shielded pit; appropriate valving is provided to permit isolating either filter unit. The internal construction of each unit is designed to permit remote removal of the unit within its container. [NPPD 2008, Section IX-4.3.1.2]

The off-gas dilution fans supply dilution air to reduce the hydrogen concentration in the ERP and maintain suitable exit velocities at the top of the ERP. Either one of the two fans provides the required dilution air flow (one normally operating and one spare). The two fans are electrically interlocked. Loss of either fan is annunciated in the main control room. Both fans are on an emergency power source. Check valves are located to prevent bypass of air. The off-gas dilution fans are located in the off-gas filter building, in a room radiation shielded from all adjoining areas. Dilution flow is added to the flow of off-gas before the off-gas pipe enters the floor of the off-gas filter building to travel underground to the ERP. Dilution flow piping has been designed to contain an explosion (off-gas flow is within extra heavy or schedule 40 pipe) and to completely seal off an inoperative dilution run. Standard weight pipe, incorporating a check valve and a butterfly valve, is maintained up to the dilution fan outlet plenum. [NPPD 2008, Section IX-4.3.1.2]

A positive pressure of approximately 1 in. w.g. exists. System operation is normal with the slight backpressure on the air ejectors because they will function with a backpressure in excess of 1 psi. A flow orifice has been located downstream of where the dilution flow enters to provide a low pressure for the off-gas inlet and to provide monitoring of the dilution flow. [NPPD 2008, Section IX-4.3.1.2]

To provide an indirect indication of hydrogen leakage into the off-gas building, a red light that is connected to the Continuous Air Monitor unit has been installed inside the northwest window of the building. This light will illuminate if high activity is present in the off-gas building. An increase in activity would also indicate the presence of hydrogen because both are a result of off-gas leakage. [NPPD 2008, Section IX-4.3.1.2]

3.2.3.3.1.2 Gland Seal Off-Gas Subsystem

The gland seal off-gas subsystem collects gases from the gland steam condenser and the mechanical vacuum pumps and passes them through holdup piping prior to release to the stack. Gland seal off-gases and gases from the mechanical vacuum pumps (used during each startup) are routed to the stack via the gland seal holdup line, which is separate from the air ejector holdup line. [NPPD 2008, Section IX-4.3.1.3]

The gland seal off-gas subsystem provides a one-minute holdup time to allow decay of N-16. The holdup time is provided by a long 48-inch diameter pipe between the gland seal exhausters and the ERP. [NPPD 2008, Section IX-4.3.1.3]

Operating pressure is atmospheric; however, design pressure for explosion possibilities is 900 psig. Hydrogen and oxygen are well below explosive limits. No filters, shut-off valves, or radiation monitors are required. The mechanical vacuum pumps are manually stopped by remote manual switch. Upon a main steam line radiation monitor isolation signal, the mechanical vacuum pumps trip and the inlet and outlet valves to the mechanical vacuum pumps close. [NPPD 2008, Section IX-4.3.1.3]

3.2.3.3.2 Augmented Off-Gas System

The Augmented Off-Gas System (AOG) functions to further delay the radioactive gases in the off-gas stream, reducing the activity level, prior to venting to the atmosphere. This system satisfies the "as low as practicable" requirements of 10 CFR Part 50, Appendix I. The off-gas stream enters the AOG system after passage through the 48-inch delay pipe at the flow rates shown in Table IX-4-2 of the CNS USAR. [NPPD 2008, Section IX-4.4.1]

The processes required to satisfy the system parameters are basically 30-minute delay, dilution, recombination, dehumidification, and long-term delay. [NPPD 2008, Section IX-4.4.2]

After the off-gas stream passes through the 30-minute delay pipe and existing filters, the steam jet air ejectors (SJAE) dilute the off-gas stream, raising pressure to the required system inlet pressure. In the recombination process, the hydrogen and oxygen are recombined stoichiometrically. Dehumidification consists of moisture removal prior to long-term delay to reduce the dewpoint of the gas to a very low level. Long-term delay for the decay of the noble gas isotopes is achieved in a series of charcoal beds. [NPPD 2008, Section IX-4.4.2]

3.2.3.3.2.1 Hydrogen Dilution

The off-gas stream, after a three-minute delay in an existing delay pipe, enters the AOG system. The normal hydrogen concentration is much greater than the lower hydrogen flammability limit of 4.1 percent and requires dilution of the off-gas stream to reduce hydrogen concentration to a safe level. The dilution requirements are based on minimum bleed air flow, which results in the highest concentration of hydrogen as the worst-case condition. [NPPD 2008, Section IX-4.4.2.1]

The off-gas stream is diluted with steam prior to entering the recombiner. The recombiner trains utilize nuclear plant steam to eliminate the recycle loop as a potential source of catalyst migration to undiluted portions of the off-gas process. Up to 7,000 lbm/hr of steam is utilized for off-gas dilution. The third stage ejector receives 2,400 lbm/hr of this steam provided by motive steam. The remaining steam is provided at the suction of the third stage ejector via a pressure reducing nozzle. Both of these sources of dilution steam are supplied from plant nuclear steam. The action of throttling the high pressure nuclear plant steam into the low pressure AOG stream superheats the stream, thereby assuring that the gas temperature entering the recombiner is well above saturation temperature to prevent condensation of moisture on the recombiner catalyst bed. [NPPD 2008, Section IX-4.4.2.1]

3.2.3.3.2.2 Recombination

The recombination process is carried out in a single-stage catalytic recombiner. Prior to entering the recombiner, the AOG stream must have hydrogen concentration lower than four percent for safety and must be preheated above the saturation temperature. As explained previously, the stream entering the recombiner is sufficiently diluted and is also preheated to about 250°F–320°F during normal operation. This dilution is also sufficient for minimum bleed air flow of 6.0 scfm; in this worst case condition, the hydrogen concentration is still only 3.96 percent. [NPPD 2008, Section IX-4.4.2.2]

The recombiner catalyst must remain dry at all times to preserve its reactivity; therefore, to prevent condensation of moisture on the catalyst bed during startup, a steam-heated preheater is used to raise the temperature of the AOG stream from 250°F to 320°F. The recombiner is also preheated prior to startup by an external electric heater. The SJAE will be running and service air may be used for additional off-gas flow. [NPPD 2008, Section IX-4.4.2.2]

In the recombiner, most of the hydrogen and oxygen present in the inlet stream are catalytically combined, reducing the hydrogen concentration from 4 percent on a wet basis to 1 percent maximum, dry basis. The heat of reaction, with the formation of water vapor, raises the temperature of the gas stream as it passes through the recombiner catalyst bed. With inlet temperature maintained at 320°F, the temperature of the effluent gas stream will equal (preheater outlet temperature) + (%H_2 into recombiner x 125°F). Example: preheater temperature of 320°F plus recombiner H_2 concentration of 2%, recombiner outlet temperature equals (320°F) + (2% x 125°F) = 570°F. [NPPD 2008, Section IX-4.4.2.2]

The hot effluent consists principally of steam, air, and very small quantities of radioactive gases (krypton and xenon). On leaving the recombiner, the AOG stream flows to a post-recombiner condenser. [NPPD 2008, Section IX-4.4.2.2]

3.2.3.3.2.3 Dehumidification

The steam in the post-recombiner condenser is desuperheated, condensed, and cooled to approximately 150°F. Condensate at 120°F (maximum) is used as the cooling medium. The AOG stream is further cooled, then flows to a water separator where the condensed liquid is separated from the gas stream and cycled back to the hotwell. [NPPD 2008, Section IX-4.4.2.3]

The effluent AOG gas from the water separator is cooled further to approximately 40°F in a cooler-condenser. A glycol cooler system provides the necessary refrigeration. Condensate is removed in a moisture separator and is sent to the chemical drain sump. [NPPD 2008, Section IX-4.4.2.3]

3.2.3.3.2.4 Drying

The AOG stream is then dried to approximately -60°F dewpoint by passing it through an adsorbent bed of a cyclic dryer system. The cyclic dryer system contains two dryer beds, each of which has the capacity of adsorbing water contained in the AOG stream at maximum flow rate for 24 hours. The two dryer beds are alternately placed in service every 24 hours, at which time the exhausted dryer bed is regenerated. For regeneration, a portion of the AOG stream is withdrawn upstream of the dryer system, heated by an electric heater, and fed to the exhausted dryer bed. This gas stream is returned to the inlet of the AOG system by the third stage SJAE. The regeneration accomplished in this manner is a closed loop operation, eliminating the possibility of accidental release of residual gases to the atmosphere. [NPPD 2008, Section IX-4.4.2.4]

3.2.3.3.2.5 Hydrogen Analyzers

Hydrogen analyzers are installed at the downstream end of the AOG system. Also, the recombiners are equipped with temperature sensors and alarms. This instrumentation system will indicate any anomalies in the hydrogen concentration and permit corrective action as required. [NPPD 2008, Section IX-4.4.2.5]

3.2.3.3.2.6 Long-Term Delay

For decay of radioactive isotopes, the AOG stream is passed through a series of charcoal adsorber beds. A lower than ambient operating temperature of 0°F is selected since the adsorption coefficients, K, of krypton and xenon increase with decrease in temperature.

Experiments were conducted by Oak Ridge using tracer gases to determine K values at various temperatures. Also, the contractor conducted its own experiments utilizing argon as a sweep gas and krypton, xenon, and carbon dioxide as the constituents. Based on this and other published data, adsorption coefficients of 75 and 1,500 cc/gm are selected for krypton and xenon, respectively. [NPPD 2008, Section IX-4.4.2.6]

A quantity of 33.3 tons of charcoal at 0°F temperature will delay krypton isotopes for 44.5 hours and xenon isotopes for 37 days. This is based on 30 scfm flow rate at 0°F temperature and about 0.5 psig pressure. These specified delays will reduce the effluent activity to less than 100 Ci/sec. [NPPD 2008, Section IX-4.4.2.6]

3.2.3.3.3 Gaseous Effluent Releases

The site maintains gaseous releases within ODAM limits. The gaseous radwaste system is used to reduce radioactive materials in gaseous effluents before discharge to meet the dose design objectives in 10 CFR Part 50, Appendix I. In addition, the limits in the ODAM are designed to provide reasonable assurance that radioactive material discharged in gaseous effluents would not result in the exposure of a member of the public in an unrestricted area in excess of the limits specified in 10 CFR Part 20, Appendix B. The quantities of gaseous effluents released from the site are controlled by the administrative limits defined in the ODAM. The controls are specified for dose rate, dose due to noble gases, and dose due to radioiodine and radionuclides in particulate form. For noble gases, the dose rate limit beyond the site and EAB is less than 5 mSv/yr (500 mrem/yr) to the total body and less than 30 mSv/yr (3,000 mrem/yr) to the skin [CNS 2004, Section D 3.2.1]. For iodine and particulates with half-lives greater than 8 days, the limit is less than 15 mSv/yr (1,500 mrem/yr) to any organ when the dose rate due to H-3, Sr-89, Sr-90 and alpha emitting radionuclides is averaged over 3 months and the dose rate due to other radionuclides is averaged over 31 days [CNS 2004, Section D 3.2.1]. The limit for air dose due to noble gases released in gaseous effluents beyond the site and EAB during a calendar quarter is less than 0.05 milligray (5 mrad) for gamma radiation and less than 0.1 mGy (10 mrad) for beta radiation [CNS 2004, Section D 3.2.2]. For a calendar year, the limit is less than 0.1 mGy (10 mrad) for gamma radiation and less than 0.2 mGy (20 mrad) for beta radiation [CNS 2004, Section D 3.2.2]. The limit for doses to any organ from iodine and particulate having a half life of 8 days beyond the site and EAB during a calendar quarter is 0.075 mSv (7.5 mrem) and 0.15 mSv (15 mrem) during a calendar year [CNS 2004, Section D 3.2.3]. The radioactive gaseous waste sampling and analysis program specifications provided in the ODAM address the gaseous release type, sampling frequency, minimum analysis frequency, type of activity analysis, and lower limit of detection.

3.2.3.4 Solid Waste Processing

The function of the solid radwaste system is to reclaim the liquid phase of the wet solid wastes for reuse within the station and to prepare the solid waste for off-site shipment with minimum exposure of the operators to radiation. Prior to off-site shipment to a licensed burial ground, solid wastes can be temporarily stored on site in shielded areas. [NPPD 2008, Section IX-3.3.1]

The solid waste processing areas are located in the radwaste building and augmented radwaste building and process both wet and dry solid wastes. Wet solid wastes include backwash sludge wastes from the RWCU system, the condensate filter demineralizer system, the fuel pool filter demineralizers, the floor drain filter, the waste collector filter, and spent resins from the waste demineralizer and floor drain demineralizer. Dry solid wastes include rags, paper, equipment parts, solid laboratory wastes, etc., which may be potentially contaminated with radioactive material. [NPPD 2008, Section IX-3.3.1]

3.2.3.4.1 Wet Solid Radwaste

Expended filter-demineralizer ion exchange resins are removed when necessary by backwashing. RWCU system sludges and condensate system sludges are collected in phase separators, where excess backwash water is removed by decantation. The sludge is accumulated for processing, with subsequent radioactivity level decay. The fuel pool filter demineralizer, floor drain collector filter and waste collector filter are backwashed to the waste sludge tank. [NPPD 2008, Section IX-3.3.2.1]

RWCU sludges, condensate system sludges, and waste filter and fuel pool sludges are kept separate because of the variation in radioactive material content. This approach minimizes shielding requirements during shipping of the solid wastes. [NPPD 2008, Section IX-3.3.2.1]

A resin dewatering system is available for processing wet solid wastes for disposal. The purpose of this system is to process the waste sludges and the spent resins. The system concentrates the bulk volume of the wet solid wastes, prepares this concentrated waste for off-site shipment, and reclaims the liquid phase of the wet solid wastes for reuse within the station. [NPPD 2008, Section IX-3.3.2.3]

3.2.3.4.1.1 Resin Dewatering System Description

Wet solid wastes are processed using a resin drying (dewatering) system. This system processes powdered and bead type ion exchange resins and other filter media by removing the excess water from the resins. This is accomplished in a three-step process, performed remotely in ventilated, shielded areas to minimize radiation exposure to workers. [NPPD 2008, Section IX-3.3.2.3.1]

First, the liner is filled from the plant's waste tanks using excess water to keep the resin in a slurry and recirculating the waste tank so that a homogeneous mixture is achieved in the liner. During this transfer, the liner will be dewatered so that the available space in the liner is filled with resin to the maximum extent practicable. [NPPD 2008, Section IX-3.3.2.3.1]

Second, the excess water is pumped out of the liner using a positive displacement diaphragm pump. [NPPD 2008, Section IX-3.3.2.3.1]

Third, when all of the pumpable water is removed, the blower is started to recirculate air through the resin. The blower heats the air and as the warm air passes through the resin, it entrains and vaporizes moisture in the resin bed. This moist air is pumped through the entrainment separator tank where refrigeration coils condense the water vapor in the air stream and any entrained water is removed. The water is pumped out of the tank using a diaphragm pump. The air is recirculated through the resin until the percent relative humidity of the air stream indicates the resin bed is dry. The system is then shut down, the fillhead removed and the container capped. The container is given a surface-wipe test for determination of surface contamination and then loaded for off-site shipment or transport to storage. [NPPD 2008, Section IX-3.3.2.3.1]

Containers which will be stored temporarily on-site are loaded into temporary storage modules (TSMs) and transferred via truck or crane to the low-level radwaste (LLRW) storage facility pad. The TSMs are concrete cylinders which provide radiation shielding, physical protection, and protection from the elements during the storage period at the pad. Storage duration at the LLRW storage facility pad is limited to five years in accordance with the guidance provided by Generic Letter 81-38. [NPPD 2008, Section IX-3.3.2.3.1]

The TSMs placed on the pad for interim storage will eventually be returned to the augmented radwaste building and the waste containers removed. The waste containers will then be placed into shipping casks for off-site shipment. The empty TSMs will be returned to the pad for storage and reuse, as necessary. [NPPD 2008, Section IX-3.3.2.3.1]

3.2.3.4.2 Dry Solid Radwaste

Two methods are presently available for processing dry, solid, radioactively contaminated waste. The preferred method is incineration, compaction, and smelting through services procured from an off-site vendor(s) due to the cost of waste disposal. However, hydraulic compaction is an alternative. [NPPD 2008, Section IX-3.3.3]

The preferred method of processing dry, solid, radioactively contaminated waste begins with its collection in large Sea Land containers at the site. The waste is not compacted or processed in any way prior to shipment to an off-site vendor. The vendor will sort all waste into three streams for processing: incineration, compaction, and smelting. The majority of the waste will be incinerated and packaged. Any non-incinerable waste may be compacted using a super-compactor. Any metallic waste may be smelted into blocks for use as shielding at Department of Energy facilities. The slag from the smelting process is incorporated into the packaging for the incinerated waste. [NPPD 2008, Section IX-3.3.3]

The last method of processing dry radioactive waste is with the hydraulic compactor. The hydraulic compactor includes the hydraulic pump with motor, hydraulic oil storage, high efficiency filter, fan, and accessories. The hydraulic compactor is designed to compress the wastes in a 55-gallon drum at 50 psi over the open area of the drum. During compression, ventilation air is pulled across the top of the drum through high efficiency filters by a fan. The filled 55-gallon drums are transferred to a temporary storage area. [NPPD 2008, Section IX-3.3.3]

3.2.4 Transportation of Radioactive Materials

CNS radioactive waste shipments are packaged in accordance with NRC and Department of Transportation (DOT) requirements. The type and quantities of solid radioactive waste generated at and shipped from CNS vary from year to year, depending on plant activities. NPPD currently transports radioactive waste to a licensed processing facility in Tennessee such as the Studsvilk, Duratek, or Race facilities, where the wastes are further processed prior to being sent to a facility such as EnergySolutions in Clive, Utah. NPPD may also transport material from an offsite processing facility to a disposal site or back to the plant site for reuse or storage.

3.2.5 Nonradioactive Waste Systems

Nonradioactive waste is produced from plant maintenance, cleaning, and operational processes. The majority of the wastes generated consists of nonhazardous waste oil and oily debris and results from operation and maintenance of oil-filled equipment. Universal wastes, such as spent fluorescent lamps and batteries common to any industrial facility, comprise a majority of the remaining waste volumes generated. Since CNS is classified as a conditionally exempt small quantity generator, hazardous wastes routinely make up only a small percentage of the total wastes generated, and include and consist of spent and off-specification (e.g., shelf-life expired) chemicals, laboratory chemical wastes, and occasional project specific wastes.

Nonradioactive chemicals, paint, oil, fluorescent lamps, and other items that have either been used or exceeded their useful shelf-life are collected in central collection areas and managed in accordance with appropriate procedures. [CNS 2006; NPPD 2007b] The materials are received in various forms and are packaged to meet all regulatory requirements prior to final disposition at an offsite facility licensed to receive and manage the material. Typical waste streams tracked by quantities at the facility, as shown in Table 3.2-1, include used oil, electronic waste, fluorescent lamps, batteries, and hazardous wastes (i.e., paints, lead abatement waste, broken lamps, and off-specification and expired chemicals).

Programs that have been implemented at the facility to reduce waste generation are described in the NPPD Corporate Environmental Manual. This manual, which also identifies waste streams (current and potential) generated at the facility, is used in conjunction with waste minimization practices in site-specific procedures to minimize waste generation to the maximum extent practicable. [CNS 2008; NPPD 2007b]

Some amount of chemical and biocide wastes are produced from processes used to control the pH in the coolant, to control scale, to control corrosion, to regenerate resins, and to clean and defoul the condenser. These waste liquids are typically combined with cooling water discharges in accordance with the site's NPDES Permit NE0001244.

With the exception of the maintenance training facility, which has a septic leach field, sanitary wastewater from the facility flows to an onsite wastewater treatment lagoon. Depending on water level in the lagoons, wastewaters are periodically pumped from the lagoons for irrigation purposes. These land application activities are regulated in accordance with NDEQ's Title 119, Chapter 12.

Nonradioactive gaseous effluents result primarily from testing of the emergency generator and diesel fire pump. Discharge of regulated pollutants is minimized by limiting fuel usage and sulfur limits in accordance with CNS's Permit to Construct an Air Contaminant Source.

Table 3.2-1
Nonradioactive Waste Generation (Typical Pounds)

Waste Stream	2003	2004	2005	2006	2007
Used Oil	8,015	32,591	20,038	306,361	54,293
Electronic Waste	No Data	No Data	4,285	5,317	20,860
Universal Waste Lamps	1,304	1,075	5,535	1,046	6,190
Universal Waste Batteries	5,000	2,610	1,084	3,700	25,200
Hazardous Waste	0	1,112	4,285	5,317	308

3.2.6 Maintenance, Inspection, and Refueling Activities

Various programs and activities currently at the site maintain, inspect, test, and monitor the performance of plant equipment. These programs and activities include, but are not limited to, those implemented to:

- meet the requirements of 10 CFR Part 50, Appendix B (Quality Assurance), Appendix R (Fire Protection), Appendices G and H, Reactor Vessel Materials;
- meet the requirements of 10 CFR 50.55a, American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI, In-service Inspection and Testing Requirements;
- meet the requirements of 10 CFR 50.65, the maintenance rule, and
- maintain water chemistry in accordance with EPRI guidelines.

Additional programs include those implemented to meet Technical Specification surveillance requirements, those implemented in response to NRC generic communications, and various periodic maintenance, testing, and inspection procedures necessary to manage the effects of aging on structures and components. Certain program activities are performed during the operation of the units, while others are performed during scheduled refueling outages.

3.2.7 Power Transmission Systems

The transmission lines which were constructed to connect CNS to the grid for purposes of power distribution and are within the scope of license renewal include the following:

- NPPD TL3501 (345 kV energized in August 1969) is 63.6 miles in length and spans from CNS to the Mark T. Moore substation near Hallam, Nebraska;

- NPPD TL3502 (345 kV energized in July 1970) is 82.6 miles in length and spans from the Mark T. Moore substation to the Grand Island substation;

- OPPD Line "60" was already planned when CNS was constructed. This transmission line consists of three segments. OPPD owns and operates two segments of the transmission lines from Omaha, Nebraska to the CNS switchyard and from the CNS switchyard to Rulo, Nebraska, while Aquila owns and operates one segment of the transmission line from Rulo, Nebraska to St. Joseph, Missouri. The transmission line from the CNS switchyard to Omaha, Nebraska is 25.74 miles in length and the line from the CNS switchyard to St Joseph, Missouri is 64.8 miles in length. However as already stated, these transmission line segments owned and operated by OPPD and Aquila were not constructed for the purpose of connecting CNS to the transmission systems. Therefore, the only line within scope of license renewal is from the plant to the switchyard that connects into this system; and

- NPPD TL3504 was energized as a 345 kV line in July 1970 and is 0.64 miles in length and spans from CNS to the center of the Missouri River. This line connects with a Mid-America Energy owned transmission line that spans to Booneville, Iowa.

Transmission Line Ownership

Of the four transmission lines discussed above, NPPD owns and operates the transmission lines specifically constructed to connect CNS to the transmission system (see Figure 3.2-6 and Figure 3.2-7). OPPD and Mid-America Energy (formerly Iowa Power and Light) own and operate the transmission lines that were not constructed to connect CNS to the transmission system, up to the point where CNS interconnects with their system.

Although NPPD owns the TL3504 transmission line to the center of the Missouri River, where ownership then changes to Mid-America Energy, the actual interconnection point to the electrical grid for distribution purposes associated with this line is the CNS switchyard.

Transmission Lines not Within License Renewal Scope

Transmission lines not within scope of the license renewal are as follows:

- A 69 kV transmission line that inter-connects with the OPPD transmission system for purposes of providing start-up power to CNS. This line is not utilized by CNS for purposes of electrical distribution to the transmission grid; therefore, it is not within the scope of license renewal.

- The Missouri, Iowa, and Nebraska Transmission (MINT) line which was constructed in 1992 by a consortium of companies as part of an upgrade to the regional grid. This line would still be an integral part of the grid even if CNS did not exist. NPPD owns the transmission line to the center of the Missouri River, where ownership then changes to Associated Electric. This transmission line, which spans from the CNS switchyard to St. Joseph, Missouri, was not specifically constructed for purposes of connecting CNS to the electrical grid; therefore, it is not within the scope of license renewal.

Transmission Line Clearances

The transmission line "K-Towers" are supported by two wooden poles that are 26 feet apart. Therefore, the farming activity adjacent to and under the towers and lines continues essentially unimpeded with the only land removed from service being that upon which transmission poles physically rest. No cultivated land along the transmission route has been removed from service as a result of rights-of-way, and access for repairs and maintenance is requested on an individual basis from each property owner. For the remainder of the transmission line route, which passes over non-cultivated land, the right-of-way (ROW) is cleared only of woody plants that have a growth pattern that would cause them to grow into or fall onto the line conductors. Thereafter, control of these species is maintained; however, all of the natural grasses and low growing bushy, woody plants are allowed to grow, which creates blended natural scenery along the ROW. Since there are no densely forested areas on the transmission route, and the land beneath the transmission lines is allowed to return to its natural state, the wildlife in these areas should remain essentially unaffected. [USAEC, Section IV] Steel towers are used for the lines crossing the Missouri River and in the immediate vicinity of the station.

Based on NPPD clearance practices, the required minimum ground clearance of 29.3 feet shown in Table 232-1 of the National Electrical Safety Code (NESC) is being met as it relates to line heights, even with anticipated additional sag.

3.2.7.1 ROW Vegetation Management Program

Ongoing ROW surveillance and maintenance activities along NPPD transmission lines are discussed below.

3.2.7.1.1 Inspection, Identification and Scheduling Procedure

NPPD utilizes the District's Work Management module of the SAP system to document all findings and schedule corrective actions as necessary. All trees and brush on the easement or ROW are classified by the priority of the notification. [NPPD 2006a]

3.2.7.1.2 Transmission Line Patrol Process

Aerial patrols are conducted six times annually, with special patrols conducted following severe storm conditions.

Foot patrols are completed annually by line technicians, generally in the fall and winter time frames. [NPPD 2006a]

3.2.7.1.3 Clearing Methods

Mechanical clearing is utilized on a very limited basis. NPPD primarily uses the manual method of removal with aerial lift equipment and chain saws.

Herbicide treatments are applied by line technicians and contractors to control brush and stump re-growth. [NPPD 2006a]

3.2.7.1.4 Herbicide Application

As a preventive maintenance practice, volunteer trees typically are controlled during the earliest stages of growth through herbicide applications or removal. To eliminate re-growth of the tree, chemically treating stumps may occur as soon as possible after removal of the trees. [NPPD 2006a]

State law requires that all commercial applicators, including District personnel and contract tree trimmers, be trained and certified on the application of restricted-use herbicides. Only a Nebraska Certified Herbicide Applicator or an applicator recognized to be from a reciprocating neighbor state as designated by the State of Nebraska, Department of Agriculture, can perform application of restricted-use herbicides. Any application of restricted use herbicides on NPPD's ROW is documented. Herbicides currently approved for use on NPPD's ROWs are as follows:

- Tordon 101 (Grazon sub) - Brush and Weed Control,
- Garlon 4 - Woody Plants and Broadleaf Weeds, and
- Pathway/Tordon RTU - Stump control. [NPPD 2006a]

3.2.7.1.5 Tree Trimming Clearances

NPPD adheres to the ANSI A300 Part 1 Standard for trimming trees to ensure that clearances are maintained for safe operation of overhead electrical systems. [NPPD 2006a]

3.2.7.1.6 Environmental

Tree trimming and removal activities are performed in compliance with the Endangered Species Act, the Bald and Golden Eagle Protection Act, and the Migratory Bird Treaty Act. Occupied active bird nests (nests with an incubating adult, eggs, and/or chicks) are protected except for pigeon, starling, and house sparrow nests. In general, most Nebraska birds nest between April and September. All nests of eagles (golden and bald) are protected by federal laws regardless of whether the nest is unoccupied or occupied. [NPPD 2006a]

3.2.7.1.7 Migratory Birds

Line-clearing personnel inspect the trees during the nesting season (April–September) for nests and avoid the destruction of active nests. If trees with nests present an emergency (electrical outage, property damage, or otherwise interfere with the safe operation of electrical systems), or if a nest is suspected to be that of an eagle, then NPPD's Corporate Environmental Department is contacted. [NPPD 2006a]

Injury to whistling swan and to some of the hawks and eagles that pass through the area may occur as a result of these birds flying into transmission lines in the vicinity of the reactor as well as the large power lines crossing the Missouri River. Large orange plastic balls have been attached to the latter to minimize this effect. Losses from this source should be small compared with the number of birds passing through the area. No impact on other endangered species of birds is foreseen. [USAEC, Section V-C-1]

3.2.7.1.8 Wetlands

Trees cut and felled in a wetland are considered by regulation as fill material and cannot be placed into a wetland without a Section 404 Permit. Therefore, if trees are to be felled in a wetland, NPPD Corporate Environmental is contacted and appropriate permits obtained. [NPPD 2006a]

3.3 Refurbishment Activities

In accordance with 10 CFR 51.53(c)(2), a license renewal applicant's environmental report must 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 10 CFR 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 10 CFR 54.21 is to determine whether the detrimental effects of aging could preclude certain systems, structures, and components from performing in accordance with the current licensing basis during the additional 20 years of operation requested in the license renewal application.

The evaluation of structures and components as required by 10 CFR 54.21 has been completed and is described in the body of the CNS License Renewal Application. This evaluation did not identify the need for refurbishment of structures or components for purposes of license renewal and there are no such refurbishment activities planned at this time. Although routine plant operational and maintenance activities will be performed during the license renewal period, these activities are not refurbishments as described in Sections 2.4 and 3.1 of the GEIS and will be managed in accordance with appropriate NPPD programs and procedures.

3.4 Programs and Activities for Managing the Effects of Aging

The programs for managing the effects of aging on certain structures and components within the scope of License Renewal at the site are described in the body of the license renewal application (see Appendix B of the CNS License Renewal Application). The evaluation of structures and components required by 10 CFR 54.21 identified some new activities necessary to continue operation of the site during the additional 20 years beyond the initial license term. These activities are described in the body of the license renewal application. The additional inspection activities are consistent with normal plant component inspections and therefore are not expected to cause significant environmental impact. The majority of the aging management programs are existing programs, some requiring modest modifications.

3.5 Employment

The non-outage work force at the site consists of approximately 750 persons (see Table 3.5-1). During refueling outages, there is typically an additional 700–900 contractor employees on-site. Refueling outages occur every 18 months. NPPD has no plans to add non-outage employees to support plant operations during the extended license renewal period.

Refueling and maintenance outages typically last approximately 30 days. The number of workers required on-site for normal plant outages during the period of extended operation is expected to be consistent with the number of additional workers used for past outages at the site, which is approximately 700–900 temporary workers.

Table 3.5-1
Employee Residence Information (January 2008)

County, State, and City	Employees (NPPD and Baseline Contractors)
Johnson County (Arkansas)	**1**
Lamar	1
Cobb County (Georgia)	**1**
Mableton	1
Fremont County (Iowa)	**13**
Farragut	2
Hamburg	9
Percival	1
Sidney	1
Page County (Iowa)	**3**
Shenandoah	3
Pottawattamie County (Iowa)	**1**
Honey Creek	1
Brown County (Kansas)	**1**
Hiawatha	1
Nemaha County (Kansas)	**1**
Sabetha	1
Riley County (Kansas)	**1**
Manhattan	1
Atchison (Missouri)	**106**
Fairfax	11
Langdon	1
Rock Port	70
Tarkio	19
Watson	2
Westboro	3

Table 3.5-1 (Continued)
Employee Residence Information (January 2008)

County, State, and City	Employees (NPPD and Baseline Contractors)
Buchanan County (Missouri)	**1**
St. Joseph	1
Christian County (Missouri)	**1**
Ozark	1
Holt County (Missouri)	**12**
Corning	1
Craig	2
Mound City	9
Nodaway County (Missouri)	**3**
Burlington Junction	1
Maryville	1
Quitman	1
Ray County (Missouri)	**1**
Lawson	1
Cass County (Nebraska)	**11**
Beaver Lake	2
Elmwood	1
Plattsmouth	8
Union	1
Douglas County (Nebraska)	**2**
Omaha	2
Jefferson County (Nebraska)	**1**
Fairbury	1

**Table 3.5-1 (Continued)
Employee Residence Information (January 2008)**

County, State, and City	Employees (NPPD and Baseline Contractors)
Johnson County (Nebraska)	**9**
Cook	1
Elk Creek	1
Sterling	2
Tecumseh	5
Lancaster County (Nebraska)	**6**
Lincoln	6
Nemaha County (Nebraska)	**359**
Auburn	251
Brock	6
Brownville	31
Johnson	19
Julian	1
Nemaha	19
Peru	31
Otoe County (Nebraska)	**100**
Dunbar	1
Lorton	1
Nebraska City	97
Talmage	1
Platte County (Nebraska)	**3**
Columbus	2
Humphrey	1

Table 3.5-1 (Continued)
Employee Residence Information (January 2008)

County, State, and City	Employees (NPPD and Baseline Contractors)
Richardson County (Nebraska)	**108**
Dawson	4
Falls City	37
Humboldt	10
Rulo	1
Salem	3
Shubert	23
Stella	19
Verdon	11
Sarpy County (Nebraska)	**2**
Bellevue	2
Washington County (Nebraska)	**1**
Blair	1
Kingsbury County (South Dakota)	**1**
Arlington	1
Hamilton County (Tennessee)	**1**
Soddy Daisy	1
Total	**750**

3.6 References

Brackett Green USA, Inc. 2004. Fish Handling Band Screens Including the Advanced S.I.M.P.L.E. Process. 2004.

CNS (Cooper Nuclear Station). 2004. Offsite Dose Assessment Manual for Assessment of Gaseous and Liquid Effluents at Cooper Nuclear Station.

CNS (Cooper Nuclear Station). 2006. Procedure 0.7.2, Hazardous Material/Waste Control. June 1, 2006.

CNS (Cooper Nuclear Station). 2007. Radwaste Procedure 2.5.2.2, Waste High Conductivity Liquid Waste Floor Drain Processing. February 15, 2007.

CNS (Cooper Nuclear Station). 2008. Procedure 0.7, Chemical Material Control. January 22, 2008.

NPPD (Nebraska Public Power District). 1971. Applicant's Environmental Report, Operating License Stage, Cooper Nuclear Station.

NPPD (Nebraska Public Power District). 2006a. Power Line Rights-of-Way Vegetation Management Program. July 31, 2006.

NPPD (Nebraska Public Power District). 2006b. Proposal for Information Collection, Cooper Nuclear Station. January 2006.

NPPD (Nebraska Public Power District). 2007a. License Amendment Request to Revise Technical Specifications - Appendix K Measurement Uncertainty Recapture Power Uprate. November 19, 2007.

NPPD (Nebraska Public Power District). 2007b. Corporate Environmental Manual Policy, Chapter 12, Waste Minimization. June 2007.

NPPD (Nebraska Public Power District). 2008. Updated Safety Analysis Report, Cooper Nuclear Station.

USAEC (United States Atomic Energy Commission). 1973. Final Environmental Statement Related to the Operation of Cooper Nuclear Station, Docket No. 50-298. United States Atomic Energy Commission, Directorate of Licensing.

USNRC (United States Nuclear Regulatory Commission). 2006. Letter from Brian Benney, NRC, to Randall Edington, NPPD, Cooper Nuclear Station - Issuance of Amendment Re: Application of the Alternative Source Term for reevaluation of the Fuel Handling Accident dose consequences and related Technical Specification changes (TAC No. MC 8566). September 5, 2006.

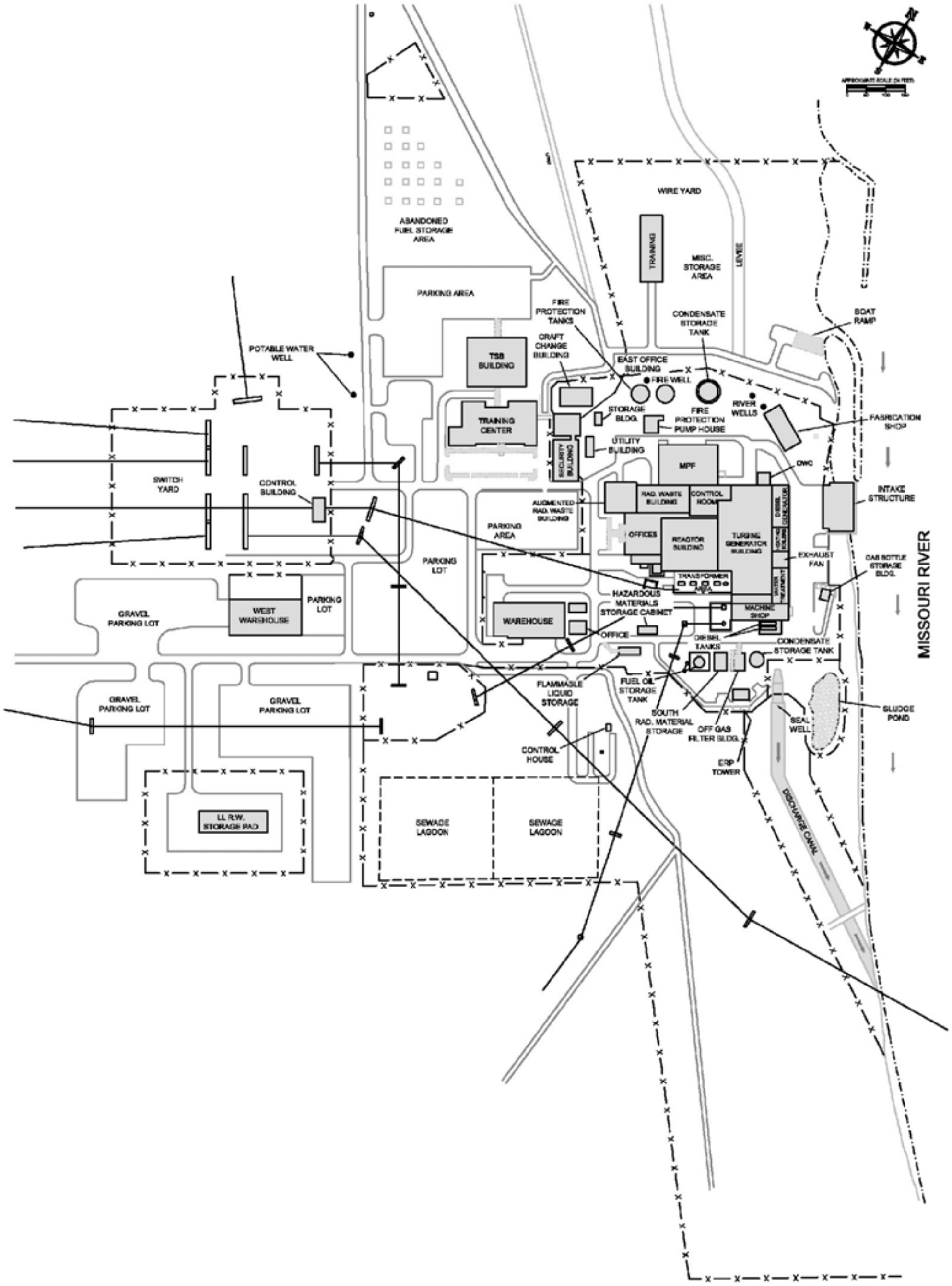

Figure 3.2-1
CNS Plant Features

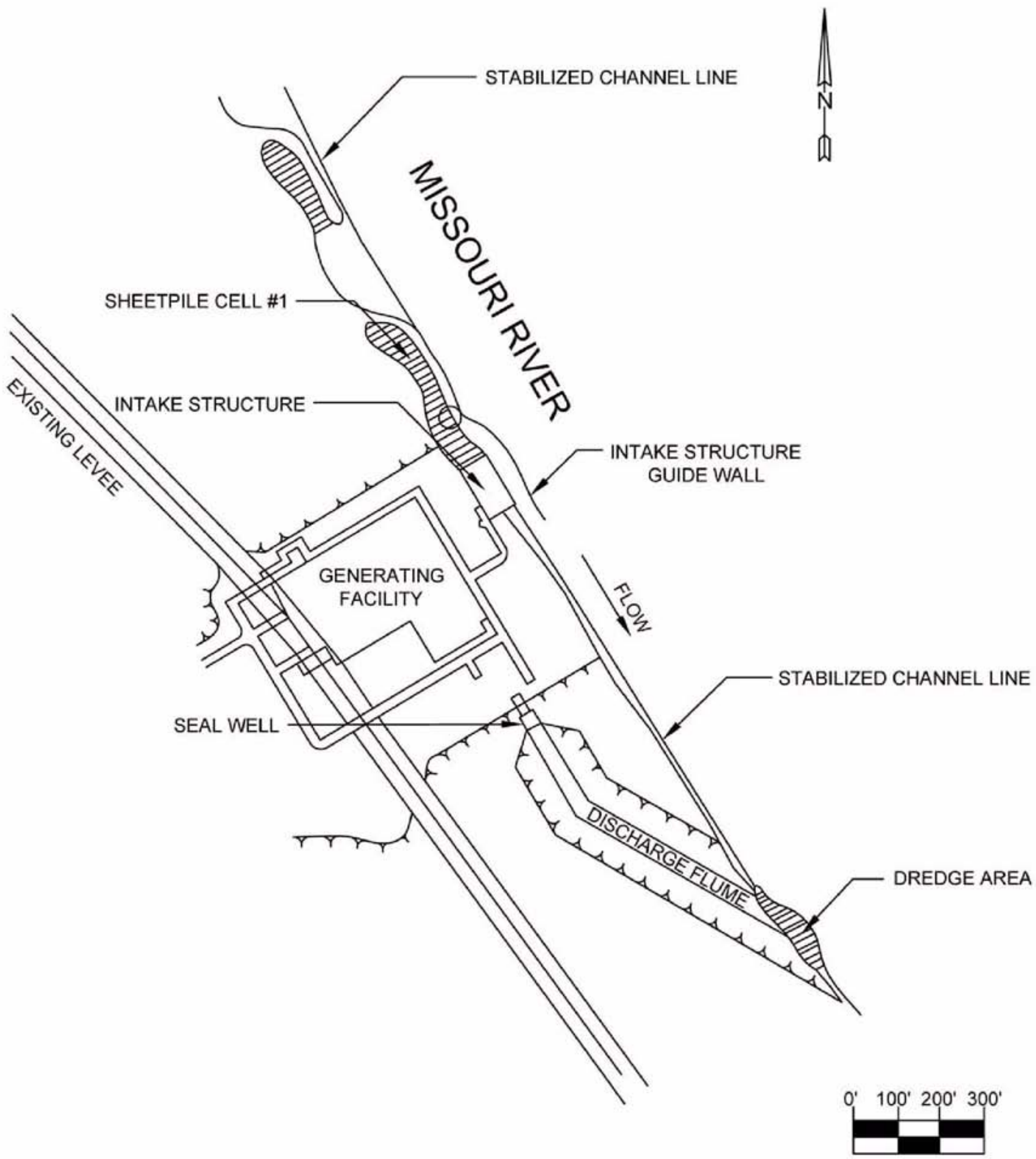

Figure 3.2-2
Circulating Water Intake Structure Location

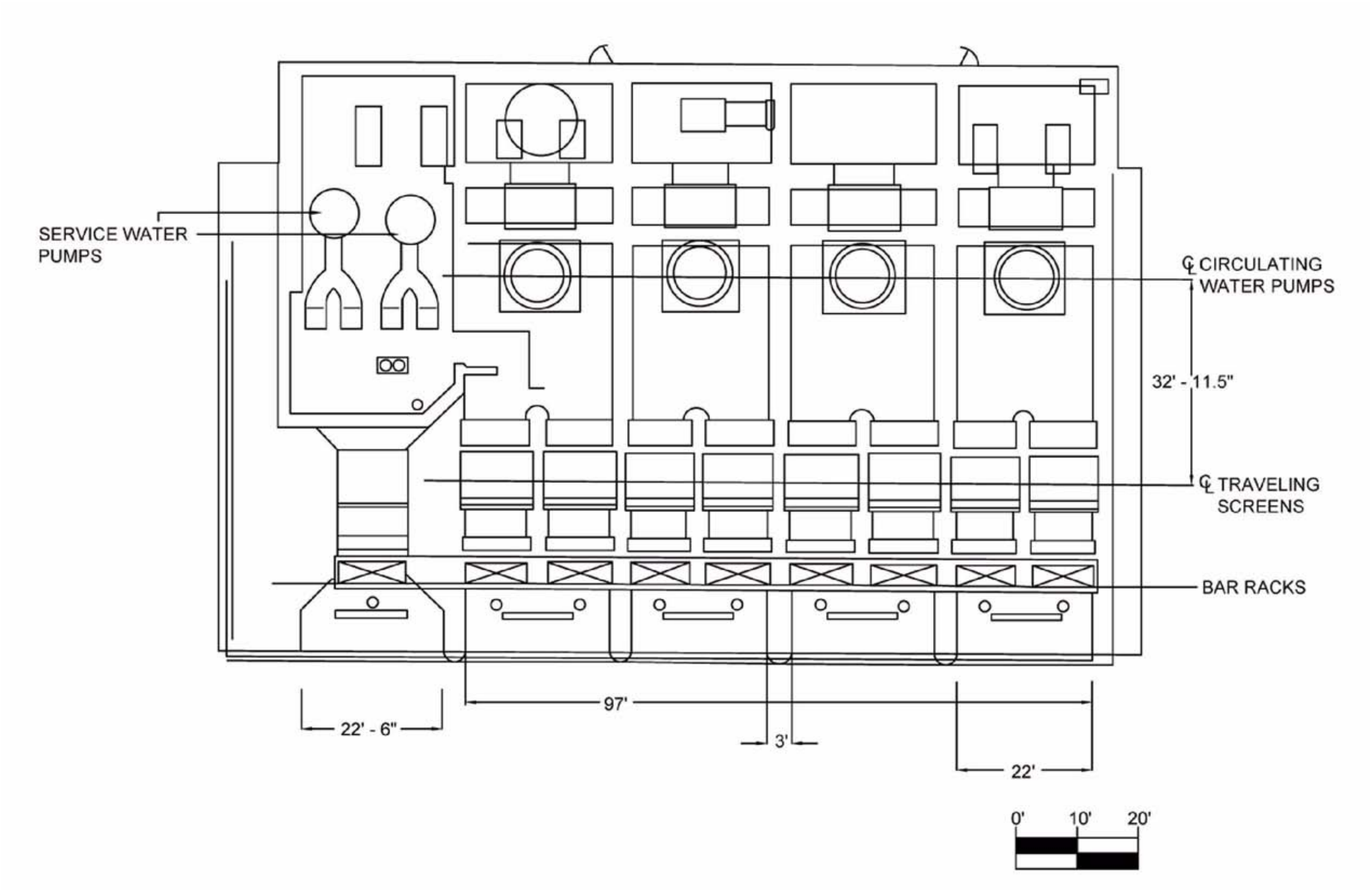

Figure 3.2-3
CNS Intake Structure Plan

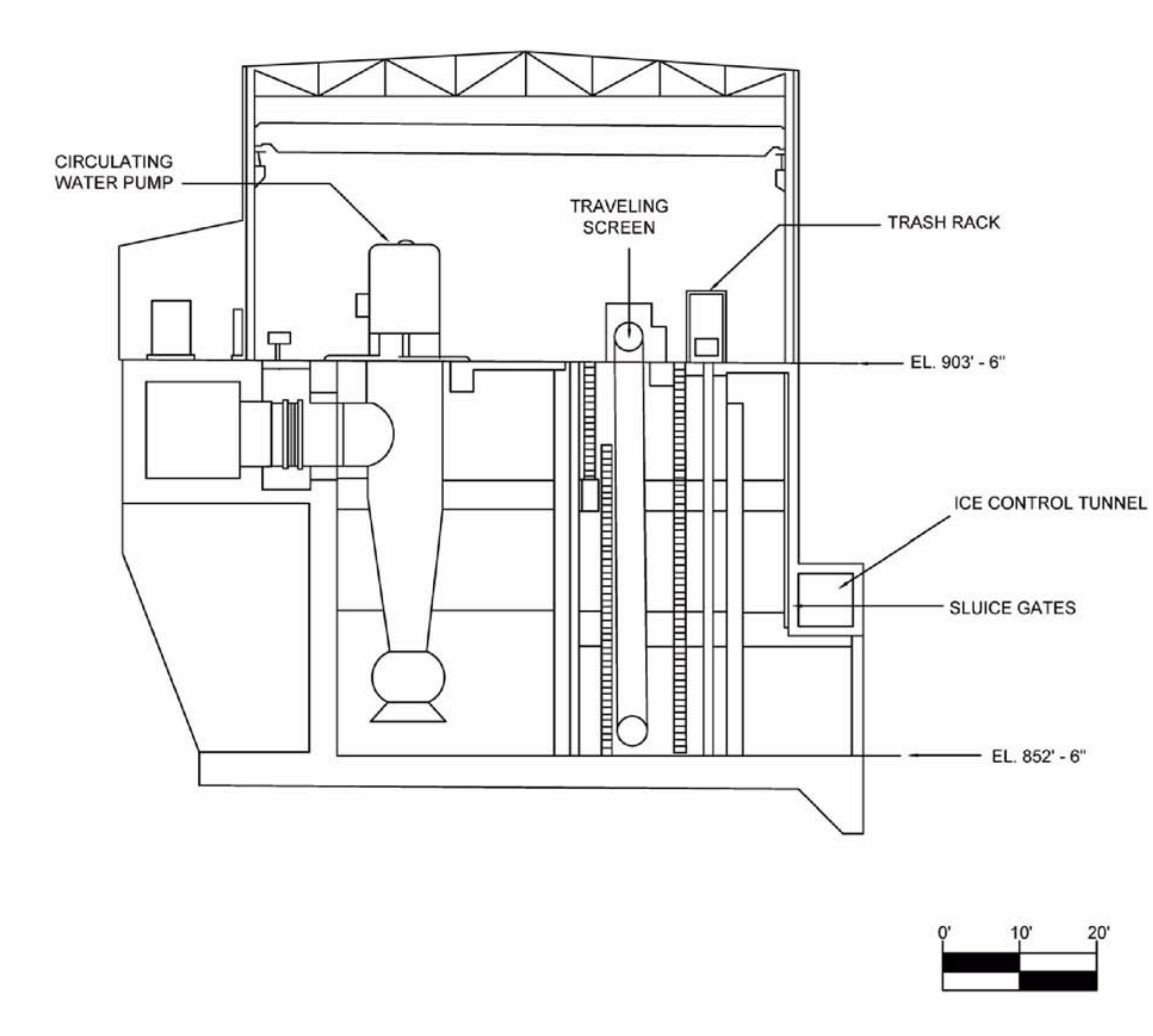

Figure 3.2-4
CNS Intake Structure Section

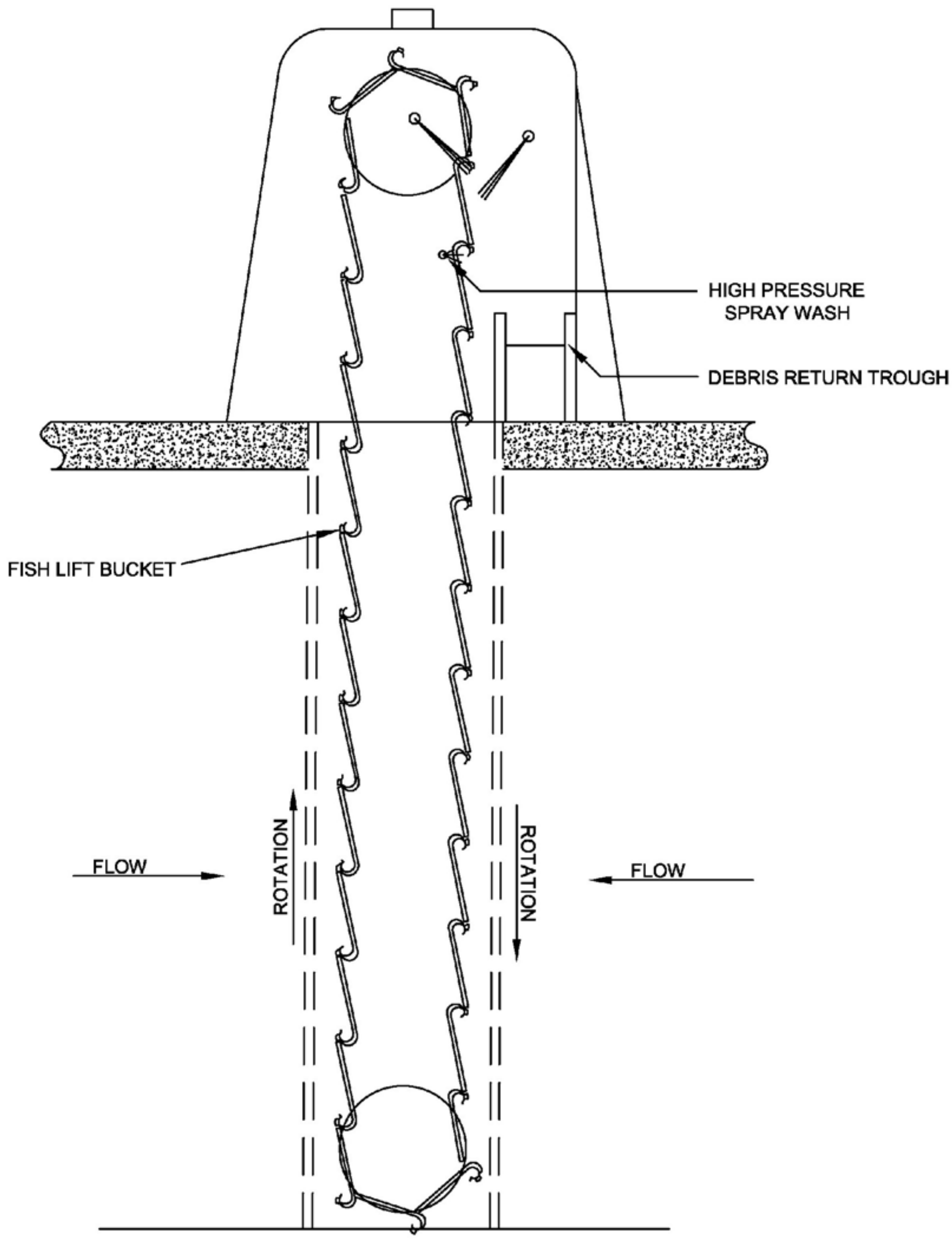

Figure 3.2-5
Typical Dual-Flow Screen

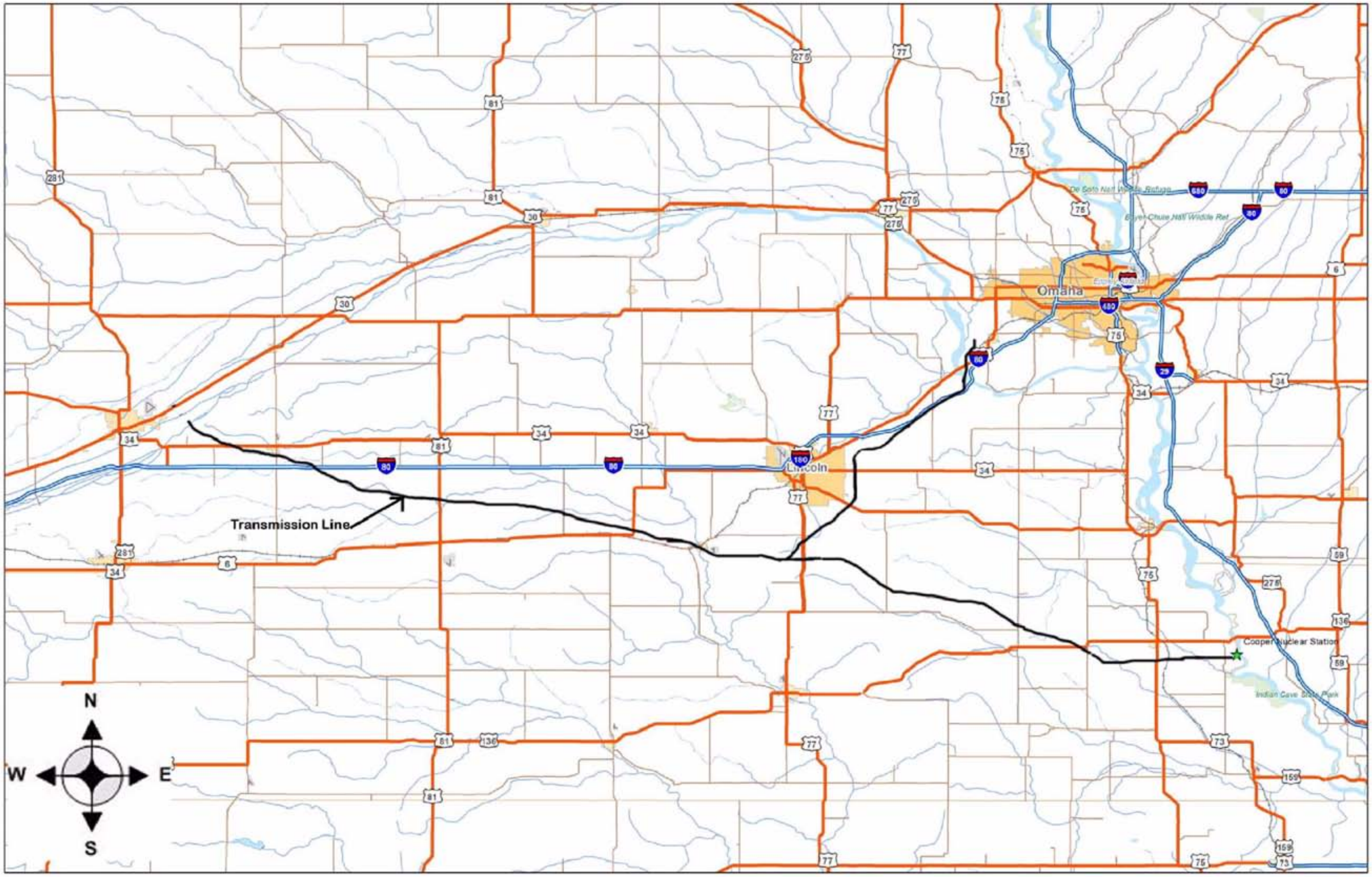

Figure 3.2-6
CNS Transmission Lines

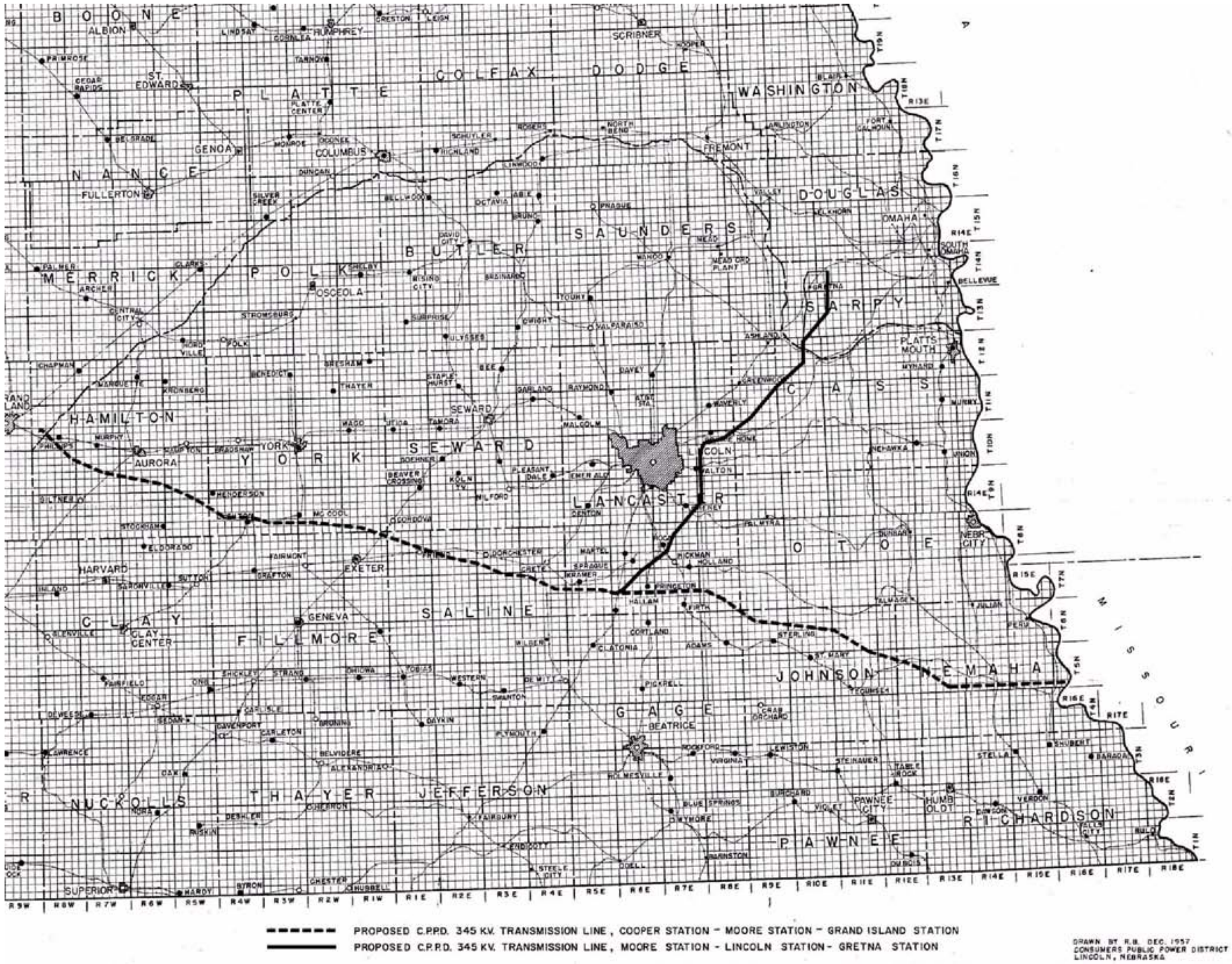

Figure 3.2-7
Transmission Lines as Proposed for CNS Construction, 1957

4.0 ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION

Discussion of GEIS Categories for Environmental Issues

The NRC has identified and analyzed 92 environmental issues that it considers to be associated with nuclear power plant license renewal and has designated the issues as Category 1, Category 2, or NA (not applicable). NRC designated an issue as Category 1 if the following criteria were met:

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

If the NRC concluded that one or more of the Category 1 criteria could not be met, NRC designated the issue Category 2. NRC requires plant-specific analysis for Category 2 issues. NRC designated two issues as NA, signifying that the categorization and impact definitions do not apply to these issues. NRC rules do not require analyses of Category 1 issues that NRC resolved using generic findings (10 CFR Part 51, Appendix B, Table B-1) as described in the GEIS [USNRC 1996]. An applicant may reference the GEIS findings for Category 1 issues.

Category 1 License Renewal Issues

NPPD has determined that, of the 69 Category 1 issues, 13 are not applicable to the site because they apply to design or operational features that do not exist at the facility. In addition, because NPPD does not plan to conduct refurbishment activities, the NRC findings for the seven Category 1 issues applicable to refurbishment do not apply. Table 4.0-1 lists these 20 Category 1 issues and provides a brief explanation of why they are not applicable to the site. Table 4.0-2 lists the 49 Category 1 issues applicable to the site. NPPD reviewed the NRC findings on these 49 issues and identified no new and significant information that would invalidate the findings for the site (see Section 5). Therefore, NPPD adopts by reference the NRC findings for these Category 1 issues.

Table 4.0-1
Category 1 Issues Not Applicable to CNS

Surface Water Quality, Hydrology, and Use (for all plants)	
Impacts of refurbishment on surface water quality	No refurbishment activities planned.
Impacts of refurbishment on surface water use	No refurbishment activities planned.
Altered salinity gradients	CNS does not discharge to an estuary.
Altered thermal stratification of lakes	The site is not located on a lake.
Eutrophication	The site does not discharge to a lake or reservoir
Aquatic Ecology (for all plants)	
Refurbishment	No refurbishment activities planned.
Aquatic Ecology (for plants with cooling tower based heat dissipation systems)	
Entrainment of fish and shellfish in early life stages	The site does not use cooling towers.
Impingement of fish and shellfish	The site does not use cooling towers.
Heat shock	The site does not use cooling towers.
Groundwater Use and Quality	
Impacts of refurbishment on groundwater use and quality	No refurbishment activities planned.
Groundwater quality degradation (Ranney Wells)	The site does not use Ranney wells.
Groundwater quality degradation (saltwater intrusion)	CNS is located on a freshwater body.
Groundwater quality degradation (cooling ponds in salt marshes)	The site does not use cooling ponds.
Human Health	
Radiation exposures to the public during refurbishment	No refurbishment activities planned.
Occupational radiation exposures during refurbishment	No refurbishment activities planned.
Terrestrial Resources	
Cooling pond impacts on terrestrial resources	The site does not use cooling ponds.
Cooling tower impacts on crops and ornamental vegetation	The site does not use cooling towers.
Cooling tower impacts on native plants	The site does not use cooling towers.
Bird collisions with cooling towers	The site does not use cooling towers.
Socioeconomics	
Aesthetic impacts (refurbishment)	No refurbishment activities planned.

Table 4.0-2
Category 1 Issues Applicable to CNS

Surface Water Quality, Hydrology, and Use (for all plants)
Water use conflicts (plants with once-through cooling systems)
Altered current patterns at intake and discharge structures
Temperature effects on sediment transport capacity
Scouring caused by discharged cooling water
Discharge of chlorine or other biocides
Discharge of sanitary wastes and minor chemical spills
Discharge of other metals in waste water
Aquatic Ecology (for all plants)
Accumulation of contaminants in sediments or biota
Entrainment of phytoplankton and zooplankton
Cold shock
Thermal plume barrier to migrating fish
Distribution of aquatic organisms
Premature emergence of aquatic insects
Gas supersaturation (gas bubble disease)
Low dissolved oxygen in the discharge
Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses
Stimulation of nuisance organisms (e.g., shipworms)
Groundwater
Groundwater use conflicts (potable and service water; plants that use < 100 gpm)
Terrestrial Resources
Bird collision with power lines
Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)
Power line right-of-way management (cutting and herbicide application)
Floodplains and wetland on power line right of way
Air Quality
Air quality effects of transmission lines
Land Use
Land use (license renewal period)

Table 4.0-2 (Continued)
Category 1 Issues Applicable to CNS

Human Health
Microbiological organisms (occupational health)
Noise
Radiation exposures to public (license renewal term)
Occupational radiation exposures (license renewal term)
Socioeconomics
Public services: public safety, social services, and tourism and recreation
Public services, education (license renewal term)
Aesthetic impacts (license renewal term)
Aesthetic impacts of transmission lines (license renewal term)
Land Use
Power line right-of-way
Postulated Accidents
Design basis accidents
Uranium Fuel Cycle and Waste Management
Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high level waste)
Offsite radiological impacts (collective effects)
Offsite radiological impacts (spent fuel and high level waste disposal)
Non-radiological impacts of the uranium fuel cycle
Low-level waste storage and disposal
Mixed waste storage and disposal
On-site spent fuel
Nonradiological waste
Transportation
Decommissioning
Radiation doses
Waste management
Air quality
Water quality
Ecological resources
Socioeconomic impacts

Category 2 License Renewal Issues

NRC designated 21 issues as Category 2. Sections 4.1 through 4.21 address the Category 2 issues, beginning with a statement of the issue. As is the case with Category 1 issues, some Category 2 issues (4) apply to operational features that the site does not have. In addition, some Category 2 issues (4) apply only to refurbishment activities. If the issue does not apply to the site, the section explains the basis.

For the 13 Category 2 issues applicable to the site, the corresponding sections contain the required analyses. These analyses include conclusions regarding the significance of the impacts relative to renewal of the OL for the site and, when applicable, discuss potential mitigative alternatives to the extent required. NPPD has identified the significance of the impacts associated with each issue as SMALL, MODERATE, or LARGE consistent with the criteria that NRC established in 10 CFR Part 51, Appendix B, Table B-1, Footnote 3 as follows.

- **SMALL**: Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

- **MODERATE**: Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attributes of the resource.

- **LARGE**: Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

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

"NA" License Renewal Issues

NRC determined that its categorization and impact-finding definitions did not apply to electromagnetic fields (chronic effect) and environmental justice. NRC noted that applicants currently do not need to submit information on chronic effects from electromagnetic fields (10 CFR Part 51, Appendix B, Table B-1, Footnote 5). For environmental justice, NRC does not require information from applicants, but noted that it would be addressed in individual license renewal reviews (10 CFR Part 51, Appendix B, Table B-1, Footnote 6). NPPD has included environmental justice demographic information in Section 2.6.

Format of Category 2 Issue Review

The review and analysis for the Category 2 issues (See Table 4.0-3), along with environmental justice and cumulative impacts are found in Sections 4.1 through 4.23. The format for the review of the Category 2 issues, Sections 4.1 through 4.21, is described below.

- *Issue*: a brief statement of the issue.
- *Description of Issue:* a brief description of the issue.
- *Findings from Table B-1, Appendix B to Subpart A:* the findings for the issue from Table B-1—Summary of Findings on NEPA Issues for License Renewal of Nuclear Power Plants, Appendix B to Subpart A.
- *Requirement:* restatement of the requirement from 10 CFR 51.53(c)(3)(ii).
- *Background*: for issues applicable to the site, a background excerpt from the applicable section of the GEIS. The specific section of the GEIS is referenced for the convenience of the reader. In most cases, background information is not provided for issues that are not applicable to the site.
- *Analysis of Environmental Impact*: an analysis of the environmental impact as required by 10 CFR 51.53(c)(3)(ii). The analysis takes into account information provided in the GEIS, Appendix B to Subpart A of 10 CFR Part 51, as well as current specific information.
- *Conclusion*: for issues applicable to the site, the conclusion of the analysis along with the consideration of mitigation alternatives as required by 10 CFR 51.45(c) and 10 CFR 51.53(c)(3)(iii).

Table 4.0-3
Category 2 License Renewal Issues

Category 2 Issue	Applicability
Water use conflicts	Applicable
Entrainment of fish and shellfish in early life stages	Applicable
Impingement of fish and shellfish	Applicable
Heat shock	Applicable
Groundwater use conflicts (plants using > 100 gpm of groundwater)	Applicable
Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	Not applicable
Groundwater use conflicts (plants using Ranney wells)	Not applicable
Degradation of groundwater quality	Not applicable
Impact of refurbishment on terrestrial resources	Not applicable
Threatened or endangered species	Applicable
Air quality during refurbishment (nonattainment and maintenance areas)	Not applicable

Table 4.0-3 (Continued)
Category 2 License Renewal Issues

Category 2 Issue	Applicability
Impact on public health of microbiological organisms	Applicable
Electromagnetic shields - acute effects	Applicable
Housing impacts	Applicable
Public utilities: public water supply availability	Applicable
Education impacts from refurbishment	Not applicable
Offsite land use - refurbishment	Not applicable
Offsite land use - license renewal term	Applicable
Transportation	Applicable
Historic and archaeological properties	Applicable
Severe accident mitigation alternatives	Applicable

4.1 Water Use Conflicts

4.1.1 Description of Issue

Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow).

4.1.2 Findings from Table B-1, Appendix B to Subpart A

SMALL or MODERATE. The issue has been a concern at nuclear power plants with cooling ponds and at plants with cooling towers. Impacts on in-stream and riparian communities near these plants could be of moderate significance in some situations. See 10 CFR 51.53(c)(3)(ii)(A).

4.1.3 Requirement [10 CFR 51.53(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 x 10^{12} ft^3/year (9 x 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.

4.1.4 Analysis of Environmental Impact

The site does not utilize cooling towers or cooling ponds. CNS utilizes a once-through cooling system. Therefore, this issue is not applicable to the site and further analysis is not required.

4.2 Entrainment of Fish and Shellfish in Early Life Stages

4.2.1 Description of Issue

Entrainment of fish and shellfish in early life stages (for all plants with once-through and cooling pond heat dissipation systems).

4.2.2 Findings from Table B-1, Appendix B to Subpart A

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 10 CFR 51.53(c)(3)(ii)(B).

4.2.3 Requirement [10 CFR 51.53(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 CWA 316(b) determinations and, if necessary, a 316(a) variance in accordance with 40 CFR Part 125, or equivalent state permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.

4.2.4 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. [USNRC 1996, Section 4.2.2.1.2]

4.2.5 Analysis of Environmental Impact

4.2.5.1 Background

The effects of entrainment on aquatic resources were considered by NRC and EPA, or a EPA-authorized state water quality permitting agency, at the time of original licensing, and are routinely reconsidered by the USEPA, or the state, oftentimes in the context of the renewals of National Pollutant Discharge Elimination System (NPDES) permits or updates of in-place 316(b) demonstrations.

As discussed in Section 3.2.2, CNS utilizes a once-through cooling system that withdraws water from the Missouri River. The circulating water intake structure is located on the west shoreline as shown in Figure 3.2-2. [NPPD 2006, Section 2.1] Figures 3.2-3 and 3.2-4 provide plan and cross section views of the CWIS, respectively. In front of the CWIS is a guide wall and submerged weir constructed of steel sheet piling which runs parallel to and at distance of 14.25 feet from the face of the intake. The weir is physically attached at its upstream terminal to the circular cell which was left in place after the remaining cofferdam structure was removed following construction of the CWIS. The downstream terminal is 40 feet below the downstream corner of the CWIS. No connection is made to the shore at the downstream terminal. The top elevation of the upstream portion is El. 885 feet (all elevations for CNS refer to AMSL), which is 5 feet higher than normal summer river elevation of 880 feet. The top of the weir gradually changes from El. 885 feet at the upstream terminal to a submerged downstream most weir section of El. 867.5 feet. [NPPD 2006, Section 2.2]

The purpose of the guide wall and weir is to reduce the sediment input to the CWIS. It accomplishes this by forcing bed load and other material contained in the river to flow around and past the CWIS. When the level of the river is higher than El. 867.5 ft, most of the water spills over the top of the wall. The bed load, composed of heavier and larger diameter particles, is usually found in the bottom part of the river and moves along the weir wall to be directed away from the CWIS. When river level drops, a higher percentage of water goes around the weir rather than going over it. As river level drops, a higher percentage of bed load comes into the CWIS due to eddy effects at the terminal end of the weir. Therefore, during 2005 turning vanes were installed in front of the CWIS to redirect bed load away from the intake structure. [NPPD 2006, Section 2.2] Twenty-three 10 ft long by six ft high sheet pile turning vanes were installed riverward of the weir wall with top elevations of EL. 860 ft. Installed at a 22 degree angle to the outer weir, and extending beyond the downstream terminus of the weir, these turning vanes redirect sand and gravel outward away from the weir and CWIS.

Water for the facility is drawn through five intake bays. Four of these bays provide circulating water to the generating unit while the other is used for service water. Each circulating water intake bay splits into two screen bays, while the service water intake bay narrows to a smaller screen bay. These bays are 9.7 feet in length by 5.6 feet wide, providing space for 4.2 feet wide dual flow screens. Each bay is fitted with modified dual flow traveling screens designed with fish collection baskets (see Figure 3.2-5). The modified dual flow screens operate at 90 degrees to the water flow. Fish and debris are collected on both the ascending and descending sides of the dual-flow screen which allows only filtered water to pass downstream to the pumps. Fish and debris are removed by a high pressure screen wash system and conveyed back to the river. Installation of the modified dual flow traveling screens began during 2005 and was completed in 2006, to address debris carry-over problems encountered with the original flow through traveling screens. A decision was made also by NPPD to install fish collection baskets on the dual flow screens to address future 316(b) issues. However, the present design and construction does not include installation of the low pressure spray system or a separate fish return trough and conveyance system to return fish back to the river. [NPPD 2006, Section 2.2]

Currently, fish and debris flushed from the screens are returned to the river via an 18 in. steel pipe which discharges downstream from the intake. The existing screen wash system does not have the capacity to provide the required flow to support both the low pressure fish protection spray system and the high pressure debris removal system. [NPPD 2006, Section 2.2] However as discussed in Section 3.2.2, CNS has already installed dual flow conversion screens that are equipped with fish baskets and is planning on installing a fish handling system consisting of inside and outside fish sprays and a separate fish return trough prior to the end of the current operational term.

CNS's 1971 OL Stage ER stated a modest fish population inhabited the Missouri River, based on sampling results of limited fish population studies initiated in 1970. Those early studies indicated that aquatic insects and zooplankton constituted the main food supply for young fish and that evidence suggested that aquatic insects cannot survive the passage through cooling condensers. The ER indicated the effects on young fish and fish eggs could not be adequately estimated. [NPPD 1971, Section IV-4.3.5.2]

The CNS 1971 Final Environmental Statement (FES) concluded the following:

- The water velocity of approximately 1.3 fps across the intake screens at annual mean flows may result in some loss of fish by entrainment or impingement.

- Aquatic biota entrained in the cooling water will be subjected to temperatures 18°F above ambient for approximately 20 minutes and will experience a substantial mortality rate. However, losses due to entrainment are expected to be small relative to the total Missouri River population, since only approximately 4 percent of the drift organisms in the river at the station location during usual summer flows will be affected and no more than 20 percent during unusually low river flows. Shutdown of the station in winter could produce mortalities in fish attracted to the discharge canal and the river area influenced by the thermal plume.

- However, at this time (1971) the predicted probable adverse environmental effects (intake velocity, entrainment time and the size and maximum temperature of the mixing zone) do not warrant implementation of an alternative cooling discharge system.

- The NRC also concluded that an environmental monitoring program should be established to evaluate potential damage to the aquatic biota of the Missouri River due to entrainment, impingement, or thermal discharge. If significant damage were determined, the applicant was to provide an analysis of design modifications to mitigate the effects. [USAEC, Summary and Conclusions]

CNS originally received authorization to discharge to the Missouri River in November 1968 from the Nebraska Department of Health Water Pollution Control Council. State certification was received from the Nebraska Water Pollution Control Council on June 11, 1971 (see Attachment C), to use and discharge water from the Missouri River warmed to a maximum of Δ18°F at the point of discharge. [NPPD 1971, p. C-18-12]

NPPD submitted 316(a) and 316(b) demonstration studies related to CNS dated October 23, 1975, to provide information and documentation of station operational effects on the Missouri River. The report included the results of NPPD's monitoring of fish larvae in 1974 and 1975, and an assessment of chemical, thermal, and biological impacts from station operations, including entrainment impacts. The study concluded that, based on the small percentage of fish larvae entrained, the fish taxa collected, and the high natural mortality of fish during early life stages, entrainment at CNS would have minimal adverse effects on the fish populations in this stretch of the Missouri River. [Nalco]

The 316(a) demonstration was submitted in support of NPPD's request for alternate thermal discharge limits. After considerable review by the Nebraska Department of Environmental Control (NDEC), which included comments by the NGPC, EPA, and USFWS, NDEC concluded in a May 4, 1976, letter, "...the discharge of once through condenser cooling water has not caused appreciable harm to the aquatic community of the Missouri River." [NDEC 1976]. The NDEC 1976 letter requested additional information regarding certain potential impacts related to 316(b) impacts on the fish population in the Missouri River resulting from CNS's intake structure [NDEC 1976]. On February 2, 1977, after a review of revised 316(b) documentation, NDEC concluded that based on available information that the effects of the CNS cooling water intake facilities were probably minimal, and that the intake structure met the minimum requirements of 316(b) [NDEC 1977]. Since that time, entrainment effects have not been a permit issue since the issuance of the 1976 and 1977 letters, nor have there been entrainment monitoring or assessment requirements included in subsequent NPDES permit renewals.

The CNS Proposal for Information Collection (PIC) was submitted in compliance with the now suspended Clean Water Act 316(b) Phase II Rule (the Rule) for existing electric generating stations published in the *Federal Register* on July 9, 2004 [USEPA 2004]. The PIC was submitted to and approved by the NDEQ, and provides plans at CNS for

- not conducting new biological studies,
- analyzing historical biological information,
- evaluating alternative fish protection technologies, and
- evaluating the Rule's compliance alternatives.
  [NPPD 2006, p. vi]

The Phase II 316(b) regulations were suspended on July 9, 2007. Based on the March 2008 316(b) annual report to the NDEQ, NPPD is not planning on specifically investigating any further technology for CNS relative to 316(b). [NPPD 2008a] However, as discussed in Section 3.2.2, CNS is planning to install a fish handling system consisting of inside and outside fish sprays and separate fish return trough prior to the end of the current operational term.

4.2.5.2 Entrainment Analysis

The current NPDES permit for CNS does not contain assessment, monitoring, or mitigation requirements for entrainment impacts. Although the Phase II 316(b) rule has been suspended, based on the Phase I rule for new plants which has been enacted and remains enforced, EPA does not consider cooling water intakes that take less than five percent of the average annual flow to be significant. The CNS design intake flow of 1,521.3 cfs is only four percent of the mean annual river flow (38,251 cfs at USGS Gauge # 06807000), and therefore would not be subject to the 316(b) entrainment performance standard under the Phase I scenario [66FR243].

EPA's 316(b) rule was promulgated to minimize the adverse environmental impact of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals associated with these structures [USEPA 2004]. EPA established the threshold criteria for its Phase II 316(b) rule because they … "will address those existing power generating facilities with the greatest potential to cause or contribute to adverse environmental impact." Based on its early entrainment studies (discussed below), the conclusions of the NDEC in its 1976 316(b) determination, and EPA's historic position not to apply entrainment performance standards to those facilities, like CNS, whose intake consists of less than five percent of the mean annual flow, NPPD concludes the impact due to entrainment of fish and shellfish in the Missouri River is SMALL. The discussion below is provided to further support this conclusion.

River Characteristics

Flow of the Missouri River at CNS is largely controlled by the Gavins Point Dam located approximately 200 miles upstream in Yankton, South Dakota. The river at CNS is about 800 feet wide and flows in a southeasterly direction. The flow is highly channelized with swift flows and heavy sediment transport. To minimize the effects of sedimentation on the intake, turning vanes and a low sheetpile wall are located in front of the intake bays. Wing dams are located on the Missouri side of the river to force the flow into a central channel. The water levels in the river range from a maximum at El. 899.0 feet to a minimum at El. 874.5 feet, with a normal level at El. 880.0 feet. The annual mean river flow is 38,251 cfs (1930-2001) based on the USGS gauging station at Nebraska City, Nebraska which is located approximately 30 RMs north of the CNS CWIS.

To prevent the formation of frazzle ice during the winter, some of the main condenser discharge water (25-30 percent) is recirculated through the ice control tunnel and released in front of the trash rack within the CWIS while the remaining water is discharged about 1,300 feet downstream of the intake via a discharge canal, which results in less water withdrawn from the river.

Pre-operational and Post-operational Studies

NPPD conducted studies of the aquatic ecology of the Missouri River in the vicinity of CNS beginning with preoperational studies in 1969. Post-operational studies began in 1974. Those studies continued during the 1970s through 1979 as part of Appendix B Environmental Technical Specification monitoring required by the NRC. After completing five years of studies and submitting the results of those studies to the NRC, NPPD submitted a request for deletion of the Aquatic Surveillance, Study and Evaluation Program from the Technical Specifications to the NRC on July 10, 1979. This deletion was approved as Amendment 60 to CNS's license on December 7, 1979. [USNRC 1979]

Details of pre-operational and early post-operational studies at CNS were summarized by Nalco Environmental Sciences in "The Evaluation of Thermal Effects in the Missouri River near Cooper Nuclear Station; 3I6(a) and 316(b) Demonstration" prepared in 1975. This document summarized data on the following topics and established a solid understanding of the ecology of the Missouri River in the vicinity of CNS.

- River flow data
- Ambient temperatures
- Intake configuration and operation
- Cooling water flow
- Phytoplankton
- Periphyton
- Fish
- River currents
- Weather data
- Outfall configuration and operation
- Thermal plume characteristics
- Zooplankton
- Macroinvertebrates

Seasonal Abundance and Densities

Seasonal abundance and overall occurrence of 57 fish species in the Missouri River in the vicinity of CNS from July 1970 to July 1975 were discussed in the Nalco 316(a) and 316(b) Demonstration report. The report included the abundance of 12 species of fish of special concern identified by the NDEC. Of the 57 species identified, gizzard shad and silvery minnow were described as abundant (more than 10 percent of the catch); carp, emerald shiner, river shiner, red shiner, and river carpsucker were described as moderately abundant (5 percent to 10 percent of the catch); and goldeye, silver chub, sand shiner, channel catfish, and freshwater drum were described as being common. The remaining species were described as being uncommon or rare during study collections. [Nalco, Table 4.4-36]

Principal fish species in the lower Missouri River include emerald shiner, river carpsucker, channel catfish, gizzard shad, red shiner, shorthead redhorse, carp, and goldeye. Pallid and shovelnose sturgeon and paddlefish are also found in the lower Missouri River. Sport fish include channel catfish, crappie, sauger, flathead catfish, white bass, largemouth bass, bluegill, walleye, northern pike, and paddlefish. Species important to the commercial fishery on the lower Missouri River include buffalo, carp, carpsucker, and freshwater drum. [USACE 2007, pp. 3-5]

Peak larval fish densities during the early 1970s were described as occurring between May and August and ranged from 59.4 per 100 cubic meters on June 17, 1974, to 328 per 100 cubic meters on June 28, 1973. Collectively Cyprinidae, Catostomidae, and freshwater drum comprised 88.1, 94.5, and 91.9 percent of the total larval fish catch at the intake during 1973, 1974, and 1975, respectively. Sport fish such as channel catfish, white bass, bluegill, largemouth bass, crappies, and sauger were not a major component of the larval drift. [Nalco, Section 4.4.1.6.5.2]

Fish monitoring in the Missouri River was also conducted in the 1970s by OPPD as part of a comprehensive examination of the effects of power plants. These studies showed that the primary recruitment sources of larval fish to the channelized Missouri River are Lewis and Clark Lake; the unchannelized Missouri River from Yankton, South Dakota, to Sioux City, Iowa; and tributaries. Freshwater drum, catostomids, cyprinids, and carp dominated (greater than 94 percent) the larval drift. Other taxa collected and considered common were the gizzard shad, goldeye, sauger, and walleye [Hergenrader et. al, p. 187]. Field studies conducted at FCS and CNS indicate that the seasonal highest abundance of fish larvae in the Missouri River occurs from May to July. [USNRC 2003, p. 2-22]

A sampling program to assess the effects of entrainment in the cooling water systems at FCS and CNS on larval fishes was carried out in the months of May, June, and July of 1974-1976. Samples collected above the intake structures of the power plants were used to determine the seasonal patterns, species composition, and abundance of ichthyoplankton in this region of the Missouri River. Relatively low larval fish densities throughout May and early June were generally followed by a single two to three week long peak in density in late June and early July, due primarily to the larvae of freshwater drum. The observed densities then declined to near zero by the end of July. The highest concentrations of larvae were generally found along the cutting bank and the lowest in the middle of the river. Twenty-four hour sampling was conducted to identify possible diurnal differences in the ichthyoplankton densities above the intake. Although great variations in densities were noted over the sampling period, significant differences between mean day and night densities were demonstrated only once, and no recurring temporal pattern in drift rates was identified. [Cada, Section IV]

Larval Fish Entrainment

Larval fish mortality due to entrainment through CNS was also evaluated in the early operational studies. Fish larvae exposed to condenser passage, as well as larvae drifting past CNS on the Nebraska side of the river, are subject to the full extent of the thermal plume. Mortalities of larval fish at the CNS discharge and within the thermal plume versus the CNS intake were not significantly different on any sampling date and were actually lower on two occasions in 1974. During 1975, mortalities of larval fish were higher at the intake than at a downstream sampling location on all but one sampling date (July 1). The results of the studies suggested no appreciable harmful effects on larval fish due to downstream passage through the thermal plume. [Nalco, Section 4.4.1.6.5.3]

As discussed in the CNS FES, the spring and early summer period when many of the fish species in the lower Missouri spawn is the period when flows in the Missouri are generally higher and intake flows are a small percentage (four percent) of the river flow. The fractional loss of fish eggs and larvae originating upstream was estimated to be less than this percentage because of the protected areas used for spawning. [USAEC, p. V-15]

Macroinvertebrate Entrainment

The pre-operational and post operational effects of entrainment of macroinvertebrate communities were also studied in the early 1970s. The studies in the vicinity of CNS were summarized in the Nalco 316(a) and 316(b) studies. Macroinvertebrate fauna in the main channel of the Missouri River is very sparse because of river currents and the resultant instability of the bottom sediments. Channel improvement structures, however, support a diverse macroinvertebrate community. Site studies have shown that hydroids, planarians, worms, mayflies, caddisflies, and midges are common and/or abundant near or in the channel improvement structures. River flow and adaptations of specific taxa to microhabitats within channelization structures are key factors controlling benthic and macroinvertebrate diversity and abundance. Station operation apparently has not affected the benthic macroinvertebrates or those found in and around the channel improvement structures. The effect of entrainment through cooling condensers on macroinvertebrates is a composite of chemical, mechanical and thermal stresses applied through the duration of the entrainment. The impact of entrainment of organisms on the receiving water is influenced further by the amount of receiving water actually entrained. As noted below, the mean annual intake of Missouri River flow is less than four percent. The addition of heat to the Missouri River from Station operation has not had an appreciable effect upon the macroinvertebrate populations sampled downstream of the discharge. [Nalco, p. 4.0-103]

Studies summarized by Carter et. al. were initiated in 1973 to assess the effects of station operations at FCS on the macroinvertebrate communities of the Missouri River. The channelized river near CNS supports relatively low densities of benthic organisms due to swift current, high turbidity, and substrate instability along the channel bottom. Suitable habitat for benthic organisms is generally restricted to pile dikes, riprap, and a narrow area along the shoreline. The current causes continuous shifting and scouring of the bottom sediments, and because of this instability, habitat in the channel area is unsuitable for macroinvertebrates. Near shore areas are also influenced by river flow fluctuations, because sediments deposited when flows decrease are scoured out and carried downstream when flows increase. Densities for macroinvertebrate drift assemblage generally were found to be highest in the spring and lowest in the fall, with peaks in density observed from February through May associated with high spring runoff. The drift assemblage at FCS was similar to that found in the vicinity of CNS. Low entrainment losses observed during the sampling periods at FCS indicated that most macroinvertebrate drift organisms were not greatly affected by condenser passage. In addition, the proportion of total river flow diverted for cooling water is relatively low, averaging less than five percent for both FCS and CNS. The total impact of entrainment passage was estimated to be negligible, and Missouri River drift dynamics probably were not affected by FCS or CNS station operation. [Carter]

Entrainment Impact Analysis

The annual post-operational aquatic monitoring program at CNS continued through 1979. Annual reports were prepared with titles related to "The Evaluation of Thermal Effects in the Missouri River Related to Cooper Nuclear Station," but monitored a range of physical, water quality, periphyton, macroinvertebrate and benthic organisms, larval fish and fish abundance and density parameters [Hazleton 1980]. After 10 years of pre-operational and post-operational monitoring of the Missouri River, these monitoring programs were discontinued at the end of 1979 when the NRC, after consultation with the State of Nebraska, agreed to deletion of the Aquatic Surveillance, Study, and Evaluation Program from the Technical Specifications in December 1979. [USNRC 1979]

Pallid Sturgeon Entrainment Impacts

The pre-operational and post-operational studies conducted from 1970 to 1979 supported this conclusion as no pallid sturgeon were collected near CNS. [Hazleton 1979; Nalco] The NGPC noted that the severe alteration of the Missouri River ecosystem has resulted in the near elimination of the pallid sturgeon from the river. Despite more recent habitat restoration projects and population augmentation efforts, the pallid sturgeon continues to decline and occurrences of this fish remain rare. [USFWS 2000]

The NRC staff prepared a biological assessment to evaluate whether the proposed renewal of the FCS OL for a period of an additional 20 years would have adverse effects on listed threatened or endangered species [USNRC 2002, Cover Letter]. Pallid sturgeon spawning is thought to be similar to that of other sturgeon species. Based on behavior of the closely related shovelnose sturgeon and some recent observations of successful pallid sturgeon spawning, it is believed that spawning occurs over rock, rubble, or gravel substrate in the main channel of the Missouri River and its major tributaries such as the Platte River. The optimum temperature for pallid sturgeon spawning is estimated to range from 16 to 18.3°C (60 to 65°F) [USFWS 2000, p. 101]. Spawning occurs during the spring and early summer in the Missouri River; in the middle Missouri River area, spawning is thought to occur primarily in May and June. Sturgeon spawn multiple times during this spring or early-summer period. [USNRC 2002, Section IV.A]

Sturgeon release their eggs at intervals in deep channels or rapids without further parental attendance. The eggs are demersal and adhesive and, therefore, not likely to drift downstream. [USFWS 2000] Pallid sturgeon have been detected near the mouth of the Platte River (RM 595) (approximately 63 miles upstream of CNS) [USNRC 2002, Section IV.A]. Due to the demersal and adhesive characteristic of sturgeon eggs, CNS would not be expected to have an adverse impact on pallid sturgeon eggs due to entrainment.

Larvae become buoyant or active immediately after hatching and may drift downstream. The behavior of young pallid sturgeon is poorly understood; however, recent research points to a downstream movement of larvae that begins immediately at hatching and continues for up to 13 days. [USFWS 2000] Scientists have used this information, in combination with water velocities, to estimate larval pallid sturgeon may drift in the water column for a distance of 64 to 644 km (40 to 400 mi). [USNRC 2002, Section IV.A]

As discussed above, the NRC prepared a Biological Assessment associated with the renewal of the FCS OL, which was submitted to the USFWS. As a result of this assessment and formal consultation conducted pursuant 50 CFR 402.14(a) with the USFWS, both agencies concurred that the OL Renewal of FCS is not likely to adversely affect the pallid sturgeon [USFWS 2003].

Fisheries Impacts Unrelated to CNS

The NRC issued a SEIS for FCS in 2003, which provided significant insight into the fish species of the lower Missouri River and discussed the apparent decline in native fish species. The NRC's FCS SEIS discusses notable recent investigations of lower Missouri River fish populations that include those Hesse reported in 1993 and 1994. Those investigators assessed the status of 13 selected fish species in the entire Missouri River reach bordering Nebraska, including the paddlefish, burbot, channel catfish, flathead catfish, blue catfish, sicklefin chub, sturgeon chub, silver chub, speckled chub, flathead chub, plains minnow, western silvery minnow, and sauger. Twenty-two years of sampling data in the Missouri River (1971 to 1992) were evaluated and presented for the selected species. The focus of the research centered on data regarding the absolute and relative abundance and commercial and recreational harvest. [USNRC 2003, p. 2-23]

The FCS SEIS states that the decline in the abundance of five of the species investigated—the channel catfish, flathead catfish, blue catfish, sauger, and paddlefish—was evident in historical commercial-harvest records, creel surveys, and fishery survey data collected from 1971 to 1992. Commercial and recreational harvest of these five species was one of the factors cited in the studies as responsible for the observed decline in their populations. However, the studies also characterized all of these fish species as being adapted for survival in large unaltered rivers, and the predominant factor for their decline was identified as the loss of suitable habitat, primarily due to channelization and impoundment of the river with the consequent loss of seasonal flood pulses, altered temperature regimes, and loss of nutrient loadings from bordering floodplains. [USNRC 2003, p. 2-23]

The remaining eight species investigated (burbot, sicklefin chub, sturgeon chub, silver chub, speckled chub, flathead chub, plains minnow, and western silvery minnow) also exhibited declines in abundance upon examination of the 22 years of Missouri River fishery survey data. Only the burbot was subject to a minor recreational fishery and was generally considered an incidental catch to the targeted fish species. All of these species are representative and indigenous to large unchannelized rivers. Again, the decline in abundance, as found in the fishery surveys, was attributed to the loss of habitat resulting from channelization, impoundment of the river, loss of seasonal flood pulses, altered temperature regimes due to impoundment, and loss of nutrient loading from the floodplains. [USNRC 2003, pp. 2-23 and 2-24]

The commercial harvest of channel catfish, flathead catfish, and blue catfish from the Missouri River was banned in 1992 due to the overharvest of recruitment-size individuals. However, the commercial harvest of the common carp and buffalo fish (*Ictiobus* spp.) from the Missouri River still continues [USNRC 2003, p. 2-24]. Recent contact with state regulatory agencies (Missouri, Iowa, and Nebraska) indicate there are as many as 18 commercial fishing licenses issued in 2008 [IDNR 2008; MDC; NGPC 2008c]. Legal species of fish that commercial fishermen may take include black bullhead, yellow bullhead, freshwater drum, yellow perch, gizzard shad, longnose gar, shortnose gar, grass carp, common carp, silver carp, bighead carp, river carpsucker, quillback, white sucker, smallmouth buffalo, bigmouth buffalo, black buffalo, largemouth buffalo, brown bullhead, northern redhorse, silver redhorse, spotted sucker, highfin carpsucker, white amur, bowfin, gizzard shad, goldeye, and mooneye [IDNR 2007; NGPC 2002, Chapter 2, Section 003.04]

While the commercial harvest of certain fish species may be a factor in the decline of those species, most studies agree that the modifications of the river during the 20th century are one of the most significant factors in the changes in fish abundance [NAS, pp. 11-12; USACE 2003, p. 3-33; USFWS 2007a]. Of particular interest is that most current studies do not mention entrainment of larval fish or icthyoplankton as a significant factor causing declines in indigenous species.

The lower Missouri River has been leveed, channelized, and its flow regulated for flood control and navigation. Channelization of the lower Missouri River reduced surface area by 50 percent, reduced turbidity by 65 percent, and decreased the number of sandbars and islands by greater than 90 percent, confining the river to a single, deep channel with swift current and little habitat complexity. [Reeves, p. 4]

Typically, fish spawning areas associated with the Missouri River are located along the shoreline, in backwaters, and behind channel control structures. However, suitable nursery areas in the Missouri River are limited due to high velocity, turbulent flows, and silt and sand loads. Construction of dikes and revetments have narrowed and deepened the channel into a fixed location, which has greatly eliminated shallow water habitat and increased water depth and current velocity. Shallow water habitat available ranged from 9.4 to 17.4 acres (five feet above and below the elevation associated with the median August discharge). In the channelized reaches of the river, fish are associated with revetments and dikes. [USACE 2007, Section 3.5.1]

<u>Summary</u>

Studies agree that the modifications of the Missouri river during the 20th century are one of the most significant factors in the changes in fish abundance. These modifications included loss of habitat resulting from channelization, impoundment of the river, loss of seasonal flood pulses, altered temperature regimes due to impoundment, and loss of nutrient loading from the floodplains. Entrainment of larval fish or icthyoplankton was not mention in most studies as a significant factor causing declines in indigenous species.

In addition, EPA does not apply entrainment performance standards to cooling water intakes that withdraw less than five percent of the average annual flow, which is the case at CNS. This is consistent with the NDEQ's previous determination that the cooling water intake impacts were probably minimal. Therefore, this information continues to confirm the absence of any adverse impact on fisheries reasonably attributable to CNS.

4.2.6 Conclusion

The results of entrainment studies related to CNS, have been reviewed by the appropriate Nebraska agencies delegated NPDES permitting authority (NDEC and NDEQ), the EPA, and the USFWS and it was determined that the cooling water intake impacts were probably minimal. Based on its review of available information, NPPD concludes that the population density impacts on the pallid sturgeon are due to factors unrelated to entrainment at CNS, both directly and cumulatively. The Missouri River studies conducted to date generally concur that the impacts related to declines in certain indigenous fish species are due to habitat changes such as Missouri River and tributary dams, channelization and other habitat management, invasive aquatic species, and similar factors. Based on its early entrainment studies, the conclusions of the NDEC in its 1976 316(b) determination, and EPA's position not to apply entrainment performance standards to those facilities, like CNS, whose intake consists of less than five percent of the mean annual flow, NPPD concludes the impact due to entrainment of fish and shellfish in the Missouri River is SMALL and mitigation measures are not warranted.

4.3 Impingement of Fish and Shellfish

4.3.1 Description of Issue

Impingement of fish and shellfish (for all plants with once-through and cooling pond heat dissipation systems).

4.3.2 Findings from Table B-1, Appendix B to Subpart A

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 10 CFR 51.53(c)(3)(ii)(B).

4.3.3 Requirement [10 CFR 51.53(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 40 CFR Part 125, or equivalent state permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.

4.3.4 Background

Aquatic organisms that are drawn into the intake with the cooling water but 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 revealed that impingement is a frequent concern at plants using once-through cooling, particularly where restoration of anadromous fish (fish that migrate from the sea to spawn in fresh water) may be affected. 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. [USNRC 1996, Section 4.2.2.1.3]

4.3.5 Analysis of Environmental Impact

4.3.5.1 Background

The effects of impingement on aquatic resources were considered by NRC and EPA, or a EPA-authorized state water quality permitting agency, at the time of original licensing, and are routinely reconsidered by the EPA, or the state, oftentimes in the context of the renewals of NPDES permits or updates of in-place 316(b) demonstrations.

As discussed in Section 3.2.2, CNS uses a once-through cooling system that withdraws water from the Missouri River. The circulating water intake structure is located on the west shoreline as shown in Figure 3.2-2. [NPPD 2006, Section 2.1] Figures 3.2-3 and 3.2-4 provide plan and cross section views of the CWIS, respectively. [NPPD 2006, Section 2.2]

The purpose of the guide wall and weir is to reduce the sediment input to the CWIS. It accomplishes this by forcing bed load and other material contained in the river to flow around and past the CWIS. When the level of the river is higher than El. 867.5 ft, most of the water spills over the top of the wall. The bed load, composed of heavier and larger diameter particles, is usually found in the bottom part of the river and moves along the weir wall to be directed away from the CWIS. When river level drops, a higher percentage of water goes around the weir rather than going over it. As river level drops, a higher percentage of bed load comes into the CWIS due to eddy effects at the terminal end of the weir. Therefore, during 2005 turning vanes were installed in front of the CWIS to redirect bed load away from the intake structure. [NPPD 2006, Section 2.2] Twenty-three 10 ft long by six ft high sheet pile turning vanes were installed riverward of the weir wall with top elevations of EL. 860 ft. Installed at a 22 degree angle to the outer weir, and extending beyond the downstream terminus of the weir, these turning vanes redirect sand and gravel outward away from the weir and CWIS.

Water for the facility is drawn through five intake bays. Four of these bays provide circulating water to the generating unit while the other is used for service water. Each circulating water intake bay splits into two screen bays, while the service water intake bay narrows to a smaller screen bay. These bays are 9.7 ft in length by 5.6 ft wide, providing space for 4.2 ft wide dual flow screens. Each bay is fitted with modified dual flow traveling screens designed with fish collection baskets (Figure 3.2-5). The modified dual flow screens operate at 90 degrees to the water flow. Fish and debris are collected on both the ascending and descending sides of the dual-flow screen which allows only filtered water to pass downstream to the pumps. Fish and debris are removed by a high pressure screen wash system and conveyed back to the river. Modified dual flow traveling screens have been installed to address debris carry-over problems encountered with the original flow through traveling screens. A decision was also made by NPPD to install fish collection baskets on the dual flow screens to address future 316(b) issues. However, the present design and construction does not include installation of the low pressure spray system or a separate fish return trough and conveyance system to return fish back to the river. [NPPD 2006, Section 2.2]

Currently, fish and debris flushed from the screens are returned to the river via an 18 in. steel pipe which discharges downstream from the intake. The existing screen wash system does not have the capacity to provide the required flow to support both the low pressure fish protection spray system and the high pressure debris removal system. [NPPD 2006, Section 2.2] However as discussed in Section 3.2.2, CNS is planning to install a fish handling system consisting of inside and outside fish sprays and a separate fish return trough prior to the end of the current operational term.

The CWIS current design has a curtain wall at the face of the structure; as a result circulating water is withdrawn from the bottom 15 ft of the water column. The modified dual flow screens have been designed to operate perpendicular to the river flow, are rotated continuously, are equipped with collection baskets, and discharge to a trash return trough. This continuous rotation is an operational measure to minimize potential impingement mortality. NPPD believes that these design and operational aspects variation may result in significant differences in impingement mortality (IM) rates at CNS. [NPPD 2006, Section 2.4]

CNS's 1971 OL Stage ER stated a modest fish population inhabited the Missouri River, based on sampling results of limited fish population studies initiated in 1970. Those early studies indicated that aquatic insects and zooplankton constituted the main food supply for young fish, and that evidence suggested that aquatic insects cannot survive the passage through cooling condensers. The ER indicated the effects on young fish and fish eggs could not be adequately estimated. [NPPD 1971, Section IV-4.3.5.2]

The CNS 1971 FES concluded:

- The water velocity of approximately 1.3 fps across the intake screens at annual mean flows may result in some loss of fish by entrainment or impingement.

- However at this time (1971) the predicted probable adverse environmental effects (intake velocity, entrainment time and the size and maximum temperature of the mixing zone) do not warrant implementation of an alternative cooling discharge system.

- The NRC also concluded that an environmental monitoring program should be established to evaluate potential damage to the aquatic biota of the Missouri River due to entrainment, impingement, or thermal discharge. If significant damage were determined, the applicant was to provide an analysis of design modifications to mitigate the effects. [USAEC, pp. i-iii]

CNS originally received authorization to discharge to the Missouri River in November 1968 from the Nebraska Department of Health Water Pollution Control Council. State certification was received from the Nebraska Water Pollution Control Council on June 11, 1971 to use and discharge water from the Missouri River warmed to a maximum of Δ18°F at the point of discharge. [NPPD 1971, p. C-18-12]

NPPD submitted 316(a) and 316(b) demonstration studies related to CNS dated October 23, 1975. These studies provided pre-operational physical, chemical, and ecological characteristics of the river in the vicinity of CNS, and documented station operational effects on the Missouri

River. The studies included the results of NPPD's monitoring of fish larvae in 1974 and 1975, and an assessment of chemical, thermal, and biological impacts from station operations, including impingement impacts. The studies also concluded that, based on the early studies of year class, breeding stock, and the apparent effects on fish populations near CNS, the operation of CNS has minimal adverse effects on the fish populations in this stretch of the Missouri River. [Nalco]

The 316(a) demonstration was submitted in support of NPPD's request for alternate thermal discharge limits. After considerable review by the NDEC which included comments by the Nebraska Game and Parks Commission, the EPA and USFWS, NDEC concluded in a May 4, 1976 letter that "the discharge of once through condenser cooling water has not caused appreciable harm to the aquatic community of the Missouri River” [NDEC 1976]. The NDEC 1976 letter requested additional information regarding certain potential impacts related to 316(b) impacts on the fish population in the Missouri River resulting from CNS's intake structure [NDEC 1976]. On February 2, 1977, after a review of revised 316(b) documentation, NDEC concluded that based on available information that the effects of the CNS cooling water intake facilities were probably minimal, and that the intake structure met the minimum requirements of 316(b) [NDEC 1977]. Since the issuance of the 1976 and 1977 letters, there has been no impingement monitoring or assessment requirements until the issuance of EPA's Phase II 316(b) Rule in 2004, which has now been suspended.

As discussed in Section 4.2.5.2 above, NPPD conducted studies of the aquatic ecology of the Missouri River in the vicinity of CNS beginning with preoperational studies in 1969. Post-operational studies began in 1974. Those studies continued during the 1970s through 1978 as part of Appendix B Environmental Technical Specification monitoring required by the NRC. After completing five years of studies and submitting the results of those studies to the NRC, NPPD submitted a request for deletion of the Aquatic Surveillance, Study and Evaluation Program from the Technical Specifications to the NRC on July 10, 1979. This deletion was approved as Amendment 60 to CNS's license on December 7, 1979. [USNRC 1979]

The CNS PIC was submitted in compliance with the now suspended CWA 316(b) Phase II Rule (the Rule) for existing electric generating stations published in the *Federal Register* on July 9, 2004 [USEPA 2004]. The PIC was submitted to and approved by the NDEQ and CNS proposed:

- not conducting new biological studies,
- analyzing historical biological information,
- evaluating alternative fish protection technologies, and
- evaluating the Rule's compliance alternatives.
  [NPPD 2006, p. vi]

The Phase II 316(b) regulations were suspended on July 9, 2007. Based on the March 2008 316(b) annual report to the NDEQ, NPPD is not planning on specifically investigating any further technology for CNS relative to 316(b). [NPPD 2008a] However as discussed in Section 3.2.2, CNS is planning to install a fish handling system consisting of inside and outside fish sprays and a separate fish return trough prior to the end of the current operational term. This change to the CWIS design would most likely be considered Best Technology Available for minimizing impingement impacts.

4.3.5.2 Impingement Analysis

River Characteristics

Flow of the Missouri River at CNS is largely controlled by the Gavins Point Dam located approximately 200 miles upstream in Yankton, South Dakota. The river at CNS is about 800 feet wide and flows in a southeasterly direction. The flow is highly channelized with swift flows and heavy sediment transport. To minimize the effects of sedimentation on the intake, turning vanes and a low sheetpile wall are located in front of the intake bays. Wing dams are located on the Missouri side of the river to force the flow into a central channel. The water levels in the river range from a maximum at El. 899.0 feet to a minimum at El. 874.5 feet, with a normal level at El. 880.0 feet. The annual mean river flow is 38,251 cfs (1930-2001) based on the USGS gauging station at Nebraska City, Nebraska which is located approximately 30 RMs north of the CNS CWIS.

During the winter when river flows are typically lower, ice is common on the river. To prevent the formation of frazzle ice, some of the main condenser discharge water (25-30 percent) is re-circulated through the ice control tunnel and released in front of the trash rack within the CWIS while the remaining water is discharged about 1,300 feet downstream of the intake via a discharge canal. This reduces the volume of water withdrawn through the intake structure and reduces the potential for entrainment or impingement.

Pre-operational and Post-operational Studies

NPPD conducted studies of the aquatic ecology of the Missouri River in the vicinity of CNS beginning with preoperational studies in 1969. Details of pre-operational and post-operational studies at CNS were summarized by Nalco Environmental Sciences in "The Evaluation of Thermal Effects in the Missouri River near Cooper Nuclear Station 3I6(a) and 316(b) Demonstration," prepared in 1975. This document summarized data on the following topics and established a solid understanding of the ecology of the Missouri River in the vicinity of CNS.

- River flow data
- Ambient temperatures
- Intake configuration and operation
- Cooling water flow
- Phytoplankton
- Periphyton
- Fish
- River currents
- Weather data

- Outfall configuration and operation
- Thermal plume characteristics
- Zooplankton
- Macroinvertebrates

Fish collections using electrofishing and various net collection techniques were made in the vicinity of CNS during pre-operational and post-operational periods. The dominant species collected by electrofishing were gizzard shad, carp, river carpsucker and goldeye. The dominant fish species collected by bag seining were members of the genus Hybognathus (silvery minnow, western silvery minnow, and plains minnow). The silver chub, emerald shiner, river shiner, and red shiner also were represented abundantly in the seining collections. [Nalco, pp. 4.0-109 and 4.0-110]

Annual impingement sampling was conducted by NPPD at CNS from 1974 to 1978 as a component of on-going NRC operational environmental studies. Samples were collected for a one hour period five days a week at random times. Fish were collected in a basket placed in the screen wash trough, identified to species, weighed, enumerated, and measured. The dominant fish specie consistently collected during the CNS impingement studies was gizzard shad. Freshwater drum and river carpsucker were the next most frequently collected species. An unidentified cyprinid minnow was the third most frequently collected taxa in 1978. Most of the fish collected were YOY, ranging from 70 to 85 percent of the total number impinged. Evaluation of the diurnal differences in impingement rates indicated that more fish were impinged at night, and an evaluation of the seasonal differences in catch rates showed the highest rates in the summer and fall sampling periods, due primarily to the impingement of each year's YOY gizzard shad. Estimates of the survival varied between years, but ranged from a low of 59.1 to a high of 80.8. Most of the dead fish were YOY gizzard shad, a specie known to be intolerant of handling. Sampling results of the 1974-1978 studies are provided in Table 4.3-1. [NPPD 2006, Section 4.1.2] It is important to note that the occurrence of pallid sturgeon is rare in the vicinity of CNS. Pre-operational and post-operational studies conducted from 1970 to 1979 indicated that the pallid sturgeon was very rare in the vicinity of CNS, as no sturgeon were collected near CNS. [Hazleton 1979; Nalco]

Table 4.3-1
Summary of Impingement Data, Cooper Nuclear Station 1974–1978

	Year				
Species (% of Total)	**1974**	**1975**	**1976**	**1977**	**1978***
Gizzard shad	66.5	32.7	56.1	41.2	47.0
Freshwater drum	21.2	16.3	14.1	15.0	25.2
River carpsucker	3.3	26.0	10.2	22.3	0.8
Total fish collected	4402	676	1176	1074	266
Annual impingement estimate	NC	45,990	63,245	40,296	NC
Percent live fish at collection	59.1	80.8	69	70.5	67
Daytime impingement rate (fish/hour)	19.8	3.9	4.8	4.1	NC
Night-time impingement rate (fish/hour)	38.1	6.6	9.6	5.1	NC

*Note - reported reduction of total fish impinged attributed to fewer sampling periods [Hazleton 1979, Chapter 8]
NC = Not calculated in report
Reference: NPPD 2006, Section 4.1.2

Impingement Analysis

The annual post-operational aquatic monitoring program at CNS continued through 1979. Annual reports were prepared with titles related to "The Evaluation of Thermal Effects in the Missouri River Related to Cooper Nuclear Station", but monitored a range of physical, water quality, periphyton, macroinvertebrate and benthic organisms, larval fish and fish abundance, and density parameters [Hazleton 1980].

Fish entrapment monitoring was discontinued in January 1978 and fish impingement studies were reduced from five hours per week to two hours per month, as long as the fish impingement rate did not exceed 90 fish per hour [Hazleton 1980, p. 3]. After 10 years of pre-operational and post-operational monitoring of the Missouri River, these monitoring programs were discontinued at the end of 1979 when the NRC, after consultation with the State of Nebraska, agreed to deletion of the Aquatic Surveillance, Study and Evaluation Program from the Technical Specifications in December 1979. [USNRC 1979]

Fish monitoring in the Missouri River, which was conducted in the 1970s by OPPD as part of a comprehensive examination of the effects of power plants, showed that the primary recruitment sources of larval fish to the channelized Missouri River are Lewis and Clark Lake; the unchannelized Missouri River from Yankton, South Dakota, to Sioux City, Iowa; and tributaries. Freshwater drum, catostomids, cyprinids, and carp dominated (greater than 94 percent) the larval drift. Other taxa collected and considered common were the gizzard shad, goldeye, sauger, and walleye [Hergenrader, p. 187]. Field studies conducted at FCS and CNS indicate that the seasonal highest abundance of fish larvae in the Missouri River occurs from May to July. [USNRC 2003, p. 2-22]

Principal fish species in the lower Missouri River include emerald shiner, river carpsucker, channel catfish, gizzard shad, red shiner, shorthead redhorse, carp, and goldeye. Pallid and shovelnose sturgeon and paddlefish are also found in the lower Missouri River. Sport fish include channel catfish, crappie, sauger, flathead catfish, white bass, largemouth bass, bluegill, walleye, northern pike, and paddlefish. Species important to the commercial fishery on the lower Missouri River include buffalo, carp, carpsucker, freshwater drum, and catfish. [USACE 2003, Section 3.3.4]

The NRC prepared a Biological Assessment associated with the renewal of the FCS OL, which was submitted to the USFWS. As a result of this assessment and formal consultation conducted pursuant to 50 CFR 402.14(a) with the USFWS, both agencies concurred that the OL Renewal of FCS is not likely to adversely affect the pallid sturgeon [USFWS 2003].

<u>Fisheries Impacts Unrelated to CNS</u>

The NRC issued a SEIS for FCS in 2003 which provided significant insight into the fish species of the lower Missouri River and discusses the apparent declines in native fish species. The NRC's FCS SEIS discusses notable recent investigations of lower Missouri River fish populations, including those reported in 1993 and 1994. Those investigators assessed the status of 13 selected fish species in the entire Missouri River reach bordering Nebraska, including the paddlefish, burbot, channel catfish, flathead catfish, blue catfish, sicklefin chub, sturgeon chub, silver chub, speckled chub, flathead chub, plains minnow, western silvery minnow, and sauger. Twenty-two years of sampling data in the Missouri River (1971 to 1992) were evaluated and presented for the selected species. The focus of the research centered on data regarding the absolute and relative abundance and commercial and recreational harvest. [USNRC 2003, p. 2-23]

The FCS SEIS states that the decline in the abundance of five of the species investigated-the channel catfish, flathead catfish, blue catfish, sauger, and paddlefish was evident in historical commercial-harvest records, creel surveys, and fishery survey data collected from 1971 to 1992. Commercial and recreational harvest of these five species was one of the factors cited in the studies as responsible for the observed decline in their populations. However, the studies also characterized all of these fish species as being adapted for survival in large unaltered rivers, and the predominant factor for their decline was identified as the loss of suitable habitat, primarily due to channelization and impoundment of the river with the consequent loss of seasonal flood pulses, altered temperature regimes, and loss of nutrient loadings from bordering floodplains. [USNRC 2003, p. 2-23]

The remaining eight species investigated (the burbot, sicklefin chub, sturgeon chub, silver chub, speckled chub, flathead chub, plains minnow, and western silvery minnow) also exhibited declines in abundance upon examination of the 22 years of Missouri River fishery survey data. Only the burbot was subject to a minor recreational fishery and was generally considered an incidental catch to the targeted fish species. All of these species are representative and indigenous to large unchannelized rivers. The FCS SEIS notes, as do other Missouri River studies, the decline in abundance, as found in the fishery surveys, was attributed to the loss of habitat resulting from channelization, impoundment of the river, loss of seasonal flood pulses, altered temperature regimes due to impoundment, and loss of nutrient loading from the floodplains. [USNRC 2003, p. 2-23]

The commercial harvest of channel catfish, flathead catfish, and blue catfish from the Missouri River was banned in 1992 due to the overharvest of recruitment-size individuals. However, the commercial harvest of the common carp and buffalo fish from the Missouri River still continues [USNRC 2003, p. 2-24]. Recent contact with state (Missouri, Iowa, and Nebraska) regulatory agencies indicate there are as many as 65 commercial fishing licenses issued in 2007 [IDNR 2008; MDC; NGPC 2008c]. Legal species of fish that commercial fishermen may take, pursuant to the state rules include buffalo, common carp, drum, flathead catfish, channel catfish, blue catfish, bowfin, shovelnose sturgeon, paddlefish, gar, eel, quillback and carpsucker, redhose and other sucker, grass carp, bighead and silver carp, yellow perch, gizzard shad, black bullhead and yellow bullhead catfish [IDNR 2007; NGPC 2002, Chapter 2, Section 003.04].

While the commercial harvest of certain fish species may be a factor in the decline of those species, most studies agree that the modifications of the river during the 20th century are one of the most significant factors in the changes in fish abundance [USFWS 2007a; NAS, pp. 11-12; USACE 2003, p. 3-33]. Further, current studies do not mention impingement of fish and shellfish as a significant factor causing declines in indigenous species.

The lower Missouri River has been leveed, channelized, and its flow regulated for flood control and navigation. Channelization of the lower Missouri River reduced surface area by 50 percent, reduced turbidity by 65 percent, and decreased the number of sandbars and islands by greater than 90 percent, confining the river to a single, deep channel with swift current and little habitat complexity. [Reeves, p. 4]

The EPA published a report in 2007 titled "Baseline Status and Cumulative Effects to the Pallid Sturgeon". In its report, the EPA summarized the most significant impact to the endangered pallid sturgeon. "Pallid sturgeon are threatened by many factors, including habitat loss and degradation, hybridization, commercial fishing, and contaminants/pollutants. These threats to the species appear to be increasing and continue to adversely affect the pallid sturgeon. Additional threats to the species further compound the species status. Entrainment due to dredging operations and commercial navigation traffic represents an unknown, but perhaps significant, threat to the species through direct mortality. The presence of exotic Asian carp has increased dramatically in the Missouri and Mississippi Rivers. These species compete with native river fish for food and habitat and may present a significant long-term threat to the pallid sturgeon." [USEPA 2007, p. 1]

In the 2004 316(b) Phase II final rule, EPA noted the impacts of the 20th Century change in the Missouri River, and its affect on impingement. The EPA discussion notes that facilities sited on waterbodies previously impaired by anthropogenic activities, such as channelization, demonstrate limited entrainment and impingement losses. The Neal Generating Complex facility, located near Sioux City, Iowa, on the Missouri River is coal-fired and utilizes once-through cooling systems. According to a ten-year study conducted from 1972-82, the Missouri River aquatic environment near the Neal complex was previously heavily impacted by channelization and very high flow rates meant to enhance barge traffic and navigation. These anthropogenic changes to the natural river system resulted in significant losses of fish habitat. At this facility, there was found to be little impingement and entrainment by cooling water intakes. [USEPA 2004, p. 41588]

Summary

Studies show that the modifications of the river during the 20th century are one of the most significant factors in the changes in fish abundance. These modifications included loss of habitat resulting from channelization, impoundment of the river, loss of seasonal flood pulses, altered temperature regimes due to impoundment, and loss of nutrient loading from the floodplains. Fish impingement was rarely mentioned as a significant factor causing declines in indigenous species.

Although NDEQ had already determined that the cooling water intake impacts were probably minimal at CNS, NPPD is planning to install a fish handling system consisting of inside and outside fish sprays and a separate fish return trough during the current operational term. This change to the existing design of the CWIS (Ristroph screens) would most likely be considered Best Technology Available for minimizing impingement impacts.

4.3.6 Conclusion

The diversity and abundance of species within the fish communities in the Missouri River ecosystem has generally been affected by the anthropogenic changes that impact fish habitat and water quality. While recent studies have not been performed at CNS related to fish impingement at its cooling water intake structures, the predominance of fisheries studies along the Missouri River identify factors other than impingement as being the primary direct and cumulative impacts to the fish populations in the river.

NPPD is planning to install a fish handling system at CNS, consisting of inside and outside fish sprays and a separate fish return trough to the existing design of the CWIS (Ristroph screens).

This change to the CWIS would most likely be considered Best Technology Available as it relates to minimizing impingement impacts. In addition, even though current impingement impacts are minimal, impacts during the license renewal period would be even smaller due to this CWIS design change. Therefore, NPPD concludes the impact due to impingement of fish and shellfish in the Missouri River is SMALL and mitigation measures are not warranted.

4.4 Heat Shock

4.4.1 Description of Issue

Heat Shock (for all plants with once through and cooling pond heat dissipation systems)

4.4.2 Findings from Table B-1, Appendix B to Subpart A

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 10 CFR 51.53(c)(3)(ii)(B).

4.4.3 Requirement [10 CFR 51.53(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 40 CFR Part 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock....

4.4.4 Background

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 the 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. Conversely, at other plants it may become advantageous to increase the temperature of the discharge in order to reduce the volume of water pumped through the plants and thereby reduce entrainment and impingement effects. 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. [USNRC 1996, Section 4.2.2.1.4]

4.4.5 Analysis of Environmental Impact

4.4.5.1 Background

Heat Dissipation System

CNS is equipped with a once-through heat dissipation system that withdraws cooling water from and discharges to the Missouri River. The details of the plant cooling systems, intake structures, and discharge systems are provided in Section 3 of this ER. CNS has a shoreline-situated intake structure that is flush with a sheetpile deflector wall, consisting of five bays (four for circulating water and one for service water). Additional information on the CNS intake and discharges are provided in NPPD's 2005 NPDES permit application to the NDEQ [NPPD 2005].

CNS has four circulating water pumps designed to pump 159,000 gpm each. CNS has four service water pumps, rated at a combined flow of 32,000 gpm. The details of the discharge system are provided in Section 3. A site plot plan showing CNS's intake and discharge at CNS is provided in Figure 3.2-1. Water elevation for siphon operation is maintained by a gated weir at a minimum elevation of 880 feet AMSL. Stone rip-rap is used to prevent scours in the vicinity of the discharge structure. [NPPD 2008b, Section XII- 2.2.7.4]

The discharge canal is approximately 1,000 feet long and enters the river at a slight angle. River level is important in determining the velocity of the discharge. Discharge velocities taken near the mouth of the discharge canal ranged from 1.3 fps at 27,000 cfs (Missouri River flow) with two circulating pumps operating to 5.6 fps at 37,600 cfs (Missouri River flow) with three circulating pumps operating. Travel time through the pumphouse–condenser–canal system is about 20 minutes at high flow and 10 to 12 minutes at low river levels. [Nalco, Section 4.2.7]

The highest expected circulating water system flow is about 636,000 gpm (approximately 1,420 cfs) occurring at full load during the hot summer months. During the winter when river flows are low, circulating water flow requirements are also low because of the cold water supply. Therefore, even under the worst conditions (3,000 cfs flow), only about one third of the river flow is required by the circulating water system at full load. Circulating water requirements can always be reduced simply by reducing load. [NPPD 2008b, Section II-4.2.1]

Nebraska has developed mixing zone criteria and thermal discharge limits for steam-electric power plants. These limits are designed to protect the existence of a balanced indigenous population of shellfish, fish, and wildlife in the receiving water body. If the facility cannot meet the stated water quality standard criteria, the facility may submit data demonstrating that its actual discharge will ensure the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife. This demonstration is referred to as a 316(a) demonstration. The NPDES permit required for a power plant typically contains discharge temperature limits that are based on either state water quality standards or 316(a) demonstrations.

CNS originally received authorization to discharge to the Missouri River in November 1968 from the Nebraska Department of Health Water Pollution Control Council. State certification was received from the Nebraska Water Pollution Control Council on June 11, 1971, to use and discharge water from the Missouri River warmed to a maximum of Δ18°F at the point of discharge. [NPPD 1971, p. C-18-12]

The site holds Nebraska NPDES Permit NE-0001244 with effluent limitations, monitoring requirements, and other conditions that ensure that all discharges are in compliance with NDEQ Title 117 Nebraska Surface Water Quality Standard and Title 119, Chapter 27, Sections 004 and 007 of the Nebraska Administrative Code and 40 CFR Part 423. In accordance with permit requirements, the site monitors discharge characteristics and reports the results to the NDEQ. A copy of the current NPDES Permit is attached (see Attachment C).

Thermal Studies

Impacts due to thermal discharge have been evaluated since the original licensing of CNS, most recently the 2006 CORMIX discussed below. A discussion of the aquatic ecology of the Missouri River is provided in Section 2 of this ER.

The CNS OL Stage ER concluded that the section of the Missouri River which was studied is such that the current velocity is very high (0.6 fps to 8.3 fps) with a modal, or most frequently observed, velocity of between 3-4 fps. The channel bottom is well-scoured, and the temperature of the water is nearly constant from top to bottom [NPPD 1971, p. C-2-1].

CNS conducted thermal mixing zone modeling downstream of its discharge in October 1972, prior to commercial startup. The transverse mixing characteristics of the Missouri River in the vicinity of CNS were investigated using the fluorescent-dye tracer technique. The results indicated that the excess temperature in the river at full plant load could be reduced by dilution to less than 5°F within a 45-acre mixing zone with the present discharge canal system, provided that the river discharge is not less than about 20,000 cfs. The results of the dye experiment led to the conclusion that the present discharge-canal arrangement should meet the temperature standards during the navigation season when the river discharge is maintained at or above 30,000 cfs, provided that the ambient temperature in the river does not go above about 87°F. [IIHR, Abstract]

NPPD submitted 316(a) and 316(b) demonstration studies dated October 23, 1975 to provide pre-operational physical, chemical, and ecological characteristics of the river in the vicinity of CNS, and document station operational effects on the Missouri River. The report included the results of NPPD's thermal monitoring in 1974 and 1975 and an assessment of chemical, thermal, and biological impacts from station operations, including thermal impacts. The study concluded that except at low flow conditions, the river was well mixed without stratification due to the turbulent flow of the river. [Nalco, p. 4.2.9] The plume during CNS operations extended along the west bank of the river and decreased in temperature by 70 percent within 800 feet of the discharge except during the winter low flows. The report discussed an NRC Environmental Technical Specification that required that the thermal plume not extend more than one-third of the river width and meet a 90°F limit at the end of a 7,500 feet mixing zone. The study further concluded the thermal discharge had little effect on water quality, aquatic biota, or fish within the area of direct thermal influence. [Nalco, p. 4.0-32]

The results of NPPD 316(a) studies and the monitoring program were submitted to the NDEC in support of NPPD's request for alternate thermal discharge limits. After considerable review by the NDEC which included comments by the NGPC, the EPA, and USFWS, NDEC concluded in its May 4, 1976 letter that the discharge of once-through condenser cooling water has not caused appreciable harm to the aquatic community of the Missouri River [NDEC 1976]. The NDEC subsequently approved NPPD's request for alternate thermal discharge limits for a discharge temperature of 103°F. [NDEC 1976; NDEQ 2006] However, the thermal discharge limits have continued to be an issue due to increasing ambient river temperatures and low flow conditions.

The annual aquatic monitoring program (which included thermal monitoring) at CNS continued from 1969 through 1979. After 10 years of pre-operational and post-operational monitoring of the Missouri River, these monitoring programs were discontinued at the end of 1979 when the NRC, after consultation with the State of Nebraska, agreed to deletion of the Aquatic Surveillance, Study and Evaluation Program from the Technical Specifications in December 1979. [USNRC 1979]

CNS's 1988 NPDES permit established an effluent discharge temperature limit of 103°F as a daily maximum, measured continuously and reported quarterly. This effluent limitation was based on protecting the water quality of the receiving stream, the Missouri River. At NPPD's request, the NPPD and NDEQ entered into a Consent Order in 2000 that increased the daily maximum effluent temperature to 108°F. The 2000 Consent Order was amended in 2002 to provide an effluent daily maximum temperature limit of 110°F. [NDEQ 2002] These Consent Orders state the NDEQ has not designated the Missouri River as impaired water for temperature, nor does it anticipate that the requested increase in the discharge limit would lead to such as designation [NDEQ 2006]. The 2006 Consent Order again approved an effluent temperature limit of 110°F for a period of one year or until a new NPDES permit could be approved with newly established effluent limits. The 2006 Consent order also noted that the NDEQ, Region VII EPA, and NPPD cooperated over the term of the 2001 NPDES permit in studies, modeling, and environmental evaluations to derive a temperature effluent limitation that is specific to protection of the receiving waters. [NDEQ 2006]

Temperature standards to protect aquatic life are set forth in NDEQ Title 117 Nebraska Surface Water Standards in Chapter 3, General Criteria for Aquatic Life. According to the requirements in Title 117, the temperature of a receiving water shall not be increased by a total of more than 5°F from natural outside the mixing zone, and for warm waters the maximum limit is 90°F. [NDEQ 2007]

On March 21, 2006, NPPD submitted data to the NDEQ consisting of inlet, discharge, and delta temperature information for NPPD's CNS during the time periods April 1 through September 30, 2004 and 2005. Also included in the data set were the power output for those two years and the discharge flow rate in millions of gallons per hour. Subsequently, these data were sent to EPA Region VII in Kansas City, Kansas, for analysis. EPA Region VII assisted the NDEQ by conducting assessment of the instream mixing of cooling water from CNS based on instream monitoring of heat using CORMIX model software. Details of the CORMIX run and temperature limit derivation can be obtained from USEPA. [NDEQ 2007]

The model was calibrated and run iteratively to find the point where the background river temperature, plus the temperature across the condensers (ΔT) diluted instream, meets the 90°F limit at the end of the 5,000-foot chronic mixing zone. Low stream flow (7Q10) and high temperature conditions encountered in late summer present the worst-case scenario in meeting the 90°F limit at the end of the mixing zone. The end of pipe temperature limits is based on the point where the inlet temperature and maximum heat discharge create an exceedance of the 90°F temperature limit at the end of the mixing zone. [NDEQ 2007]

Application of the CORMIX model as described above gives an end-of-pipe temperature limit for CNS of 109.4°F based on a ΔT of 23.9°F across the condensers at an 85.54°F river temperature. [NDEQ 2007, Attachment A]

4.4.5.2 Thermal Discharge Analysis

The post-operational monitoring performed at CNS through 1975 indicated the thermal discharge plume extends along the west bank of the river and generally is limited to approximately one-third of the width of the river [Nalco, Figure 4.2-9]. Therefore, the plume would not be expected to create a barrier to fish migration through the mixing zone. The operational studies from 1974 through 1979 also did not indicate adverse impacts on the aquatic communities resulting from the CNS thermal discharge [Nalco; Hazleton 1980].

The EPA, in a cooperative effort with the USGS and the NDEQ, collected and analyzed heat data from the Missouri River at CNS and three other power plants to map heat in the Missouri River and predict compliance with Nebraska Water Quality Standards under various river conditions to establish appropriate NPDES permit limits. This study began in the Autumn of 2001. The study which included thermal modeling, focuses on power plants and other industries discharging to the lower Missouri River and addresses the potential effects of historically high ambient river temperatures. In a letter response to the NRC draft SEIS on FCS, USEPA indicated its study is assisting the NDEQ in assessing the implications of reduced river flows in the summer, such as those being considered by the USACE in the context of revisions to the Missouri River Master Water Control Manual and the associated USFWS Biological Opinion. [USNRC 2003, Appendix A].

The USEPA's thermal modeling programs are indicative of potential impacts to aquatic ecology. Region VII EPA conducted thermal CORMIX modeling studies to support the NDEQ for CNS's most recent NPDES permit. EPA calibrated its CORMIX modeling using field data generated in 2001. Use of the calibrated model allowed EPA to accurately predict modeling under different conditions, such as at the seasonally calculated 7Q10 flow, and match mixing seen in the river. Special emphasis was placed on modeling to evaluate compliance with the 32°C (90°F) limit of the Nebraska Surface Water Quality Standards (Title 117 Chapter 4.003.01B) at the end of the 5,000 feet mixing zone. EPA and NDEQ assessed summer heat discharge data from the summer of 2005 as a representative sample for determining a representative ΔT for the high electric power production rates of summer. The model was calibrated and run iteratively to find the point where the background river temperature, plus the temperature across the condensers (ΔT), diluted in-stream, meets the 90°F limit at the end of the 5,000 foot chronic mixing zone.

Low stream flow (7Q10) and high temperature conditions encountered in late summer were used as the worst-case scenario in meeting the 90°F limit at the end of the mixing zone. [NDEQ 2007]

The NDEQ issued CNS a renewed NPDES permit effective July 1, 2007, which set thermal limits for Outfall 001. Conditions established by the NDEQ related to thermal discharge and included in NPDES Permit NE0001244 set a maximum discharge temperature not to exceed 109.4°F. These conditions were established by the NDEQ to ensure the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife in the Missouri River.

CNS may be constrained by the thermal discharge limits of its NPDES permit. As the temperature exceeds the 85°F used in USEPA's CORMIX modeling, CNS's power output may have to be derated to meet its discharge limit, under certain low flow conditions. Based on an evaluation developed in cooperation with the NPA, CNS should be able to comply with its NPDES discharge limit. However, at higher ambient river temperatures and at summer low flow conditions (below 25,000 cfs), operational problems and station output derating may occur. [NPA, Figure III.B-3, p.14]

As indicated in Sections 4.2 and 4.3 above, review of available information leads to a conclusion that the changes observed in fish population abundance and density all along the Missouri River are due to factors unrelated to entrainment, impingement, or thermal discharges at CNS, either directly or cumulatively. The Missouri River studies conducted to date generally concur that the impacts related to declines in certain indigenous fish species are due to habitat changes such as Missouri River and tributary dams, channelization and other habitat management, invasive aquatic species, and similar factors.

NPPD is not aware of any evidence that operation of CNS during the license renewal term would create any adverse thermal impacts. CNS holds a valid NPDES permit that has been supported by NDEQ and EPA modeling that provides adequate protection of water quality. There has been no evidence of fish mortality due to CNS thermal discharges that have adversely affected commercial or recreational harvests. The effects of CNS operations on sport fisheries and the impact of commercial harvests along the Missouri River were discussed in Sections 4.2 and 4.3 above.

Also, as indicated above, the NDEQ has made a determination to issue an NPDES permit to CNS based on predictive modeling of thermal discharge that limits the station's maximum discharge at 109.4°F. CNS will continue to comply with the NDEQ thermal-discharge standards through the duration of the current OL and the license renewal term.

4.4.6 Conclusion

Pursuant to 10 CFR 51.53(c)(3)(ii)(B), cited above in relation to "equivalent State Permits and supporting documentation", the site holds an NDEQ NPDES permit (NE-0001244) for discharge of cooling waters from CNS (see Attachment C). The Station is complying with this permit, including limits and conditions established by the NDEQ for thermal discharges. NDEQ, EPA, and NPPD have conducted recent CORMIX modeling studies of the ability of CNS operations to meet Nebraska thermal discharge limits that protect the water quality of the Missouri River. The maximum discharge temperatures from CNS will continue to be limited by the NPDES permit which has been established at 43.0°C (109.4°F) as a result of the modeling. Therefore, NPPD concludes that continued operation in the manner required by the current NPDES permit and the current Missouri River Master Water Control Manual flows will result in thermal impacts that will remain SMALL during the license renewal term. Further mitigation measures are not warranted.

4.5 Groundwater Use Conflicts (Plants Using > 100 gpm of Groundwater)

4.5.1 Description of Issue

Groundwater use conflicts (potable and service water and dewatering: plants that use > 100 gpm).

4.5.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Plants that use more than 100 gpm may cause groundwater use conflicts with nearby groundwater users. See 10 CFR 51.53(c)(3)(ii)(C).

4.5.3 Requirement [10 CFR 51.53(c)(3)(ii)(C)]

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

4.5.4 Background

Those nuclear plants that use groundwater may affect the utility of groundwater to neighbors. This impact could occur as a direct effect of pumping groundwater, thereby either lowering the water table and reducing the availability or inducing infiltration of water of lesser quality into the ground. Neighboring groundwater users could also be affected indirectly if construction or operation of the power plant were to disrupt the normal recharge of the groundwater aquifer. The impact to neighboring groundwater users is likely to be most significant at a site where water resources are limited. Groundwater usage impact may be important at those sites where a power plant's usage rate exceeds 0.0063 m^3/s (100 gpm). Lower usage rates are not expected to impact sole source or other aquifers significantly. [USNRC 1996, Section 4.8.1].

4.5.5 Analysis of Environmental Impact

4.5.5.1 Background

The annual average groundwater utilization at CNS has not been measured. However, NPPD is assuming that the annual average pumping rate is greater than 100 gpm, and thus an assessment of the impact of license renewal on groundwater use must be provided. CNS's circulating cooling water is withdrawn from the Missouri River; therefore the site does not use Ranney wells.

A description of regional, vicinity, and site groundwater characterization in the vicinity of CNS is presented in Section 2.3. Table 2.3-1 provides the location and available information regarding all identified wells within two miles, including inactive, abandoned and decommissioned wells.

The site uses two wells, registered with the NDNR as G-030088 and G-030089, for supplying potable water to the facility (See Figure 4.5-1) [NDNR 2008, p. 41]. They are approximately 150 feet apart, located on a north-south line approximately 860 feet west and 250 feet north of the reactor building. Both wells are over 60 feet deep and currently each have an NDNR registered capacity of approximately 500 gpm. However, current total pumping capacity is 250 gpm for both wells. The normal pumping rate is anticipated to be 125 gpm, with one well in service at a time. Maximum short-term plant demand is approximately 250 gpm which is the capacity of the plant Makeup Water Treatment System [NPPD 2008b, Section II-4.4.2]. A third site well (NDNR Registration No. G-040718) was installed in 1973 and is currently used by the CNS Fire Protection personnel for training exercises. Maximum registered capacity of this well was reported to be approximately 750 gpm with a depth of 73 feet.

River Wells A and B are industrial wells that supply water for pump seals (G-100339 and G-100340). Available well construction and registration data for the River Wells is listed in Table 2.3-1. According to a review of site engineering drawings, the River Wells A and B have been relocated and redrilled at their current locations. The former locations of River Wells A and B were approximately 100 feet and 125 feet, respectively, from their current locations. [CRA, Section 2.4.1]

Existing monitoring wells at the Station include three decomissioned piezometers (G-143738A, G-143738B, and G-143738C). These three piezometers were installed during the soil boring investigation program associated with the ISFSI project. The primary purpose for the installation of these piezometers was to obtain groundwater levels/gradients across the Station property. [NDNR 2008]

4.5.5.2 Aquifers

A brief description of the regional and local aquifers is provided in Section 2.3. CNS is located over the Western Interior Plains Aquifer System. However, little water is withdrawn from the Western Interior Plains aquifer system because the aquifer system is deeply buried and contains highly mineralized water [USGS 1997]. Thus, the Western Interior Aquifer is not considered further in the discussion of impacts below.

The CNS site overlies a surficial aquifer system consisting of alluvial deposits of the Missouri River Valley aquifer and glacial deposits of the Glacial Drift Aquifer. The groundwater aquifers surrounding the site are illustrated by Figure 2.3-3. The maximum southern extent of glacial ice and glacial-drift deposits was about the present location of the Missouri River in Missouri and just south of the Kansas River in northeastern Kansas. The glacial deposits are pre-Illinoian age. Some of the drift might be of late Pliocene age, whereas most glacial deposits in North America are considered to be Pleistocene. [USGS 1997]

Alluvial deposits along the Missouri River form the stream-valley Missouri River Valley aquifer from the Iowa-Missouri State line to the junction of the Missouri and the Mississippi Rivers (Figure 2.3-2); small areas of similar deposits in eastern Nebraska compose local aquifers. The deposits partly fill an entrenched bedrock valley that ranges from about 2 to 10 miles wide. In many places in northern Missouri, the bedrock contains slightly saline to saline water, and the stream-valley aquifers, along with aquifers in glacial drift, are the only sources of fresh ground water. [USGS 1997]

Groundwater at the site occurring near the river is primarily taken from the sand and gravels in the alluvium over the bedrock. Although the unconsolidated sediments are mostly sand, some silt and clay seams, probably discontinuous, are found in the upper 15 feet of the deposit and in discontinuous lenses at a depth of about 40 feet. Over 90 percent of the deposit is loose to medium dense, fine to coarse, sand. From the hydrologic point of view, the sand deposits constitute an open hydraulic system with the Missouri River. [NPPD 2008b, Section II-4.4.1]

The average overburden thickness is estimated to be approximately 70 feet, of which approximately 40 to 55 feet are saturated. Hydraulic conductivity (K) was computed from an analysis of data obtained from the USACE pumping tests on the pressure relief wells. The results indicate that the K of the sand ranges between 10×10^{-2} and 20×10^{-2} centimeters per second (cm/sec). These figures are in agreement with the range 6×10^{-2} to 9×10^{-2} cm/sec stated by the USACE as typical for the Missouri Valley sands. The permeability of the gravel and sand just above the rock surface is expected to be higher than the overlying sands and may be on the order of 10 cm/sec. [CRA, Section 2.4.3]

4.5.5.3 Onsite and Offsite Water Wells

CNS lies within the Nemaha River Basin in Nebraska, which is under the management of the NNRD (see Figure 2.3-3). The Nemaha River Basin (Basin) in Nebraska is defined as the areas of Nebraska south of the Platte River Basin that drain directly into the Missouri River and includes the Missouri River below its confluence with the Platte River [NDNR 2006]. Groundwater in the Basin is used for a variety of purposes: domestic, industrial, livestock, irrigation, and others. There were 1,400 registered groundwater wells within the Basin as of October 1, 2005, according to the NDNR registered groundwater wells database. Not all wells are registered in the NDNR database, especially stock and domestic wells, which if drilled prior to 1993 are not required to be registered. Certain dewatering and other temporary wells are also not required to be registered. Irrigation is the largest consumer of groundwater, with approximately 46,000 acres being supplied with water from approximately 400 wells as of October 1, 2005. [NDNR 2006, p. N-3] Figure 4.5-1 provides a map of onsite wells at CNS that are registered with the NDNR.

4.5.5.3.1 Offsite Wells

There were no offsite groundwater wells identified within one mile of CNS on the Missouri side of the river. In addition, there are no groundwater withdrawals associated with the operation of CNS from the NPPD property on the east side of the Missouri River in Atchison County. Since the surficial aquifer at CNS is in hydraulic connection with the Missouri River, it is unlikely there could be any impact on groundwater users on the east side of the river. Therefore, consideration of groundwater use involves only those users west of the Missouri River.

A search of the NDNR website identified water wells within the vicinity of the Station. The water well database includes all irrigation wells installed since 1953 and all water wells since 1983. The database search revealed 351 water wells within Nemaha County [NDNR 2008]. Ten of the 351 recorded water wells are owned by NPPD or CPPD (predecessor of NPPD). Two of the ten wells registered to NPPD are shown as having been decommissioned, and were replaced by two new wells with the same registration numbers (G-100339 and G-100340). Three recent water wells have been installed by the Nebraska Game and Parks Commission (Registration Numbers: G-146401A, G-146401B, and G-146401C), between approximately 1.5 and 1.8 miles to the south-southwest. The City of Auburn, Nebraska, has a well located approximately 1.9 miles south of CNS (G-142071). There are private wells identified beyond two miles that are not included in Table 2.3-1. [NDNR 2008]

4.5.5.3.2 Onsite Wells

Table 2.3-1 of this ER presents an overview of the existing well inventory including water supply wells and monitoring wells. Available well construction details are also provided in Table 2.3-1. Figure 4.5-1 presents the existing wells. The well names and aquifers are listed below:

- Water Supply Well #1 (presumed overburden);
- Water Supply Well #2 (presumed overburden);
- River Well A (overburden);
- River Well B (overburden);
- Fire Well (presumed overburden); and
- Piezometers B-1, B-12, and B-31 (decommissioned).
  [CRA 2007, Section 2.4.1]

4.5.5.3.3 Well Drawdown

Maps of steady-state piezometric surfaces from CNS or nearby wells at average and peak pumpage or no flow conditions are not available. The nearest known wells are hand-dug farm wells located approximately 0.7 mile (~3,700 feet) south-southwest from the reactor building, and are used for domestic and livestock purposes [NPPD 2008b, Section II-4.4.2]. Since the estimated yield of these wells is only 10 gpm, drawdown is expected to be minimal.

The nearest downstream public water supply is the Village of Nemaha approximately 2.1 miles (11,090 feet) south-southwest of CNS. Present water supply is from about 80 private residential wells ranging in depth from 16 to 18 feet and a municipal water system. The latter has a total capacity in excess of 250 gpm from two municipal wells located at 7th and Otoe Streets and 4th and Otoe Streets. They are eight-inch cased wells drilled to approximately 80 feet in depth. Normal static water level is approximately 30 feet. They are equipped with submersible pumps rated at 60-gpm capacity at normal system head. Drawdown is minimal, estimated to be less than six feet. The aquifer receives recharge from the Nemaha River. [CRA, Section 2.3.5]

Estimates of the radius of influence under steady-state pumping conditions were developed using the equilibrium equation cited in Driscoll [Driscoll, Equation 9.1]. Various iterative estimates of the radius of the cone of depression (R) were developed for the two potable water wells at CNS. The following assumptions were used for the calculations of R:

- Maximum flow (Q) is 250 gpm and 500 gpm for the potable water wells (note: 500 gpm is greater than the current capacity for treatment).
- Hydraulic conductivity (K) is between 0.01-0.10 cm/sec.
- Static Head (H) measured from the bottom of the aquifer is 55 feet.
- Depth of water in the well (h) while pumping is 15 feet (worst case) above the bottom of the aquifer.
- Radius of the potable water well is 0.75 feet.

Based on the above two rates of pumping from a single well, the estimated equilibrium radius of influence surrounding the well is between approximately 100 to 1,250 feet [Enercon 2008]. If both wells were pumped simultaneously, it would be assumed that each well would affect the drawdown in the other well, and reduce the effective yield from each well. However, due to the pump settings, the maximum drawdown above the bedrock would not be lower than 15 feet above the bedrock. The maximum anticipated radius of influence from the two potable water wells at CNS is not expected to extend beyond the CNS property boundary. Therefore, the pumping at CNS is not expected to extend to the nearest existing farm well to the south-southwest (i.e., approximately 3,700 feet southwest of the reactor). Thus, no impact on offsite groundwater use is expected.

As the wells at CNS are hydraulically connected to the Missouri River, groundwater withdrawal could potentially create a lowering of the water table west of the river. However, these effects, if any, would be limited to the CNS site.

4.5.5.4 Wetlands

Within the site boundary of CNS there are three federal jurisdictional mapped wetlands. Within a 6-mile radius of CNS there are more than 700 mapped wetlands listed in the USFWS National Water Information System [USFWS 2007b]. Based on anticipated pumping zones of influence around wells used for onsite operations, impact to even the nearest wetland is expected to be minimal. [Enercon 2008]

4.5.5.5 Water Use Impacts

The Station is located on the western bank of the Missouri River and within the alluvial floodplain. Groundwater at CNS is unconfined and occurs within underlying sands that appear to be either fluvial or glacial outwash deposits that comprise the surficial Missouri River stream valley aquifer adjacent to the river. Although local recharge may occur due to precipitation, the groundwater is in hydraulic communication with the river. Groundwater beneath the site may flow either toward the river or away from the river depending on the river stage. Thus, the local groundwater level fluctuates depending on precipitation and water level changes in the Missouri River.

The passage of LB 962 in Nebraska in 2004 is anticipated to have a major impact on water in Nebraska. It requires that the NDNR evaluate every river basin in Nebraska and make a determination whether a basin is fully or over appropriated. NDNR announced in 2005 that after reviewing the best available data, the Nemaha Basin will not be declared fully appropriated. This means there will be no restrictions on the drilling of new wells and the State will continue to issue surface water permits so long as flows are present. [NDNR 2006; NNRD 2005]

No additional groundwater use is anticipated during the period of license renewal. Also, no direct or indirect impact on local groundwater resources has been attributed to the operation of CNS. At this time, there are restrictions on the installation of additional wells in the NNRD. However, this is due to local problems in the northeastern part of the district in an aquifer unit unrelated to the Missouri River valley alluvial aquifer at CNS. The limited restriction is a temporary moratorium on large capacity wells, for which a potential new well owner can apply for a waiver. Contact with a representative with the NNRD indicated there have been no groundwater use conflicts in the Missouri River stream valley alluvial aquifer around Cooper [NNRD 2008].

4.5.6 Conclusion

Based on available information, there is no discernible radius of influence from the pumping cones of depression around the onsite pumping wells that extend offsite. The wells at CNS are in direct hydraulic communication with the Missouri River, which further minimizes any potential for overutilization of groundwater in the vicinity. Therefore, NPPD concludes that environmental impacts of water use from license renewal would be SMALL and does not warrant further mitigation measures.

4.6 Groundwater Use Conflicts (Plants Using Cooling Towers Withdrawing Make-Up Water from a Small River)

4.6.1 Description of Issue

Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river).

4.6.2 Findings from Table B-1, Appendix B to Subpart A

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 groundwater or upstream surface water users come on line before the time of license renewal. See 10 CFR 51.53(c)(3)(ii)(A).

4.6.3 Requirement [10 CFR 51.53(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 x 10^{12} ft^3/year (9 x 10^{10} m^3/year), an assessment of the impact of the proposed action on the flow of the river and related impacts on in-stream 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.

4.6.4 Analysis of Environmental Impact

The site does not utilize cooling towers or cooling ponds. Therefore, this issue is not applicable to the site and further analysis is not required.

4.7 Groundwater Use Conflicts (Plants Using Ranney Wells)

4.7.1 Description of Issue

Groundwater use conflicts (plants using Ranney wells).

4.7.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Ranney wells can result in potential groundwater depression beyond the site boundary. Impacts of large groundwater withdrawal for cooling tower makeup at nuclear power plants using Ranney wells must be evaluated at the time of application for license renewal. See 10 CFR 51.53(c)(3)(ii)(C).

4.7.3 Requirement [10 CFR 51.53(c)(3)(ii)(C)]

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

4.7.4 Analysis of Environmental Impact

The site, which utilizes cooling and service water taken directly from the Missouri River, does not utilize Ranney wells. Therefore, this issue is not applicable to the site and further analysis is not required.

4.8 Degradation of Groundwater Quality

4.8.1 Description of Issue

Groundwater quality degradation (cooling ponds at inland sites).

4.8.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. 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 10 CFR 51.53(c)(3)(ii)(D).

4.8.3 Requirement [10 CFR 51.53(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.

4.8.4 Analysis of Environmental Impact

The site uses a once-through cooling system and does not utilize cooling ponds. Therefore, this issue is not applicable to the site and further analysis is not required.

4.9 Impacts of Refurbishment on Terrestrial Resources

4.9.1 Description of Issue

Refurbishment impacts—Terrestrial Resources

4.9.2 Findings from Table B-1, Appendix B to Subpart A

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 10 CFR 51.53(c)(3)(ii)(E).

4.9.3 Requirement [10 CFR 51.53(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.

4.9.4 Analysis of Environmental Impact

As noted in Section 3.3, there are no refurbishment activities required for CNS license renewal. Therefore this issue is not applicable to the site and further analysis is not required

4.10 Threatened or Endangered Species

4.10.1 Description of Issue

Impacts from refurbishment and continued operations on threatened or endangered species.

4.10.2 Finding from Table B-1, Appendix B to Subpart A

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 10 CFR 51.53(c)(3)(ii)(E).

4.10.3 Requirement of 10 CFR 51.53(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.

4.10.4 Background

The NRC did not reach a conclusion about the significance of potential impacts to threatened and endangered species in the GEIS because (1) the significance of impacts on such species cannot be assessed without site- and project-specific information that will not be available until the time of license renewal and (2) additional species that are threatened with extinction and that may be adversely affected by plant operations may be identified between the present and the time of license renewal. [USNRC 1996, Section 3.9]

4.10.5 Analysis of Environmental Impact

Section 2.4 addresses issues related to critical and important habitats, wetlands, and unique natural areas and Section 2.5 discusses threatened or endangered species that could occur within the vicinity of the site and along the associated transmission lines. Potential threatened and endangered state-listed plants and animals that could occur in the vicinity of the site and associated transmission lines have been identified in Table 2.5-1. These state-listed species are not further addressed in this ER, as the species are not known to occur on the CNS site.

As discussed in Section 3.3, NPPD has no plans to conduct refurbishment or construction activities at the site during the license renewal term. Therefore, there would be no refurbishment-related impacts to special-status species and no further analysis of refurbishment related impacts is applicable.

NPPD contacted the USFWS and NGPC (see Attachment A) for input on the presence of listed threatened or endangered species in the vicinity of CNS. (At the time of submittal of this ER, neither agency had responded to the request for information). As stated in Section 2.5, there are four federally protected animal species and one plant species that may occur in the vicinity of the site: the pallid sturgeon, piping plover, Indiana Bat, and interior least tern, and the western prairie fringed orchid. Of these, only the pallid sturgeon is believed to be potentially present in Nemaha County, where CNS is located. There have been no sightings or knowledge of local populations of the piping plover, interior least tern, Indiana bat, or western prairie fringed orchid either on the CNS site or in the vicinity of the site.

The transmission lines included within the scope of license renewal are discussed in Section 3.2. Three additional protected species were identified as potentially present along the transmission lines corridor. Federally protected species not already listed above are the black-footed ferret, the whooping crane, and the Salt Creek tiger beetle. All three are listed as endangered. The western prairie fringed orchid, mentioned above, is also listed by the USFWS as being present along the transmission line corridors in certain counties [USFWS 2007c]

A sharp decline in pallid sturgeon observations occurred after the 1960s and over the entire range of the species, especially from the Gavins Point Dam to the Missouri River's headwaters. This decline continues and is largely a result of habitat modification, either directly (e.g., reduction of habitat diversity) or indirectly (e.g., alteration of food sources).

Commercial fishing of a closely related species, the shovelnose sturgeon, may also negatively impact the pallid sturgeon, and this potential threat continues as the value of sturgeon roe increases. Over the entire species' range, an average of 50 observations per year of the pallid sturgeon occurred in the 1960s with a subsequent decreasing trend. An average of 21 observations per year was noted in the 1970s and an average of seven observations per year in the 1980s [USNRC 2002, p. 5].

Critical habitat has not been defined for the pallid sturgeon either in the vicinity of CNS or elsewhere in the Missouri River [USFWS 2007d]. Recent pallid sturgeon recovery efforts include augmentation of its populations by releases of hatchery-reared fish. Despite such efforts, pallid sturgeon observations remain infrequent or rare. Similarly, evidence of successful reproduction and recruitment throughout its range is rare. However, recent collections of three pallid sturgeon larvae from the lower Missouri River indicate that suitable spawning habitat and hydrologic conditions remain in the lower Missouri River below Gavins Point Dam or in the Platte River. Although collection efforts in the Missouri River have yielded these few pallid sturgeon larvae, their relative number to other species of collected larvae suggest that spawning success and larval abundance for the pallid sturgeon remains low [USNRC 2002, pp. 6-7].

The USFWS has identified four principal reasons for decline of the pallid sturgeon:

- Habitat loss: destruction and alteration of habitats by modification of the river system are believed to be the primary causes of decline in reproduction, growth, and survival of pallid sturgeon.

- Commercial harvest: sturgeon have historically been harvested, especially the lake sturgeon and pallid sturgeon, for their eggs, historically sold as caviar. Sturgeon may continue to be harvested as a by-catch of commercial fishing.

- Pollution/contaminants: PCBs, cadmium, mercury, and selenium have been detected at elevated concentrations in tissue of sturgeon, along with detectable concentrations of chlordane, DDE, DDT, and dieldrin.

- Hybridization: pallid/shovelnose sturgeon hybrids have been identified in the lower Missouri River. Hybrids may represent a high proportion of remaining sturgeon stocks. [USFWS 1993, p. 10-15]

Overall, these conditions result in unfavorable habitat for the pallid sturgeon. With the current overall water management regime of the Missouri River (i.e., without increased flows and with warmer water temperatures, between June and July), it is believed that the cues for spawning are no longer present [USNRC 2002, p. 7].

Severe alteration of the Missouri River ecosystem has resulted in the near elimination of the pallid sturgeon from the river. Despite more recent habitat restoration projects and population augmentation efforts, the pallid sturgeon continues to decline and occurrences of this fish remain rare. [USNRC 2002, Section IV.A] The lack of suitable habitat in the vicinity of the CNS site as a result of previous habitat modification and the rare documented occurrence of the pallid sturgeon, including larvae, indicate a low potential for impingement or entrainment with the cooling water system associated with CNS [USFWS 2000].

Pallid sturgeon have been detected near the mouth of the Platte River (RM 595) (approximately 63 miles upstream of CNS) [USNRC 2002, Section IV.A]. Although a concern was raised regarding thermal impacts on pallid sturgeon during NRC's formal consultation process with the USFWS regarding the renewal of the FCS OL, the CNS thermal discharge is located downstream of the Platte River; and due to the demersal and adhesive characteristic of sturgeon eggs, CNS would not be expected to have an adverse impact on pallid sturgeon eggs due to entrainment.

The route of the transmission line included within the scope of license renewal are shown in Figure 3.2-6. The interior least tern, piping plover, black-footed ferret, and whooping crane are known to be potentially present near the western terminus of the transmission lines near Grand Island in Hamilton County. The western prairie fringed orchid, mentioned above, is also listed by the USFWS as being present along the transmission line corridor in Hall, Lancaster, Otoe, Selene, and Seward counties. [USFWS 2007c]

Discussion of the piping plover and the interior least tern is presented in Section 2.5. Piping plovers and interior least terns are residents along the Missouri River and the Platte River. Habitat requirements for piping plover breeding include large expanses of gravel bars and sparsely vegetated river banks and islands, which are not found at CNS. Threats to piping plovers include habitat modification/loss due to channelization, nest disturbance, and predation. Critical habitat has been designated for the piping plover along the Nebraska-South Dakota border, but does not include the section of the Missouri River adjacent to CNS or Nebraska counties along the transmission line corridors. Interior least tern habitat requirements are dry, exposed sandbars and favorable river flows that support a forage fish supply and isolate the sandbars from the riverbanks. Characteristic riverine nesting sites are dry, flat, sparsely vegetated sand and gravel bars within a wide, unobstructed, water-filled river channel. Both the piping plover and the interior least tern may potentially be found near the transmission lines in scope for license renewal where the lines are located near the Platte River.

The Indiana bat is discussed in Section 2.5. Indiana bats hibernate during winter in caves or, occasionally, in abandoned mines. For hibernation, they require cool, humid caves with stable temperatures, under 50°F, but above freezing. Very few caves within the range of the species have these conditions. After hibernation, Indiana bats migrate to their summer habitat in wooded areas where they usually roost under loose tree bark on dead or dying trees. During summer, males roost alone or in small groups, while females roost in larger groups of up to 100 bats or more. Indiana bats also forage in or along the edges of forested areas. Indiana bats are found over most of the eastern half of the United States. The USFWS estimates a Missouri Indiana bat population of approximately 65,000. [USFWS 2006] While the Indiana bat is included in the USFWS' Missouri endangered species list, it is not included on the USFWS Nebraska list. [USFWS 2007c] The Indiana bat is not believed to be present on CNS property or in Nemaha County.

The western prairie fringed orchid is discussed in Section 2.5. The orchid is a perennial belonging to the family Orchidaceae. The western prairie fringed orchid is distributed throughout lowland, damp tallgrass prairies in Iowa, Kansas, Minnesota, Missouri, Nebraska, and North Dakota [USFWS 1992]. However, the western prairie fringed orchid is not indicated to be present in Nemaha County, Nebraska [USFWS 2007c]. Habitat modification by loss or conversion of native prairie, woody encroachment, and fire suppression are some causes of its decline [USFWS 1992].

Whooping cranes do not nest or winter in Nebraska, but their migration brings them to Nebraska's Platte River valley twice a year, usually in April and October. Whooping cranes do not stage during migration, rather they stop briefly, often only overnight, before continuing their journey. The likelihood of spotting one in Nebraska is small. However, the Big Bend reach of the Platte River (from Overton to Chapman, Nebraska) boasts the greatest number of spring sightings than any other location along their migration corridor while the Rainwater Basin area is a good place to find them in the fall. [NGPC 2008a] The Rainwater Basin area stretches from Seward County west of Lincoln to Gosper County near Lexington, spanning 17 counties and nearly 4,200 square miles. The Rainwater Basin contains wetlands used by thousands of waterfowl each year in the Central Flyway on their migratory routes north to Canada and south to the Gulf Coast area. [NGPC 2008b] The chances of encountering a whooping crane along the transmission corridor would be most likely near the Platte River or one of the wetlands.

A segment of the line shown in Figure 3.2-6 passes through southern Lancaster County. The Salt Creek tiger beetle is identified in USFWS databases as being potentially present in Lancaster County, but its habitat is identified only in the northern portions of the county. Brief characteristics of these and other species were presented in the environmental interfaces in Section 2.5 of this ER.

The Salt Creek tiger beetle is confined to eastern Nebraska saline wetlands and associated streams and tributaries of Salt Creek in the northern third of Lancaster County. It is found along mud banks of streams and seeps and in association with saline wetlands and exposed mud flats of saline wetlands. They have adapted to brief periods of high water inundation and highly saline conditions. [USFWS 2008] Portions of the Salt Creek watershed has been proposed for Critical

Habitat designation by the USFWS. The proposed critical habitat is in an area of approximately 1,795 acres in northern Lancaster County. [72FR238] None of the propose critical habitat for the Salt Creek tiger beetle is near the in-scope transmission lines for CNS.

Although a portion of NPPD's lines pass through Lancaster County, Nebraska, the lines do not pass through this proposed critical habitat. NPPD's in-scope transmission lines are located more than 20 miles from the closest of the proposed critical habitat areas. NPPD personnel have not had any sightings of the beetles within its corridor right-of-ways. This is due to the lines being outside the beetle's current range and habitat being near the streams of the Salt Creek watershed north of Lincoln.

All of NPPD operations, including those necessary for transmission line maintenance and operation, are conducted in accordance with NPPD policies and procedures that require special precautions related to operations involving threatened and endangered species and avian protection [NPPD 2007a; NPPD 2007b].

NPPD is not aware of any potential concerns regarding threatened or endangered species which could occur due to the site or transmission line operations. Maintenance activities necessary to support license renewal would be limited to previously disturbed areas on-site and no additional land disturbance is anticipated in support of license renewal. In addition there are no plans to alter plant operations during the license renewal term which would affect threatened and endangered species. Transmission line maintenance is conducted in accordance with NPPD policies that are protective of threatened and endangered species.

NPPD's review identified no state-listed or federal-listed critical or important habitats in the vicinity of the site or along the associated transmission lines. In addition, NPPD's review identified no adverse impacts to state-listed or federal-listed threatened or endangered species that would occur as a result of license renewal. The NGPC and the Missouri Department of Conservation (MDC) were contacted for information regarding state listed threatened and endangered species and unique natural areas in the vicinity of the site (see Attachment A). However, as of the time of the submittal of this ER, neither agency had responded to this request for information.

4.10.6 Conclusion

There are no critical habitats for threatened or endangered species or species of concern within the vicinity of CNS or NPPD's transmission lines that are within scope of license renewal. The continued operation of the site and transmission lines will not adversely impact any federally listed species that may exist on or pass through the NPPD facilities that are considered for license renewal. Any maintenance activities necessary to support continued plant or line operations during the license renewal period would be limited to previously disturbed areas on site and no additional land disturbance is anticipated in support of license renewal and there are no plans to alter plant or line operations that would affect the aquatic or terrestrial ecology. In addition, NPPD has procedural controls in place to ensure that threatened and endangered terrestrial species are adequately protected, if present, during operations and project planning [CNS 2007; NPPD 2007a]. Therefore, NPPD concludes that impacts to threatened or endangered species from license renewal would be SMALL and do not warrant additional mitigation measures.

4.11 Air Quality During Refurbishment (Nonattainment and Maintenance Areas)

4.11.1 Description of Issue

Air quality during refurbishment (nonattainment and maintenance areas).

4.11.2 Findings from Table B-1, Appendix B to Subpart A

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 number of workers expected to be employed during the outage. See 10 CFR 51.53(c)(3)(ii)(F).

4.11.3 Requirement [10 CFR 51.53(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.

4.11.4 Analysis of Environmental Impact

As discussed in Section 2.11, the 50-mile region surrounding CNS has not been designated as a nonattainment area (40 CFR 81.333) for any priority pollutant standard (40 CFR 50.10) or criteria pollutants (40 CFR 50.7) promulgated by USEPA. As discussed in Section 3.3, NPPD has no plans for refurbishment at CNS during the license renewal period. Therefore, this issue is not applicable to the site and further analysis is not required.

4.12 Impact on Public Health of Microbiological Organisms

4.12.1 Description of Issue

Microbiological organisms (public health) (plants using lakes or canals, or cooling towers, or cooling ponds that discharge to a small river).

4.12.2 Finding from Table B-1, Appendix B to Subpart A

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 10 CFR 51.53(c)(3)(ii)(G).

4.12.3 Requirement [10 CFR 51.53(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 x 10^{12} ft^3/year (9 x 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.

4.12.4 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 a 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 [USNRC 1996, Section 4.3.6].

4.12.5 Analysis of Environmental Impact

Because the average Missouri River flow in the vicinity of CNS is approximately 1.2 x 10^{12} cubic feet per year, the NRC considers it a small river, making this issue applicable to CNS. The Missouri River in the vicinity of the plant is confined to a channelized bed with a current velocity that is very high (0.6 fps to 8.3 fps.) with a modal, or most frequently observed, velocity of between 3-4 fps [NPPD 1971, p. C-2-1]. The channel bottom is well-scoured, and the temperature of the water is nearly constant from top to bottom [NPPD 1971, p. C-2-1]. Water flow is regulated to meet the needs of barge traffic, flood control, irrigation, and threatened and endangered species habitat according to the Missouri River Master Manual. Recreational use (i.e., swimming, boating, fishing) may occur and sampling in the river may be performed, creating the potential for human exposure.

Thermophilic bacteria generally occur at temperatures of 77°F to 178°F, with maximum growth at 122°F to 140°F [OPPD, Section 4.8]. Studies suggest that a temperature range of 30°C to 40°C (86°F to 104°F) is associated with increased occurrence of *Naegleria fowleri* in thermally elevated environments [Huizinga and McLaughlin]. The ambient temperatures of the Missouri River near CNS vary from freezing (approximately 32°F) in the winter to 87–89°F in the summer. The period of higher ambient river temperatures typically occurs for a short period (two to four weeks) in late summer. [NPPD 2005] Therefore, ambient river conditions generally would not support the thermophilic organisms of concern.

Based on CNS discharge monitoring data submitted to the NDEQ for the period January 2003 to September 2005, the mean monthly average temperature of the thermal discharge at the outfall was 75.7°F, and the maximum daily temperature was 109.2°F. The maximum temperatures, however, occur during periodic short-term condenser backwash lasting no longer than two hours. Monthly average discharge temperatures at or above 95°F occur only during July and August. The highest monthly average discharge temperature was 101.7°F in August 2003 and 101.3°F in July 2005. [NPPD 2005] Based on the studies cited above related to favorable conditions, organisms inhabiting sediments or other substrates on the river bottom or immersed banks that are exposed to the highest temperatures would only be likely in a small zone near the plant (less than 5,000 feet downstream from the outfall) due to the mixing characteristics of the discharge in the Missouri River.

The Missouri River in the vicinity of CNS generally offers poor conditions for supporting populations of thermophilic organisms. Ambient river temperatures during much of the year are not ideal for thermophilic organism occurrence, where even in the thermal mixing zone river temperatures fall below 77°F from October to April [NPPD 2005].

NPPD is unaware of cases of *Naegleria fowleri* infection or other thermophilic bacterial infection along the channelized section of the river. According to the Nebraska Department of Health, no cases of any water-borne illness related to contact with the Missouri River have been reported [NDHHS]. In addition, due to the low probability of swimming and diving activities occurring in the river near CNS, the potential for exposure to the microorganism is low.

4.12.6 Conclusion

NPPD contacted the Nebraska Department of Public Health and Human Services and the Missouri Department of Public Safety regarding CNS license renewal and the potential of thermophilic organisms resulting from CNS. There are no historical records of any *Naegleria fowleri* infections from the Missouri River in the CNS vicinity. Based on the evaluation presented above, NPPD concludes that impacts on public health from thermophilic microbiological organisms are not likely to occur as a result of license renewal. Based on the limited conditions within the section of the Missouri River conducive to thermophilic organism growth (relatively high flow and the small segment of the river with elevated temperatures favorable to organism proliferation), and the lack of reported problems related to thermophilic organism infection, the impact on public health of microbiological organisms from continued operation of CNS in the license renewal period is SMALL, and further mitigation is unwarranted.

4.13 Electromagnetic Fields—Acute Effects

4.13.1 Description of Issue

Electromagnetic fields, acute effects (electric shock)

4.13.2 Findings from Table B-1, Subpart A, Appendix A

SMALL, MODERATE, or LARGE. Electric shock resulting from direct access to energized conductors or from induced charges in metallic structures has not been a problem at most operating plants and generally is 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. See 10 CFR 51.53(c)(3)(ii)(H).

4.13.3 Requirements [10 CFR 51.53(c)3)(ii)(H)]

If the applicant's transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electric Safety Code (NESC) 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.

4.13.4 Background

The transmission line of concern is that between the plant switchyard 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 OLs 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.

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. [USNRC 1996, Sections 4.5.4 and 4.5.4.1]

4.13.5 Analysis of Environmental Impact

<u>Background</u>

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

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

In 1977, the NESC adopted a provision that describes an additional criterion to establish minimum vertical clearances to the ground for electric lines having voltages exceeding 98 kV alternating current to ground. The clearance must limit the steady-state induced current to 5 milliamperes if the largest anticipated truck, vehicle, or equipment were short-circuited to ground. By way of comparison, the setting of ground fault circuit interrupters used in residential wiring (special breakers for outside circuits or those with outlets around water pipes) is 4 to 6 milliamperes.

NPPD owns and operates the transmission lines constructed for purposes of connecting CNS to the transmission system (see Figure 3.2-6). The transmission lines that were considered in scope for license renewal (see Section 3.2.2) include the following:

- NPPD TL3501 (345 kV energized in August 1969) is 63.6 miles in length and spans from CNS to the Mark T. Moore substation near Hallam, Nebraska;

- NPPD TL3502 (345 kV energized in July 1970) is 82.6 miles in length and spans from the Mark T. Moore substation to the Grand Island substation.

- NPPD TL3504 was energized as a 345 kV line in July 1970 and is 0.64 miles in length and spans from CNS to the center of the Missouri River. This line connects with a Mid-America Energy owned transmission line that spans to Booneville, Iowa.

- OPPD Line "60" was already planned when CNS was constructed. This transmission line consists of three segments. OPPD owns and operates two segments of the transmission lines from Omaha, Nebraska to the CNS switchyard and from the CNS switchyard to Rulo, Nebraska, while Aquila owns and operates one segment of the transmission line from Rulo, Nebraska to St. Joseph, Missouri. The transmission line from the CNS switchyard to Omaha, Nebraska is 25.74 miles in length and the line from the CNS switchyard to St Joseph, Missouri is 64.8 miles in length. However as already stated, these transmission line segments owned and operated by OPPD and Aquila were not constructed for the purpose of connecting CNS to the transmission systems. Therefore, the only line within scope of license renewal is from the plant to the switchyard that connects into this system.

Analysis of Impacts

NPPD transmission lines were constructed in accordance with applicable NESC standards in effect at the time of their construction, but prior to the 1977 NESC revision. NPPD has maintained the lines in accordance with pre-1977 NESC standards, but is not required under the standards or the applicable administrative authority in Nebraska to modify those lines specifically to meet subsequent induced current standards.

However, NPPD has developed a process to review its transmission line clearances to determine compliance with post-1977 NESC criteria. As part of its license renewal evaluations, NPPD reviewed the in-scope transmission line clearances and configurations and the current NESC criteria for induced current shock potential. Based on review of transmission line construction drawings and the on-going Transmission Line Assessment Program (TLAP), NPPD has determined that the transmission lines meet the NESC code as it relates to induced shock potential at all road and railroad crossings, plus the Missouri River crossing.

NPPD implemented the TLAP program in the late 1980s which was established to provide guidelines and standards for use in reviewing the condition of NPPD transmission lines. As stated in the TLAP document, "the primary purpose of the assessment guidelines is to document existing conditions so that appropriate action can be taken to help assure the continued reliability of the NPPD transmission system as it ages, and to maintain a high level of safety to both the public and NPPD personnel." [NPPD 2007d].

NPPD Line Operations personnel conduct ground (walking) patrols of each line annually, and each line is also flown (patrolled by aircraft) six times per year, as discussed in Section 3.2.2. Clearance measurements (i.e., ground clearances in each span, as well as critical crossing clearances to objects such as other power lines, irrigation systems, etc.), are an integral part of line evaluations performed in conjunction with NPPD's TLAP. In addition, both the annual ground patrol report and aerial patrol reports can trigger a clearance check if a concern is reported by Line Operations. To ensure corrective actions are taken to address line concerns, NPPD has implemented an integrated Work Management System to facilitate processing of Maintenance Notifications.

NPPD has also developed a review process to determine compliance with the NESC induced current standard. This process includes electrical design parameters, such as transmission design voltages, line capacity, conductor type and configuration, spacing between phases, minimum conductor clearances to ground, maximum predicted electrical field strength(s), temperature, etc. Based on its review process, NPPD has developed the minimum clearances provided in Table 4.13-1 that assure compliance with the NESC standards. [NPPD 1994]

Table 4.13-1
Induced Current Transmission Line Clearances

Crossing Type	Minimum Vertical Clearance (ft) 345 kV Circuit
Railroads[1]	36
Highways, Roads	37
Cultivating, grazing land, Irrigation equipment less than 19 ft.	33
Irrigation equipment greater than 19 ft.(vertical clearance equipment)	**[2]

Table 4.13-1 (Continued)
Induced Current Transmission Line Clearances

Crossing Type	Minimum Vertical Clearance (ft) 345 kV Circuit
Communication wires Supply conductors 115 kV and below Span wires Shield wires Supporting structures of another line	15
Water areas not suitable for sail boating[3]	33
Wells	50
Building, Grain Bins, Signs, Radio and Television antennas	**[4]

1. Required clearance over railroad shall be verified with the requirements of the individual railroad companies.
2. For irrigation equipment greater than 19 ft., the ground clearance required in the cultivating and grazing category shall be used and shall be increased by one foot for each foot in height the irrigation equipment is above 19 ft. (Example: Ground clearance for a 345 kV circuit above a 21 foot piece of irrigation equipment is 35 ft.)
3. This clearance specified exceeds the NESC required clearance.
4. Any facilities (buildings, grain bins, etc.) located within the right-of-way shall be relocated.

Reference: NPPD 1994

NPPD has reviewed the segments along the NPPD TL3501 transmission lines from CNS to the Mark T. Moore substation, and the NPPD TL3502 lines from the Mark T. Moore substation to the Grand Island substation, and has determined that the minimum clearances are met for all road and railroad crossings. In some cases, the clearances exceed the minimum criteria by up to 20 feet. In addition, based on engineering drawings, the TL3504 lines crossing the Missouri River are more than 90 feet at the line structures and easily meet the 33 feet clearance for barge and other river traffic. Plant lines to the switchyard also meet the NESC required minimum clearances.

Future land uses along the transmission line corridors are anticipated to remain much the same as exists today, and are not expected to change significantly during the license renewal term. As discussed above and in Section 3.2.2, NPPD has procedures in place to provide frequent review of land use, vegetation management and maintenance, and line maintenance issues. These procedures provide adequate review of changes to conditions along the transmission line corridors, while at the same time requiring appropriate review for any line structure modifications. NPPD procedures assure that any line refurbishment or replacement of line structures will meet the NESC induced current shock standards.

4.13.6 Conclusion

Lines that connect CNS to the transmission grid meet the applicable vertical clearance requirements specified by the NESC for limiting the steady-state induced current to 5 mA. Therefore, impacts due to the electrical shock potential for these lines is of SMALL significance and does not warrant further assessment or mitigation measures.

4.14 Housing Impacts

4.14.1 Description of Issue

Housing Impacts.

4.14.2 Findings from Table B-1, Appendix B to Subpart A

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 10 CFR 51.53(c)(3)(ii)(I).

4.14.3 Requirement [10 CFR 51.53(c)(3)(ii)(I)]

An assessment of the impact of the proposed action on housing availability...(impacts from refurbishment activities only) within the vicinity of the plant must be provided.

4.14.4 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. [USNRC 1996, Section 3.7.2]

4.14.5 Analysis of Environmental Impact

Supplement 1 to Regulatory Guide 4.2, provides the following guidance.

Section 4.14.1 states, "If there will be no refurbishment or if refurbishment involves no additional workers then there will be no impact on housing and no further analysis is required."

Section 4.14.2 states, "If additional workers are not anticipated there will be no impact on housing and no further analysis is required."

As of January 2008 the site had approximately 750 full time workers (NPPD employees and baseline contractors) during normal plant operations. The majority of these employees live within a four-county area (Nemaha, Richardson, Otoe, and Atchison) surrounding the plant. As discussed in Section 2.9, there has been minimal growth in the housing market since 1990. In addition, vacancy rates have generally remained about the same and the total number of new housing units has kept pace with the low growth in the area population.

As noted in Section 3.3, there are no refurbishment activities required for license renewal at the CNS site. Additionally, NPPD does not anticipate a need for additional full-time workers during the license renewal period.

4.14.6 Conclusion

Although Otoe County has adopted land use planning regulations such as zoning to manage future growth and development (see Section 2.8.2), NPPD concludes that the impact on housing from the continued operation of the site will be SMALL and further mitigation is not warranted. This conclusion is based on the following:

- CNS is located in a low population area (see Section 2.6.1).
- There are no refurbishment activities required for license renewal at the site (see Section 3.3).
- NPPD does not anticipate an increase in employment during the license renewal period (see Section 3.5).
- Vacancy rates and new housing units have kept pace with the low growth in the area population (see Section 2.9).
- Growth control measures at the county level exist only in one county (Otoe) in the four-county region.
- The number of the site employees will continue to be a small percentage of the population in the adjacent counties during the period of the renewed license (see Sections 2.6.1 and 3.5).

4.15 Public Utilities; Public Water Supply Availability

4.15.1 Description of Issue

Public Services (public utilities).

4.15.2 Findings from Table B-1, Appendix B to Subpart A

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 10 CFR 51.53(c)(3)(ii)(I).

4.15.3 Requirement [10 CFR 51.53(c)(3)(ii)(I)]

The applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.

4.15.4 Background

Impacts on public utility services are considered small if little or no change occurs in the utility's 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 [USNRC 1996, Section 3.7.4.5].

4.15.5 Analysis of Environmental Impact

As discussed in Section 3.3, there are no refurbishment activities required for the renewal of the CNS OL. In addition, NPPD does not anticipate a need for additional workers during the license renewal period. Therefore, there will be no impact to public utilities from refurbishment activities or additional plant workers.

CNS and nearby groundwater users are discussed in Section 2.3. Most of the public water systems in the vicinity of CNS utilize groundwater wells. As noted in Section 2.10.1, the CNS site does not utilize a public water system to supply water for the plant potable, cooling, or process water systems. Instead, the site relies on groundwater and surface water from the Missouri River, and no significant change in this design and operational feature of CNS is anticipated. The impact of CNS groundwater utilization is discussed in Section 4.5. As noted in Section 4.5, groundwater utilization at CNS is not expected to result in adverse impacts to nearby groundwater users.

Table 2.10-1 provides details on the major community water suppliers in the area surrounding the plant site. For all systems, the current system capacities are above the average daily demand on the respective water systems. Most systems report having groundwater available for industrial uses and no significant changes in the water table during the past five years. Therefore, plant operations during the license renewal period are not projected to cause a noticeable effect on the local water supply. Because no site-related population increases will occur, there will be no indirect impacts to any public water systems in the area.

4.15.6 Conclusion

Because CNS obtains all of its water from the Missouri River and groundwater wells, public water systems near the site will remain unaffected. As noted in Section 3.3, there are no refurbishment activities required for CNS license renewal. NPPD also does not anticipate a need for additional workers during the license renewal period. Therefore, impacts to public water supplies will continue to be SMALL during the CNS OL renewal period. Further consideration of mitigation measures is not warranted.

4.16 Education Impacts from Refurbishment

4.16.1 Description of Issue

Public Services (effects of refurbishment activities upon local educational system).

4.16.2 Findings from Table B-1, Appendix B to Subpart A

SMALL or MODERATE. Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors. See 10 CFR 51.53(c)(3)(ii)(I).

4.16.3 Requirement [10 CFR 51.53(c)(3)(ii)(I)]

An assessment of the impact of the proposed action on … public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided.

4.16.4 Analysis of Environmental Impact

As noted in Section 3.3, there are no refurbishment activities required for CNS license renewal. Therefore this issue is not applicable to the site and further analysis is not required.

4.17 Offsite Land Use—Refurbishment

4.17.1 Description of Issue

Offsite Land Use (effects of refurbishment activities).

4.17.2 Findings from Table B-1, Appendix B to Subpart A

SMALL or MODERATE. Impacts may be of moderate significance at plants in low population areas. See 10 CFR 51.53(c)(3)(ii)(I).

4.17.3 Requirement [10 CFR 51.53(c)(3)(ii)(I)]

An assessment of the impact of the proposed action on… land-use…(impacts from refurbishment activities only) within the vicinity of the plant must be provided.

4.17.4 Analysis of Environmental Impact

As noted in Section 3.3, there are no refurbishment activities required for CNS license renewal. Therefore, there will be no impacts from refurbishment activities and further analysis is not required.

4.18 Offsite Land Use—License Renewal Term

4.18.1 Description of Issue

Offsite Land Use (effects of license renewal).

4.18.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Significant changes in land-use may be associated with population and tax revenue changes resulting from license renewal. See 10 CFR 51.53(c)(3)(ii)(I).

4.18.3 Requirement [10 CFR 51.53(c)(3)(ii)(I)]

An assessment of the impact of the proposed action on …land-use…(impacts from refurbishment activities only) within the vicinity of the plant must be provided.

4.18.4 Background

During the license renewal term, new land use impacts could result from plant-related population growth or from the use of tax payments from the plant by local government to provide public services that encourage development.

However, as noted in Regulatory Guide 4.2, Section 4.17.2, Table B-1 of 10 CFR Part 51 partially misstates the conclusion reached in Section 4.7.4.2 of NUREG-1437. NUREG-1437, Section

4.7.4.2 concludes that "population-driven land use changes during the license renewal term at all nuclear plants will be small." Regulatory Guide 4.2 further states that "Until Table B-1 is changed, applicants only need cite NUREG-1437 to address population-induced land-use change during the license renewal term."

The assessment of new tax-driven land use impacts in the GEIS considered the following:

(1) the size of the plant's tax payments relative to the community's total revenues,

(2) the nature of the community's existing land use pattern, and

(3) the extent to which the community already has public services in place to support and guide development.

In general, if the plant's tax payments are projected to be small relative to the community's total revenue, new tax-driven land use changes during the plant's license renewal term would be small, especially where the community has pre-established patterns of development and has provided adequate public services to support and guide development. If the plant's tax payments were projected to be medium to large relative to the community's total revenue, new tax-driven land use changes would be moderate.

This is most likely to be true where the community has no pre-established patterns of development (i.e., land use plans or controls) or has not provided adequate public services to support and guide development in the past, especially infrastructure that would allow industrial development. If the plant's tax payments are projected to be a dominant source of the community's total revenue, new tax-driven land use changes would be large. This would be especially true where the community has no pre-established pattern of development or has not provided adequate public services to support and guide development in the past.

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. In addition, 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 [USNRC 1996, Section 4.7.4.2].

4.18.5 Analysis of Environmental Impact

The environmental impacts from this issue are from population-driven land use changes, tax-driven land use changes, and the potential effects on land values.

4.18.5.1 Population-Driven Land Use Changes

NPPD agrees with the GEIS conclusion that new population-driven land use changes at the site during the license renewal term will be SMALL [USNRC 1996, Section 4.7.4.2]. NPPD does not anticipate that additional workers will be employed at the site during the license renewal period. Therefore, there will be no adverse impact resulting from population-driven land use changes associated with license renewal.

4.18.5.2 Tax-Driven Land Use Changes

As discussed in Section 2.7, NPPD is exempt from paying state occupational, personal property, and real estate taxes. Instead, as mandated in the Nebraska Constitution, NPPD makes payments in lieu of taxes each year to the municipalities and 91 Nebraska counties in which NPPD sold power. The in-lieu payments are based upon the gross revenues NPPD receives from electricity sales from within the applicable counties, regardless of where the power is generated, and are not anticipated to change significantly during the license renewal period. The magnitude of the in-lieu payments relative to the receiving county's total revenues is not relevant in assessing new tax driven land-use impacts since NPPD will still be responsible for producing and distributing electricity (and the resulting in-lieu payments) even if the license for CNS is not renewed. Therefore, NPPD concludes that impacts would be SMALL since there would be no tax-driven land-use impacts related to license renewal activities at CNS.

4.18.5.3 Land Value Land Use Changes

As discussed in the GEIS, land use changes as a result of a nuclear power plant not having its license renewed could result in SMALL to MODERATE impacts on the surrounding community. With the loss of jobs and taxes and an increase of housing vacancies and perhaps even population as the former employees left the area to take employment elsewhere, this would have a noticeable effect on the local economy and in turn on the local land use values. Therefore, NPPD concludes that impacts would be SMALL to the local community related to license renewal activities at CNS, as there would be no adverse impact from the continued operation of CNS.

4.18.6 Conclusion

NPPD agrees with the GEIS conclusion that new population-driven land use changes at the site during the license renewal term would be SMALL. NPPD does not anticipate that additional workers will be employed at the site during the license renewal period. Therefore, there will be no adverse impact to the offsite land use from additional plant workers and mitigation measures are not warranted.

In addition, the impact to tax-driven land use changes would be SMALL since the magnitude of the in-lieu payments relative to the receiving county's total revenues is not relevant since NPPD will still be responsible for producing and distributing electricity (and the resulting in-lieu payments) even if the license for CNS is not renewed. Therefore, mitigation measures are not warranted.

In addition, the impact to offsite land values would be SMALL as the continued operation of CNS has no adverse effect on the land values in the communities surrounding CNS.

4.19 Transportation

4.19.1 Description of Issue

Public services, Transportation

4.19.2 Findings from Table B-1, Appendix B to Subpart A

SMALL, MODERATE, or LARGE. Transportation impacts (level of service) of highway traffic generated during the term of the renewed license are generally expected to be of small significance. See 10 CFR 51.53(c)(3)(ii)(J).

4.19.3 Requirement [10 CFR 51.53(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.

4.19.4 Background

Transportation impacts would continue to be of 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 forecasted, 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. [USNRC 1996, Section 4.7.3.2]

4.19.5 Analysis of Environmental Impact

As there are no refurbishment activities required for the license renewal period and no expected increase in total number of employees that will be on-site at CNS during the same period, impacts to transportation during the license renewal term would be similar to those experienced during current operations and would be dictated by the workers currently involved in plant operations. As of January 2008, the site employed approximately 750 workers during normal operations (see Section 3.5). An additional 700–900 workers may also be present at the facility during refueling outages.

As indicated in Section 2.6.1, CNS is located in a low density sparsely populated region of rural southeast Nebraska. The vicinity of CNS is bisected by the Missouri River, with the CNS site itself straddling the river. However, the plant facilities and station operations are centered on the Nebraska side of the river. Traffic volumes for the area were obtained from the NDOR and the MODOT (see Table 2.10-2). The heaviest volumes of traffic were recorded on US Highway 136 at Brownville, Nebraska, approximately 2.5 miles north of CNS, on US Highway 136 west of

Interstate 29 on the Missouri side of the river, and on Interstate 29 just north of US Highway 136 in Missouri.

Section 2.10.2 further discusses the LOS for traffic routes serving CNS for workers and shipments. Regulatory Guide 4.2, Supplement 1, "Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses," Section 4.18 states, "LOS A and B are associated with small impacts because operation of individual users is not substantially affected by the presence of other users. At this level, no delays occur and no improvements are needed". US Highway 136 in the vicinity of CNS carries an LOS designation of Level B. All other roads in the vicinity carry an LOS Level A designation.

Based on available information, the Nebraska and Missouri traffic counts did not include temporary traffic increases due to annual outages at the site. The site generally schedules its outages in the spring, and may have an average of approximately 700 to 900 temporary workers on-site for the duration of the outage. Peak traffic during outages would be expected to be leaving and entering the site from 5:30 to 7:00 a.m. and from 6:30 to 8:00 p.m. Compensatory measures, such as staggered shift starting and quitting times, are not needed, but occur to facilitate security checkpoint processing. This helps ensure that the increased traffic flow during outages will continue to maintain a reasonable level of service.

4.19.6 Conclusion

As noted in Section 3.3, there are no refurbishment activities required for CNS license renewal and no expected increases in the total number of employees that will be on-site during this same period. Although LOS road designations in the vicinity of CNS are adequate, compensating measures, such as staggered shift starting and ending times, are taken by the site to account for the increased traffic flow during outages to maintain a reasonable level of service. Therefore, impacts on local traffic will be SMALL and further mitigation measures are not warranted.

4.20 Historic and Archaeological Resources

4.20.1 Description of Issue

Historic and Archaeological Resources

4.20.2 Finding from Table B-1, Appendix B to Subpart A

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 NHPA requires the federal agency to consult with the SHPO to determine whether there are properties present that require protection. See 10 CFR 51.53 (c)(3)(ii)(K).

4.20.3 Requirement [10 CFR 51.53(c)(3)(ii)(K)]

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

4.20.4 Background

It is unlikely that moderate or large impacts to historic resources would occur at any site unless new facilities or service roads are constructed or new transmission lines are established.

The identification of historic resources and determination of possible impacts to them must be done on a site-specific basis through consultation with the SHPO. The site-specific nature of historic resources and the mandatory NHPA consultation process mean that the significance of impacts to historic resources and the appropriate mitigation measures to address those impacts cannot be determined generically. [USNRC 1996, Section 3.7.7]

4.20.5 Analysis of Environmental Impact

As discussed in Section 3.3, there are no refurbishment activities required for CNS license renewal. Therefore, no further analysis is required with respect to refurbishment activities.

No aboveground prehistoric or historic archaeological sites eligible for listing or listed on the NRHP or the Nebraska and Missouri state registers are located on the site. In addition, NPPD has no plans to alter its operations on the site, expand existing facilities, or disturb additional land in support of license renewal. Therefore, renewal of the license would result in no adverse impacts to any archaeological sites.

CNS is located on the west bank of the Missouri River at RM 532.5, referred to by the USACE as the Lower Brownville Bend. Facilities for CNS are located on approximately 55 acres of the site, which consists of 1,359 acres, which is inclusive of 239 acres on the opposite bank (east) of the Missouri River in Atchinson County, Missouri. With the exception of the 55-acre portion upon which the station sets, much of the station site area continues to be dedicated to agricultural crop production. In recent historic time, USACE levees have been constructed to control flooding, which may also have disturbed prehistoric and historic resources that may have been present. The 239 acres on the east side of the Missouri River in Atchison County, Missouri is primarily within a wooded and agricultural belt along the river.

Although historic farmsteads have been identified as having existed on CNS property, no aboveground historic sites eligible for listing or listed on the NRHP or Nebraska or Missouri state registers are located within the current operational areas of the site. In addition, NPPD has no plans to alter its operations on the 1,359-acre site, expand existing facilities, or disturb additional land in support of license renewal.

The area within a 6-mile radius of the site consisting of land primarily within Nemaha County, Nebraska and Atchison County, Missouri, may be archaeologically sensitive, which means that NRHP-eligible and listed archaeological sites (prehistoric and historic) are present. The historic sites have been catalogued and listed on the state registries, or recorded for potential listing (see Table 2.12-1). Prehistoric sites have also been recorded as well, and are summarized in Table 2.12-2. For those yet unidentified archaeological sites, adverse impacts would only occur as a result of soil intrusive activities. NPPD has no plans to conduct such soil intrusive activities at any location outside of the site boundaries or outside its transmission line corridors associated with connecting CNS to the transmission grid under a renewed license. Therefore, renewal of the license would result in no adverse impacts to archaeological sites located outside of the site or associated transmission lines.

The Phase 1A Survey, discussed in Section 2.12 of this ER identified that the site has been repeatedly flooded, historically, and farmed during present and historic times. Although two locations of lithic scatter were potentially identified during the Phase 1A Survey, no significant cultural resources are expected to remain.

There are many eligible and listed aboveground historic sites in the vicinity (6-mile radius) of the site. Such historic properties are susceptible to any substantial force that could degrade their physical or historical integrity. Physical integrity refers to the structural condition (or soundness) of a historic property such as a house. The physical integrity of a historic site can be affected by the nearby operation of heavy equipment or by vibrations from the detonation of explosives. Historical integrity is the ability of a property to convey its significance to the public by virtue of its location, design, setting, materials, workmanship, feeling, and association (36 CFR 60.4). The historical integrity of a site can be adversely impacted by factors such as noise.

CNS plant operations and associated transmission lines produce no intense vibrations or other substantial physical forces that would adversely impact historic properties located outside of the site property and transmission line corridors. In addition, CNS and the associated facilities produce little noise. As a result, impacts on the physical and historical integrity of such sites would be expected to be small.

There are no current plans for significant additional construction or plant refurbishments planned in conjunction with license renewal. However, NPPD has procedural administrative controls in place to ensure that cultural resource reviews are conducted prior to engaging in construction or operational activities in previously undisturbed areas that may result in a potential impact to cultural resources at the site. [NPPD 2007c]. Areas depicted in Figure 5 of the Phase 1A Literature Review and Archeological Sensitivity Assessment were identified as higher probability archeological site areas on the CNS Owner Controlled Area. However, NPPD has developed a Cultural Resources Protection Plan in an effort to meet state and federal expectations and includes measures for archeological investigations (Phase 1B) and consultations with the Nebraska and Missouri SHPOs, and the appropriate Native American groups prior to any future ground disturbing activities [CNS 2008]. These measures provide adequate protection for potential area cultural resources.

In addition, based on consultation with the Nebraska and Missouri SHPO's, no concerns were identified regarding adverse impacts as it related to renewal of the CNS OL (see Attachment B).

The Phase 1A Report will be available for onsite review during the site audit due to the archaeologically sensitive information which is included within the report.

4.20.6 Conclusion

No refurbishment activities are required for license renewal at CNS. There are also no plans to alter operations, expand existing facilities, or disturb additional land in support of license renewal. In addition, as discussed in Section 4.20.5 above, no historic properties such as NRHP eligible or listed archaeological sites or aboveground historical sites would be affected by operation of the plant during the license renewal period. Therefore, under a renewed license, the potential impacts on historic properties from continued operation of CNS would be SMALL and further mitigation measures are not warranted.

4.21 Severe Accident Mitigation Alternatives

4.21.1 Description of Issue

Severe accidents

4.21.2 Finding from Table B-1, Appendix B to Subpart A

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 10 CFR 51.53(c)(3)(ii)(L).

4.21.3 Requirement [10 CFR 51.53(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.

4.21.4 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 ground water, 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 [USNRC 1996, Section 5.5.2.5].

4.21.5 Analysis of Environmental Impact

The method used to perform the Severe Accident Mitigation Alternatives (SAMA) analysis was based on the handbook used by the NRC to analyze benefits and costs of its regulatory activities [USNRC 1997].

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

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

(1) Establish the Baseline Consequences of a Severe Accident

Severe accident consequences were evaluated in four areas.

- Off-site exposure costs: monetary value of consequences (dose) to off-site population.

  The Probabilistic Safety Assessment (PSA) model was used to determine total accident frequency (core damage frequency [CDF] and containment release frequency). The Melcor Accident Consequences Code System 2 (MACCS2) was used to convert release input to public dose. Dose was converted to present worth dollars (based on a valuation of $2,000 per person rem and a present worth discount rate of 7 percent).

- Off-site economic costs: monetary value of damage to off-site property.

  The PSA model was used to determine total accident frequency (CDF and containment release frequency). MACCS2 was used to convert release input to off-site property damage. Off-site property damage was converted to present worth dollars based on a discount rate of 7 percent.

- On-site exposure costs: monetary value of dose to workers.

  Best-estimate occupational dose values were used for immediate and long-term dose. Dose was converted to present worth dollars (based on a valuation of $2,000 per person-rem and a present worth discount rate of 7 percent).

- On-site economic costs: monetary value of damage to on-site property.

  Best-estimate cleanup and decontamination costs were used. On-site property damage estimates were converted to present worth dollars based on a discount rate of 7 percent. It was assumed that, subsequent to a severe accident, the plant would be decommissioned rather than restored. Therefore replacement/refurbishment costs were not included in on-site costs. Replacement power costs were considered.

(2) Identify SAMA Candidates

Potential SAMA candidates were identified from the following sources (see Attachment E for reference details):

- SAMA analyses for other BWR plants;
- NRC and industry documentation discussing potential plant improvements;
- CNS Individual Plant Examination of internal and external events reports and their updates; and
- CNS updated PSA model lists of risk significant contributors.

(3) <u>Phase I – Preliminary Screening</u>

Potential SAMA candidates were screened out if they modified features not applicable to CNS, if they had already been implemented at CNS, or if they were similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate.

(4) <u>Phase II – Final Screening and Cost Benefit Evaluation</u>

The remaining SAMA candidates were evaluated individually to determine the benefits and costs of implementation, as follows:

- The total benefit of implementing a SAMA candidate was estimated in terms of averted consequences (benefits estimate).
  - The baseline PSA model was modified to reflect the maximum benefit of the improvement. Generally, the maximum benefit of a SAMA candidate was determined with a bounding modeling assumption. For example, if the objective of the SAMA candidate was to reduce the likelihood of a certain failure mode, then eliminating the failure mode from the PSA would bound the benefit, even though the SAMA candidate would not be expected to be 100% effective in eliminating the failure. The modified model was then used to produce a revised accident frequency.
  - Using the revised accident frequency, the method previously described for the four baseline severe accident impact areas was used to estimate the cost associated with each impact area following implementation of the SAMA candidate.
  - The benefit in terms of averted consequences for each SAMA candidate was then estimated by calculating the arithmetic difference between the total estimated cost associated with all four impact areas for the existing plant design and the revised plant design following implementation of the SAMA candidate.
- The cost of implementing a SAMA was estimated by one of the following methods (cost estimate).

- An estimate for a similar modification considered in a previously performed SAMA analysis was used. These estimates were developed in the past and no credit was taken for inflation when applying them to CNS.

- Engineering judgment on the cost associated with procedural changes, engineering analysis, testing, training and hardware modification was applied to formulate a conclusion regarding the economic viability of the SAMA candidate.

The detail of the cost estimate was commensurate with the benefit. If the benefit was low, it was not necessary to perform a detailed cost estimate to determine if the SAMA was cost beneficial.

(5) Sensitivity Analyses

Two sensitivity analyses were conducted to gauge the impact of key assumptions upon the analysis. One sensitivity analysis was to investigate the sensitivity of assuming a 26-year period for remaining plant life (i.e., six years on the original plant license plus the 20-year license renewal period). The other sensitivity analysis was to investigate the sensitivity of each analysis case to a more conservative discount rate of 3 percent.

The SAMA analysis for CNS is presented in the following sections. Sections E.1 and E.2 of Attachment E provide a more detailed discussion of the process presented above.

4.21.5.1 Establish the Baseline Consequences of a Severe Accident

A baseline was established to enable estimation of the risk reductions attributable to implementation of potential SAMA candidates. The baseline severe accident risk was estimated using the CNS PSA model and the MACCS2 consequence analysis software code. The PSA model used for the SAMA analysis (CNS 2007TM model, Revision 1, December 2007) is an internal events risk model.

4.21.5.1.1 The PSA Internal Events Model – Level 1 and Level 2 Analysis

The PSA model (Level 1 and Level 2) used for the SAMA analysis was the most recent internal events risk model for CNS (2007TM model, Rev. 1). This model is an updated version of the model used in the IPE and reflects the CNS configuration and design as of December 2007. It uses component failure and unavailability data as of March 2006. The CNS model adopts the small event tree / large fault tree approach and uses the CAFTA code for quantifying CDF.

The CNS Level 2 analysis uses a Containment Event Tree (CET) to analyze all core damage sequences identified in the Level 1 analysis. The CET evaluates systems, operator actions, and severe accident phenomena to characterize the magnitude and timing of radionuclide release. The result of the Level 2 analysis is a list of sequences involving radionuclide release, along with the frequency, magnitude and timing of release for each sequence.

4.21.5.1.2 The PSA External Events Model – Individual Plant Examination of External Events (IPEEE) Model

The CNS IPEEE determined that the plant is adequately designed to protect against the effects of seismic, high wind and external flooding events. The seismic portion of the IPEEE was completed in conjunction with the Seismic Qualification Utility Group program using a seismic margin method following the guidance of NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities", June 1991. A number of plant improvements were identified as described in NUREG-1742, "Perspectives Gained from the IPEEE Program," Final Report, April 2002. These improvements were implemented or evaluated as SAMAs.

The CNS Fire analysis was performed using the EPRI Fire Induced Vulnerability Evaluation (FIVE) method for qualitative and quantitative screening of fire areas. Unscreened fire zones were then analyzed in more detail using a fire PRA approach. The FIVE method is primarily a screening approach used to identify plant vulnerabilities due to fire initiating events. The end result of CNS IPEEE fire analysis identified the CDF for significant fire areas. Following this analysis, a number of administrative procedures were revised to improve combustible and flammable material control. Two plant improvements were identified as described in NUREG-1742, "Perspectives Gained from the IPEEE Program," Final Report, April 2002. One of the improvements (switchyard breaker control) was determined to have little impact on CDF and was not implemented or evaluated as a SAMA. The other improvement (service water supply) was evaluated as a SAMA.

4.21.5.1.3 MACCS2 Model - Level 3 Analysis

A Level 3 model was developed using the MACCS2 consequence analysis software code to estimate the hypothetical impacts of severe accidents on the surrounding environment and members of the public. The principal phenomena analyzed were atmospheric transport of radionuclides; mitigation 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 included the core radionuclide inventory, source terms from the CNS PSA model, site meteorological data, projected population distribution (within 50-mile radius) for the year 2034, emergency response evacuation modeling, and economic data. The MACCS2 input data are described in Section E.1.5 of Attachment E.

4.21.5.1.4 Evaluation of Baseline Severe Accident Consequences Using the Regulatory Analysis Technical Evaluation Handbook Method

This section describes the method used to estimate the cost associated with each of the four impact areas for the baseline case (i.e., without SAMA implementation). This analysis was used to establish the maximum benefit that a SAMA could achieve if it eliminated all risk due to CNS at-power internal events.

Off-Site Exposure Costs

The Level 3 baseline analysis resulted in an annual off-site exposure risk of 2.14 person rem. This value was converted to its monetary equivalent (dollars) via application of the $2,000 per person rem conversion factor from the *Regulatory Analysis Technical Evaluation Handbook* [USNRC 1997]. This monetary equivalent was then discounted to present value using the formula from the same source:

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

where,

APE = monetary value of accident risk avoided from population doses, after discounting;

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

F = accident frequency (events/year);

D_P = population dose factor (person-rem/event);

S = status quo (current conditions);

A = after implementation of proposed action;

r = discount rate (%); and

t_f = license renewal period (years).

Using a 20-year license renewal period, a 7% discount rate, assuming F_A is zero, and the baseline CDF of 1.16 x 10^{-5}/ry [Table E.1-9 of Attachment E] resulted in the monetary equivalent value of $46,065. This value is presented in Table 4.21-1.

Off-Site Economic Costs

The Level 3 baseline analysis resulted in an annual off-site economic risk monetary equivalent of $7,010. This value was discounted in the same manner as the public health risks in accordance with the following equation:

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

where,

AOC = monetary value of risk avoided from off-site property damage, after discounting;

P_D = off-site property loss factor ($/event);

F = accident frequency (events/year);

S = status quo (current conditions);

A = after implementation of proposed action;

r = discount rate (%); and

t_f = license renewal period (years).

Using previously defined values; the resulting monetary equivalent is $75,448. This value is presented in Table 4.21-1.

On-Site Exposure Costs

The values for occupational exposure associated with severe accidents were not derived from the PSA model, but from information in the *Regulatory Analysis Technical Evaluation Handbook* [USNRC 1997]. The values for occupational exposure consist of "immediate dose" and "long-term dose." The best-estimate value provided for immediate occupational dose is 3,300 person rem, and long-term occupational dose is 20,000 person-rem (over a 10 year clean-up period). The following equations were used to estimate monetary equivalents.

Immediate Dose

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

Where,

W_{IO} = monetary value of accident risk avoided from immediate doses, after discounting;

IO = immediate occupational dose;

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

F = accident frequency (events/year);

D_{IO} = immediate occupational dose (person-rem/event);

S = status quo (current conditions);

A = after implementation of proposed action;

r = discount rate (%); and

t_f = license renewal period (years).

The values used in the analysis were as follows:

R = \$2,000/person rem;

r = 0.07;

D_{IO} = 3,300 person rem /accident; and

t_f = 20 years.

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

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

$$W_{IO} = 3300 \cdot F_S \cdot \$2000 \cdot \frac{1 - e^{-(0.07 \cdot 20)}}{0.07}$$

$$W_{IO} = \$7.10 \times 10^7 \cdot F_S$$

For the baseline CDF, 1.16 x 10^{-5}/ry,

$$W_{IO} = \$821$$

Long-Term Dose

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

where,

W_{LTO} = monetary value of accident risk avoided long-term doses, after discounting ($);

LTO = long-term occupational dose;

m = years over which long-term doses accrue;

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

F = accident frequency (events/year);

D_{LTO} = long-term occupational dose (person-rem/event);

S = status quo (current conditions);

A = after implementation of proposed action;

r = discount rate (%); and

t_f = license renewal period (years).

The values used in the analysis were as follows:

R =$2,000/person rem;

r = .07;

D_{LTO} =20,000 person-rem /accident;

m =10 years; and

t_f = 20 years.

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

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

$$W_{LTO} = (F_S \times 20{,}000)\$2000 \cdot \frac{1-e^{-0.07 \cdot 20}}{0.07} \cdot \frac{1-e^{-0.07 \cdot 10}}{0.07 \cdot 10}$$

$$W_{LTO} = \$3.10 \times 10^8 \cdot F_S$$

For the CDF for the baseline, 1.16×10^{-5}/ry,

$$W_{LTO} = \$3576$$

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 on-site (occupational) exposure avoided is

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

where,

AOE = on-site exposure avoided

The bounding value for occupational exposure (AOE_B) is

$$AOE_B = W_{IO} + W_{LTO} = \$821 + \$3{,}576 = \$4{,}397.$$

The resulting monetary equivalent of $4,397 is presented in Table 4.21-1.

On-Site Economic Costs

Clean-Up/Decontamination

The total cost of clean-up/decontamination of a power reactor facility subsequent to a severe accident is estimated in the *Regulatory Analysis Technical Evaluation Handbook* to be $\$1.5 \times 10^9$; this same value was adopted for these analyses [USNRC 1997]. Considering a 10-year clean-up 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 = clean-up/decontamination;

C_{CD} = total cost of the cleanup/decontamination effort ($);

m = cleanup period (years); and

r = discount rate (%).

Based upon the values previously assumed,

$$PV_{CD} = \left(\frac{\$1.5 \times 10^9}{10}\right)\left(\frac{1 - e^{-0.07 \cdot 10}}{0.07}\right)$$

$$PV_{CD} = \$1.08 \times 10^9.$$

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

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

where,

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

Based upon the values previously assumed,

$$U_{CD} = \$1.16 \times 10^{10}.$$

Replacement Power Costs

Replacement power costs were estimated in accordance with the *Regulatory Analysis Technical Evaluation Handbook* [USNRC 1997]. Since replacement power will be needed for the time period following a severe accident, for the remainder of the expected generating plant life, long-term power replacement calculations have been used. The present value of replacement power was estimated as follows:

$$PV_{RP} = \left(\frac{\$1.2 \times 10^8}{r}\right)(1 - e^{-rt_f})^2$$

where,

PV_{RP} =present value of the cost of replacement power for a single event;

t_f = license renewal period (years); and

r = discount rate (%).

The $1.2 x 10^8 value has no intrinsic meaning but is a substitute for a string of non-constant replacement power costs that occur over the lifetime of a "generic" reactor after an event. This equation was developed in the *Regulatory Analysis Technical Evaluation Handbook* for discount rates between 5% and 10% only [USNRC 1997].

Based upon the values previously assumed:

$$PV_{RP} = \left(\frac{\$1.2 \times 10^8}{r}\right)(1 - e^{-rt_f})^2 = \left(\frac{\$1.2 \times 10^8}{0.07}\right)(1 - e^{-(0.07)20})^2$$

$$PV_{RP} = \$9.73 \times 10^8$$

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

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

where,

U_{RP} =present value of the cost of replacement power over the remaining life;

t_f = license renewal period (years); and

r = discount rate (%).

Based upon the values previously assumed:

$$U_{RP} = \frac{PV_{RP}}{r}(1 - e^{-rt_f})^2 = \frac{\$9.73 \times 10^8}{0.07}(1 - e^{(-0.07)20})^2 = \$7.89 \times 10^9.$$

Total On-site Property Damage Costs

Combining the clean-up/decontamination and replacement power costs, using delta (ΔF) to signify the difference in accident frequency resulting from the proposed actions, and using the above numerical values, the best-estimate value of averted occupational exposure can be expressed as

$$AOSC = \Delta F(U_{CD} + U_{RP}) = \Delta F(\$1.16 \times 10^{10} + \$7.89 \times 10^9)$$

$$AOSC = \Delta F(\$1.95 \times 10^{10})$$

where,

ΔF = difference in annual accident frequency resulting from the proposed action.

For the baseline CDF, 1.16×10^{-5}/ry,

$$AOSC = \$225{,}409$$

The resulting monetary equivalent of $225,409 is presented in Table 4.21-1.

Table 4.21-1
Estimated Present Dollar Value Equivalent of Internal Events CDF at CNS

Parameter	Present Dollar Value ($)
Off-site population dose	$46,065
Off-site economic costs	$75,448
On-site dose	$4,397
On-site economic costs	$225,409
Total	$351,319

4.21.5.2 Identify SAMA Candidates

Based on a review of industry documents, an initial list of SAMA candidates was identified. Since CNS is a BWR, considerable attention was paid to the SAMA candidates from SAMA analyses for other BWR plants. Attachment E lists the specific documents from which SAMA candidates were initially gathered.

In addition to SAMA candidates from review of industry documents, additional SAMA candidates were obtained from plant-specific sources, such as the CNS IPE and IPEEE. In the IPE and IPEEE, several enhancements related to severe accident insights were recommended. These enhancements were included in the comprehensive list of SAMA candidates and were assessed during preliminary screening. Table E.2-1 of Attachment E lists the IPE and IPEEE SAMA candidates

In addition, the current CNS PSA Levels 1 and 2 models were also used to identify plant-specific modifications for inclusion in the comprehensive list of SAMA candidates. The risk-significant events from the PSA Level 1 and Level 2 models were reviewed for similar failure modes and effects that could be addressed through a potential enhancement to the plant. The correlation between candidate SAMAs and the risk significant events are listed in Tables E.1-3 and E.1-5 of Attachment E. The comprehensive list contained a total of 244 SAMA candidates. The first step in the analysis of these candidates was to eliminate the non-viable SAMA candidates through preliminary screening.

4.21.5.3 Preliminary Screening (Phase I)

The purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were not viable for implementation at CNS. Potential SAMA candidates were screened out if they modified features not applicable to CNS or if they had already been implemented at CNS. In addition, where it was determined those SAMA candidates were potentially viable, but similar in nature, they were combined to develop a more comprehensive or plant-specific SAMA candidate.

During this process, 164 of the 244 initial SAMA candidates were eliminated, leaving 80 SAMA candidates for further analysis. The list of 244 original SAMA candidates and applicable screening criterion is available in on-site documentation.

4.21.5.4 Final Screening and Cost Benefit Evaluation (Phase II)

A cost/benefit analysis was performed on the remaining SAMA candidates. The method for determining if a SAMA candidate was cost beneficial consisted of determining whether the benefit provided by implementation of the SAMA candidate exceeded the expected cost of implementation. The benefit was defined as the sum of the reduction in dollar equivalents for each severe accident impact area (off-site exposure, off-site economic costs, occupational exposure, and on-site economic costs). If the expected implementation cost exceeded the estimated benefit, the SAMA was not considered cost beneficial.

The result of implementation of each SAMA candidate would be a change in the severe accident risk (i.e., a change in frequency or consequence of severe accidents). The method of calculating the magnitude of these changes is straightforward. First, the severe accident risk after implementation of each SAMA candidate was estimated using the same method as for the baseline. 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 the SAMA candidates are presented in Table E.2-2 of the Attachment E.

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 dealt with installing digital large break LOCA protection; the bounding calculation estimated the benefit of this improvement by total elimination of risk due to large break LOCA (see analysis in phase II SAMA 66 of Table E.2-2). Such a calculation obviously overestimated the benefit, but if the inflated benefit indicated that the SAMA is not cost beneficial, then the purpose of the analysis was satisfied.

As described above for the baseline, values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the *Regulatory Analysis Technical Evaluation Handbook* conversion factor of $2,000 per person-rem and discounted to present value [USNRC 1997]. Values for avoided off-site economic costs were also discounted to present value. The formula for calculating net value for each SAMA was

Net value = (APE + AOC + AOE + AOSC) - COE

where,

APE = value of averted public exposure ($);

AOC = value of averted off-site costs ($);

AOE = value of averted occupational exposure ($);

AOSC = value of averted on-site costs ($); and

COE = cost of enhancement ($).

If the net value of a SAMA was negative, the cost of the enhancement was greater than the benefit and the SAMA was not cost beneficial.

The SAMA analysis considered that external events (including fires and seismic events) could lead to potentially significant risk contributions. To account for the risk contribution from external events, the cost of SAMA implementation was compared with a benefit value estimated by applying a multiplier of 3 to the internal events estimated benefit. This value is defined as an "Internal and External Benefit." To account for uncertainties associated with the internal events CDF calculations, the cost of SAMA implementation was also compared with a benefit value estimated by applying an uncertainty multiplier of 3 to the internal and external estimated benefit. This value is defined as the "Internal and External Benefit with Uncertainty." Development of the multipliers for CNS is described in the following paragraphs.

The CNS IPEEE concluded for high winds, floods, and other external events that no undue risks are present that might contribute to CDF with a predicted frequency in excess of 1×10^{-6}/ry. As these events are not dominant contributors to external event risk and quantitative analysis of these events is not practical, they are considered negligible in estimation of the external events multiplier.

A seismic margin assessment was performed for the seismic portion of the CNS IPEEE. Thus, no core damage frequency sequences were quantified as part of the IPEEE seismic risk analysis. The review level earthquake is 0.3g. As seismic events are not dominant contributors to external event risk and quantitative analysis of these events is not practical, they are considered negligible in estimation of the external events multiplier.

The EPRI Fire PRA Implementation Guide was followed for the CNS IPEEE fire analysis. The EPRI Fire Induced Vulnerability Evaluation method was used for the initial screening, for treatment of transient combustibles, and as the source of fire frequency data. The sum of the resulting fire zone CDF values (Table E.1-11) is approximately 1.93×10^{-5} per reactor-year. However, a more realistic fire CDF may be much less than this value due to conservatisms in the IPEEE fire analysis.

Generic conservatisms in the IPEEE fire analysis methods mentioned in NEI 05-01, "Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document," that are applicable to the CNS fire analysis include the following.

- The frequency and severity of fires were generally conservatively overestimated. A revised NRC fire events database indicates a trend toward lower frequency and less severe fires. This trend reflects improved housekeeping, reduction in transient fire hazards, and other improved fire protection steps at utilities.

- There is little industry experience with crew actions following fires. This led to conservative characterization of crew actions in the IPEEE fire analysis. Because CDF is strongly correlated with crew actions, this conservatism has a profound effect on fire results.

- The peer review process for fire analyses is less well developed than for internal events PSAs.

Plant-specific conservative assumptions in the CNS IPEEE fire analysis include the following.

- Cable failure due to fire damage was assumed to arise from open circuits, hot shorts circuits, and short circuits to ground. In damaging a cable, the fire was always assumed to induce the conductor failure mode of concern.

- Manual fire suppression was only credited in the control room and non-essential switchgear room evaluations.

- Generic fire frequencies were used.

- Hardware repair activities were not credited.

The IPEEE fire CDF value is 1.93 x 10^{-5} per year, which is almost twice the internal events CDF. Therefore, a multiplier of 3 was used on the averted cost estimates (for internal events) to result in a value that represents the "Internal and External Benefit."

The internal and external benefit with uncertainty is intended to account for both the internal and external events impacts with uncertainty. CDF uncertainty estimates conservatively resulted in a factor of 3. Therefore, "Internal and External Benefit" values were multiplied by a factor of 3 to provide the "Internal and External Benefit with Uncertainty."

Use of an internal and external benefit (with uncertainty) is considered appropriate because of the inherent conservatism in the external events modeling approach and conservative assumptions in benefit modeling of individual SAMA candidates. In addition, not all potential enhancements would be impacted by an external event. In some cases an external event would only impose partial failure of systems or trains. Therefore, using 9 times the internal events estimated benefit to account for internal and external events with uncertainty is appropriate.

The expected cost of implementation of each SAMA was established from existing estimates of similar modifications combined with engineering judgment. Most of the cost estimates were developed from similar modifications considered in previous SAMA analyses. In particular, these cost-estimates were derived from the following major sources.

- Pilgrim SAMA Analysis
- Vermont Yankee SAMA Analysis
- James A. FitzPatrick SAMA Analysis
- Peach Bottom SAMA Analysis
- Quad Cities SAMA Analysis
- Susquehanna Steam Electric Station SAMA Analysis
- Monticello SAMA Analysis
- Browns Ferry, Units 1, 2, and 3 SAMA Analysis
- Brunswick, Units 1 and 2 SAMA Analysis
- Oyster Creek SAMA Analysis
- Nine Mile Point, Units 1 and 2 SAMA Analysis

A number of additional conservatisms associated with implementation were included in the cost benefit analysis. The cost estimates for implementing the SAMAs did not include the cost of replacement power during extended outages required to implement the modifications. Estimates based on modifications that were implemented or estimated in the past were presented in terms of dollar values at the time of implementation, and were not adjusted to present-day dollars.

Detailed cost estimates were often not required to make informed decisions regarding the economic viability of a potential plant enhancement when compared to attainable benefit. Several of the SAMA candidates were clearly in excess of the attainable benefit estimated from a particular analysis case. For less clear cases, engineering judgment was applied to determine if a more detailed cost estimate was necessary to formulate a conclusion regarding the economic viability of a particular SAMA. In most cases, more detailed cost estimates were not required, particularly if the SAMA called for the implementation of a hardware modification. Nonetheless, the cost of SAMA candidates was conceptually estimated to the point where conclusions regarding the economic viability of the proposed modification could be adequately gauged. The cost benefit comparison and disposition of each of the 80 Phase II SAMA candidates is presented in Table E.2-2 of Attachment E.

4.21.5.5 Sensitivity Analyses

Two sensitivity analyses were conducted to gauge the impact of key assumptions upon the analysis. The main factors affecting present worth are the extended plant life and the discount rate. A description of each follows.

Sensitivity Case 1: Years Remaining Until End of Plant Life

The purpose of this sensitivity case was to investigate the sensitivity of assuming a 26-year period for remaining plant life (i.e., six years on the original plant license plus the 20-year license renewal period), rather than the 20-year license renewal period used in the base case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

Sensitivity Case 2: Conservative Discount Rate

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the discount rate. The discount rate of 7.0% used in the base case analyses is conservative relative to corporate practices. Nonetheless, a lower discount rate of 3.0% was assumed in this case to investigate the impact on each analysis case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

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

4.21.6 Conclusion

This analysis addressed 244 SAMA candidates for mitigating severe accident impacts. Phase I screening eliminated 164 SAMA candidates from further consideration, based on either inapplicability to CNS's design or features that had already been incorporated into CNS's current design, procedures and/or programs. During the Phase II cost-benefit evaluation of the remaining 80 SAMA candidates, an additional 69 SAMA candidates were eliminated because their cost was expected to exceed their benefit.

Eleven Phase II SAMA candidates presented in Table 4.21-2 were found to be potentially cost-beneficial for mitigating the consequences of a severe accident at CNS.

SAMA 14 Provide a portable generator for DC power. This modification involves use of a portable generator to supply DC power to individual panels during a station blackout, which would allow increased time available for AC power recovery.

SAMA 25 Develop procedures to allow bypass of the RCIC turbine exhaust pressure trip. This would allow for extended RCIC operation.

SAMA 30 Revise procedures to allow manual alignment of the fire water system to the RHR heat exchangers. This would allow for improved ability to cool the RHR heat exchangers.

SAMA 33 Create the ability for emergency connection of existing or new water sources to feedwater and condensate systems. This would allow for increased availability of feedwater.

SAMA 40 Revise procedures to provide additional space cooling to the emergency diesel generator (EDG) room via the use of portable equipment. This procedure would improve the availability of the EDG system.

SAMA 45 Provide an alternate means of supplying the instrument air header. This SAMA involves use of an additional portable compressor to be aligned to the supply header to reduce the risk associated with loss of instrument air.

SAMA 64 Revise procedures to allow use of a fire pumper truck to pressurize the fire water system. This procedure would improve the availability of the fire water system.

SAMA 68 Revise procedures to allow the ability to cross-connect the circulating water pumps and the service water going to the turbine equipment cooling (TEC) heat exchangers. This procedure revision would allow for continued use of the power conversion system after service water is lost.

SAMA 75 Implement Generation Risk Assessment (trip and shutdown risk modeling) into plant activities. This would reduce the risk from plant trips and shutdowns.

SAMA 78 Improve training on alternate injection via the fire water system. This would improve operator ability to align the fire water system for alternate injection.

SAMA 79 Revise procedures to allow use of the RHRSW system without a service water booster pump. This procedure would improve the availability of the RHRSW system.

The above SAMA candidates do not relate to adequately managing the effects of aging during the period of extended operation. In addition, since the SAMA analysis is conservative and is not a complete engineering project cost-benefit analysis, it does not estimate all the benefits or all of the costs of a SAMA. For instance, it does not consider increases or decreases in maintenance or operation costs following SAMA implementation. Also, it does not consider the possible adverse consequences of the changes. Although not related to adequately managing the effects of aging during the period of extended operation, detailed engineering project cost-benefit analyses were initiated for the above, potentially cost-beneficial SAMAs. The sensitivity studies indicated that the results of the analysis would not change for the conditions analyzed.

Table 4.21-2
Final SAMAs

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert.	CNS Cost Estimate
014	Portable generator for DC power to supply the individual panels.	Increased time available for AC power recovery.	31.93%	22.43%	22.40%	$301,827	$905,481	$714,000
	Basis for Conclusion: Set the CDF contribution due to unavailability of the HPCI system to zero in the level 1 PSA model. The cost for implementing this SAMA was specifically estimated for CNS.							
025	Revise procedure to allow bypass of RCIC turbine exhaust pressure trip [This SAMA will revise EOP 5.8.20 to give direction to allow bypass of RCIC turbine exhaust pressure trip].	Extended RCIC operation.	3.93%	0.47%	0.43%	$28,693	$86,079	$25,000
	Basis for Conclusion: Eliminate failures due to the RCIC backpressure trip. The cost for implementing this SAMA was specifically estimated for CNS.							
030	Revise procedures to allow manual alignment of the fire water system to RHR heat exchangers.	Improved ability to cool RHR heat exchangers.	20.62%	15.89%	15.83%	$199,969	$599,907	$25,000
	Basis for Conclusion: Eliminate failure of the SW to provide cooling to the RHR heat exchangers. The cost for implementing this SAMA was specifically estimated for CNS.							

Table 4.21-2 (Continued)
Final SAMAs

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert.	CNS Cost Estimate
033	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	Increased availability of feedwater.	38.31%	45.79%	46.08%	$431,725	$1,295,174	$25,000
	Basis for Conclusion: Eliminate the CDF contribution due to loss of the feedwater and condensate systems as alternate injection paths in the PSA model. The cost for implementing this SAMA was specifically estimated for CNS							
040	Operator procedure revisions to provide additional space cooling to the EDG room via the use of portable equipment.	Increased availability of the EDG system.	2.94%	3.27%	3.71%	$33,160	$99,480	$25,000
	Basis for Conclusion: Eliminate failure of the EDG HVAC. The cost for implementing this SAMA was specifically estimated for CNS.							
045	Provide an alternate means of supplying the instrument air header.	Increased availability of instrument air.	16.79%	13.55%	14.12%	$166,450	$499,350	$100,000
	Basis for Conclusion: Eliminate failure of the instrument air compressors in the level 1 PSA model. The cost for implementing this SAMA was specifically estimated for CNS.							

Table 4.21-2 (Continued)
Final SAMAs

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert.	CNS Cost Estimate
064	Proceduralize the use of a fire pumper truck to pressurize the fire water system.	Increased availability of fire water system.	2.67%	2.34%	2.57%	$27,465	$82,395	$50,000
	Basis for Conclusion: Eliminate failure of the diesel-driven fire pump in the PSA model. The cost for implementing this SAMA was specifically estimated for Monticello.							
068	Proceduralize the ability to cross-connect the circulating water pumps and the service water going to the TEC heat exchangers.	Continued use of the power conversion system after service water is lost.	15.39%	19.63%	19.69%	$177,788	$533,364	$50,000
	Basis for Conclusion: Eliminate failure of the service water to provide cooling to the TEC heat exchangers. The cost for implementing this SAMA was specifically estimated for Browns Ferry.							
075	Generation Risk Assessment implementation into plant activities.	Decreases the probability of trip/shutdown.	38.76%	34.58%	35.09%	$394,444	$1,183,332	$500,000
	Basis for Conclusion: Reduce the initiating events that could be improved by the GRA by a factor of 2. The cost for implementing this SAMA was specifically estimated for CNS.							

Table 4.21-2 (Continued)
Final SAMAs

Phase II SAMA ID	SAMA Title	Result of Potential Enhancement	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert.	CNS Cost Estimate
078	Improve training on alternate injection via fire water system.	Reduced failure of operator to align fire water system for injection.	5.29%	4.21%	4.56%	$52,605	$157,816	$25,000
	Basis for Conclusion: Reduce operator actions that could be improved via training for alternate injection via the fire water system by a factor of 2. The cost for implementing this SAMA was specifically estimated for CNS.							
079	Modify procedures to allow use of the RHRSW system without a service water booster pump.	Improved RHRSW system.	10.75%	9.81%	10.13%	$110,566	$331,699	$25,000
	Basis for Conclusion: Eliminate failure to use the RHRSW system without a service water booster pump. The cost for implementing this SAMA was specifically estimated for CNS.							

4.22 Environmental Justice

4.22.1 Description of Issue

Environmental Justice

4.22.2 Finding from Table B-1, Appendix B to Subpart A

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

4.22.3 Requirement

Other than the above referenced finding, there is no requirement concerning environmental justice in 10 CFR Part 51.

4.22.4 Background

The following background information is from the Regulatory Guide 4.2.

Environmental justice was not reviewed in NUREG-1437. Executive Order 12898, "Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations," issued on February 11, 1994, is designed to focus the attention of Federal agencies on the human health and environmental conditions in minority and low-income communities. The NRC Office of Nuclear Reactor Regulation (NRR) is guided in its consideration of environmental justice by Attachment 4, "NRR Procedures for Environmental Justice Reviews," to NRR Office Letter No. 906, Revision 2, "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues." NRR Office Letter No. 906 is revised periodically. The environmental justice review involves identifying off-site environmental impacts, their geographic locations, minority and low-income populations that may be affected, the significance of such effects, and whether they are disproportionately high and adverse compared to the population at large within the geographic area, and if so, what mitigative measures are available, and which will be implemented. The NRC staff will perform the environmental justice review to determine whether there will be disproportionately high human health and environmental effects on minority and low-income populations and report the review in its SEIS. The staff's review will be based on information provided in the ER and developed during the staff's site-specific scoping process.

NRR's Office Letter No. 906, Revision 2 contains a procedure for incorporating environmental justice into the licensing process [USNRC 2004]. CNS used this process in conducting the review and analysis of this issue.

4.22.5 Analysis

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…" NPPD's analyses of the Category 2 issues defined in 10 CFR 51.53(c)(3)(ii) determined that there were no adverse impacts from the renewal of the CNS OL. Thus, no disproportionate impact on minority or low-income populations would occur from the proposed action. Based on the review of these issues, no review for environmental justice is necessary. However, NPPD presents environmental justice demographic information in Section 2.6.2 of this ER to assist the NRC in its review.

4.22.6 Conclusion

As part of its environmental assessment of this proposed action, NPPD has determined that no significant offsite environmental impacts will be created by the renewal of the CNS OL. This conclusion is supported by the review performed of the Category 2 issues defined in 10 CFR 51.53(c)(3)(ii) presented in this ER.

As the NRR procedure recognizes, if no significant offsite 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 adverse impacts or effects on members of the public, including minority and low-income populations, resulting from the renewal of the CNS OL.

4.23 Cumulative Impacts

NPPD considered potential cumulative impacts in its environmental analysis associated with CNS operations during the license renewal period. For the purposes of this analysis, past actions are those related to the resources at the time of plant licensing and construction, present actions are those related to the resources at the time of current operation of the power plant, and future actions are considered to be those that are reasonably foreseeable through the end of plant operation, which would include the 20-year license renewal term. The geographic area over which past, present, and future actions would occur is dependent on the type of action considered and is described below for each impact area.

The impacts of the proposed action are combined with other past, present and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. These combined impacts are defined as "cumulative" in 40 CFR 1508.7 and include individually minor, but collectively significant actions taking place over a period of time. It is possible that an impact that may be SMALL by itself could result in a MODERATE or LARGE impact when considered in combination with the impacts of other actions on the affected resource. Likewise, if a resource is regionally declining or imperiled, even a SMALL individual impact could be important if it contributes to or accelerates the overall resource decline.

4.23.1 Cumulative Impacts on Aquatic Resources

Existing Missouri River Impacts to Aquatic Resources

Flow of the Missouri River at CNS is largely controlled by the Gavins Point Dam located approximately 200 miles upstream in Yankton, South Dakota. The river at CNS is about 800 ft wide and flows in a southeasterly direction. The flow is highly channelized with swift flows and heavy sediment transport. The annual mean river flow is 38,251 cfs (1930-2001) based on the

USGS gauging station at Nebraska City, Nebraska, which is located approximately 30 RMs north of the CNS CWIS.

The lower Missouri River has been leveed, channelized, and its flow regulated for flood control and navigation. Channelization of the lower Missouri River reduced surface area by 50 percent, reduced turbidity by 65 percent, and decreased the number of sandbars and islands by greater than 90 percent, confining the river to a single, deep channel with a swift current and little habitat complexity. [Reeves, p. 4]

The aquatic ecological setting described in Section 2.2 discussed cumulative impacts on the lower Missouri River from a number of causes. Studies agree that the modifications of the river during the 20th century are one of the most significant factors in the changes in fish abundance [NAS, p. 1; USFWS 2000; USNRC 2002; USACE 2003]. These modifications have included loss of habitat resulting from channelization, impoundment of the river, loss of seasonal flood pulses, altered temperature regimes due to impoundment, and loss of nutrient loading from the floodplains. In addition to habitat loss, overfishing has also been the focus of the identified impacts to aquatic resources on the Missouri River.

Invasive fish species such as the bighead and silver carp are also believed to be having an impact on the lower Missouri River. These Asian species can reach weights that exceed fifty pounds. Asian carp are probably the most abundant large (> 5 pounds) fish in the lower Missouri River. These highly invasive carp feed by filtering zooplankton and phytoplankton from the water and compete for food directly with the paddlefish, a native fish, and with most fish in the early life stages of life that feed on zooplankton. There is concern these carp species may have disastrous effects on the lower Missouri. [USGS 2003]

<u>Cumulative Impacts Associated with Cooling Water Intake and Discharge</u>

CNS operations are considered to be of small impact compared with the impacts unrelated to station operations. As discussed in Sections 2.2 and 4.2, entrainment of larval fish or icthyoplankton has not been mentioned in most studies as a significant factor causing declines in indigenous species. During the spring and early summer period when many of the fish species in the lower Missouri River spawn is the period when flows in the river are generally higher. The CNS intake flows are a small percentage (four percent) of that river flow. The fractional loss of fish eggs and larvae originating upstream was estimated to be less than this percentage because of the protected areas used for spawning. However, CNS cooling water intake flows continue to remain less than five percent of the mean annual flow of the Missouri River.

EPA does not apply Phase I 316(b) entrainment performance standards to cooling water intakes that withdraw less than five percent of the average annual flow, which is the case at CNS. This is consistent with the NDEQ's previous determination that the cooling water intake impacts were probably minimal (see Section 4.2) and is reflected as such in the 2007 NPDES permit issued by NDEQ for CNS which does not include requirements for mitigation due to entrainment. This continues to confirm the absence of any adverse impact on fisheries reasonably attributable to entrainment at CNS. Therefore, NPPD concludes the cumulative impact due to entrainment is SMALL and mitigation measures are not warranted.

Impingement of fish species has also not been identified as a significant factor on aquatic resources in the lower Missouri River. As noted in Section 4.3 above, Hesse and others completed more than twenty-two years of sampling data in the Missouri River (1971 to 1992). The focus of the research centered on data regarding the absolute and relative abundance and commercial and recreational harvest. [USNRC 2003]

The FCS SEIS noted that the decline in the abundance of five of the species investigated-the channel catfish, flathead catfish, blue catfish, sauger, and paddlefish was evident in historical commercial-harvest records, creel surveys, and fishery survey data collected from 1971 to 1992. Commercial and recreational harvest of these five species was one of the factors cited in the studies as responsible for the observed decline in their populations. While the commercial harvest of certain fish species may be a factor in the decline of those species, most studies agree that the modifications of the river during the 20th century are one of the most significant factors in the changes in fish abundance [USFWS 2007a; NAS, p. 1; USACE 2003, Section 3.3.4]. Further, current studies do not mention impingement of fish and shellfish as a significant factor causing declines in indigenous species.

The predominance of fisheries studies along the Missouri River identify factors other than impingement as being the primary direct and cumulative impacts to the fish populations in the river. Even though current impingement impacts from CNS cooling water withdrawals are minimal, impacts during the license renewal period are expected to be even smaller due to the planned CWIS design change. NPPD is planning to install a fish handling system consisting of inside and outside fish sprays and a separate fish return trough to the existing design of the CWIS (Ristroph screens). This change to the CWIS would most likely be considered Best Technology Available as it relates to minimizing impingement impacts. Therefore, NPPD concludes the cumulative impact due to impingement of fish and shellfish in the Missouri River is SMALL and mitigation measures are not warranted.

The thermal discharges from CNS may also produce a localized effect on the Missouri River. The post-operational monitoring performed at CNS through 1975 indicated the thermal discharge plume extends along the west bank of the river, and generally is limited to approximately one-third of the width of the river [Nalco, Figure 4.2-9]. Therefore, the plume would not be expected to create a barrier to fish migration through the mixing zone.

The EPA, in a cooperative effort with the USGS and the NDEQ, has collected and analyzed heat data from the Missouri River at CNS and three other power plants to map heat in the Missouri River and predict compliance with Nebraska Water Quality Standards under various river conditions to establish appropriate NPDES permit limits. This study, which included thermal modeling, focuses on power plants and other industries discharging to the lower Missouri River, and addresses the potential effects of historically high, ambient river temperatures. In a letter response to the NRC draft SEIS on FCS, EPA indicated its study is assisting the NDEQ in assessing the implications of reduced river flows in the summer, such as those being considered by the USACE in the context of revisions to the Missouri River Master Water Control Manual and the associated USFWS Biological Opinion [USNRC 2003, p. E-35]. EPA's CORMIX modeling has developed thermal discharge limits that assure that the background river temperature, plus the temperature across the condensers (ΔT) and diluted instream will achieve a 90°F limit at the end of a 5,000 ft. chronic mixing zone. As a result, the NDEQ issued CNS a renewed NPDES permit effective July 1, 2007 with thermal limits that will ensure the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife in the Missouri River.

CNS is a baseload unit, which means it generally operates at full power. In the short-term an increase in power demand will not result in CNS increasing its power output because it is already operating at full power. Power demands are expected to increase with population and growth of industry over the license renewal period, and this may cause NPPD to seek an increase in the authorized power level for CNS. However, NPPD would be required to request an amendment to CNS's OL for any increase in the plant's authorized power level. Any power uprate could have a minor impact on the modeling results; however, the maximum discharge temperatures will continue to be limited by the NPDES permit, thus assuring continued minimal impact to aquatic resources.

CNS may be constrained by the thermal discharge limits of its NPDES permit. As the temperature exceeds the 85°F used in EPA's CORMIX modeling, CNS's power output may have to be derated to meet its discharge limit, under certain low flow conditions. Based on an evaluation developed in cooperation with the NPA, CNS should be able to comply with its NPDES discharge limit [NPA, Figure III.B-3]. However, at higher ambient river temperatures and at summer low flow conditions (below 25,000 cfs), operational problems and station output derating may occur. [NPA, p. 5] Nevertheless, the maximum discharge temperatures from CNS will continue to be limited by the NPDES permit. Therefore, NPPD concludes that cumulative impacts associated with continued operation in the manner required by the current NPDES permit and the current Missouri River Master Water Control Manual flows will result in thermal impacts that will remain SMALL during the license renewal term. Further mitigation measures are not warranted.

There are operations associated with CNS operations that may potentially produce a localized aquatic effect on the lower Missouri River during the license renewal term such as minimal maintenance dredging associated with the intake structure to facilitate water flow, installation of the fish return system, or maintenance of weir walls associated with the intake structure. These operations would be localized, and performed in accordance with state and federal environmental permits, including 404 permitting, so any potential impacts would be SMALL, and no mitigation warranted beyond those required by these permitting processes.

Threatened and Endangered Species

The pallid sturgeon, which was once common in the Missouri River, is the only federal aquatic threatened or endangered species known to be in the vicinity of CNS. Although there is potential for pallid sturgeon presence within the vicinity of CNS, most frequent reports of potential pallid sturgeon spawning have been near the mouth of the Platte River (RM 595) (approximately 63 miles upstream of CNS) [USNRC 2002, Section IV.A]. The CNS thermal discharge is located downstream of the Platte River; therefore, no impacts would occur as a result of the thermal discharge. Due to the demersal and adhesive characteristic of sturgeon eggs, CNS would also not be expected to have an adverse impact on pallid sturgeon eggs due to entrainment. While recent studies have not been performed at CNS related to fish impingement at its cooling water intake structures, the predominance of fisheries studies along the Missouri River identify factors other than impingement as being the primary direct and cumulative impacts to the fish populations in the river. Severe alteration of the Missouri River ecosystem has resulted in the near elimination of the pallid sturgeon from the river. Despite more recent habitat restoration projects and population augmentation efforts, the pallid sturgeon continues to decline and occurrences of this fish remain rare [USFWS 2000, pp. 95-117]. The lack of suitable habitat as a result of previous habitat modification and the rare documented occurrence of the pallid sturgeon, including larvae, indicate a low potential for adverse impact to the pallid sturgeon from impingement, entrainment, or thermal discharges associated with the cooling water system at CNS. Therefore, NPPD concludes that the cumulative impacts associated with continued operation of CNS will remain SMALL during the license renewal term, and further mitigation measures are not warranted.

Missouri River Flow Management

The USACE, USFWS, and other stakeholders have been examining the impact of alternatives for regulating flows in the Missouri River Main Stem Reservoir System, which was constructed and is operated by the USACE. The Reservoir System is operated using guidelines published in the Missouri River Main Stem Reservoir System Master Manual. The Master Manual prescribes implementation protocols for Reservoir System storage and release functions to accommodate the multiple purposes described below. Although hydropower and water supply provide about 70 percent of the economic benefits, the release criteria for Gavins Point Dam are currently influenced most by navigation considerations. The navigation considerations are overridden by the need to either cut back releases for downstream flood control or to evacuate flood-control storage space in the reservoirs. [USNRC 2003, Section 2.2.10]

The USFWS has raised concerns related to the ecological impacts of the USACE's Missouri River projects on the interior least tern, piping plover, and pallid sturgeon. The USACE and USFWS are negotiating the objectives of the Master Manual for what best meets the current needs of the basin and to incorporate controls to appropriately meet those needs. These activities, which began in 1989, include development of an Environmental Impact Statement (EIS). In a Revised Draft EIS issued August 2001, USFWS examines the impact of six alternatives for regulating flows in the Reservoir System. [USNRC 2003, Section 2.2.10]

The USFWS has been working closely with the USACE in the review and update of the Master Manual and related management practices for the Missouri River, and has issued a Biological Opinion that addresses actions to protect and enhance federally listed populations of interior least tern, piping plover, and pallid sturgeon [USFWS 2000]. This Opinion requires the USACE to adopt an adaptive management approach to preclude jeopardy of these species. Specifically proposed actions include flow modifications in the lower river to restore and maintain nesting and foraging habitat for the interior least tern and piping plover, and to trigger spawning and enhance nursery habitat for the pallid sturgeon and other native fish species. The flow scenario specified by USFWS as a starting point includes lowering target flows below Gavins Point Dam to 25,000 cfs from June 21 to July 15, 21,000 cfs from July 15 to August 15, and 25,000 cfs from August 15 to September 1. [USNRC 2003, Section 2.1]

Modifications of river flow on electric power generating stations utilizing the Missouri River for cooling water have been evaluated by a consortium of potentially affected utilities. Although NPPD did not directly participate as a member of the consortium, CNS was included in the study of impacts to plants affected by river flows, and potential costs to consumers. The study considered flows of a new Master Manual in severe droughts where navigation is not supported, flow levels fall to as low as 18,000 cfs during the May to August period and as low as 9,000 cfs during the September to November period. Depending on the ultimate flow regime implemented by the USACE, the annual summer expected economic loss generated by reduced river flow could be more than 46 million dollars. The economic damages calculated in this study pertained only to the summer month period of June through September. Other economic damages may be incurred during the October through May period, but those are not considered in this study. In reviewing this study, several power plants commented that the grid prices used in this study may be conservative and may not reflect additional price pressure associated with power plant de-ratings in extreme situations. [FAPRI, p. 11]

The NPA assessment concluded that modified 7Q10 flows pursuant to revisions to the Missouri River Master Water Control Manual would likely have an economic impact on NPPD customers. The impacts to the regional transmission grid from a sequential unit tripping of the larger baseload power plants along the Missouri River could be substantial. Losing this much generation would have severe impacts on the system frequency and would require manual or automatic underfrequency load shedding to help stabilize frequency. It would also have negative impacts on voltages due to the lost voltampere reactive injection supplied by these units. This type of event is similar in nature to what happened during the northeastern United States blackout in August 2003. Generation outages, reactive deficiencies, voltage and power swings can lead to lost transmission lines, uncontrolled cascading outages, and a subsequent blackout situation for a large portion of the four (4) state region that have steam and nuclear plants along the Missouri River. This load would not be fully restored until sufficient external resources and transmission capability is available. [NPA, p. 21]

Should the revisions to the Missouri River Master Water Control Manual flows be implemented that effect lower than historic river flows during the late summer, the socioeconomic impact due to station derating may be MODERATE.

Review of available information leads to a conclusion that the changes observed in aquatic resources all along the Missouri River are due to factors unrelated to current operations at CNS, either directly or cumulatively. The effects to susceptible species will continue whether CNS's OL is renewed or not. The Missouri River studies conducted to date generally concur that the impacts related to declines in certain indigenous fish species are due to habitat changes such as the Missouri River and tributary dams, channelization and other habitat management, invasive aquatic species, and similar factors. Therefore, NPPD concludes that the cumulative impacts to aquatic resources along the Missouri River related to license renewal are SMALL, and further mitigation measures are not warranted.

4.23.2 Cumulative Impacts on Terrestrial Resources

NPPD evaluated cumulative impacts of past, current, and future activities in the four-county geographic area in which the plant, its transmission corridors, and its employees reside: Nemaha, Richardson, and Otoe counties in Nebraska, and Atchison County, Missouri. Terrestrial resource impacts might include those to upland and river valley habitats, wetlands, and land use. NPPD has evaluated the incremental impacts associated with the proposed action to renew the CNS OL.

The CNS environmental setting is described in Section 2. The description of CNS facilities and operations are described in Section 3, while analyses of impacts to various resources are described in this section of the ER (Section 4). The potential impacts of the various alternatives to the proposed action are discussed in Section 8 of this ER. Again, the cultural and natural history of this area has been studied and described by various individuals, organizations, institutions, and governmental agencies since the beginning of recorded history in America.

Past land use changes include the construction of the CNS facilities and its associated transmission lines. There has been little significant residential and commercial development in the area since the construction of CNS. The four counties in this region have limited controls on future development and land use (see Section 2.8). In fact, due to the region's historically declining population, most counties have strategies to encourage economic development.

The USACE and USFWS both regulate some actions involving terrestrial resources along the Missouri River, as do various other agencies including, but not limited to, the NGPC, MDC, and NDEQ. The USFWS National Wetlands Inventory indicates there are more than 700 wetlands within the 6-mile vicinity of CNS, including three identified within the site boundary [USFWS 2007b]. Langdon Bend is located immediately south of CNS, and the 239 acres on the Missouri side of the Missouri River within the exclusion area boundary includes wetlands areas. NPPD has administrative procedures in place to minimize and control any potential impacts to nearby wetlands.

As the transmission line owner and operator, NPPD vegetative management, environmental control, cultural resources protection plan, and threatened and endangered species protection procedures address impacts to the transmission line corridors. None of the station or transmission line management procedures are expected to alter wetland or riverine hydrology or adversely affect vegetation characteristics of these habitats or other habitats.

The open water of the Missouri River and its emergent wetland habitat supports a number of migrant waterfowl and wildlife species. The State and federally listed threatened or endangered terrestrial species and species of concern in Nemaha County and those along the transmission line corridors are cited in Table 2.5-1. There are no critical habitats designated in any of the counties associated with CNS or its transmission lines. Federally listed threatened or endangered species that could potentially be present in the vicinity of CNS or along the corridors of the in-scope transmission lines include the Salt Creek tiger beetle, black-footed ferret, piping plover, whooping crane, and western prairie fringed orchid. These are all located outside of Nemaha County along portions of the transmission corridors. The federally listed Indiana bat is reported as potentially present in Atchison County, Missouri. The bald eagle remains a protected species and a nesting pair has been monitored on the Missouri side of the EAB. However, none of the management procedures for station operations or transmission line maintenance are expected to have significant impact on species habitat or interfere with wintering or nesting. Therefore, CNS and its associated transmission lines are not expected to contribute to adverse cumulative impacts on this species. NPPD has reviewed its potential incremental contributions to cumulative impacts on terrestrial resources resulting from continued operation of CNS and from the transmission lines that transmit electrical power to the electrical grid. NPPD has concluded that any potential impacts would be SMALL and further mitigation measures are not warranted.

4.23.3 Cumulative Radiological Impacts

The radiological dose limits for protection of the public and workers have been developed by the EPA and the NRC to address the cumulative impact of acute and long-term exposure to radiation and radioactive material. These dose limits are codified in 40 CFR Part 190 and 10 CFR Part 20. For the purpose of this analysis, the area within a 50-mile radius region of interest (ROI) around CNS was included. There are no other nuclear fuel cycle facilities within the 50-mile ROI. The FCS is located in Nebraska approximately 85 miles northeast of CNS. However, a portion of the population within the CNS ROI is also within the 50-mile ROI for FCS.

NPPD has conducted a radiological environmental monitoring program around the site since 1974. The results of the operational Radiological Environmental Monitoring Program (REMP) are reported to the NRC in the CNS Annual Radiological Environmental Operating Report. The REMP measures radiation and radioactive materials from all sources, including, but not limited to, CNS radioactive emissions discussed in Section 3.2.3, and thus considers cumulative radiological impacts. On the basis of an evaluation of REMP results, NPPD concludes that impacts of radiation exposure on the public and workers (occupational) from operation of CNS during the renewal term would be SMALL. With respect to the future, the REMP sampling locations shown in the CNS ODAM has not identified increasing levels or the accumulation of radioactivity in the environment over time. At this time, NPPD is not aware of any proposals for new nuclear facilities in the vicinity of CNS that would potentially contribute to cumulative radiological impacts. The NRC and the State of Nebraska would regulate any future actions in the vicinity of the site that could contribute to cumulative radiological impacts. Therefore, NPPD concludes that future cumulative radiological impacts would be SMALL and therefore mitigation measures are not warranted.

4.23.4 Cumulative Socioeconomic Impacts

The socioeconomic conditions involving housing, local public services, utilities, education, employment, transportation, and personal income were presented for Nemaha, Richardson, and Otoe Counties in Nebraska, and Atchison County, Missouri in Section 2. The impacts to housing, local public services/utilities, education, and transportation as measures of socioeconomic indicators for these counties were evaluated separately in Sections 4.14, 4.15, 4.16, and 4.19. As noted in Section 2.7, NPPD makes a contribution to the tax base in 91 of the 93 counties in

Nebraska, although not relevant here in the context of license renewal as discussed in Section 4.18 since NPPD will still be responsible for producing and distributing electricity (and the resulting in-lieu payments) even if the license for CNS is not renewed. Taxes paid by the site have a positive impact on the fiscal condition of these counties, although in most cases the direct taxes paid impact is moderate or small. However, CNS is the largest employer in Nemaha County and makes a significant contribution to the rural economic base of the four counties. Continued operation of the plant through the license renewal term would provide a significant continuing source of economic support and tax revenues statewide that provide beneficial economic impact to the surrounding counties and communities.

In addition, the continuance of the 830 MWe (gross) base-load electrical power generation capacity of CNS provides relatively low cost and environmentally-clean power to Nebraska and Iowa. As discussed in Section 2, the region is in attainment with air quality regulations. However, as discussed in Section 8, alternative power supplies would create a deficit of base-load electrical power generation capacity that would likely have to be replaced by fossil fuel power generation which would create adverse air quality impacts, especially for particulates and greenhouse gases.

When combined with the impact of other potential activities, such as residential development and population growth in the area surrounding the plant, socioeconomic impacts from CNS license renewal would not produce a noticeable incremental change in any adverse impact measures. Therefore, NPPD concludes that the socioeconomic impact from the renewal of the CNS OL, in addition to the impacts of other potential economic activities in the area, would be SMALL compared to other contributors and therefore further mitigation measures are not warranted.

4.23.5 Cumulative Impacts on Groundwater Use and Quality

The area of analysis for cumulative impacts on groundwater would encompass wells primarily within Nemaha County, Nebraska. However, Richardson and Otoe County in Nebraska and Atchison County, Missouri are also considered since a majority of the CNS employees also resides in these counties.

Groundwater at the site is hydraulically connected with the Missouri River and generally flows toward the river during lower river stages and may flow away from the river during higher river stages. As discussed in Section 2.3, the site is situated within the Missouri River stream valley aquifer system in the alluvial flood plain. Alluvial deposits along the Missouri River form an important stream-valley aquifer from the Iowa-Missouri State line to the junction of the Missouri and the Mississippi Rivers; small areas of similar deposits in eastern Nebraska compose local aquifers. The deposits partly fill an entrenched bedrock valley that ranges from about 2 to 10 miles wide. In many places in northern Missouri, the bedrock contains slightly saline to saline water, and the stream-valley aquifers, along with aquifers in glacial drift, are the only sources of fresh ground water.

Groundwater is encountered at the site primarily in the alluvium within the Missouri River stream-valley aquifer at relatively shallow depth. There have been no known releases of contaminants to the groundwater at the site.

NPPD has implemented the NEI groundwater protection initiative for monitoring radiological contaminants as discussed in Section 2.3. This program which also includes monitoring the CNS onsite non-transient non-community public water system, has not identified any activity above normal background levels.

Public water supply systems (see Table 2.10-1) in the vicinity of the site include community and non-community (including non-transient non-community and transient non-community) systems. CNS's public water system is located within a 1,000-foot radius wellhead protection area. However, CNS is currently located more than six miles from the nearest Community Public Water System wellhead protection area (Auburn and Nemaha County RWD #1). The residents of all four counties obtain almost 100 percent of their potable water from groundwater. Nemaha, Richardson and Otoe Counties are all located within the NNRD, which has been designated by the NDNR as not Fully Appropriated as discussed in Section 2.3. Adequate groundwater supply is available for current CNS station operations, as well as for further development within the NNRD district.

Based on the fact that there is adequate supply of potable water to meet the current and future demand, the fact that there is no planned increase in the employment at CNS, and that there is adequate supply for short-term increases of temporary labor during refueling or any foreseeable construction activities at the site during the license renewal term, NPPD concludes that the cumulative impact on groundwater resources would be SMALL and mitigation measures are not warranted. On the basis of groundwater quality, NPPD also concludes that the cumulative impact on the quality of local groundwater resources would be SMALL and mitigation measures are not warranted.

4.23.6 Conclusion

NPPD considered the potential impacts from CNS operations during the license renewal term and other past, present, and future actions in the vicinity of the site. NPPD's conclusion is that the potential cumulative impacts resulting from CNS operations during the license renewal term would be SMALL. Therefore, further mitigation measures are not warranted.

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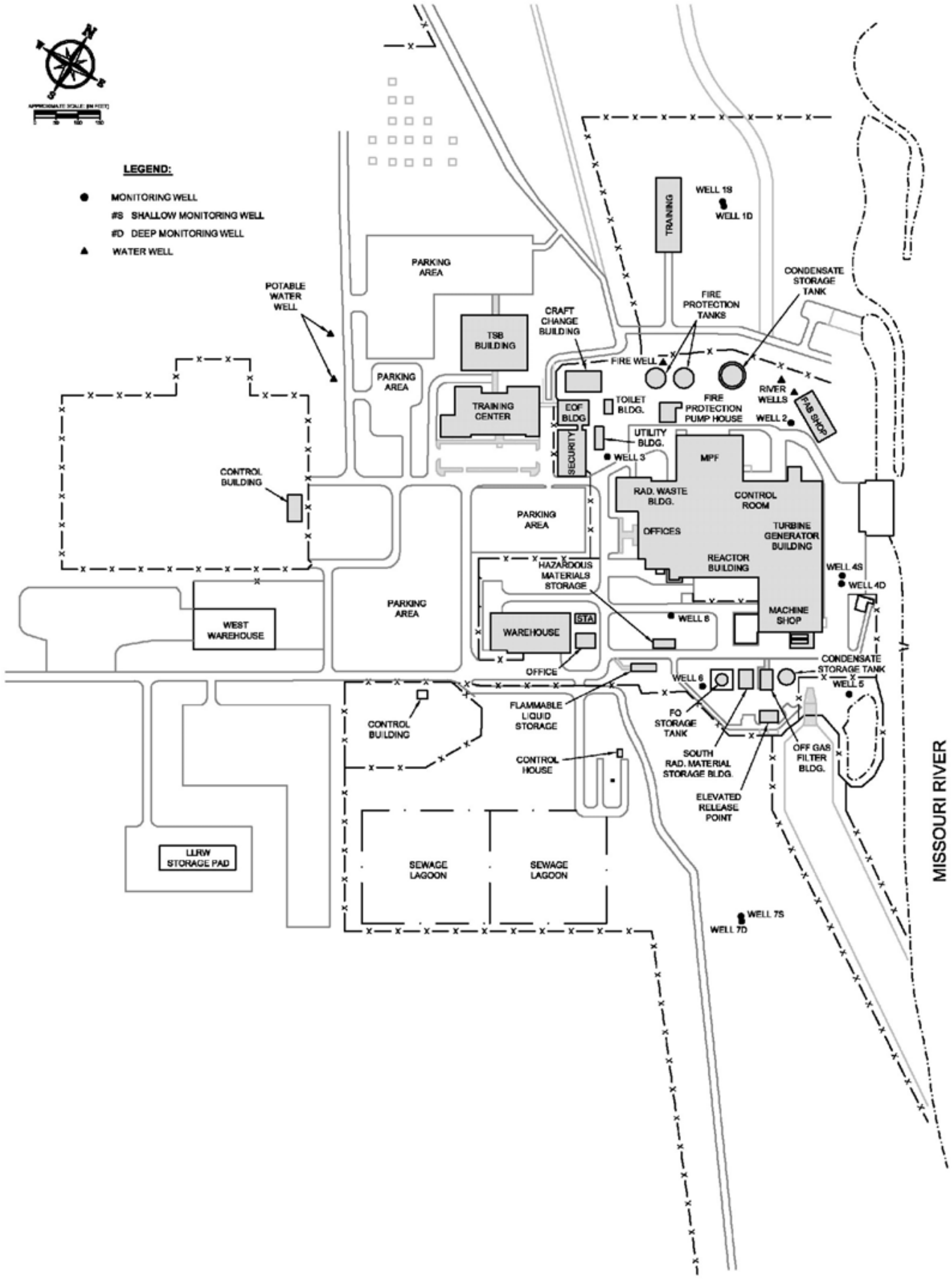

Figure 4.5-1
CNS Onsite Wells Registered with NDNR

5.0 ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

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

The NRC has resolved most license renewal environmental issues generically and only requires an applicant to analyze those issues the NRC has not resolved generically. While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those environmental issues that have been generically resolved [10 CFR 51.53(c)(3)(i)], the regulations do require that an applicant identify any new and significant information of which the applicant is aware. [10 CFR 51.53(c)(3)(iv)]

NPPD performed an analysis to identify the following:

- information that identifies a significant environmental issue not covered in the NRC's GEIS and codified in the regulation, or

- information not covered in the GEIS analyses that leads to an impact finding different from that codified in the regulation.

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

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

The NPPD License Renewal team reviewed SEISs and associated environmental Requests for Additional Information with license renewal applications to determine if there were new issues identified for those plants that may be applicable to CNS. State and federal regulatory agencies were also consulted regarding new and significant information as it related to license renewal environmental matters. In addition, NPPD has an ongoing assessment process for identifying and evaluating new and significant information that may affect programs at the CNS site, including those related to license renewal matters.

This process is directed in a joint effort by the NPPD Corporate Environmental Group and CNS station personnel responsible for environmental matters. A summary of this process follows.

- Issues relative to environmental matters are identified as follows:
  - → participation in industry utility groups (i.e., EEI, EPRI, NEI, and USWAG);
  - → participation in non-utility groups (i.e., Institute of Hazardous Materials Management and National Registry of Environmental Professionals);
  - → periodic reviews of proposed regulatory and legislative changes;
  - → NPPD site environmental meetings.
- If the issue is applicable to the CNS site, it is then further evaluated by the NPPD Corporate Environmental Group and CNS station personnel that consist of technical personnel involved in environmental compliance, environmental monitoring, environmental planning, natural resource management, and health and safety issues. Necessary changes are made to the program and implemented in accordance with site and corporate procedures.

Additional actions incorporated into this assessment process specifically for CNS license renewal include the following:

- review of documents related to environmental issues at CNS;
- review of current site activities and interview of site personnel;
- review of internal procedures for reporting to the NRC events that could have environmental impacts;
- credit for the oversight provided by inspections of plant facilities by state and federal regulatory agencies;
- review of environmental issues associated with other license renewal activities.

As a result of this assessment, NPPD is aware of no new and significant information regarding the environmental impacts of CNS license renewal.

6.0 SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 License Renewal Impacts

NPPD has reviewed the environmental impacts of renewing the CNS OL and has concluded that all impacts would be SMALL and further mitigation measures are not warranted. This environmental report documents the basis for NPPD's conclusion. Section 4 incorporates by reference NRC findings for the 49 Category 1 issues that apply to CNS (and for the two "NA" issues for which NRC came to no generic conclusion), all of which have environmental impacts that are SMALL. The remainder of Section 4 analyzes Category 2 issues, all of which are either not applicable or have impacts that would be SMALL. Table 6.2-1 identifies the environmental impacts that CNS license renewal would have on resources associated with Category 2 issues.

6.2 Mitigation

6.2.1 Requirement [10 CFR 51.45(c)]

The report must contain a consideration of alternatives for reducing adverse impacts, as required by §51.45(c), for all Category 2 license renewal issues in Appendix B to subpart A of this part. No such consideration is required for Category 1 issues in Appendix B to subpart A of this part. [10 CFR 51.53(c)(3)(iii)]

6.2.2 NPPD Response

As discussed in Supplement 1 to Regulatory Guide 4.2, "Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses," when adverse environmental effects are identified, 10 CFR 51.45(c) requires consideration of alternatives available to reduce or avoid these adverse effects. Furthermore, Supplement 1 states, "Mitigation alternatives are to be considered no matter how small the adverse impact; however, the extent of the consideration should be proportional to the significance of the impact" [USNRC, p. 4.2-S-5].

As described in Section 6.1 and shown in Table 6.2-1, analysis of the Category 2 issues found the impacts to be small for the applicable issues. For these issues, the current permits, practices, and programs (e.g., radiological monitoring and environmental review programs) that mitigate the environmental impacts of plant operations are adequate. Therefore, this ER finds that no additional mitigation measures are sufficiently beneficial as to be warranted.

Table 6.2-1
Environmental Impacts Related to License Renewal at CNS

Issue	Environmental Impact
Surface Water Quality, Hydrology and Use (for all plants)	
Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow) [10 CFR 51.53(c)(3)(ii)(A)]	**NONE.** CNS is equipped with a once-through cooling system that utilizes make-up water from the Missouri River. CNS does not have or use cooling ponds or cooling towers. Consideration of mitigation is not required.
Aquatic Ecology (for all plants with once-through and cooling pond heat dissipation systems)	
Entrainment of fish and shellfish [10 CFR 51.53(c)(3)(ii)(B)]	**SMALL.** Based on previous regulatory agency positions regarding entrainment impacts from CNS, river studies consistently showing that declines in certain indigenous fish species are due to habitat changes (i.e., river and tributary dams, channelization and other habitat management, invasive aquatic species), and EPA's position not to apply entrainment performance standards to facilities like CNS whose intake consists of less than five percent of the mean annual flow, NPPD concludes the impact from plant operations due to entrainment of fish and shellfish in the Missouri River is SMALL. Further consideration of mitigation measures is not warranted.
Impingement of fish and shellfish [10 CFR 51.53(c)(3)(ii)(B)]	**SMALL.** Missouri River studies and previous agency determinations identify factors (i.e., river and tributary dams, channelization and other habitat management, invasive aquatic species) other than impingement as being the primary cause of direct and cumulative impacts to the fish populations. CNS is also planning to install a fish handling system consisting of inside and outside fish sprays and a separate fish return trough to the existing CWIS design (Ristroph screens) which would most likely be considered Best Technology Available. Therefore, NPPD concludes the impact from plant operations due to impingement of fish and shellfish in the Missouri River is SMALL. Further consideration of mitigation measures is not warranted.
Heat shock [10 CFR 51.53(c)(3)(ii)(B)]	**SMALL.** CNS compliance with the station's NDEQ NPDES Permit thermal discharge and associated water quality limits provide assurance of SMALL impacts to the Missouri River. Further consideration of mitigation measures is not warranted.

Table 6.2-1 (Continued)
Environmental Impacts Related to License Renewal at CNS

Issue	Environmental Impact
Ground-water Use and Quality	
Groundwater use conflicts (plants using > 100 gpm of groundwater) [10 CFR 51.53(c)(3)(ii)(C)]	**SMALL.** The surficial aquifer at CNS is hydraulically connected to the Missouri River, and the radius of influence created by groundwater withdrawals are not expected to extend beyond CNS's property boundary. Consideration of mitigation measures is not warranted.
Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river) [10 CFR 51.53(c)(3)(ii)(A)]	**NONE.** CNS does not have or use cooling towers. The Station obtains plant cooling and service water from the Missouri River, and potable and process water from onsite groundwater wells. Consideration of mitigation is not required.
Groundwater use conflicts (Ranney Wells) [10 CFR 51.53(c)(3)(ii)(C)]	**NONE.** CNS does not have or use Ranney wells. Consideration of mitigation is not required.
Degradation of groundwater quality [10 CFR 51.53(c)(3)(ii)(D)]	**NONE.** CNS does not have or utilize cooling ponds. The Station is equipped with a once-through cooling system. Consideration of mitigation is not required.
Terrestrial Resources	
Refurbishment impacts on terrestrial resources [10 CFR 51.53(c)(3)(ii)(E)]	**NONE.** No refurbishment activities have been identified. Consideration of mitigation is not required.
Threatened or Endangered Species (for all plants)	
Threatened or endangered species [10 CFR 51.53(c)(3)(ii)(E)]	**SMALL.** No refurbishment activities have been identified. No adverse impacts to threatened or endangered species are expected due to continued operation of CNS. Further consideration of mitigation measures is not warranted.
Air Quality	
Air quality during refurbishment [10 CFR 51.53(c)(3)(ii)(F)]	**NONE.** No refurbishment activities have been identified. Consideration of mitigation is not required.
Human Health	
Microbiological (Thermophilic) Organisms [10 CFR 51.53(c)(3)(ii)(G)]	**SMALL.** The Missouri River in the vicinity of CNS generally offers poor conditions for supporting populations of thermophilic organisms and no cases of water-borne illness related to contact with the Missouri River have been reported. Consideration of mitigation is not required.

Table 6.2-1 (Continued)
Environmental Impacts Related to License Renewal at CNS

Issue	Environmental Impact
Electromagnetic fields—Acute effects [10 CFR 51.53(c)(3)(ii)(H)]	**SMALL.** Transmission lines constructed to connect the plant to the transmission system grid meet the NESC® recommendations for preventing electric shock from induced currents. Further consideration of mitigation measures is not warranted.
Socioeconomics	
Housing impacts [10 CFR 51.53(c)(3)(ii)(I)]	**SMALL.** No major refurbishment activities identified and no additional workers anticipated during the period of extended operation. Therefore, no additional impacts to housing are expected due to continued operation of CNS. Further consideration of mitigation measures is not warranted.
Public utilities: public water supply availability [10 CFR 51.53(c)(3)(ii)(I)]	**SMALL.** No major refurbishment activities identified and no additional workers anticipated during the period of extended operation. Although CNS does not utilize public water, systems near CNS currently have adequate system capacity to meet demand of residential and industrial customers in the area. Further consideration of mitigation measures is not warranted.
Education impacts from refurbishment [10 CFR 51.53(c)(3)(ii)(I)]	**NONE.** No refurbishment activities have been identified. Consideration of mitigation is not required.
Offsite land use (effects of refurbishment activities) [10 CFR 51.53(c)(3)(ii)(I)]	**NONE.** No refurbishment activities have been identified. Consideration of mitigation is not required.
Offsite land use (effects of license renewal) [10 CFR 51.53(c)(3)(ii)(I)]	**SMALL.** The area around CNS will continue to be sparsely populated and minimal population growth and resulting development is anticipated during the license renewal term. In addition, no additional workers are anticipated during the period of extended operation. Further consideration of mitigation measures is not warranted.
Local transportation impacts [10 CFR 51.53(c)(3)(ii)(J)]	**SMALL.** No refurbishment activities have been identified and no increases in total number of employees during the period of extended operation are expected. Further consideration of mitigation measures is not warranted.

Table 6.2-1 (Continued)
Environmental Impacts Related to License Renewal at CNS

Issue	Environmental Impact
Historic and archaeological properties [10 CFR 51.53(c)(3)(ii)(K)]	**SMALL.** No refurbishment activities have been identified. Although potential unidentified archaeologically and historically sensitive areas may be present onsite, administrative procedures ensure protection of these type resources in the event of excavation activities. Further consideration of mitigation measures is not warranted.
Postulated Accidents	
Severe accident mitigation alternatives [10 CFR 51.53(c)(3)(ii)(L)]	**SMALL.** No impact from continued operation. Potentially cost-effective SAMAs are not related to adequately managing the effects of aging during period of extended operation. Further consideration of mitigation measures is not warranted.

6.3 Unavoidable Adverse Impacts

6.3.1 Requirement [10 CFR 51.45(b)(2)]

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

6.3.2 NPPD Response

Section 4 of this ER contains the results of NPPD's review and the analyses of the Category 2 issues as required by 10 CFR 51.53(c)(3)(ii). These reviews take into account the information that has been provided in the GEIS, Appendix B to Subpart A of 10 CFR Part 51, and information specific to CNS.

An environmental review conducted at the license renewal stage differs from the review conducted in support of a construction permit because the facility is in existence at the license renewal stage and has operated for a number of years. As a result, adverse impacts associated with the initial construction have been avoided, have been mitigated, or have already occurred.

The environmental impacts to be evaluated for license renewal are those associated with refurbishment and continued operation during the renewal term. The review and analysis of Category 2 issues associated with refurbishment and continued operation of CNS did not identify any significant adverse environmental impacts. The evaluation of structures and components required by 10 CFR 54.21 has been completed. No plant refurbishment activities, outside the bounds of normal plant component replacement and inspections, have been identified to support continued operation of CNS beyond the end of the existing OL. As a result of these reviews and analyses, NPPD is not aware of significant adverse environmental effects that cannot be avoided upon implementation of the proposed project.

6.4 Irreversible or Irretrievable Resource Commitments

6.4.1 Requirement [10 CFR 51.45(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.

6.4.2 NPPD Response

The continued operation of CNS for the period of extended operation will result in irreversible and irretrievable resource commitments, including the following:

- nuclear fuel, which is consumed in the reactor and converted to radioactive waste;
- the land required to permanently store or dispose of spent nuclear fuel, low-level radioactive wastes generated as a result of plant operations, and sanitary wastes generated from normal industrial operations;
- elemental materials that will become radioactive;
- materials used for the normal industrial operations of CNS that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms.

Other than the above, there are no refurbishment activities or changes in operation of CNS during the period of extended operation that would irreversibly or irretrievably commit environmental components of land, water, and air.

However, the likely power generation alternatives if CNS ceases operations on or before the expiration of the current OL would require a commitment of resources for construction of the replacement plants as well as for fuel to run the plants.

6.5 Short-term Use Versus Long-term Productivity

6.5.1 Requirement [10 CFR 51.45(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.

6.5.2 NPPD Response

The current balance between short-term use and long-term productivity of the environment at the site has remained relatively constant since CNS began operating in 1974. The CNS 1971 FES evaluated the relationship 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 CNS [USAEC, Section VIII]. The period of extended operation will not alter the short-term uses of the environment from the uses previously evaluated in the FES. The period of extended operation will postpone the availability of the site resources (land, air, water). Denial of the application to renew the CNS OL would lead to the shutdown of the plant and would alter the balance in a manner that depends on the subsequent uses of the site. For example, the environmental consequences of turning the CNS site into a park or an industrial facility are quite different. However, extending operations will not adversely affect the long-term uses of the site.

There are no refurbishment activities or changes in operation of CNS planned for the period of extended operation that would alter the evaluation of the FES for the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity of these resources.

6.6 References

USAEC (United States Atomic Energy Commission). 1973. Final Environmental Statement Related to the Operation of Cooper Nuclear Station, Docket No. 50-298. United States Atomic Energy Commission, Directorate of Licensing.

USNRC (United States Nuclear Regulatory Commission). 2000. Supplement 1 to Regulatory Guide 4.2, Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses.

7.0 ALTERNATIVES CONSIDERED

7.1 Introduction

NRC regulations require that an applicant's environmental report discuss alternatives to a proposed action [10 CFR 51.45(b)(3)]. The intent of this review is to enable the Commission to consider the relative environmental consequences of the proposed action as compared to the environmental consequences of other activities that also meet the purpose of the proposed action and meet system generation needs. In addition, this review addresses the environmental consequences of taking no action. The alternatives are discussed below.

7.2 Proposed Action

The proposed action is to renew the operating license (OL) for CNS which would provide the option for NPPD to continue to operate CNS through the 20-year period of extended operation. CNS uses a boiling water reactor licensed for 2,419 MWt. The turbine generator has a maximum output of approximately 830 MWe gross.

The review of the environmental impacts required by 10 CFR 51.53(c)(3)(ii) is provided in Section 4. Based on this review, NPPD concludes that the environmental impacts of CNS operation during the license renewal period would be SMALL.

7.3 No-Action Alternative

The "no-action alternative" to the proposed action is not to renew the OL for CNS. In this alternative, it is expected that CNS would continue to operate up through the end of the existing OL, at which time plant operations would cease and decommissioning would begin. Because CNS constitutes a significant block of long-term baseload capacity, it is reasonable to assume that a decision not to renew the CNS license would necessitate the replacement of its approximately 830 MWe gross capacity with another generation source. The environmental impacts of the no-action alternative would be

- the environmental impacts from decommissioning CNS, and
- the environmental impacts from a replacement power source or sources.

Environmental impacts associated with decommissioning are discussed in Section 7.4. The environmental impacts associated with replacement power would be the impacts from the construction and operation of a source of replacement power at a new location (greenfield) or at the site (brownfield). The environmental impacts of these various types of replacement power are discussed in Section 8 of this ER.

7.4 Decommissioning Impacts

A nuclear power plant licensee is required to submit decommissioning plans within two years following permanent cessation of operation of a unit or at least five years before expiration of the OL, whichever occurs first, pursuant to the requirements of 10 CFR 50.54(b).

The GEIS defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license [USNRC 1996, Section 7.1]. NRC-evaluated decommissioning options include immediate decontamination and dismantlement (DECON) and safe storage of the stabilized and defueled facility (SAFSTOR) for a period of time, followed by decontamination and dismantlement.

Regardless of the option chosen, decommissioning must be completed within a 60-year period. Under the no-action alternative, NPPD would continue operating CNS until the current license expires, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of an example reactor (the "reference" reactor is the 1,155 MWe Washington Public Power Supply System's Columbia Nuclear Power Plant) [USNRC 1996, Section 7.1]. This plant is 28 percent larger in generating capacity when compared with CNS. Thus, the impacts from decommissioning CNS would presumably be bounded by the impacts cited for the Columbia Nuclear Power Plant.

As the GEIS notes, NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts include occupational and public radiation dose; impacts of waste management; impacts to air and water quality; and ecological, economic, and socioeconomic impacts. NRC indicated in Section 4.3.8 of the *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* that the environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations [USNRC 1996, Section 8.4.5]. NPPD adopts by reference the NRC conclusions regarding environmental impacts of decommissioning.

NPPD notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. NPPD will eventually have to decommission CNS; license renewal would only postpone decommissioning for a maximum of 20 years. NRC has established in the GEIS that the timing of decommissioning activities does not substantially influence their environmental impacts. NPPD adopts by reference the NRC findings (10 CFR Part 51, Appendix B, Table B-1, Decommissioning) to the effect that delaying decommissioning until after the renewal term would have small environmental impacts.

NPPD concludes that the decommissioning impacts under the no-action alternative would not be substantially different from those occurring following license renewal, as identified in the GEIS and in the decommissioning generic environmental impact statement [USNRC 1996, Section 8.2]. These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs.

7.5 Alternative Energy Sources

CNS is used for baseload generation. The GEIS states that coal-fired and gas-fired generation capacity are the feasible alternatives to nuclear power generating capacity, based on current (and expected) technological and cost factors. The following generation alternatives were considered in detail in this ER.

- Coal-fired generation at an alternate site (Section 8.1.1).
  NPPD did not consider coal-fired generation at the site since it was concluded that there was not enough land to build a comparable coal-fired unit and a coal yard. Based on Table 8.1 of the GEIS, it would take approximately 1.7 acres of land per MWe to construct a coal-fired plant. The site is situated on approximately 1,359 acres, 239 of which are located on the opposite side of the Missouri River. Therefore, for the 816 gross MWe plant described in Section 8.1.1, a coal-fired plant would require approximately 1,387 acres of land.

- Natural gas-fired generation at the site or at an alternate site (Section 8.1.2).
  The site is situated on approximately 1,359 acres (239 of which are located on the opposite side of the Missouri River). For the power block area only, the GEIS estimated that 110 acres are needed for a 1,000 MWe natural gas-fired facility [USNRC 1996, Section 8.3.10]. Scaling down for the 816 gross MWe facility would indicate a land requirement of approximately 90 acres, which would not be inclusive of support facilities. In addition, new generation units would have to be constructed in a timely manner concurrent with decommissioning, so the entire site would not be available.

- Nuclear generation at the site or an alternate site (Section 8.1.3).
  Based on Table 8.1 of the GEIS, it would take approximately 0.5 to 1.0 acres of land per MWe to construct a new nuclear plant. The site is situated on 1,359 acres (239 of which are located on the opposite side of the Missouri River). If the existing support facilities were utilized to the maximum extent possible, a new nuclear unit could be built on the current CNS site.

NPPD's experience indicates that, although customized unit sizes can be built, using standardized sizes is more economical. For example, a standard-sized gas-fired combined cycle plant has a gross capacity of 143 MWe of heat recovery capacity. For comparability, NPPD set the gross power of the hypothetical coal-fired unit equal to the hypothetical gas-fired units. Either a coal- or multiple gas-fired plants as one unit would provide approximately the same capacity as CNS (830 gross MWe).

These alternatives are presented (Sections 8.1.1, 8.1.2, and 8.1.3, respectively) as if such plants were constructed at the site (natural gas-fired and nuclear), using the existing water intake and discharge structures, switchyard, and transmission lines, or at an alternate location that could be either a current industrial site or an undisturbed, pristine site requiring a new generating building and facilities, new switchyard, and at least some new transmission lines. In this ER, a "greenfield" site is assumed to be an undisturbed, pristine site.

Depending on the location of an alternative site, it might also be necessary to connect to the nearest gas pipeline (in the case of natural gas) or rail line (in the case of coal). The requirement for these additional facilities may increase the environmental impacts relative to those that would be experienced at the site.

The potential for using imported power is discussed in Section 8.1.4. Imported power is considered potentially feasible, but would result in the transfer of environmental impacts from the current region in Nebraska to some other location in Nebraska or another state. In addition, there is no assurance that the capacity or energy would be available during the required time frame.

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" [USNRC 1996, Section 8.1]. Accordingly, the following alternatives were not considered as reasonable replacement baseload power generation. Although several of these alternatives could be considered in combination for replacement power generation at multiple sites, they do not generally provide baseload generation, and would entail greater environmental impacts.

- wind
- solar
- hydropower
- geothermal
- wood energy
- municipal solid waste
- other biomass-derived fuels
- oil
- fuel cells
- delayed retirement of other existing units
- utility-sponsored conservation
- purchased/imported power
- combination of alternatives

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 (wind, solar, and hydroelectric) would require a large area of land and would thus require a greenfield siting plan. This would result in a greater environmental impact than continued operation of CNS.

- Low capacity factors.
  Some of the technologies identified above (wind, solar, geothermal, and hydroelectric) are not capable of replacing the 830 MWe of power at high capacity factors. These generation technologies are used as peaking power sources, as opposed to baseload power sources, and for this reason are not reasonable alternatives.

- Geographic availability of the resource.
  Some of the technologies are not feasible because there is no feasible location in the area served by the site (geothermal).

- Emerging technology.
  Some of the technologies have not been proven as reliable and cost-effective replacements for a large generation facility (fuel cells, biomass derived fuels, municipal solid waste). Therefore, these technologies are typically used with smaller (lower MWe) generation facilities.

- Availability.
  There is no assurance of the availability of imported power, of power saved as the result of utility sponsored conservation, or that retirement of other existing units can be delayed.

- Cost
  Some of the technologies above are very expensive and are not a cost effective way to produce baseload power (solar, fuel cells, and oil).

7.6 References

USNRC (United States Nuclear Regulatory Commission). 1996. NUREG-1437, Generic Environmental Statement for License Renewal of Nuclear Power Plants, Final Report. Washington, DC.

USNRC (United States Nuclear Regulatory Commission). 2002. NUREG-0586, Supplement 1, Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities, Supplement 1, Regarding the Decommissioning of Nuclear Power Reactors. Washington, DC.

8.0 COMPARISON OF IMPACTS

The following key assumptions have been made in the review of alternative energy sources. 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 continued production of approximately 830 gross MWe of base-load generation. Alternatives that do not meet this goal are not considered in detail.
- The time frame for the needed generation is 2014–2034.
- Purchased power is not considered a reasonable alternative because there is no assurance that the capacity or energy would be available. See Section 8.1.4.
- The annual capacity factor of CNS based on a three year average is 93 percent. The capacity factor is targeted to remain near this value throughout the plant's operating life.
- All necessary Federal permits, licenses, approvals, and other entitlements would be obtained.

8.1 Comparison of Environmental Impacts for Reasonable Alternatives

Each year the Energy Information Administration (EIA), a component of the U.S. Department of Energy (DOE), issues an Annual Energy Outlook. In its Annual Energy Outlook 2008 with Projections to 2030, EIA projects that coal-fired plants will continue to provide the majority of the United States' electric power, providing 54 percent in 2030 [USDOE 2008, p. 11]. Combined-cycle or combustion turbine technology fueled by natural gas is likely to account for the largest increase in new generating capacity over the next ten years, but as the cost of natural gas increases, additional coal-fired units will be built [USDOE 2008, p. 54]. Both technologies are designed primarily to supply peak and intermediate capacity, but combined-cycle technology can also be used to meet base load requirements. Coal-fired plants are generally used to meet base load requirements. Renewable energy sources (excluding hydropower), primarily wind, biomass gasification, and municipal solid waste units, are projected by EIA to at least double the capacity of the 2005 values [USDOE 2008]. EIA's projections are based on the assumption that providers of new generating capacity will seek to minimize cost while meeting applicable environmental requirements.

As a result of federal tax breaks and incentives, as well as concerns about climate change and economic analysis, additional baseload generating capacity from nuclear power is expected in the United States. Even with new and additional power (power uprates) generated by nuclear power plants during the 2007 to 2030 time period, the nuclear share of the electricity market in the United States is expected to fall from 19 percent to 18 percent as the demand for electricity increases throughout the United States [USDOE 2008, p. 11]. Since 1997, the NRC has certified four new standard designs for nuclear power plants under the procedures in 10 CFR Part 52, Subpart B, an additional four designs are currently under review, and three designs are in pre-application review. A new nuclear plant alternative for replacing power generated by CNS is considered in Section 8.1.3. As of June 2008, the NRC has received nine applications, for a total of fifteen units, for Combined Operating Licenses and four applications for Early Site Permits for new nuclear plants. Three Early Site Permits have been issued.

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" [USNRC 1996, Section 8.1]. Below is a discussion of the supply side alternative energy technologies that NPPD could utilize if the license for CNS is not renewed. These alternatives are within the range of alternatives capable of meeting the goal of approximately 830 gross MWe as base-load generation (replacement power for CNS).

Carbon dioxide emissions are a major contributor to anthropogenic greenhouse gas emissions, which many scientists believe contribute to climate change. These emissions result from the efficiency of the technologies utilized to produce and deliver the energy and carbon content of the fuel being utilized. Table 8.1-1 demonstrates the differences of CO_2 emissions for various fuels which are used for electricity generation.

Table 8.1-1
CO_2 Emissions From Electricity Generation

Fuel	Pounds CO_2 per Million Btu
Subbituminous coal	212.7
Bituminous coal	205.3
#6 fuel oil	173.9
Natural gas	117.1
Nuclear	0
Renewable sources	0

Reference: USDOE 2007d

Based on the discussion above, conventional coal-fired, natural gas-fired combined cycle, and advanced light water reactors are currently available conventional base-load technologies considered to replace CNS generation upon its termination of operation.

The environmental impacts discussed in this chapter are for the construction and operation of these generation facilities. Impacts are evaluated for a greenfield case (building on a new, pristine condition site) and a brownfield case (constructing new generation on the existing CNS site, with the exception of a coal-fired unit, or at a different brownfield site).

As described below, the continued operation of CNS for the period of extended operation would result in less environmental impact than that of the replacement power that could be obtained from other reasonable generating sources.

8.1.1 Coal-Fired Generation

NRC has evaluated coal-fired generation alternatives in each of the plant-specific Supplements to the GEIS. For the V. C. Summer pressurized water reactor, NRC analyzed 816 MWe of coal-fired generation capacity [USNRC 2004, Section 8.2.1]. NPPD has reviewed the NRC analysis and believes it to be sound. In defining the CNS coal-fired alternative, NPPD has used site-specific input as appropriate.

Tables 8.1-2 through 8.1-4 present the basic coal-fired alternative emission control characteristics, emission estimates, and waste generation volumes. NPPD based its emission control technology and percent control assumptions on alternatives that the EPA has identified as being available for minimizing emissions [USEPA 1998]. The coal-fired alternative that NPPD has defined would be located at an alternative site.

8.1.1.1 Closed-Cycle Cooling System

The overall impacts at an alternate site of the coal-fired generating system using a closed-cycle cooling system with cooling towers are discussed below. The magnitude of impacts for the alternate site will depend on the location of the particular site selected. CNS currently uses a once-through system.

The environmental impacts of building a coal-fired generation facility with a closed-cycle cooling system at an alternate site are summarized in Table 8.1-5.

8.1.1.1.1 Land Use

Based on Table 8.1 of the GEIS, approximately 1.7 acres of land per MWe would be required to construct a coal-fired plant. Therefore, for the 816 MWe plant utilized in this analysis, approximately 1,387 acres of land would be needed. This could amount to a considerable loss of natural habitat or agricultural land for the plant site alone dependant upon if a greenfield or brownfield site was used, excluding that required for mining and other fuel-cycle impacts.

Additional land might also be needed for transmission lines and rail lines, depending on the location of the site relative to the nearest inter-tie connection and rail spur. Depending on the transmission line routing and nearest rail line, these alternatives could result in MODERATE to LARGE land use impacts.

Land-use changes would occur offsite in an undetermined coal-mining area to supply coal for the plant. In the GEIS, the staff estimated that approximately 22 acres of land per MWe would be affected for mining the coal and disposing of the waste to support a coal-fired plant during its operational life [USNRC 1996, Section 8.3.9]. Therefore, for the 816 MWe plant utilized in this analysis, approximately 17,952 acres of land would be needed. Partially offsetting this offsite land use would be the elimination of the need for uranium mining and processing to supply fuel for CNS. In the GEIS, the staff estimated that approximately one acre per MWe would be affected for mining and processing the uranium during the operating life of a nuclear power plant [USNRC 1996, Section 8.3.12]. Therefore, for the 816 MWe plant utilized in this analysis, approximately 816 acres of land would be required.

The impact of a coal-fired generating unit with a closed-cycle cooling system on land use located at an alternate site is considered as MODERATE to LARGE.

8.1.1.1.2 Ecology

Constructing a coal-fired plant at an alternate site could alter ecological resources because of the need to convert roughly 1,387 acres of land at the site to industrial use for the plant, coal storage, and ash and scrubber sludge disposal. However, some of this land might have been previously disturbed if a brownfield site was chosen for the coal plant siting.

Coal-fired generation at an alternative site would introduce construction impacts and new incremental operational impacts. Even assuming siting at a previously disturbed area, the impacts would alter the ecology. Impacts could include wildlife habitat loss, reduced productivity, habitat fragmentation, and a local reduction in biological diversity.

Use of cooling system makeup water from a nearby surface water body could have adverse impacts on aquatic resources. If needed, construction and maintenance of an electric power transmission line and a rail spur would have ecological impacts. There would be some impact on terrestrial ecology from water drift from the cooling towers. There would also be some impact on the body of water from the chemicals used onsite, as well as the chemicals found in emissions. Overall, the ecological impacts of constructing a coal-fired plant with a closed-cycle cooling system at an alternate site are considered to be MODERATE to LARGE.

8.1.1.1.3 Water Use and Quality

Surface Water: Cooling water at an alternate site would likely be withdrawn from a surface water body and would be regulated by permit. Depending on the water source, the impacts of water use for cooling system makeup water and the effects on water quality caused by cooling tower blowdown could have noticeable impacts. Therefore, the impacts of a new coal-fired plant utilizing a closed-cycle cooling system at an alternate site are considered SMALL to MODERATE.

Groundwater: Impacts of groundwater withdrawal would be SMALL if only used for potable water. If groundwater is used to supply makeup water, the impacts could be MODERATE to LARGE. Therefore, groundwater impacts from a coal-fired plant on the aquifer would be site-specific and dependent on aquifer recharge and other withdrawals. The overall impacts would be SMALL to LARGE.

8.1.1.1.4 Air Quality

Air quality impacts of coal-fired generation are considerably different from those of nuclear power. A coal-fired plant emits oxides of sulfur (SO_x), nitrogen oxides (NO_x), particulate matter, and carbon monoxide, all of which are regulated pollutants. As already stated, NPPD has assumed a plant design that would minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. NPPD estimates the coal-fired alternative emissions to be as follows (from Table 8.1-3).

- Oxides of sulfur = 1,036 tons per year
- Oxides of nitrogen = 654 tons per year
- Carbon monoxide = 908 tons per year
- Particulates
    - → Total suspended particulates = 92 tons per year
    - → PM_{10} (particulates having a diameter of less than 10 microns) = 21 tons per year

The acid rain requirements of the Clean Air Act amendments capped the nation's SO_x emissions from power plants. Under the Clean Air Act amendments, each fossil-fuel-fired unit was allocated SO_x allowances. To be in compliance with the Act, each facility must hold enough allowances to cover their annual SO_x emissions. NPPD would have to purchase allowances to cover its SO_x emissions.

NRC did not quantify coal-fired emissions in the GEIS, but implied that air impacts would be substantial. NRC noted that adverse human health effects from coal combustion have led to important federal legislation in recent years and that public health risks, such as cancer and emphysema, have been associated with coal combustion and also mentioned global warming and acid rain as potential impacts. NPPD concludes that federal legislation and large-scale concerns, such as global warming and acid rain, are indications of concerns about destabilizing important attributes of air resources. However, SO_x emission allowances, NO_x emission offsets, low NO_x burners with overfire air and selective catalytic reduction, fabric filters or electrostatic precipitators, and scrubbers are provided as mitigation measures. As such, NPPD concludes that the coal-fired alternative would have MODERATE impacts on air quality. The emission of "greenhouse" gases would be significantly greater than for the existing emissions at CNS.

8.1.1.1.5 Waste

NPPD concurs with the GEIS assessment that the coal-fired alternative would generate substantial solid waste. The coal-fired plant would annually consume approximately 3,633,858 tons of coal having an ash content of 5.06 percent. After combustion, 99.9 percent of this ash (approximately 183,505 tons per year) would be collected and disposed of at either an onsite or offsite landfill. In addition, approximately 56,446 tons of scrubber waste would be disposed of each year (based on annual calcium hydroxide usage of approximately 19,052 tons). NPPD estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 136 acres. The amount of land needed for final disposal of ash may be less, dependant upon the availability of local recycling options for the ash. Table 8.1-4 shows how NPPD calculated ash and scrubber waste volumes. While only half this waste volume and land use would be attributable to the 20-year license renewal period alternative, the total numbers are pertinent as a cumulative impact.

NPPD believes that, with proper siting coupled with current waste management and monitoring practices, waste disposal would not destabilize any resources. Some wooded terrestrial habitat would be dedicated to the waste site. However, after closure of the waste site and revegetation, the land could potentially be available for other uses. For these reasons, NPPD believes that waste disposal for the coal-fired alternative would have MODERATE impacts; the impacts of increased waste disposal would be clearly noticeable, but would not destabilize any important resource and further mitigation would be unwarranted.

8.1.1.1.6 Human Health

Coal-fired power generation introduces worker risk from coal and limestone mining, worker and public risk from coal and lime/limestone transportation, worker and public risk from disposal of coal combustion wastes, and public risk from inhalation of stack emissions. Emission impacts can be widespread and health risk is difficult to quantify. The coal alternative also introduces the risk of coal pile fires and attendant inhalation risk.

The NRC stated in the GEIS that there could be human health impacts (cancer and emphysema) from inhalation of toxins and particulates from a coal-fired plant, but the GEIS does not identify the significance of these impacts [USNRC 1996, Section 8.3.9]. In addition, the discharges of uranium and thorium from coal-fired plants can potentially produce radiological doses in excess of those arising from nuclear power plant operations [Gabbard].

Regulatory agencies, including the EPA and State agencies, set air emission standards and requirements based on human health impacts. These agencies also impose site-specific emission limits as needed to protect human health. EPA has recently concluded that certain segments of the U.S. population (e.g., the developing fetus and subsistence fish-eating populations) are believed to be at potential risk of adverse health effects due to mercury exposures from sources such as coal-fired power plants. However, in the absence of more quantitative data, human health impacts from radiological doses and inhaling toxins and particulates generated by a coal-fired plant at an alternate site are considered to be SMALL.

8.1.1.1.7 Socioeconomics

Based on Table 8.1 of the GEIS, construction of the coal-fired alternative would take approximately 1 year per 200 MWe rating. The peak workforce is estimated to range from 1.2 to 2.5 additional workers per MWe during the construction period, based on estimates given in Table 8.1 of the GEIS. Therefore, for the 816 MWe plant utilized in this analysis, approximately four years would be required to construct the plant with the workforce ranging from approximately 979 to 2,040 workers.

Communities around the new site would have to absorb the impacts of a large, temporary work force (up to approximately 2,040 workers at the peak of construction) and a permanent work force of approximately 0.2 workers per MWe based on Table 8.1 of the GEIS, or approximately 163 workers for the 816 MWe plant utilized in this analysis. In the GEIS, the staff stated that socioeconomic impacts at a rural site would be larger than at an urban site, because more of the peak construction work force would need to move to the area to work. Alternate sites would need to be analyzed on a case-by-case basis. Therefore, socioeconomic impacts at an isolated rural site could be LARGE.

Transportation-related impacts associated with commuting construction workers at an alternate site would be site dependent, but could be MODERATE to LARGE. Transportation impacts related to commuting of plant operating personnel would also be site dependent, but can be characterized as SMALL to MODERATE.

At most alternate sites, coal and lime would be delivered by rail, although barge delivery is feasible for a location on navigable waters. Transportation impacts would depend upon the site location. Socioeconomic impacts associated with rail transportation would be MODERATE to LARGE. Barge delivery of coal and lime/limestone would have SMALL socioeconomic impacts.

8.1.1.1.8 Aesthetics

Alternative site locations could reduce the aesthetic impact of a coal-fired generation if siting were in an area that was already industrialized. In such a case, however, the introduction of tall stacks and cooling towers would probably still have a MODERATE incremental impact. Locating at other largely undeveloped sites could show a LARGE impact. There would also be an aesthetic impact if construction of a new transmission line and/or rail spur were needed. Noise impacts associated with rail delivery of coal and lime/limestone would be most significant for residents living in the vicinity of the facility and along the rail route. Although noise from passing trains significantly raises noise levels near the rail corridor, the short duration of the noise reduces the impact. In a more suburban location, the impacts are considered MODERATE. This is due to the frequency of train transport, the fact that many people are likely to be within hearing distance of the rail route, and the impacts of noise on residents in the vicinity of the facility and the rail line. At a more rural location, the impacts could be SMALL. Noise and light from the plant would be detectable offsite. Overall, the aesthetic impacts associated with locating at an alternative site can be categorized as SMALL to LARGE, depending on the characteristics of the alternative site.

8.1.1.1.9 Historic and Archaeological Resources

Before construction at an alternate site, studies would be needed to identify, evaluate, and address mitigation of the potential impacts of new plant construction on cultural resources. The studies would be needed for areas of potential disturbance at the proposed plant site and along associated corridors where new construction would occur (e.g., roads, transmission corridors, rail lines, or other rights-of-way). Historic and archeological resource impacts can generally be effectively managed and as such are considered SMALL.

Table 8.1-2
Coal-Fired Alternative Emission Control Characteristics

Characteristic	Basis
Unit size = 408 MW ISO rating net[a]	Chosen as comparable to CNS unit.
Number of units = 2	
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxide emissions [USEPA 1998, Table 1.1-3]
Fuel type = subbituminous pulverized coal	Typical for coal used in Nebraska [USDOE 2007c, Table 4.A]
Fuel heating value = 8,514 Btu/lb	2006 value for coal used in Nebraska [USDOE 2007c, Table 15.A]
Fuel ash content by weight = 5.06%	2006 value for coal used in Nebraska [USDOE 2007c, Table 15.A]
Fuel sulfur content by weight = 0.30%	2006 value for coal used in Nebraska [USDOE 2007c, Table 15.A]
Uncontrolled NO_x emission = 7.2 lb/ton Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS [USEPA 1998, Table 1.1-3]
Heat rate = 10,164 Btu/kWh	Typical for coal-fired, single-cycle steam turbines [USDOE 2007d, Table A6]
Capacity factor = 0.85	Typical for newer large coal-fired units
NO_x control = low NO_x burners, overfire air and selective catalytic reduction (95% reduction)	Best available and widely demonstrated for minimizing NO_x emissions [USEPA 1998, Table 1.1-2]
Particulate control = fabric filters (baghouse - 99.9% removal efficiency)	Best available for minimizing particulate emissions [USEPA 1998, pp. 1.1-6 and 1.1-7]
SO_x control = Wet scrubber – lime (95% removal efficiency)	Best available for minimizing SO_x emissions [USEPA 1998, Table 1.1-1]

Btu = British thermal unit
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60% relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt-hour
NSPS = New Source Performance Standard
lb = pound
MW = megawatt
NO_x = nitrogen oxides
SO_x = oxides of sulfur

a. The difference between "net" and "gross" is electricity consumed by auxiliary equipment and environmental control devices [USDOE 2002, page 109].

Table 8.1-3
Air Emissions from Coal-Fired Alternative

Parameter	Calculation	Result
Annual coal consumption	$\frac{2 \times 408\ \text{MW}}{\text{unit}} \times \frac{10{,}164\ \text{Btu}}{\text{kW x hr}} \times \frac{1{,}000\ \text{kW}}{\text{MW}} \times \frac{\text{lb}}{8{,}514\ \text{Btu}} \times \frac{24\text{hr}}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times 0.85$	3,633,858 tons of coal per year
SO_x [a, b]	$\frac{3,633,858\ \text{tons}}{\text{yr}} \times \frac{0.30 \times 38\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100 - 95}{100}$	1,036 tons SO_x per year
NO_x [b, c]	$\frac{3,633,858\ \text{tons}}{\text{yr}} \times \frac{7.2\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100 - 95}{100}$	654 tons NO_x per year
CO [b]	$\frac{3,633,858\ \text{tons}}{\text{yr}} \times \frac{0.5\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}}$	908 tons CO per year
TSP [d]	$\frac{3,633,858\ \text{tons}}{\text{yr}} \times \frac{5.06\%\ \text{x}\ 10\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100 - 99.9}{100}$	92 tons TSP per year
PM_{10} [d]	$\frac{3,633,858\ \text{tons}}{\text{yr}} \times \frac{5.06\%\ \text{x}\ 2.31\ \text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{100 - 99.9}{100}$	21 tons PM_{10} per year

CO = carbon monoxide
NO_x = nitrogen oxides
PM_{10} = particulates having diameter less than 10 microns
SO_x = oxides of sulfur
TSP = total suspended particulates

a. USEPA 1998, Table 1.1-1
b. USEPA 1998, Table 1.1-3
c. USEPA 1998, Table 1.1-2
d. USEPA 1998, Table 1.1-4

Table 8.1-4
Solid Waste from Coal-Fired Alternative

Parameter	Calculation	Result
Annual SO_x generated[a]	$\frac{3,633,858 \text{ tons coal}}{\text{yr}} \times \frac{0.30 \text{ tons}}{100 \text{ tons coal}} \times \frac{64.1 \text{ tons } SO_2}{32.1 \text{ tons S}}$	21,769 tons of SO_x per year
Annual SO_x removed	$\frac{21,769 \text{ tons } SO_2}{\text{yr}} \times \frac{95}{100}$	20,681 tons of SO_x per year
Annual ash generated	$\frac{3,633,858 \text{ tons coal}}{\text{yr}} \times \frac{5.06 \text{ tons ash}}{100 \text{ tons coal}} \times \frac{99.9}{100}$	183,689 tons of ash per year
Annual lime consumption[b]	$\frac{21,769 \text{ tons } SO_2}{\text{yr}} \times \frac{56.1 \text{ tons CaO}}{64.1 \text{ tons } SO_2}$	19,052 tons of CaO per year
Calcium sulfate[c]	$\frac{20,681 \text{ tons } SO_2}{\text{yr}} \times \frac{172 \text{ tons } CaSO_4 \bullet 2H_2O}{64.1 \text{ tons } SO_2}$	55,493 tons of $CaSO_4 \bullet 2H_2O$ per year
Annual scrubber waste[d]	$\frac{19,052 \text{ tons CaO}}{\text{yr}} \times \frac{100 - 95}{100} + 55,493 \text{ tons } CaSO_4 \bullet 2H_2O$	56,446 tons of scrubber waste per year
Total volume of scrubber waste[e]	$\frac{56,446 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{144.8 \text{ lb}}$	31,185,635 ft^3 of scrubber waste
Total volume of ash[f]	$\frac{183,689 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{100 \text{ lb}}$	149,951,200 ft^3 of ash
Total volume of solid waste	$31,185,635 \text{ ft}^3 + 146,951,200 \text{ ft}^3$	178,136,835 ft^3 of solid waste
Waste pile area (acres)	$\frac{178,136,835 \text{ ft}^3}{30 \text{ ft}} \times \frac{\text{acre}}{43,560 \text{ ft}^2}$	136 acres of solid waste
Waste pile area (ft x ft square)	$\sqrt{178,136,835 \text{ ft}^3 / 30 \text{ ft}}$	2,437 feet by feet square of solid waste

Based on annual coal consumption of 3,633,858 tons per year (see Table 8.1-3).

S = sulfur
SO_2 = sulfur dioxide
SO_x = oxides of sulfur
CaO = calcium oxide (lime)
$CaSO_4 \bullet 2H_2O$ = calcium sulfate dihydrate

a. Calculations assume 100% combustion of coal.
b. Lime consumption is based on total SO_2 generated.
c. Calcium sulfate generation is based on total SO_2 removed.
d. Total scrubber waste includes scrubbing media carryover.
e. Density of $CaSO_4 \bullet 2H_2O$ is 144.8 lb/ft^3.
f. Density of coal bottom ash is 100 lb/ft^3 [FHA].

Table 8.1-5
A Summary of Environmental Impacts from Coal-Fired Generation Using Closed-Cycle Cooling at an Alternate Greenfield Site

Impact Category	Impact	Comments
Land Use	MODERATE to LARGE	Approximately 1,387 acre site, with additional land potentially needed for transmission lines and rail line for coal delivery.
Ecology	MODERATE to LARGE	Impact will depend on ecology of site and need for additional transmission lines.
Surface Water Use and Quality	SMALL to MODERATE	Impact will depend on volume and other characteristics of receiving water.
Groundwater Use and Quality	SMALL to LARGE	Impact will depend on site characteristics and availability of groundwater.
Air Quality	MODERATE	SO_x – 1,036 tons/yr – allowances required NO_x – 654 tons/yr – allowances required Particulate – 92 tons/yr (filterable) – 21 tons/yr (unfilterable) Carbon monoxide – 908 tons/yr Trace amounts of mercury, arsenic, chromium, beryllium, and selenium
Waste	MODERATE	Total waste volume would be estimated around 249,231 tons/yr of ash and scrubber sludge.
Human Health	SMALL	Impacts considered minor.
Socioeconomics	SMALL to LARGE	Communities would have to absorb impacts of a large, temporary workforce (up to approximately 2,040 workers at the peak of construction) and a permanent work force of approximately 163 workers. Impacts at a rural site would be larger. Transportation-related impacts associated with commuting construction workers would be site dependent.
Aesthetics	SMALL to LARGE	Could reduce aesthetic impact if siting is in an industrial area; impact would be large if siting is in a largely undeveloped area.
Historic and Archaeological Resources	SMALL	Would necessitate cultural resource studies.

8.1.1.2 Once-Through Cooling System

The environmental impacts of constructing a coal-fired generation system at an alternate greenfield site using once-through cooling are similar to the impacts for a coal-fired plant using a closed-cycle cooling system. However, there are some environmental differences between the closed-cycle and once-through cooling systems. Table 8.1-6 summarizes the incremental differences.

Table 8.1-6
Summary of Environmental Impacts from Coal-Fired Generation Using Once-Through Cooling at an Alternate Greenfield Site

Impact Category	Comments
Land Use	Compared with a closed-cycle cooling system, less land would be required because cooling towers and associated infrastructure not needed.
Ecology	Slightly reduced environmental impacts because there are no cooling towers; however, increased water withdrawal may impact aquatic resources.
Surface Water Use and Quality	Impact would depend on surface water body characteristics, volume of water withdrawn, and characteristics of the discharge.
Groundwater Use and Quality	Impact would depend on site characteristics and availability of groundwater. It is unlikely that groundwater would be used for once-through cooling, but could be used for sanitary water.
Air Quality	No change.
Waste	No change.
Human Health	No change.
Socioeconomics	No change.
Aesthetics	Reduced aesthetic impact because cooling towers would not be used.
Historic and Archaeological Resources	Less land impacted.

8.1.2 Natural Gas-Fired Generation

NPPD has chosen to evaluate gas-fired generation, using combined-cycle turbines, because it has determined that the technology is mature, economical, and feasible. Table 8.1-7 presents the basic gas-fired alternative characteristics and Table 8.1-8 presents emission estimates.

NRC has evaluated gas-fired generation alternatives in each of the plant-specific Supplements to the GEIS, focusing on combined-cycle plants. For the V. C. Summer pressurized water reactor, the NRC analyzed 816 MWe of gas-fired generation capacity [USNRC 2004, Section 8.2.2]. NPPD has reviewed the NRC analysis and believes it to be sound. In defining the CNS gas-fired alternative, NPPD has used site-specific input as appropriate.

8.1.2.1 Closed-Cycle Cooling System

The overall impacts of the natural-gas-generating system with a closed-cycle cooling system located at the CNS site or an alternate greenfield site are summarized in Table 8.1-9 and discussed in the following sections. The magnitude of impacts at an alternate site will depend on the location of the particular site selected.

8.1.2.1.1 Land Use

For siting at CNS, existing facilities and infrastructure would be used to the extent practicable, limiting the amount of new construction that would be required. Specifically, it was assumed that the natural gas-fired replacement plant alternative would use the intake and discharge systems, switchyard, offices, and transmission line right(s)-of-way. The GEIS estimated that 110 acres are needed for a 1,000 MWe natural gas-fired facility [USNRC 1996, Section 8.3.10]. Scaling down for the 816 MWe facility considered by NPPD would indicate a somewhat smaller land requirement (90 acres). Operation of a new gas-fired facility at the CNS site would require the construction of approximately 40 miles of pipeline and there is no guarantee that gas supplies would be available from the nearest line to CNS. It is estimated that this pipeline would require approximately 582 acres for an easement. The onsite facilities would represent expansion of an existing industrial land use, and CNS expects there would be little or no adverse-impact on land uses adjacent to the site, with the exception of the land which must be cleared for installation of the gas line.

For construction at an alternate site, the full land requirement of 90 acres for a natural gas-fired facility would be necessary because no existing infrastructure would be available. Additional land could be impacted by construction of a transmission line and natural gas pipelines to serve the plant. The gas line requirements at an alternate site would depend on the characteristics and location of the alternate site.

Regardless of where the natural gas-fired plant is built, additional land would be required for natural gas wells and collection stations. Partially offsetting these offsite land requirements would be the elimination of the need for uranium mining to supply fuel for CNS. In the GEIS, the staff estimated that approximately one acre per MWe would be affected for mining and processing the uranium during the operating life of a nuclear power plant [USNRC 1996, Section

8.3.12]. Therefore, for the 816 MWe plant utilized in this analysis, approximately 816 acres of land would be required.

Overall, the land-use impacts of constructing the natural gas-fired alternative at CNS are considered SMALL to MODERATE. The land-use impacts of siting the natural gas-fired alternative at an alternate greenfield site would depend on the chosen site, but are characterized as SMALL to LARGE.

8.1.2.1.2 Ecology

Siting gas-fired generation at the existing CNS site would have MODERATE ecological impacts because the facility would be constructed partly on previously disturbed areas and would disturb relatively little acreage at the site. However, significant habitat would be disturbed by approximately 40 miles of pipeline construction. Ecological impacts could be reduced by using the existing intake and discharge system. Past operational monitoring of the effects of the cooling system at CNS has not shown detectable impacts to the Missouri River ecology, and this would be expected to remain unchanged.

The GEIS noted that land-dependent ecological impacts from construction would be SMALL unless site-specific factors indicate a particular sensitivity and that operational impact would be smaller than for other fossil fuel technologies of equal capacity. The connection to a gas pipeline located approximately 40 miles from the CNS site is a site-specific factor that would make the gas-fired alternative's ecological impacts larger than those of license renewal. Therefore, in this case, the appropriate characterization of gas-fired generation ecological impacts is MODERATE.

Construction at a greenfield site could alter the ecology of the site and could impact threatened and endangered species. These ecological impacts could be SMALL to MODERATE.

8.1.2.1.3 Water Use and Quality

Surface Water: The plant would use the existing CNS intake and discharge structures as part of the closed-cycle cooling system. Therefore, water quality impacts would continue to be SMALL.

Water quality impacts from sedimentation during construction is another land-related impact that the GEIS categorized as SMALL. The GEIS also noted that operational water quality impacts would be similar to, or less than, those from other centralized generating technologies. The NRC has concluded that water quality impacts from coal-fired generation would be SMALL, and gas-fired alternative water usage would be less than that for coal-fired generation. Surface water impacts would remain SMALL; the impacts would not be detectable or be so minor that they would not noticeably alter important attributes of the resource.

For alternative greenfield sites, the impact on surface water would depend on the volume and other characteristics of the receiving body of water. The impacts would be SMALL to MODERATE.

<u>Groundwater</u>: As discussed in Section 2.3, CNS has five onsite pumpable groundwater wells. These wells provide potable and plant process water for the site. Maximum short-term plant demand is approximately 250 gpm. Cooling water is taken from the Missouri River. Therefore, groundwater impacts would be SMALL; the impacts would be so minor that they would not noticeably alter important resources.

For alternative greenfield sites, the impact to the groundwater would depend on the site characteristics, including the amount of groundwater available. The impacts would range between SMALL and LARGE.

8.1.2.1.4 Air Quality

Natural gas is a relatively clean-burning fossil fuel; the gas-fired alternative would release similar types of emissions, but in lesser quantities, than the coal-fired alternative. Control technology for gas-fired turbines focuses on NO_x emissions. NPPD estimates the gas-fired alternative emissions to be as follows (from Table 8.1-8).

- Sulfur oxides = 77 tons per year
- Oxides of nitrogen = 248 tons per year
- Carbon monoxide = 52 tons per year
- Filterable particulates = 43 tons per year (all particulates are PM_{10})

Regional air quality and Clean Air Act requirements are also applicable to the gas-fired generation alternative. NO_x effects on ozone levels, SO_x allowances, and NO_x emission offsets could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, and regulatory requirements are less stringent, the emissions are still substantial. NPPD concludes that emissions from the gas-fired alternative located at CNS would noticeably alter local air quality, but would not destabilize regional resources. Air quality impacts would therefore be MODERATE, but substantially smaller than those of coal-fired generation.

Siting the gas-fired plant elsewhere would not significantly change air quality impacts because the site could be in a greenfield area that is not a serious nonattainment area for ozone. In addition, the location could result in installing more or less stringent pollution control equipment to meet the regulations. Therefore, the impacts would be MODERATE.

8.1.2.1.5 Waste

There are only small amounts of solid waste products (i.e., ash) from burning natural gas fuel. The GEIS concluded that waste generation from gas-fired technology would be minimal. Gas firing results in very few combustion by-products because of the clean nature of the fuel. Waste generation would be limited to typical office wastes. This impact would be SMALL; waste generation impacts would be so minor that they would not noticeably alter important resource attributes.

Siting the facility at an alternate greenfield site would not alter the waste generation; therefore, the impacts would continue to be SMALL.

8.1.2.1.6 Human Health

The GEIS analysis mentions potential gas-fired alternative health risks (cancer and emphysema). The risk may be attributable to NO_x emissions that contribute to ozone formation, which in turn contributes to health risks. As discussed in Section 8.1.1.1.6 for the coal-fired alternative, legislative and regulatory control of the nation's emissions and air quality are protective of human health, and the human health impacts from gas-fired generation would be SMALL; that is, human health effects would not be detectable or would be so minor that they would neither destabilize nor noticeably alter important attributes of the resource.

Siting of the facility at an alternate greenfield site would not alter the possible human health effects. Therefore, the impacts would be SMALL.

8.1.2.1.7 Socioeconomics

Construction of a natural gas-fired plant would take approximately two years. Peak employment during construction would be approximately 979 workers [USNRC 1996, Section 8.3.10]. It is assumed that gas-fired construction would take place while CNS continues operation, with completion of the replacement plant at the time that the nuclear plant would halt operations. During construction, the communities surrounding the CNS site would experience demands on housing and public services that could have MODERATE impacts. These impacts would be tempered by construction workers commuting to the site from other parts of Nemaha, Richardson, and Otoe Counties in Nebraska and Atchison County in Missouri. After construction, the communities would be impacted by job loss. The current CNS workforce (750 workers) would decline through a decommissioning period to a minimal maintenance size.

The natural gas-fired plant would introduce a replacement tax base at CNS, or at an alternate greenfield site, and approximately 122 new permanent jobs [USNRC 1996, Section 8.3.10]. Impacts in Nemaha and Atchison Counties resulting from the decommissioning of CNS may be offset by potential unrelated job opportunities in the Omaha and Lincoln areas.

In the GEIS, the staff concluded that socioeconomic impacts from constructing a natural gas-fired plant would not be very noticeable and that the small operational workforce would have the smallest socioeconomic impacts of any nonrenewable technology [USNRC 1996, Section 8.3.10]. Compared to the coal-fired and nuclear alternatives, the smaller size of the construction work force, the shorter construction time frame, and the smaller size of the operations work force would mitigate socioeconomic impacts. For these reasons, natural gas-fired generation socioeconomic impacts associated with construction and operation of a natural gas-fired power plant would be MODERATE for siting at CNS. Depending on other growth in the area, socioeconomic effects could be noticed, but they would not destabilize any important socioeconomic attribute.

Socioeconomic impacts of constructing and operating the representative natural gas-fired alternative at a greenfield site in Nebraska would be highly location dependent. Not considering impacts from terminating CNS operations, community impacts resulting from location of the representative natural gas-fired plant in areas within reasonable distance to large population centers (i.e., Lincoln or Omaha), would likely be small, with moderate impacts possible in more rural areas. However, communities in Nemaha, Richardson, and Otoe counties in Nebraska and Atchison County in Missouri, in particular, would experience losses in both employment and tax revenues due to CNS closure, assuming the natural gas-fired alternative plant is constructed outside the area. Considered in combination with the closure and decommissioning of CNS, overall socioeconomic impacts of the natural gas-fired alternative at a greenfield site would likely range from MODERATE to LARGE.

Transportation impacts associated with construction and operating personnel commuting to the plant site would depend on the population density and transportation infrastructure in the vicinity of the site. The impacts can be classified as MODERATE for siting at CNS or at an alternate greenfield site.

8.1.2.1.8 Aesthetics

The turbine buildings and exhaust stacks would be visible during daylight hours from offsite. The gas pipeline compressors would also be visible. However, development of the representative natural gas-fired plant at the CNS site would represent an incremental addition to an existing plant with similar characteristics. Overall, the aesthetic impacts from development of a natural gas-fired plant at the CNS site would be SMALL.

At an alternate greenfield site, the buildings and the associated transmission line and gas pipeline compressors would be visible offsite. The visual impact of a new transmission line would be especially significant. Aesthetic impacts could be mitigated if the plant were located in an industrial area adjacent to other power plants. Overall, the aesthetic impacts associated with an alternate greenfield site are categorized as MODERATE to LARGE. The greatest contributor to this categorization is the aesthetic impact of the new transmission line.

Natural gas generation would introduce mechanical sources of noise that would be audible offsite. Sources contributing to total noise produced by plant operation are classified as continuous or intermittent. Continuous sources include the mechanical equipment associated with normal plant operations. Intermittent sources include the use of outside loudspeaker and the commuting of plant employees. However, it is expected that the plant would comply with all applicable noise ordinances and standards. Therefore, the noise impacts of a natural gas-fired plant at the CNS site are considered to be SMALL.

At an alternate site, these noise impacts would be SMALL to LARGE depending on the site.

8.1.2.1.9 Historic and Archaeological Resources

At both CNS and at an alternate greenfield site, a cultural resource inventory would likely be needed for any onsite property that has not been previously surveyed. Although a Phase 1A Literature Review and Archeological Sensitivity Assessment has been performed for CNS, additional historical and archeological studies could be required in the event a natural gas-fired unit was sited at CNS. Other lands, if any, that are acquired to support the plant would also likely need an inventory of field cultural resources, identification and recording of existing historic and archaeological resources, and possible mitigation of adverse effects from subsequent ground disturbing actions related to physical expansion of the plant site.

Before construction at CNS or an alternate greenfield site, studies would likely be needed to identify, evaluate, and address mitigation of the potential impacts of new plant construction on cultural resources. The studies would likely be needed for all areas of potential disturbance at the proposed plant site and along associated corridors where new construction would occur (e.g., roads, transmission and pipeline corridors, or other rights-of-way). Impacts to cultural resources can be effectively managed under current laws and regulations and kept SMALL.

Table 8.1-7
Gas-Fired Alternative Emission Control Characteristics

Characteristic	Basis
Unit size = 408 MW ISO rating net[a] Two 135 MW combustion turbines and a 138 MW heat recovery boiler	Manufacturer's standard size gas-fired combined cycle plant
Number of units = 2	
Fuel type = natural gas	Assumed
Fuel heating value = 984 Btu/ft^3	2006 value for gas used in Nebraska [USDOE 2007c, Table 14.A]
Fuel sulfur content = 0.0034 lb/MMBtu	Used when sulfur content is not available [USEPA 2000, Table 3.1-2a]
NO_x control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NO_x emissions [USEPA 2000, Table 3.1 Database]
Fuel NO_x content = 0.0109 lb/MMBtu	Typical for large SCR-controlled gas-fired units with water injection [USEPA 2000, Table 3.1 Database]
Fuel CO content = 0.0023 lb/MMBtu	Typical for large SCR-controlled gas-fired units [USEPA 2000, Table 3.1]
Heat rate = 7,502 Btu/kWh	Typical for combined cycle gas-fired turbines [USDOE 2007d, Table A6]
Capacity factor = 0.85	Typical for large gas-fired base load units.

Btu = British thermal unit
ft^3 = cubic foot
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60% relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt-hour
MM = million
MW = megawatt
NO_x = nitrogen oxides
SCR = selective catalytic reduction

a. The difference between "net" and "gross" is electricity consumed by auxiliary equipment and environmental control devices [USDOE 2002, page 109]

Table 8.1-8
Air Emissions from Gas-Fired Alternative

Parameter	Calculation	Result
Annual gas consumption	$\frac{2 \times 408\ \text{MW}}{\text{unit}} \times \frac{7{,}502\ \text{Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\ \text{kW}}{\text{MW}} \times 0.85 \times \frac{\text{ft}^3}{984\ \text{Btu}} \times \frac{24\ \text{hr}}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}}$	46,322,837,268 ft^3 per year
Annual Btu input	$\frac{46{,}322{,}837{,}268\ \text{ft}^3}{\text{yr}} \times \frac{984\ \text{Btu}}{\text{ft}^3} \times \frac{\text{MMBtu}}{10^6\text{Btu}}$	45,581,672 MMBtu per year
SO_x[a]	$\frac{0.0034\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{45{,}581{,}672\ \text{MMBtu}}{\text{yr}}$	77 tons SO_x per year
NO_x[b]	$\frac{0.0109\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{45{,}581{,}672\ \text{MMBtu}}{\text{yr}}$	248 tons NO_x per year
CO[b]	$\frac{0.0023\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{45{,}581{,}672\ \text{MMBtu}}{\text{yr}}$	52 tons CO per year
TSP[a]	$\frac{0.0019\ \text{lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} \times \frac{45{,}581{,}672\ \text{MMBtu}}{\text{yr}}$	43 tons filterable TSP per year
PM_{10}[a]	$\frac{43\ \text{tons TSP}}{\text{yr}}$	43 tons filterable PM_{10} per year

CO = carbon monoxide
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter less than 10 microns
SO_x = oxides of sulfur
TSP = total suspended particulates

a. USEPA 2000, Table 3.1-2a
b. USEPA 2000, Table 3.1-1

Table 8.1-9
Summary of Environmental Impacts from Gas-Fired Generation Using Closed-Cycle Cooling at CNS and Alternate Greenfield Site

Impact Category	CNS Site		Alternative Greenfield Site	
	Impact	Comments	Impact	Comments
Land Use	SMALL to MODERATE	~135 acres for power block, offices, roads, parking areas, and cooling tower(s). Use existing infrastructure to minimize new land requirements. Additional land impacts for construction of underground gas pipeline.	SMALL to LARGE	Land use requirement higher due to need for developing infrastructure. Total impact would depend on whether the alternate site is previously disturbed.
Ecology	MODERATE	Constructed on land within CNS site. Possible significant habitat loss due to pipeline construction. Additional impact to terrestrial biota from cooling tower drift.	SMALL to MODERATE	Impact depends on location and ecology of site; potential habitat loss and fragmentation; reduced productivity and biological diversity.
Surface Water Use and Quality	SMALL	Uses existing intake and discharge structures. Discharge of cooling tower blowdown containing dissolved solids. Discharge would be regulated. Decreased water withdrawal and less thermal load on receiving body of water. Consumptive use of water due to evaporation.	SMALL to MODERATE	Impact depends on volume and characteristics of receiving water body. Discharge of cooling tower blowdown containing dissolved solids. Discharge would be regulated. Decreased water withdrawal and less thermal load on receiving body of water. Consumptive use of water due to evaporation.
Groundwater Use and Quality	SMALL	CNS does not use onsite groundwater for cooling water. Groundwater is used for potable and process water only.	SMALL to LARGE	Impacts dependent on site characteristics, including amount of groundwater available.

Table 8.1-9 (Continued)
Summary of Environmental Impacts from Gas-Fired Generation Using Closed-Cycle Cooling at CNS and Alternate Greenfield Site

Impact Category	CNS Site		Alternative Greenfield Site	
	Impact	**Comments**	**Impact**	**Comments**
Air Quality	MODERATE	Primarily NO_X. Impacts could be noticeable, but not destabilizing.	MODERATE	Same impacts as CNS site.
Waste	SMALL	Small amount of ash produced.	SMALL	Same impacts as CNS site.
Human Health	SMALL	Impacts considered minor.	SMALL	Same impacts as CNS site.
Socioeconomics	MODERATE	Additional workers during construction period, followed by reduction from current CNS workforce.	MODERATE to LARGE	Construction impacts would be relocated. Community near CNS would still experience workforce reduction.
Aesthetics	SMALL	Visual impact of stacks, equipment, and cooling tower(s) would be noticeable, but not as significant as coal option. Possible noise impact from operation of cooling tower(s).	SMALL to LARGE	Significance of impacts would depend on the characteristics of the alternate site. The gas-fired alternative at an alternate site could require transmission lines with attendant aesthetic impacts.
Historic and Archaeological Resources	SMALL	Any potential impacts can likely be effectively managed.	SMALL	Any potential impacts can likely be effectively managed.

8.1.2.2 Once-Through Cooling System

The environmental impacts of constructing a natural-gas-fired generation system at CNS and at an alternate site using a once-through cooling system are similar to the impacts for a natural-gas-fired plant using closed-cycle cooling with cooling towers. However, there are some environmental differences between the closed-cycle and once-through cooling systems. Table 8.1-10 summarizes the incremental differences.

Table 8.1-10
Summary of Environmental Impacts from Natural Gas-Fired Generation Using Once-Through Cooling at CNS and Alternate Greenfield Site

Impact Category	CNS Site	Alternate Greenfield Site
Land Use	Compared with a closed-cycle cooling system, less land would be required because cooling towers and associated infrastructure not needed.	Compared with a closed-cycle cooling system, less land would be required because cooling towers and associated infrastructure not needed.
Ecology	Slightly reduced environmental impacts because there are no cooling towers; however, increased water withdrawal may impact aquatic resources.	Slightly reduced environmental impacts because there are no cooling towers; however, increased water withdrawal may impact aquatic resources.
Surface Water Use and Quality	Impact would depend on surface water body characteristics, volume of water withdrawn, and characteristics of the discharge.	Impact would depend on surface water body characteristics, volume of water withdrawn, and characteristics of the discharge.
Groundwater Use and Quality	No change.	Impact would depend on site characteristics and availability of groundwater. It is unlikely that groundwater would be used for once-through cooling, but could be used for sanitary water.
Air Quality	No change.	No change.
Waste	No change.	No change.
Human Health	No change.	No change.
Socioeconomics	No change.	No change.
Aesthetics	Reduced aesthetic impact because cooling towers would not be used.	Reduced aesthetic impact because cooling towers would not be used.
Historic and Archaeological Resources	Less land impacted.	Less land impacted.

8.1.3 Nuclear Power Generation

Since 1997, the NRC has certified four new standard designs for nuclear power plants under 10 CFR Part 52, Subpart B. These designs are the 1,300 MWe U.S. Advanced Boiling Water Reactor (10 CFR Part 52, Appendix A), the 1,300 MWe System 80+ Design (10 CFR Part 52, Appendix B), the 600 MWe AP600 Design (10 CFR Part 52, Appendix C), and the 1,100 MWe AP1000 Design (10 CFR Part 52, Appendix D). All of these design are for light-water reactors. Four additional designs are under review and awaiting certification and three others are undergoing pre-application reviews. Several designs in pre-application review are not light water reactors; these include the helium-cooled Pebble Bed Modular Reactor and the heavy water moderated and cooled Advanced Candu Reactor. As of June 2008, nine applications, for 15 units, for combined licenses and four applications for early site permits have been submitted to the NRC for review. Three early site permit applications have been approved and issued. As a result of federal tax breaks and incentives, as well as concerns about climate change and economic analysis, additional generation capacity from nuclear power is expected. In addition, recent volatility of natural gas prices and electricity in general has made new nuclear power plant construction more attractive from a cost standpoint. [USNRC 2003, Section 8.2.3] Consequently, construction of a new nuclear power plant at CNS or at an alternate site using closed-cycle cooling is considered in this section. It was assumed that the new nuclear plant would have an initial 40-year license term with the opportunity to renew for an additional 20- year license term.

The NRC summarized environmental data associated with the uranium fuel cycle in Table S-3 of 10 CFR 51.51. The impacts shown in Table S-3 are representative of the impacts that would be associated with a replacement nuclear power plant built to one of the certified designs, sited at an alternate site. The impacts shown in Table S-3 are for a 1,000 MWe reactor and would need to be adjusted to reflect replacement of CNS, which has a capacity of approximately 816 gross MWe. The environmental impacts associated with transporting fuel and waste to and from a light-water cooled nuclear power reactor are summarized in Table S-4 of 10 CFR 51.52. The summary of the NRC's findings on NEPA issues for license renewal of nuclear power plants in Table B-1 of 10 CFR Part 51, Subpart A, Appendix B, is also relevant, although not directly applicable, for consideration of environmental impacts associated with the operation of a replacement nuclear power plant [USNRC 2003, Section 8.2.3].

8.1.3.1 Closed-Cycle Cooling System

The environmental impacts of constructing a nuclear power plant at the existing CNS site or at an alternate greenfield site using closed-cycle cooling are summarized in Table 8.1-11.

Table 8.1-11
Summary of Environmental Impacts from Nuclear Power Generation Using Closed-Cycle Cooling at CNS and Alternate Greenfield Site

Impact Category	CNS Site		Alternate Greenfield Site	
	Impact	Comments	Impact	Comments
Land Use	MODERATE	Requires approximately 500 to 1,000 acres for the plant and 1,000 acres for uranium mining.	MODERATE to LARGE	Same impacts as CNS site, plus the potential need for land for transmission line(s). Overall, the impacts would depend on whether the alternate site is previously disturbed.
Ecology	SMALL to MODERATE	Uses undeveloped areas at current CNS site. Potential habitat loss and fragmentation; reduced productivity and biological diversity. Impact to terrestrial ecology from cooling tower drift.	MODERATE to LARGE	Impact depends on location and ecology of the site, surface water body used for intake and discharge, and transmission line route; potential habitat loss and fragmentation; reduced productivity and biological diversity. Impact to terrestrial ecology from cooling tower drift.
Surface Water Use and Quality	SMALL to MODERATE	Discharge of cooling tower blowdown containing dissolved solids. Discharge would be regulated by the State of Nebraska. Consumptive use of water due to evaporation from cooling towers.	SMALL to MODERATE	Impacts would depend on the volume of water withdrawn and discharged and the characteristics of the surface water sources. Discharge of cooling tower blowdown containing dissolved solids. Discharge would be regulated by the State of Nebraska. Consumptive use of water due to evaporation from cooling towers.

**Table 8.1-11 (Continued)
Summary of Environmental Impacts from Nuclear Power Generation
Using Closed-Cycle Cooling at CNS and Alternate Greenfield Site**

Impact Category	CNS Site		Alternate Greenfield Site	
	Impact	Comments	Impact	Comments
Groundwater Use and Quality	SMALL	Groundwater at CNS is only used as potable water and plant process water, not for plant cooling water.	SMALL to MODERATE	Impacts would depend on the volume of water withdrawn and discharged and the characteristics of the groundwater source.
Air Quality	SMALL	Fugitive emissions and emissions from vehicles and equipment during construction. Small amount of emissions from diesel generators and possibly other sources during operation.	SMALL	Same impacts as CNS site.
Waste	SMALL	Waste impacts for an operating nuclear power plant are set out in 10 CFR Part 51, Appendix B, Table B-1. Debris would be generated and removed during construction.	SMALL	Same impacts as CNS site.
Human Health	SMALL	Human health impacts for an operating nuclear power plant are set out in 10 CFR Part 51, Appendix B, Table B-1.	SMALL	Same impacts as CNS site.

Table 8.1-11 (Continued)
Summary of Environmental Impacts from Nuclear Power Generation Using Closed-Cycle Cooling at CNS and Alternate Greenfield Site

Impact Category	CNS Site		Alternate Greenfield Site	
	Impact	**Comments**	**Impact**	**Comments**
Socioeconomics	SMALL to LARGE	During construction, impacts would be MODERATE to LARGE, with up to 2,500 workers during peak period of the five-year construction period. During operation, employment levels would be similar to those for CNS. Overall, socioeconomic impacts from operation are SMALL.	SMALL to LARGE	The characteristics of the construction period and operation at an alternate site would be similar to those at CNS. Socioeconomic impacts to the local community would depend on the characteristics of the alternate site and might vary from SMALL to LARGE.
Socioeconomics (Transportation)	SMALL to LARGE	Transportation impacts associated with construction workers could be MODERATE to LARGE. Transportation impacts of commuting workers during operations would be SMALL.	SMALL to LARGE	Transportation impacts associated with construction workers could be MODERATE to LARGE. Transportation impacts of commuting workers during operations would be SMALL to MODERATE.

**Table 8.1-11 (Continued)
Summary of Environmental Impacts from Nuclear Power Generation
Using Closed-Cycle Cooling at CNS and Alternate Greenfield Site**

Impact Category	CNS Site		Alternate Greenfield Site	
	Impact	**Comments**	**Impact**	**Comments**
Aesthetics	SMALL to MODERATE	Introduction of cooling towers and associated plume. Natural draft towers could be up to 520 feet in height. Mechanical draft towers could be up to 100 feet in height and also have an associated noise impact.	SMALL to LARGE	Impacts would depend on the characteristics of the alternate site. Natural draft towers could be up to 520 feet in height. Mechanical draft towers could be up to 100 feet in height and also have an associated noise impact Impacts would be SMALL if the plant is located adjacent to an industrial area. New transmission lines would add to the impacts and could be MODERATE. If a greenfield site is selected, the impacts could be LARGE.
Historic and Archaeological Resources	SMALL	Any potential impacts can likely be effectively managed.	SMALL	Same impacts as CNS site.

8.1.3.1.1 Land Use

The existing facilities and infrastructure at the CNS site would be used to the extent practicable, limiting the amount of new construction that would be required. Specifically, the replacement nuclear power plant would use the existing transmission facilities, roads, parking areas, office buildings, and the existing cooling system. According to the GEIS, a light-water reactor requires approximately 500 to 1,000 acres excluding transmission lines (these estimates are not scaled to any particular facility size). Much of the land that would be used has been previously disturbed. The CNS site consists of approximately 1,359 acres, of which 239 acres are on the opposite bank of the Missouri River, and should be adequate to support a new nuclear facility by using some existing structures. There would be no net change in land needed for uranium mining because land needed to supply the new nuclear plant would offset the land needed to supply uranium for fueling the existing reactor CNS. Overall, the impact of a replacement nuclear generating plant on land use at the existing CNS site is characterized as MODERATE.

Land-use requirements at an alternate greenfield site would be similar to siting at the CNS site plus the possible need for land to support a new transmission line. In addition, it may be necessary to construct a rail spur to an alternate site to bring in equipment during construction. Depending particularly on transmission line routing, siting a new nuclear plant at an alternate greenfield site would result in MODERATE to LARGE land-use impacts.

8.1.3.1.2 Ecology

Locating a replacement nuclear power plant at the CNS site would alter ecological resources because of construction and the need to convert currently unused land to industrial use. In total, impact could include habitat degradation, fragmentation, or loss as a result of construction activities and conversion of land to industrial use. Ecological communities may experience reduced productivity and biological diversity from disturbing previously intact land. Overall, the ecological impacts of the nuclear alternative at the CNS site are considered SMALL to MODERATE.

An alternate site would be impacted by construction and new incremental operations. Even assuming siting at a previously disturbed area, the impacts may alter the ecology. Impacts could include (1) habitat degradation, habitat fragmentation, or habitat loss; (2) reduced ecosystem productivity; and (3) reduced biological diversity. Construction and maintenance of transmission lines, a rail spur, or a barge offloading facility could result in the same types of ecological impacts. Use of makeup cooling water from a nearby surface water body could have adverse aquatic resource impacts. Overall, the impacts of the nuclear alternative at an alternate site would be MODERATE to LARGE.

8.1.3.1.3 Water Use and Quality

Surface Water: A replacement nuclear power plant located at the CNS site is assumed to use the existing intake structure, with cooling water supplied by the Missouri River. However, cooling towers would need to be constructed. Plant discharges would be regulated by the State of Nebraska. Some erosion and sedimentation may occur during construction of the new unit and cooling tower. The impact would be SMALL to MODERATE.

For a replacement reactor located at an alternate site, new intake structures would need to be constructed to provide water needs for the facility. The impact would depend on the volume of water withdrawn for makeup, relative to the amount available from the intake source and the characteristics of the surface water. Plant discharges would be regulated by the State of Nebraska. Some erosion and sedimentation may occur during construction. The impact would be SMALL to MODERATE.

Groundwater: As discussed in Section 2.3, CNS has five onsite pumpable groundwater wells. These wells provide potable and plant process water for the site. Maximum short-term plant demand is approximately 250 gpm. Cooling water is taken from the Missouri River. Therefore, groundwater impacts would be SMALL; the impacts would be so minor that they would not noticeably alter important resources. A newly constructed nuclear plant at the CNS site would most likely be able to tie into the current well system at the site. Therefore, groundwater impact would be SMALL. The impact of the nuclear alternative at an alternate site would be SMALL to MODERATE.

8.1.3.1.4 Air Quality

Construction of a new nuclear plant at the CNS site or an alternate site would result in fugitive emissions during the construction process. Exhaust emissions would also come from vehicles and motorized equipment used during the construction process. An operating nuclear plant would have minor air emissions associated with diesel generators and other minor intermittent sources. These emissions would be regulated by the NDEQ. Overall, emissions and associated impacts to air quality of a nuclear plant at either the CNS site or an alternate site are considered SMALL.

8.1.3.1.5 Waste

The waste impacts associated with operation of a nuclear power plant are listed in Table B-1 of 10 CFR Part 51, Subpart A, Appendix B. Construction-related debris would be generated during construction activities and removed to an appropriate disposal site. Overall, waste impacts of a new nuclear plant at either the CNS site or an alternate site are considered SMALL.

8.1.3.1.6 Human Health

Human health impacts for an operating nuclear power plant are identified in 10 CFR Part 51, Subpart A, Appendix B, Table B-1. Overall, human health impacts of a new nuclear plant at either the CNS site or an alternate site are considered SMALL.

8.1.3.1.7 Socioeconomics

For a 1,000 MWe reactor, it was assumed that the construction period would be 5 years and the peak construction workforce would be 2,500. It was also assumed that construction would take place while the existing nuclear unit continues operation and would be completed by the time CNS permanently ceases operations. The current CNS workforce (750 workers) would decline through a decommissioning period to a minimal maintenance size.

For a facility constructed at the CNS site, construction workers would be in addition to the employees that currently work at the site. Surrounding communities would experience significant, but not necessarily destabilizing, demands on housing and public services. After construction, the communities would be impacted by the loss of the construction jobs. In total, the socioeconomic impacts during the construction period for the nuclear alternative at the CNS site are considered MODERATE to LARGE.

At an unnamed alternate site, the construction impacts could be smaller or larger than those at the CNS site, depending on how close the site is to a vital economic center. These impacts are considered to be SMALL to LARGE depending on the site.

The replacement nuclear unit is assumed to have an operating work force comparable to the 750 employees currently working at CNS. The replacement nuclear unit would provide a new tax base to offset the loss of tax base associated with decommissioning of CNS. For all of these reasons, the appropriate characterization of socioeconomic impacts for operating a new nuclear power plant constructed at CNS is considered SMALL.

The impacts of operating the nuclear alternative at an unnamed alternate site could be smaller or larger than those at the CNS site, depending on how close the alternate site is to an economic center. These impacts are considered SMALL to LARGE, depending on the site.

During the five-year construction period, up to approximately 2,500 construction workers could be working at the site, in addition to the 750 employees workers currently employed at CNS. The addition of the construction workers could place significant traffic loads on existing highways. Such impacts would be MODERATE to LARGE. Transportation impacts related to commuting of plant operating personnel would be similar to current impacts associated with operation of CNS and are considered SMALL.

Transportation-related impacts associated with commuting construction workers at an alternate greenfield site are site-dependent, but could be MODERATE to LARGE. Transportation impacts related to commuting of plant operating personnel would also be site-dependent, but can be characterized as SMALL to MODERATE.

8.1.3.1.8 Aesthetics

The nuclear alternative would result in aesthetic impacts. Visual impacts would result from several structures, including, most prominently, the containment building and the cooling tower(s). The replacement nuclear unit would also likely be visible at night because of outside lighting. Visual impact at night could be mitigated by reduced use of lighting and appropriate use of shielding. Overall, the visual aesthetic impacts of the nuclear unit alternative at the CNS site are considered MODERATE.

At an alternate site, depending on placement, there would be an aesthetic impact from the buildings and cooling towers. There would also be a significant aesthetic impact associated with construction of a new transmission line to connect to other lines to enable delivery of electricity. Light from the plant would be detectable offsite, but could be mitigated if the plant is located in an industrial area adjacent to other power plants, in which case the impact could be SMALL. The impact could be MODERATE if a transmission line needs to be built to the alternate site. The impact could be LARGE if a greenfield site is selected.

Nuclear generation would introduce mechanical sources of noise from plant operation. The noise sources are both continuous and intermittent. Continuous sources include the mechanical equipment associated with normal plant operations. Intermittent sources include the use of outside loudspeakers and the commuting of plant employees. At the CNS site, the plant operation noises would be similar to existing noise levels from operating the plant. The noise impacts of the nuclear alternative at CNS are considered to be SMALL.

At an alternate site, these noise impacts would be SMALL to LARGE, depending on the site.

8.1.3.1.9 Historic and Archeological Resources

At both CNS and at an alternate greenfield site, a cultural resource inventory would likely be needed for any onsite property that has not been previously surveyed. Although a Phase 1A Literature Review and Archeological Sensitivity Assessment has been performed at CNS, additional historical and archeological studies could be required in the event a replacement nuclear unit was sited at CNS. Other lands, if any, that are acquired to support the plant would also likely need an inventory of field cultural resources, identification and recording of existing historic and archaeological resources, and possible mitigation of adverse effects from subsequent ground disturbing actions related to physical expansion of the plant site.

Before construction at CNS or an alternate greenfield site, studies would likely be needed to identify, evaluate, and address mitigation of the potential impacts of new plant construction on cultural resources. The studies would likely be needed for all areas of potential disturbance at the proposed plant site and along associated corridors where new construction would occur (e.g., roads, transmission and pipeline corridors, or other rights-of-way). Impacts to cultural resources can be effectively managed under current laws and regulations and kept SMALL.

8.1.3.2 Once-Through Cooling System

The environmental impacts of constructing a nuclear power plant that uses once-through cooling at CNS or at an alternate greenfield site are similar to the impacts for a nuclear power plant using closed-cycle cooling with cooling towers. However, there are some differences in the environmental impacts between the closed-cycle and once-through cooling systems. In those impact categories related to land-area requirements, such as land use, terrestrial ecology, and cultural resources, the impacts are likely to be smaller if the site uses a once-through cooling system rather than a closed-cycle cooling system. However, the impacts of a plant with a once-through cooling system are likely to be greater than a plant with a closed-cycle cooling system in the areas of water use and aquatic ecology because of the need for greater quantities of cooling water. Table 8.1-12 summarizes the incremental differences.

Table 8.1-12
Summary of Environmental Impacts from Nuclear Power Generation Using Once-Through Cooling at CNS or Alternate Greenfield Site

Impact Category	CNS	Alternate Greenfield Site
Land Use	Compared with a closed-cycle cooling system, less land would be required because cooling towers and associated infrastructure not needed.	Compared with a closed-cycle cooling system, less land would be required because cooling towers and associated infrastructure not needed.
Ecology	No impact to terrestrial ecology from cooling tower drift. Increased water withdrawal with possible greater impact to aquatic ecology.	Impact would depend on ecology of the site. No impact to terrestrial ecology from cooling tower drift. Increased water withdrawal with possible greater impact to aquatic ecology.
Surface Water Use and Quality	No discharge of cooling tower blowdown. Increased water withdrawal and more thermal load on the receiving body of water.	No discharge of cooling tower blowdown. Increased water withdrawal and more thermal load on the receiving body of water.
Groundwater Use and Quality	No change.	Impact would depend on site characteristics and availability of groundwater. It is unlikely that groundwater would be used for once-through cooling, but could be used for sanitary water.
Air Quality	No change.	No change.
Waste	No change.	No change.
Human Health	No change.	No change.
Socioeconomics	No change.	No change.
Aesthetics	Reduced aesthetic impact because cooling towers would not be used.	Reduced aesthetic impact because cooling towers would not be used, but impacts could still be large if lengthy transmission line is required.
Historic and Archaeological Resources	Less land impacted.	Less land impacted.

8.1.4 Purchased Electrical Power

"Purchased power" is power purchased and transmitted from electric generation plants that the applicant does not own and that are located elsewhere within the region, nation, Canada, or Mexico. If available, purchased power from other sources could potentially preclude the need to renew the CNS license.

In theory, purchased power is a feasible alternative to CNS license renewal. There is no assurance, however, that sufficient capacity or energy would be available during the entire time frame of 2014 through 2034 to replace the approximately 830 MWe of base-load generation. For example, EIA projects that total gross U.S. imports of electricity from Canada and Mexico will gradually decrease from 30 percent in 2006 to 27 percent in 2030 [USDOE 2008, p. 9]. It appears unlikely that electricity imported from Canada or Mexico would be able to replace the CNS generating capacity.

If power to replace CNS capacity were to be purchased from sources within the U.S. or a foreign country, the generating technology would likely be one of those described in this ER and in the GEIS (probably coal, natural gas, or nuclear). The description of the environmental impacts of other technologies in Chapter 8 of the GEIS is representative of the purchased power alternative to renewal of the CNS OL. Thus, the environmental impacts of purchased power would still occur, but would be located elsewhere within the region, nation or another country. For these reasons, NPPD does not believe that purchasing power to make up for the generation at CNS is a meaningful alternative that requires independent analysis.

8.2 Alternatives Not Within the Range of Reasonable Alternatives

Other commonly known generation technologies considered are listed in the following paragraphs. However, these sources have been eliminated as reasonable alternatives to the proposed action because the generation of approximately 830 MWe of electricity as a base-load supply using these technologies is not technologically feasible.

8.2.1 Wind

As of July 2006, there were approximately 73 MWe of grid-connected wind power facilities in Nebraska [AWEA]. Statewide, it is estimated that there is a potential for approximately 99,100 MWe of installed capacity, the sixth highest potential in the United States [AWEA].

Wind power by itself is not suitable for large baseload capacity. As discussed in Section 8.3.1 of the GEIS, wind has a high degree of intermittency and average annual capacity factors for wind plants are relatively low (less than 30 percent). Wind power in conjunction with energy storage mechanisms might serve as a means of providing base-load power. However, current energy storage technologies are too expensive for wind power to serve as a large base-load generator. [USNRC 2005, Section 8.2.5.2]

For these reasons development of large-scale, land-based wind power facilities are likely not only to be costly, but could have MODERATE to LARGE impacts on aesthetics, archaeological resources, land use, and terrestrial ecology.

Wind power could be included in a combination of alternatives to replace CNS. The environmental impacts of a large-scale wind farm are described in the GEIS [USNRC 1996, Section 8.3.1]. The construction of roads, transmission lines, and turbine tower supports would result in short-term impacts, such as increases in erosion and sedimentation, and decreases in air quality from fugitive dust and equipment emissions. Construction in undeveloped areas would have the potential to disturb and impact cultural resources or habitat for sensitive species. During operation, some land near wind turbines could be available for compatible uses such as agriculture. The continuing aesthetic impact would be considerable and there is a potential for bird and bat collisions with turbine blades. Wind farms generate very little waste and pose no human health risk other than from occupational injuries. Although most impacts associated with a wind farm are SMALL or can be mitigated, some impacts such as the continuing aesthetic impact and impacts to sensitive habitats could be LARGE, depending on the location.

8.2.2 Solar

Solar technologies use the sun's energy to provide heat, cooling, light, hot water, and electricity for homes, businesses, and industry. Solar power technologies, both photovoltaic (PV) and thermal, cannot currently compete with conventional fossil-fueled technologies in grid-connected applications due to higher capital costs per kilowatt of capacity. The average capacity factor of PV cells is about 25 percent and the capacity factor for solar thermal systems is about 25–40 percent. These capacity factors are low because solar power is an intermittent resource, providing power when the sun is strong, whereas CNS provides constant base-load power. Solar technologies simply cannot make up for the capacity from CNS during the night and in overcast conditions. [USNRC 2005, Section 8.2.5.3]

There are also substantial impacts to natural resources (wildlife habitat, land use, and aesthetic impacts) from construction of solar power generation facilities. As stated in the GEIS, land requirements are high. Based on the land requirements of 14 acres for every 1 MWe generated, over 11,620 acres would be required to replace the approximately 830 MWe produced by CNS. There is not enough land for either type of solar electric system at the existing CNS site and both types of systems would have LARGE environmental impacts at an alternate site.

The construction impacts would be similar to those associated with a large wind farm as discussed in Section 8.2.1. The operating facility would also have considerable aesthetic impact. Solar installations pose no human health risk other than from occupational injuries. The manufacturing process for constructing a large amount of photovoltaic cells would result in waste generation, but this waste generation has not been quantified. Some impacts, such as impacts to sensitive areas, loss of productive land, and the continuing aesthetic impact, could be LARGE, depending on the location.

8.2.3 Hydropower

Nebraska has a technical potential for 345 MWe of additional installed hydroelectric capacity. This 345 MWe is divided amongst 45 potential sites, with the largest having a potential for 22 MWe. Fifty-three percent of the sites have a potential capacity of less than 1 MWe. [INEL 1997] As stated in Section 8.3.4 of the GEIS, hydropower's percentage of United States generating capacity is expected to decline because the facilities have become difficult to site as a result of public concern about flooding, destruction of natural habitat, and alteration of natural river courses. As stated in Section 8.3.4 of the GEIS, the percentage of the U.S. electrical generation consisting of hydroelectricity is expected to decline because hydroelectric facilities have become difficult to site as a result of public concern over flooding, destruction of natural habitat, and destruction of natural river courses.

An additional area for potential consideration would be that of hydropump storage. Hydropump storage could be used as an intermediate source, but is not used as base-load power. Siting such a facility could potentially be an issue as well.

The GEIS estimated that land requirements for hydroelectric power are approximately 1 million acres per 1,000 MWe. Replacement of the CNS generating capacity would therefore require flooding a substantial amount of land (830,000 acres). Due to the large land-use and related environmental and ecological resource impacts associated with siting hydroelectric facilities large enough to replace CNS, it can be concluded that local hydropower alone is not a feasible alternative to the renewal of the CNS OL on its own, even if the capacity for development were available in Nebraska. Any attempts to site hydroelectric facilities large enough to replace CNS would result in LARGE environmental impacts.

8.2.4 Geothermal

Geothermal has an average capacity factor of 90 percent and can be used for base-load power where available. However, as illustrated by Figure 8.4 in the GEIS, geothermal plants would primarily be located in the western continental United States, Alaska, and Hawaii where geothermal 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. [USNRC 1996, Section 8.3.5] In addition, although Nebraska may have the potential for the use of geothermal energy in a heating/thermal capacity, it does not have the potential for development of geothermal powered electricity. [USDOE 2007f] Therefore, geothermal energy is not a feasible alternative to renewal of the CNS OL.

8.2.5 Wood Energy

The use of wood waste to generate electricity is largely limited to those states with significant wood resources, such as California, Maine, Georgia, Minnesota, Oregon, Washington, and Michigan. Electric power is generated in these states by the pulp, paper, and paperboard industries, which consume wood and wood waste for energy, benefiting from the use of waste materials that could otherwise represent a disposal problem. [USNRC 2005, Section 8.2.5.6]

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 [USNRC 1996, Section 8.3.6]. The fuels required are variable and site-specific. A significant barrier to the use of wood waste to generate electricity is the high delivered-fuel cost and high construction cost per MWe of generating capacity. The larger wood-waste power plants are only 40 to 50 MWe in capacity. Estimates in the GEIS suggest that the overall level of construction impact per megawatt of installed capacity should be approximately the same as that for a coal-fired plant, although facilities using wood waste for fuel would be built at smaller scales. Like coal-fired plants, wood-waste plants require large areas for fuel storage and processing and involve the same type of combustion equipment. [USNRC 2005, Section 8.2.5.6]

Due to uncertainties associated with obtaining sufficient wood and wood waste to fuel a base load generating facility, ecological impacts of large-scale timber cutting (e.g., soil erosion and loss of wildlife habitat), and high inefficiency, wood waste is not a feasible alternative to renewing the CNS OL.

8.2.6 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 municipal solid waste-handling and waste-separation equipment and stricter environmental emissions controls. The decision to burn municipal waste to generate energy is usually driven by the need for an alternative to landfills rather than by energy considerations. [USNRC 1996, Section 8.3.7] High costs prevent this technology from being economically competitive. Thus, municipal solid waste generation is not a reasonable alternative. [USNRC 2001, p. 8-26]

As of 2007 there are 87 waste-to-energy plants operating in the United States, none of which are located in Nebraska. These plants generate approximately 2,720 MWe, or an average of approximately 31 MWe per plant, much smaller than needed to replace the approximately 830 gross MWe at CNS. [IWSA]

Estimates in the GEIS suggest that the overall level of construction impact from a waste-fired plant should be approximately the same as that for a coal-fired plant. Additionally, waste-fired plants have the same or greater operational impacts (including impacts on the aquatic environment, air, and waste disposal). Some of these impacts would be moderate, but still larger than the environmental effects of license renewal of CNS. Therefore, municipal solid-waste combustors would not be a feasible alternative to renewal of the CNS OL, particularly at the scale required.

8.2.7 Other Biomass-Derived Fuels

In addition to wood and municipal solid waste fuels, there are several other concepts for fueling electric generators, including burning energy crops, converting crops to a liquid fuel such as ethanol (ethanol is primarily used as a gasoline additive for automotive fuel), and gasifying energy crops (including wood waste) [USNRC 2001, p. 8-26]. The GEIS points out that none of these technologies has progressed to the point of being competitive on a large scale or of being reliable enough to replace a base-load plant such as CNS. For these reasons, such fuels do not offer a feasible alternative to CNS license renewal. In addition, these systems have LARGE impacts on land use.

8.2.8 Oil

Oil-fired operation is more expensive than nuclear or coal-fired operation. Future increases in oil prices are expected to make oil-fired generation increasingly more expensive than coal-fired generation. The high cost of oil has prompted a steady decline in its use for electricity generation. Increasing domestic concerns over oil security will only exacerbate the move away from oil-fired electricity generation. Therefore, oil-fired generation by itself is not considered a feasible alternative to the renewal of the CNS OL.

8.2.9 Fuel Cells

Fuel cells work without combustion and its environmental side effects. Power is produced electrochemically by passing a hydrogen-rich fuel over an anode, passing air over a cathode, and separating the two by an electrolyte. The only by-products are heat, water, and carbon dioxide. Hydrogen fuel can come from a variety of hydrocarbon resources by subjecting them to steam under pressure. Natural gas is typically used as the source of hydrogen. [USNRC 2005, Section 8.2.5.9]

Phosphoric acid fuel cells are generally considered first-generation technology. These fuel cells are commercially available at cost of approximately $4,500 per kW of installed capacity. The U.S. Department of Energy has launched a major initiative, the Solid State Energy Conversion Alliance, to bring about dramatic reductions in fuel cell costs. The goal is to cut costs to as low as $400 per kilowatt by 2010, which would make fuel cells competitive for virtually every type of power application. For comparison, the installed capacity cost for a natural gas-fired, combined-cycle plant is about $400 per kW. [USDOE 2007e] However, at the present time, fuel cells are not economically or technologically competitive with other alternatives for base-load electricity generation. Fuel cells are, consequently, not a feasible alternative to renewal of the CNS OL.

8.2.10 Delayed Retirement

Even without retiring any generating units, NPPD expects to require additional capacity in the near future. At this time NPPD does not have any planned retirement of any generating units prior to 2014. Thus, even if substantial capacity were scheduled for retirement and could be delayed, some of the delayed retirement would be needed just to meet load growth. Therefore, any such retirements that do occur in this period would merely act to further increase projected demand.

CNS would be required, in part, to offset any actual retirements that occur. Delayed retirement of other NPPD generating units would not provide a replacement of the power supplied by CNS and would not be a feasible alternative to CNS license renewal.

8.2.11 Utility-Sponsored 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 generation sources that are technically feasible and commercially viable". It is neither single, nor discrete, nor is it a source of generation [USNRC 1996, Section 8.1].

Demand side management resource strategies aimed at increasing energy efficiency on the customer side of the electric meter generally fall under the following categories.

- Energy efficiency-selecting equipment that will perform the same work with less energy input.
- Load response-customers who agree to respond to utility requests to reduce use during times of utility peak demand.
- Load management, which encourages customers to reduce their loads during peak times of day and peak season through the use of time-of-use rates, seasonal rates, and interruptible contracts; or direct load control, in which a utility interrupts power supply to customer equipment.

Typically, demand side management induced load reductions are acknowledged in load forecasts. Therefore they cannot be used as credits to offset the power generated by CNS. However, NPPD does encourage demand side management and in 2007 realized 515 MWe of demand reduction and an additional 57 MWe from several other conservation programs [NPPD]. As a practical matter, it would be virtually impossible to increase those energy savings to completely and consistently replace the CNS generating capability.

The environmental impacts of an energy conservation program would be SMALL, but the potential to displace the entire generation at CNS solely with conservation is not realistic. Although it is recognized that energy conservation is promoted and increases in energy efficiency occur as a normal result of replacing older equipment with modern equipment, the conservation option by itself is not considered a reasonable replacement for the CNS OL renewal alternative.

8.2.12 Combination of Alternatives

NRC indicated in the GEIS that, while many methods are available for generating electricity and a huge number of combinations or mixes can be assimilated to meet system needs, such expansive consideration would be too unwieldy given the purposes of the alternatives analysis. Therefore, NRC determined that a reasonable set of alternatives should be limited to analysis of single discrete electrical generation sources and only those electric generation technologies that are technically reasonable and commercially viable [USNRC 1996, Section 8.1]. Although several of these alternatives could be considered in combination for replacement power generation at multiple sites, they do not generally provide baseload generation, and would entail greater environmental impacts. Therefore consistent with the NRC determination, NPPD has not evaluated mixes of generating sources.

8.3 Proposed Action vs. No Action

The proposed action is to renew the operating license (OL) for CNS which would provide the option for NPPD to continue to operate CNS through the 20-year period of extended operation. The specific review of the thirteen environmental impacts required by 10 CFR 51.53(c)(3)(ii) concluded that there would be no adverse impact to the environment from the continued operation of CNS through the period of extended operation.

The no-action alternative to the proposed action is the decision not to pursue renewal of the OL for CNS. 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 net environmental impacts would be transferred from the continued operation of CNS to the environmental impacts associated with the construction and operation of a new generating facility. Therefore, the no-action alternative would have no net environmental benefits.

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

The Joint DOE-Electric Power Research Institute Strategic Research and Development Plan to Optimize U.S. Nuclear Power Plants stated, "… 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, "…it is important to maintain the operation of the current fleet of nuclear power plants throughout their safe and economic lifetimes". [Duke] The renewal of the CNS OL is consistent with these goals.

8.4 Summary

The proposed action is to renew the operating license (OL) for CNS which would provide the option for NPPD to continue to operate CNS through the 20-year period of extended operation. The proposed action would provide the continued availability of approximately 830 gross MWe of base-load power generation through 2034.

The environmental impacts of the continued operation of CNS, providing approximately 830 MWe of base-load power generation through 2034, are superior to impacts associated with the best case among reasonable alternatives. The continued operation of CNS would create significantly less environmental impact than the construction and operation of new base-load generation capacity.

Finally, the continued operation of CNS will have a significant positive economic impact on the communities surrounding the station.

8.5 References

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9.0 STATUS OF COMPLIANCE

9.1 Requirement [10 CFR 51.45(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 which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection. The discussion of alternatives in the report shall include a discussion of whether the alternatives will comply with such applicable environmental quality standards and requirements."

9.2 Environmental Permits

Table 9.2-1 provides a list of the environmental permits held by CNS 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. Table 9.2-2 lists environmental consultations related to the renewal of the CNS OL.

Table 9.2-1
CNS Environmental Permits and Compliance Status

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
NRC	Atomic Energy Act, 10 CFR 50	Operating license	DPR-46	January 18, 2014	Operation of CNS.
NDEQ	Federal Water Pollution Control Act Section 402	NPDES Permit	NE0001244	June 30, 2012	Discharge of wastewaters to water of the State.
NDEQ	Federal Water Pollution Control Act Section 402	General NPDES Permit	NER000059	September 17, 2012	Discharge of stormwater to waters of the State.
NDEQ	Title 129, Nebraska Air Quality Regulations	Permit to Construct an Air Contaminant Source	Not applicable	Not applicable	Operation of air emission sources (one emergency generator and one fire pump).
NDEQ	Title 128, Nebraska Hazardous Waste Regulations	Hazardous Waste Generator Identification	NED1055071064-2	Not applicable	Hazardous waste generation
NDEQ	Title 122, Rules and Regulations for Underground Injection and Mineral Production Wells	Class V Well Underground Injection	NE0208256	November 16, 2010	Underground injection of fluid using 10-5D2 stormwater drainage wells
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-030088	Not applicable	Onsite potable well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-030089	Not applicable	Onsite potable well

Table 9.2-1 (Continued)
CNS Environmental Permits and Compliance Status

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-040718	Not applicable	Fire protection well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-100339	Not applicable	River Well A
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-100340	Not applicable	River Well B
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-149001A	Not applicable	Observation well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-149001B	Not applicable	Observation well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-149001C	Not applicable	Observation well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-149001D	Not applicable	Observation well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-149001E	Not applicable	Observation well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-149001F	Not applicable	Observation well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-149001G	Not applicable	Observation well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-149001H	Not applicable	Observation well

Table 9.2-1 (Continued)
CNS Environmental Permits and Compliance Status

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-149001I	Not applicable	Observation well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-149001J	Not applicable	Observation well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Well registration	G-149001K	Not applicable	Observation well
NDNR	Neb. Rev. Stat. 46-602 to 46-604	Water withdrawal permit	D-1071	Not applicable	Withdrawal of water from Missouri River for use at CNS
NHHSS	Title 179, Chapter 9, Nebraska Department of Health and Human Services Regulation And Licensure	Class III Public Water Supply System Permit	NE3150505	Not applicable	Withdrawal of groundwater for drinking and plant water purposes.
NWPCC	33 U.S.C. §1341, Clean Water Act, Section 401	401 Certification	Not applicable	Not applicable	Discharge of once-through cooling water to the Missouri River
SCDHEC	Act No. 429 of 1980, South Carolina Radioactive Waste Transportation and Disposal Act	CNS Radioactive Waste Transport Permit	0218-26-08-X	December 31, 2008	Transportation of radioactive waste into the State of South Carolina

Table 9.2-1 (Continued)
CNS Environmental Permits and Compliance Status

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
TDEC	Tennessee Department of Environment and Conservation Regulations	CNS Radioactive Waste License for Delivery	T-NE002-L08	December 31, 2008	Shipment of radioactive material into Tennessee to a disposal/processing facility
UDEQ	Utah Radiation Control Rules R313-26	Generator Site Access Permit	0111000042	January 3, 2009	Accessing a land disposal facility in Utah

DOT U.S. Department of Transportation
NDEQ Nebraska Department of Environmental Quality
NDNR Nebraska Department of Natural Resources
NHHSS Nebraska Health and Human Services System
NRC U.S. Nuclear Regulatory Commission
NWPCC Nebraska Water Pollution Control Council
SCDHEC South Carolina Department of Health and Environmental Control
TDEC Tennessee Department of Environment and Conservation (Division of Radiological Health)
UDEQ Utah Department of Environmental Quality (Division of Radiological Health)

Table 9.2-2
Environmental Consultations Related to License Renewal

Agency	Authority	Activity Covered	Response
U.S. Fish and Wildlife Service	Endangered Species Act Section 7 (16 USC 1636)	Requires federal agency issuing a license to consult with USFWS	As of the time of the ER submittal, no agency response received in reply to NPPD consultation letter.
Nebraska Game and Parks Commission	Endangered Species Act Section 7 (16 USC 1636)	Requires federal agency issuing a license to consult with the fish and wildlife agency at the state level.	As of the time of the ER submittal, no agency response received in reply to NPPD consultation letter.
Missouri Department of Conservation	Endangered Species Act Section 7 (16 USC 1636)	Requires federal agency issuing a license to consult with the fish and wildlife agency at the state level.	As of the time of the ER submittal, no agency response received in reply to NPPD consultation letter.
Nebraska State Historical Society (NESHPO)	National Historic Preservation Act Section 106	Requires federal agency issuing a license to consider cultural impacts and consult with SHPO.	No impacts anticipated from CNS License Renewal.
Missouri Department of Natural Resources (SHPO)	National Historic Preservation Act Section 106	Requires federal agency issuing a license to consider cultural impacts and consult with SHPO.	Survey requested. Phase 1A study completed March 2008.

9.3 Water Quality (401) Certification

Federal CWA, Section 401, requires an applicant for a federal license to conduct an activity that might result in a discharge into navigable waters to provide the licensing agency a certification from the state that the discharge will comply with applicable CWA requirements (33 USC 1341). The Nebraska Water Pollution Control Council issued a Section 401 State Water Quality Certification for CNS on June 11, 1971 (provided in Attachment C). The NDEQ has confirmed that the certification would remain valid throughout the period of extended plant operation. See Attachment C. The NRC has indicated in its GEIS that issuance of an NPDES permit implies continued certification by the state [NRC, Section 4.2.1.1]. The EPA granted Nebraska the authority to issue NPDES permits under its own program, the Nebraska NPDES program. Attachment C contains the NPDES permit that authorizes plant discharges at CNS. Consistent with the GEIS, NPPD is providing a copy of its NPDES permit as evidence of a state water quality (401) certification.

9.4 Environmental Permits—Discussion of Compliance

CNS has established control measures in place to ensure compliance with its environmental permits, including monitoring, reporting, and operating within specified limits. CNS Chemistry personnel and NPPD Corporate Environmental personnel are primarily responsible for monitoring and ensuring that the site complies with its environmental permits and applicable regulations. Sampling results are submitted to appropriate agencies.

9.4.1 Water Quality

The release of pollutants in wastewaters at the CNS facility is regulated and controlled through NPDES Permit NE0001244 issued by the NDEQ. There are six outfalls identified in the NPDES Permit as follows.

- Outfall 001 (Discharge of Once Pass Through Cooling Water)
- Outfall 002B (Clear Well Discharge and Outfall 004 Emergency Overflow)
- Outfall 002C (Floor Drains)
- Outfall 004 (RO Reject and Boiler Blowdown Wastestreams)
- Outfall 008 (Waste Sample Tank)
- Outfall 009 (Sample Tank Floor Drain)

Compliance with the NPDES Permit over previous years has been excellent. For example, there has never been an exceedance relative to thermal discharge limits as identified in the station's NPDES Permit over the previous five years (2003–2007). Non-related thermal noncompliances such as pH, total suspended solids, and oil and grease exceedances have been very infrequent in previous years, with any deviations properly addressed and reported in accordance with either the conditions outlined in the permit or as recommended by the regulatory agency. Table 9.4-1 provides a summary of non-related thermal noncompliances since 2003.

Table 9.4-1
CNS Non-Related Thermal Noncompliances Summary

NPDES Outfall	Noncompliance	Date
002C	Oil & grease exceedance	February 2003
002A*	Total suspended solids exceedance	May 2003
002C	Oil & grease exceedances (2)	October 2003
004	Oil and grease exceedance	January 2004
*Outfall has been deleted from permit.		

Stormwater discharges associated with industrial activities at the CNS site are regulated and controlled through an industrial stormwater general permit (NPDES Permit NER000059) issued by the NDEQ. This Permit requires CNS to develop, maintain, and implement a stormwater pollution prevention plan for the facility that minimizes the discharge of pollutants in stormwater runoff, ensures stormwater discharges do not result in or significantly contribute to violations of NDEQ Title 117 (Nebraska Surface Water Quality Standards) or NDEQ Title 118 (Groundwater Quality Standards and Use Classifications) and, maintains compliance with other requirements listed in the industrial stormwater general permit. CNS is in compliance with the terms and conditions of this permit.

Potable water for the site is supplied by two onsite wells. These wells are registered with the Nebraska Department of Natural Resources and permitted as non-transient non-community public water supply system by the Nebraska Department of Health and Human Services System via Permit NE3150505. Nebraska's Regulations Governing Public Water Supply, Title 179, NAC2, regulates and controls the operation of this drinking water system. CNS is in compliance with these regulations.

With the exception of the Maintenance Training Facility, which has septic leaching fields, sanitary wastewaters from plant locations are transferred to two onsite sewage lagoons (A and B), where it undergoes normal digestion processes. Depending on water level in the lagoons, wastewaters are periodically pumped from the lagoons for irrigation purposes. These land application activities are regulated in accordance with NDEQ's Title 119, Chapter 12. CNS is in compliance with this regulation.

CNS has a Class V Well Underground Injection permit which covers the operation of a series of catchment basins (or drywells) that collect stormwater runoff from the site. These basins or drains do not discharge directly to a surface water body, but instead seep into the groundwater table. There is no routine regulatory monitoring or reporting requirements associated with this permit.

The EPA's Oil Pollution Prevention Rule became effective January 10, 1974, and was published under the authority of Section 311(j)(1)(C) of the Federal Water Pollution Control Act (CWA). The regulation has been published in 40 CFR Part 112 and facilities subject to the rule must prepare and implement a Spill Prevention, Control, and Countermeasure (SPCC) Plan to prevent any discharge of oil into or upon navigable waters of the United States or adjoining shorelines. CNS is subject to this rule and has a written SPCC Plan that identifies and describes the procedures, materials, equipment, and facilities that are utilized at the station to minimize the frequency and severity of oil spills in order to meet the requirements of this rule.

9.4.2 Air Quality

As shown in Table 9.2-1, the station has a permit to operate one emergency diesel generator and one diesel fire pump. Operation of these air emission sources is maintained within the operating fuel usage and sulfur limits established in the station air permit, issued by NDEQ. For purposes of the Clean Air Act, CNS is considered a minor air emission source and is reflected as such in the air permit. CNS is in compliance with this permit. There are additional generators on site which are not required to be permitted under NDEQ air quality regulations.

Under Title VI of the Clean Air Act, the EPA is responsible for several programs that protect the stratospheric ozone layer. Regulations promulgated by EPA to protect the ozone layer are in 40 CFR Part 82. Motor vehicle air conditioners and refrigeration appliances are regulated under Sections 608 and 609 of the Clean Air Act. A number of service practices, refrigerant reclamation, technician certification, and other requirements are covered by these programs. CNS is in compliance with Section 608 of the Clean Air Act as amended in 1990 and the implementing regulations codified in 40 CFR Part 82. The program to manage stationary refrigeration appliances at CNS is described in the NPPD Corporate Environmental Manual, [NPPD 2007a]. Since motor vehicle air conditioners are not serviced on-site, Section 609 of the Clean Air Act is not applicable.

9.4.3 Solid Waste

As a generator of both low-level and high-level radioactive wastes, CNS is subject to and complies with provisions and requirements of the Low-Level Radioactive Waste Policy Amendment Act of 1985 and the Nuclear Waste Policy Act of 1982, as subsequently amended, and the Nuclear Waste Policy Act of 1982.

9.4.4 Emergency Planning and Community Right-to-Know

CNS complies with Section 312 of the Emergency Planning and Community Right-to-Know Act that requires the submittal of an emergency and hazardous chemical inventory report (Tier II) to the Local Emergency Planning Commission, the State Emergency Response Commission, and the local fire department. This report, which typically include such chemicals as fuel oil, lead-acid batteries, liquid nitrogen, and sulfuric acid are submitted to these agencies annually. However, CNS is not subject to the Risk Management Plan (RMP) requirements described in 40 CFR 68 since no threshold quantities of a regulated substance are exceeded.

9.4.5 Hazardous Materials

There are several stationary bulk petroleum tanks located on-site. For underground bulk petroleum storage tanks, CNS has made the appropriate notifications to the NDEQ regarding these tanks. Aboveground bulk petroleum storage tanks are not required to be registered in the State of Nebraska. However, the CNS SPCC Plan includes all bulk oil storage tanks and oil-filled operational and electrical equipment located on-site.

Herbicide and pesticide usage occurs periodically at the site and in transmission line right-of-ways owned by NPPD. Herbicides utilized for onsite weed control and pesticides utilized for control of onsite insects, such as wasps, is hand-applied by contractors via sprayers. Herbicides utilized for weed control along the transmission line ROWs owned by NPPD are applied mechanically and occasionally hand-applied by contractors. State law requires that all applicators be trained and certified on the application of restricted use herbicides. Herbicides are applied in accordance with the manufacturer's labeled directions by a Certified Pesticide Applicator (if restricted use herbicide), and application documented (NPPD K142 Record Form) as per NPPD, Corporate Environmental Manual, Section 12, Chapter 1, Managing Pesticides.

The Toxic Substances Control Act of 1976 regulates polychlorinated biphenyls (PCBs) and asbestos. Asbestos in the form of insulation and gaskets is present on-site. However, NPPD has phased out the use of PCBs onsite. NPPD is in compliance with the asbestos regulations applicable to the CNS facility.

CNS is also subject to the hazardous substance release and reporting provisions of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980, as subsequently amended. Any release of reportable quantities of listed hazardous substances to the environment requires a report to the National Response Center and to the NDEQ and subsequent written follow-up. There have been no CERCLA reportable spills over the previous five years (2003–2007).

Hazardous Materials Transportation Act

Since NPPD is a subdivision of the Nebraska state government, the Hazardous Materials Transportation Act (HMTA) does not apply to NPPD's transportation of these materials, because governmental transportation of hazardous materials is excepted from HMTA requirements when it is carried out by government personnel for a governmental purpose. NPPD's transport would also be exempt from the HMTA even if it used privately-owned vehicles to transport hazardous materials, so long as NPPD controlled the operation of those vehicles. The HMTA would only apply if NPPD employed private contractor personnel to transport hazardous materials. [NPPD 1994; DOT 2006]

9.4.6 Biological

Potential impacts on federal- and state-listed species were considered in NPPD's review and analysis and impacts were determined to be SMALL. However, per Section 7 of the Endangered Species Act, a more structured consultation process with the USFWS may be initiated by the NRC.

9.4.7 Zoning-Related Codes (Nemaha, Nebraska)

CNS is not subject to any Nemaha County, Nebraska, zoning-related codes.

9.4.8 Wetlands

As discussed in Section 2.4 of this ER, there are federal jurisdictional wetlands located on CNS's owner-controlled area. For federal jurisdictional wetland areas, a Section 404 Permit would have to be obtained from the USACE prior to performing activities in these type areas. NPPD complies with regulatory requirements imposed by USACE as it relates to performing activities in federal jurisdictional wetland areas.

9.4.9 Noise

There are no sound ordinances imposed by Nemaha that limit allowable sound levels at CNS. Due to the rural location of the site and the lack of nearby residences, noise impacts to the public are negligible. In addition, there are no site activities that would create a condition such that the OSHA 8-hour Time Weighted Allowance would be exceeded at the CNS property line, as discussed in Section 2.1 of this ER.

9.4.10 Air Navigation

Coordination with the Federal Aviation Administration (FAA) is required when it becomes necessary to ensure that the highest structures associated with the project do not impair the safety of aviation. Submission of a letter of notification (with accompanying maps and project description) to the FAA would result in a written response from the FAA certifying that no hazard exists or recommending project changes and/or the installation of warning devices such as lighting.

The site elevation is dominated by the 328.8-foot high elevated release point and meteorological tower, which are equipped with FAA lighting systems. There are no plans at this time to build any new structures during the license renewal periods; therefore, no new notifications to the FAA are required.

9.4.11 Health and Safety

OSHA governs the occupational safety and health of the construction workers and the operational staffs. These requirements are incorporated into the site's occupational health and safety practices. NPPD complies with OSHA requirements and, as discussed in Section 4.13.5 of this ER, NPPD complies with requirements of the NESC.

9.4.12 Environmental Reviews

NPPD has procedural controls in place to ensure that environmentally sensitive areas, if present, are adequately protected during site operations and project planning [CNS 2007; NPPD 2007b]. These controls, which encompass nonradiological program areas such as air, stormwater, NPDES, spill prevention, and waste, consist of the following:

- required nonradiological review and documentation process prior to engaging in additional construction or operational activities that may result in an environmental impact, and

- required review for protection of either existing or potentially existing cultural resources.

These measures ensure that appropriate local, state, and/or federal permits are obtained or modified as necessary, that cultural resources and threatened and endangered species are protected if present, and that other regulatory issues are adequately addressed if necessary.

9.5 References

CNS (Cooper Nuclear Station). 2007. Procedure 0.40.4, Planning, August 30, 2007, Revision 4.

DOT (United States Department of Transportation). 2006. Letter from H. L. Mitchell, Department of Transportation, Pipeline and Hazardous Materials Safety Administration to C. Nunez, City of Surprise, Water Services Department. November 15, 2006.

NPPD (Nebraska Public Power District). 1994. Letter from D. G. Dales, NPPD Senior Staff Attorney to J. L. Citta, Jr., NPPD. June 22, 1994.

NPPD (Nebraska Public Power District). 2007a. Corporate Environmental Manual, Section 11, Chapter 3, Managing Refrigerants and Associated Stationary Appliances. January 2007

NPPD (Nebraska Public Power District). 2007b. Corporate Environmental Manual, Section 9, Chapter 3, Land Disturbing Activities. December 2007.

NRC (United States Nuclear Regulatory Commission). 1996. NUREG-1437, Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, Final Report. May 1996.

Attachment A

Threatened and Endangered Species Correspondence

- J.L. Citta, Jr., NPPD, to J. Hoskins, Missouri Department of Conservation, January 15, 2008.
- J.L. Citta, Jr., NPPD, to R. Amack, Nebraska Game and Parks Commission, January 15, 2008.
- J.L. Citta, Jr., NPPD, to C. Scott, United States Fish and Wildlife Service, Columbia, Missouri Field Office, January 15, 2008.
- J.L. Citta, Jr., NPPD, to J. Cochnar, United States Fish and Wildlife Service, Columbia, Nebraska Field Office, January 15, 2008.

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. John Hoskins, Director
Missouri Department of Conservation
P.O. Box 180
2901 W. Truman Blvd.
Jefferson City, MO 65102

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Hoskins:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential environmental impacts from the continued operation of CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist. If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Peggy Horner w/att.
Endangered Species Coordinator
Missouri Department of Conservation

Tom Nagel, Natural History Biologist w/att.
Northwest Regional Office
Missouri Department of Conservation

Rick Buckley (Entergy Nuclear) w/att.

Nebraska Public Power District

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Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. Rex Amack, Director
Nebraska Game and Parks Commission
2200 N. 33rd St.
Lincoln, NE 68503

**RE: Nebraska Public Power District
Cooper Nuclear Station**

Dear Mr. Amack:

Nebraska Public Power District (NPPD) is preparing an application to the US Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts in the vicinity of CNS or its associated transmission lines and corridors, as a result of license renewal at CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Kristal Stoner (GPC) w/att.
Rick Buckley (Entergy Nuclear) w/att.

Nebraska Public Power District
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Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. Charlie Scott, Field Supervisor
U. S. Fish and Wildlife Service
Columbia Ecological Services Field Office
101 Park DeVille Drive, Suite A
Columbia, MO 65203-0057

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Scott:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts in the vicinity of CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Mr. Steve Anschutz (USFWS) w/att.
Rick Buckley (Entergy Nuclear) w/att.

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Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. John Cochnar
U. S. Fish and Wildlife Service
Ecological Services - Nebraska Field Office
203 West Second Street,
Grand Island, NE 68801

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Cochnar:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

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To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts in the vicinity of CNS or its associated transmission lines and corridors, as a result of license renewal at CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Charlie Scott (USFWS) w/att.
Rick Buckley (Entergy Nuclear) w/att.

Attachment B

Historic and Archaeological Properties Correspondence

- J. L. Citta, Jr., NPPD, to M. Miles, Missouri Department of Natural Resources, January 15, 2008.
- M. Miles, Missouri Department of Natural Resources, to J. L. Citta, Jr., NPPD, February 5, 2008.
- K. M. Krumland, NPPD, to M. Miles, Missouri Dept of Natural Resources, May 30, 2008.
- J. L. Citta, Jr., NPPD, to M. J. Smith, Nebraska State Historical Society, January 15, 2008.
- L. R. Puschendorf, Nebraska State Historical Society, to J. L. Citta, Jr., NPPD, February 11, 2008.
- M. Miles, Missouri Department of Natural Resources, to K. M. Krumland, NPPD, June 9, 2008.
- K. M. Krumland, NPPD, to M. J. Smith, Nebraska State Historical Society, May 30, 2008.

Nebraska Public Power District

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Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. Mark Miles
State Historic Preservation Officer
Department of Natural Resources
P.O. Box 176
Jefferson City, MO 65102

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Miles:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts to cultural resources in the vicinity of CNS as a result of license renewal at CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist. If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

If you have any questions or need additional information, please feel free to call me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Rick Buckley (Entergy Nuclear) w/att.

STATE OF MISSOURI
Matt Blunt, Governor • Doyle Childers, Director

DEPARTMENT OF NATURAL RESOURCES

www.dnr.mo.gov

RECEIVED
FEB 11 2008

February 5, 2008

Joe L. Citta, Jr.
Corporate Environmental Manager
Nebraska Public Power District
P.O. Box 499
Columbus, Nebraska 68602-0499

Re: Cooper Nuclear Station (NRC) 55 Acres, Atchison County, Missouri

Dear Mr. Citta:

Thank you for submitting information on the above referenced project for our review pursuant to Section 106 of the National Historic Preservation Act (P.L. 89-665, as amended) and the Advisory Council on Historic Preservation's regulation 36 CFR part 800, which require identification and evaluation of cultural resources.

We have reviewed the information provided concerning the above referenced project, and cannot find any reference in our files that the project area was surveyed for historic architectural and archaeological resources. We have determined that there is a moderate to high potential for the presence of archaeological sites near and within the area of the proposed project, as indicated by the topographic location, and that an historic architectural and archaeological survey should be conducted.

A list of independent historians/architectural historians and archaeological contractors who can perform such services is available through the Department of Natural Resources, Division of Administrative Support. The list can be obtained by calling (573) 751-0958 and requesting the "historians/architectural historians list" and "archaeological contractors list." Note that any 36 CFR Part 61 qualified archaeologist may perform an archaeological survey. If you choose a contractor not on the list, please be certain to include his or her curriculum vitae in the report. We would appreciate one (1) hard copy and one (1) pdf copy of the survey report when it is finished so we may complete the review and comment process.

If you have any questions, please write Judith Deel at State Historic Preservation Office, P.O. Box 176, Jefferson City, Missouri 65102 or call Ms. Deel at 573/751-7862. Please be sure to include the SHPO Log Number **(004-AT-08)** on all future correspondence or inquiries relating to this project.

Sincerely,

STATE HISTORIC PRESERVATION OFFICE

Mark A. Miles

Mark A. Miles
Director and Deputy
State Historic Preservation Officer

c Robert Stout, DNR/OD

Recycled Paper

ENV-705.0350

Nebraska Public Power District

"Always there when you need us"

K. Michael Krumland
Environmental Protection Supvr.
PH: 402-563-5329

May 30, 2008

Mr. Mark Miles
State Historic Preservation Officer
Department of Natural Resources
P.O. Box 176
Jefferson City, MO 65102

RE: Nebraska Public Power District - Cooper Nuclear Station
SHPO Log Number (004-AT-08)

Dear Mr. Miles:

In response to your letter of February 5, 2008 I have enclosed the "Phase 1A Literature Review and Archeological Sensitivity Assessment of the Cooper Nuclear Station" for Nemaha County, Nebraska and Atchison County, Missouri. The enclosures include a hard copy of the document and a CD with the document in pdf format.

The report was prepared by Dr. James M. Briscoe for Enercon Services, Inc. Dr. Briscoe's curriculum vitae is included as an attachment to the report. Also, for your information, Cooper Nuclear Station's Administrative Procedure 0.51, "Cultural Resources Protection Plan" is attached to the report.

If you have any questions, please feel free to contact me at 402-563-5329.

Sincerely,

K. Michael Krumland

K. Michael Krumland
Environmental Protection Supervisor

Enc.

bc: Joe Citta, Jr. w/o enc.
Dave Bremer w/o enc.
Ricky Buckley (Entergy Nuclear) w/o enc.

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Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. Michael J. Smith
State Historic Preservation Officer
Nebraska State Historical Society
P.O. Box 82554
Lincoln, NE 68501

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Smith:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential impacts to cultural resources in the vicinity of CNS or its associated transmission lines and corridors, as a result of license renewal at CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Rick Buckley (Entergy Nuclear) w/att.

NEBRASKA STATE HISTORICAL SOCIETY
1500 R STREET, P.O.BOX 82554, LINCOLN, NE 68501-2554
(402) 471-3270 Fax: (402) 471-3100 1-800-833-6747 www.nebraskahistory.org

February 11, 2008

Joel L. Citta, Jr.
NPPD
PO Box 499
Columbus, NE 68602-0499

RE:

hp_num	descr
0801-050-01	NPPD; COOPER NUCLEAR STATION

Dear Mr. Citta:

Thank you for submitting the referenced project proposal for our review and comment. Our comment on this project and its potential to affect historic properties is required by Section 106 of the National Historic Preservation Act of 1966, as amended, and implementing regulations 36 CFR Part 800.

Given the information provided, in our opinion there will be no historic structures affected by the project as proposed. Should any changes in the project be made or in the type of funding or assistance provided through federal or state agencies, please notify this office of the changes before further project planning continues.

Please retain this correspondence and your documented finding in order to show compliance with Section 106 of the National Historic Preservation Act, as amended. If you have any questions, please do not hesitate to our office at 402.471.4787.

Sincerely,

Bob Puschendorf

L. Robert Puschendorf
Deputy State Historic Preservation Officer
Nebraska State Historic Preservation Office

RECEIVED
FEB 13 2008

STATE OF MISSOURI
Matt Blunt, Governor • Doyle Childers, Director
DEPARTMENT OF NATURAL RESOURCES
www.dnr.mo.gov

June 9, 2008

K. Michael Krumland
Nebraska Public Power District
P.O. Box 499
Columbus, Nebraska 68602-0499

Re: Cooper Nuclear Station (NRC) 55 Acres, Atchison County, Missouri

Dear Mr. Krumland:

Thank you for submitting information on the above referenced project for our review pursuant to Section 106 of the National Historic Preservation Act (P.L. 89-665, as amended) and the Advisory Council on Historic Preservation's regulation 36 CFR Part 800, which requires identification and evaluation of cultural resources.

We have reviewed the May 2008 report entitled *Phase IA Literature Review and Archaeological Sensitivity Assessment of the Cooper Nuclear Station, Nemaha County, Nebraska and Atchison County, Missouri* by Enercon Services, Inc. Based on this review we concur with the investigator's recommendations for areas of high potential for the occurrence of archaeological sites in the fifty-five (55) acres of the Cooper Nuclear Station in Atchison County, Missouri. We also concur with the recommendations as presented in the CNS Operations Manual for the survey prior to any project activities and treatment of historic properties.

Please be advised that, should project plans change, information documenting the revisions should be submitted to this office for further review. In the event that cultural materials are encountered during project activities, all construction should be halted, and this office notified as soon as possible in order to determine the appropriate course of action.

If you have any questions, please write Judith Deel at State Historic Preservation Office, P.O. Box 176, Jefferson City, Missouri 65102 or call 573/751-7862. Please be sure to include the SHPO Log Number **(004-AT-08)** on all future correspondence or inquiries relating to this project.

Sincerely,

STATE HISTORIC PRESERVATION OFFICE

Mark A. Miles

Mark A. Miles
Director and Deputy
State Historic Preservation Officer

RECEIVED
JUN 23 2008

MAM:jd

c Robert Stout, DNR/OD

Nebraska Public Power District
"Always there when you need us"

K. Michael Krumland
Environmental Protection Supvr.
PH: 402-563-5329

May 30, 2008

Mr. Michael J. Smith
State Historic Preservation Officer
Nebraska State Historical Society
P.O. Box 82554
Lincoln, NE 68501

RE: Nebraska Public Power District - Cooper Nuclear Station

Dear Mr. Smith:

Enclosed is the "Phase 1A Literature Review and Archeological Sensitivity Assessment of the Cooper Nuclear Station" for Nemaha County, Nebraska and Atchison County, Missouri. The enclosures include a hard copy of the document and a CD with the document in pdf format.

The report was prepared by Dr. James M. Briscoe for Enercon Services, Inc. Dr. Briscoe's curriculum vitae is included as an attachment to the report. Also, for your information, Cooper Nuclear Station's Administrative Procedure 0.51, "Cultural Resources Protection Plan" is attached to the report.

If you have any questions, please feel free to contact me at 402-563-5329.

Sincerely,

K. Michael Krumland
csa

K. Michael Krumland
Environmental Protection Supervisor

Enc.

bc: Joe Citta, Jr. w/o enc.
Dave Bremer w/o enc.
Ricky Buckley (Entergy Nuclear) w/o enc.
ENV-705.0350

Attachment C

Clean Water Act Documentation

- Nebraska Department of Environmental Quality, NPDES Permit NE0001244
- Water Quality Certification Letter from Nebraska Water Pollution Control Council, June 11, 1971.
- K. M. Krumland, NPPD, to J. Bender, Nebraska Department of Environmental Quality. Letter not dated, sent August 8, 2008.

Nebraska Department
of Environmental Quality

Wastewater Section
Suite 400, The Atrium, 1200 'N' Street
PO Box 98922
Lincoln, NE 68509-8922
Tel. 402/471-4220
Fax 402/471-2909

Authorization to Discharge Under the National Pollutant Discharge Elimination System (NPDES)

This NPDES permit is issued in compliance with the provisions of the Federal Water Pollution Control Act (33 U.S.C. Secs. 1251 *et. seq.* as amended to date), the Nebraska Environmental Protection Act (Neb. Rev. Stat. Secs. 81-1501 *et. seq.* as amended to date), and the Rules and Regulations promulgated pursuant to these Acts. The facility and outfalls identified in this permit are authorized to discharge wastewater and are subject to the limitations, requirements, prohibitions and conditions set forth herein. This permit regulates and controls the release of pollutants in the discharges authorized herein. This permit does not relieve permittees of other duties and responsibilities under the Nebraska Environmental Protection Act, as amended, or established by regulations promulgated pursuant thereto.

NPDES Permit No.:	**NE0001244**
IIS File Number	**PCS 36750-P**
Facility Name:	**NPPD Cooper Nuclear Station**
Permittee	**Nebraska Public Power District**
Facility Location:	**Two and one-half miles south of Brownville, Nebraska**
Legal Description	**NE ¼, NW ¼, Section 32, Township 5 N, Range 16 W, Nemaha County, Nebraska**
Receiving Water	**Missouri River, segment NE1-10000 of the Nemaha River Basin**
Effective Date:	**July 1, 2007**
Expiration Date:	**June 30, 2012**

Pursuant to a Delegation Memorandum dated July 26, 1999 and signed by the Director, the undersigned hereby executes this document on behalf of the Director.

Signed this 26th day of June, 2007

Jay D. Ringenberg, Deputy Director, Programs

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Part I. Effluent Limits and Monitoring Requirements

A. Outfall 001- Discharge of Once Pass Through Cooling Water

The discharge of once pass-through cooling water from Outfall 001 to the Missouri River must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 001 shall be monitored and subject to the limits set forth below in Table 1

Table 1: Discharge Limits and Monitoring Requirements for Outfall 001

Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			30 Day Average	Maximum		
Flow	50050	MGD	Report	Report	Continuous	Calculated or Metered
Temperature	00011	°F	Report	109.4	Continuous	Metered
Interim Total Residual Chlorine [(a)]	50060	mg/L	Report [(b)]	Report [(b)]	Weekly	Grab
Final Total Residual Chlorine [(a)]	50060	mg/L	0.01 [(b)]	0.02 [(b)]	Weekly	Grab
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			Daily Minimum	**Daily Maximum**		
pH	00400	Standard Units	6.5	9.0	Weekly	Grab

Footnotes:
(a) Monitoring for TRC is required only when chlorine is introduced into any wastestreams.

(b) See Part III for the compliance schedule to meet final total residual chlorine limits.

B. Outfall 002B– Clear Well Discharge and Outfall 004 Emergency Overflow

The discharge of low volume wastewater from Outfall 002B must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 002B shall be monitored and subject to the limits set forth below in Table 2.

Table 2: Discharge Limits and Monitoring Requirements for Outfall 002B						
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			30 Day Average	**Maximum**		
Flow	50050	MGD	Report	Report	Quarterly	Calculated or Metered
Oil and Grease	00552	mg/L	Report	10	Quarterly	Grab
Total Suspended Solids	00530	mg/L	30	100	Quarterly	Grab
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			Daily Minimum	**Daily Maximum**		
pH	00400	Standard Units	6.5	9.0	Quarterly	Grab
Footnotes:						

C. Outfall 002C – Floor Drains

The discharge of categorical low volume wastewater from Outfall 002C must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 002C shall be monitored and subject to the limits set forth below in Table 3.

Table 3: Discharge Limits and Monitoring Requirements for Outfall 002C

Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			30 Day Average	Maximum		
Flow	50050	MGD	Report	Report	Quarterly	Calculated or Metered
Oil and Grease	00552	mg/L	Report	10	Quarterly	Grab
Total Suspended Solids	00530	mg/L	30	100	Quarterly	Grab
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			Daily Minimum	**Daily Maximum**		
pH	00400	Standard Units	6.5	9.0	Quarterly	Grab
Footnotes:						

D. Outfall 004 – RO Reject and Boiler Blowdown Wastestreams

The discharge of low volume wastewater from Outfall 004 must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 004 shall be monitored and subject to the limits set forth below in Table 4.

Table 4: Discharge Limits and Monitoring Requirements for Outfall 004

Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			30 Day Average	Maximum		
Flow	50050	MGD	Report	Report	Monthly	Calculated or Metered
Oil and Grease	00552	mg/L	Report	10	Monthly	Grab
Total Suspended Solids	00530	mg/L	30	100	Monthly	Grab
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			Daily Minimum	**Daily Maximum**		
pH	00400	Standard Units	6.5	9.0	Monthly	Grab
Footnotes:						

E. Outfall 008 – Waste Sample Tank

The discharge of tank waste low volume discharge from Outfall 008 must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 008 shall be monitored and subject to the limits set forth below in Table 5.

Table 5: Discharge Limits and Monitoring Requirements for Outfall 008						
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			30 Day Average	**Maximum**		
Flow	50050	MGD	Report	Report	Semiannually	Calculated or Metered
Oil and Grease	00552	mg/L	Report	10	Semiannually	Grab
Total Suspended Solids	00530	mg/L	30	100	Semiannually	Grab
Parameters	**Storet #**	**Units**	**Discharge Limits**		**Monitoring Frequency**	**Sample Type**
			Daily Minimum	**Daily Maximum**		
pH	00400	Standard Units	6.5	9.0	Semiannually	Grab
Footnotes:						

F. Outfall 009 – Sample Tank Floor Drain

The discharge sample tank low volume wastewater from Outfall 009 must be consistent with the description provided in the permit application and any supplemental information submitted used in the development of this permit. The discharge from Outfall 009 shall be monitored and subject to the limits set forth below in Table 6.

Table 6: Discharge Limits and Monitoring Requirements for Outfall 009						
Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			30 Day Average	Maximum		
Flow	50050	MGD	Report	Report	Semiannually	Calculated or Metered
Oil and Grease	00552	mg/L	Report	10	Semiannually	Grab
Total Suspended Solids	00530	mg/L	30	100	Semiannually	Grab
Parameters	Storet #	Units	Discharge Limits		Monitoring Frequency	Sample Type
			Daily Minimum	Daily Maximum		
pH	00400	Standard Units	6.5	9.0	Semiannually	Grab
Footnotes:						

Part II. Compliance Schedule for Evaluating Cooling Water Intake Structure(s) at Cooper Nuclear Station

The Nebraska Public Power District (NPPD) shall continue to evaluate selected technologies to reduce impingement of fish and shellfish at the cooling water intake structure(s) at Cooper Nuclear Station. The NPPD shall send a report to the NDEQ annually by March 1 that gives an account of the evaluation of selected technologies from the previous calendar year (Jan. through Dec.). This schedule may be modified in accordance with NDEQ Title 119 and written notice from the NDEQ.

Part III. Compliance Schedule for Meeting Final Total Residual Chlorine (TRC) Limits

Upon issuance of this permit, the Nebraska Public Power District (NPPD) shall implement the compliance schedule set forth below for meeting final TRC limits in Table 1 by installing equipment for dechlorination and/or by submitting a study that demonstrates that the TRC limits in Table 1 ought to be modified. This schedule may be revised in accordance with the requirements set forth in NDEQ Title 119 and written notice from the NDEQ.
The reporting requirements for TRC in Table 1 shall apply until completion of the schedule set forth below at which time the current final limits in Table 1will apply or revised limits approved by the NDEQ based on an environmental study will apply.
The NPPD shall send a report to the NDEQ every 6 months outlining progress in achieving the compliance schedule set forth below.

1. Six Months
On or before six months after the issuance of this permit, the NPPD shall complete and submit a plan for an environmental study to the NDEQ for review. The study design may include sampling, modeling, or testing that would determine if the final residual chlorine concentration in Table 1 for the effluent discharge from Cooper Nuclear Station to the Missouri River could be revised.

2. One Year
On or before one year after the issuance of this permit, the NPPD shall submit the results of the environmental study to the NDEQ for evaluation. The NDEQ will determine if the study demonstrates whether the current final limits for TRC in Table 1 shall continue to apply or if the current final TRC limits in Table 1 should be revised based on the conclusions of the study.

3. Two years
On or before two years after the issuance of this permit, the discharge form Cooper Nuclear Station shall routinely meet the current final limits in Table 1 or revised limits approved by the NDEQ that are based on the results of the NPPD environmental study.

Part IV. Other Requirements and Conditions

A. Polychlorinated Biphenyls (PCB)

There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid. At the discretion of the NDEQ, this requirement for no discharge of PCBs can be confirmed either by chemical analysis of the discharge effluent or by an engineering study which would demonstrate that PCBs are not present in the final discharge.

B. Radionuclides

The discharge of beta particles and photon emitters from Cooper Nuclear Station to the Missouri River shall not exceed 4 millirems per year. To document compliance with this limit, the NPPD shall submit an annual report to the NDEQ by June 1 of each year for radionuclide releases from Cooper Nuclear Station to the Missouri River from the preceding calendar year (January – December) that provides the date of release and a list of radionuclides released reported in terms of both activity (pCi/l) and exposure (millirems).

C. Narrative Limits

Discharges authorized under this permit:

Shall not be toxic to aquatic life in surface waters of the State outside the mixing zones allowed in NDEQ Title 117 - *Nebraska Surface Water Quality Standard*;

Shall not contain pollutants at concentrations or levels that produce objectionable films, colors, turbidity, deposits, or noxious odors in the receiving stream or waterway; and

Shall not contain pollutants at concentrations or levels that cause the occurrence of undesirable or nuisance aquatic life in the receiving stream.

D. Disposal of Sewage Sludge

The permittee shall dispose of sludge in accordance with 40 CFR Part 503. which is administered by EPA Region VII. Adherence to these regulations does not exempt the permittee from applicable NDEQ requirements.

The permittee preparing and/or applying sewage sludge shall develop all of the information required in 40 CFR Part 503.17. This information shall be retained as required by 40 CFR Part 503.

Any proposed biosolids application site must be approved by the NDEQ prior to the initial biosolids application.

E. Method Detection Limit Reporting Requirements

The minimum detection limit (MDL) is defined as the level at which the analytical system gives acceptable calibration points. If the analytical results are below the MDL then the reported value on the DMR shall be a numerical value less than the MDL (e.g. <0.005).

Appendix A – Standard Conditions that Apply to NPDES and NPP Permits

These general conditions are applicable to all NPDES and NPP permits. These conditions shall not preempt any more stringent requirements found elsewhere in this permit.

A. General Conditions

1. Information Available

All permit applications, fact sheets, permits, discharge data, monitoring reports, and any public comments concerning such shall be available to the public for inspection and copying, unless such information about methods or processes is entitled to protection as trade secrets of the owner or operator under Neb. Rev. Stat. §81-1527, (Cum. Supp. 1992) and NDEQ Title 115, Chapter 4.

2. Duty to Comply

All authorized discharges shall be consistent with the terms and conditions of this permit. The discharge of any pollutant identified in this permit more frequently than or at a level in excess of that authorized shall constitute a violation of the permit.

The permittee shall comply with all conditions of this permit. Failure to comply with these conditions may be grounds for administrative action or enforcement proceedings including injunctive relief and civil or criminal penalties.

The filing of a request by the permittee for a permit modification, revocation and re-issuance, termination or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

3. Duty to Mitigate

The permittee shall take all reasonable steps to minimize, prevent or correct any adverse impact to the environment resulting from noncompliance with this permit, including such accelerated or additional monitoring as required by the NDEQ to determine the nature and impact of the noncompliant discharge.

4. Permit Actions

This permit may be modified, suspended, revoked or reissued, in part or in whole, in accordance with the regulations set forth in NDEQ Titles 119, Chapter 24. In addition, this permit may be modified, revoked and reissued to incorporate standards or limitations issued pursuant to Sections 301(b)(b)(c), 301(b)(b)(d), 304(b)(b), 307(a)(b), or 405(d) of the Clean Water Act and Public Law 100-4 (i.e., industrial categorical standards and municipal sludge regulations).

5. Land Application of Wastewater Effluent

The permittee shall be permitted to discharge treated wastewater effluent by means of land application in accordance with the regulations and standards set forth in NDEQ Title 119, Chapter 12, 002.

6. Toxic Pollutants

The permittee shall not discharge pollutants to waters of the state that cause a violation of the standards established in NDEQ Titles 117, 118 or 119. All discharges to surface waters of the state shall be free of toxic (acute or chronic) substances which alone or in combination with other substances, create conditions unsuitable for aquatic life outside the appropriate mixing zone.

7. Oil and Hazardous Substances/Spill Notification

Nothing in this permit shall preclude the initiation of any legal action or relieve the permittee from any responsibilities, liabilities or penalties under Section 311 of the Clean Water Act. The permittee shall conform to the provisions set forth in NDEQ Title 126, *Rules and Regulations Pertaining to the Management of Wastes*. If the permittee knows, or has reason to believe, that oil or hazardous substances were released at the facility and could enter waters of the state or any of the outfall discharges authorized in this permit, the permittee shall immediately notify the Department of a release of oil or hazardous substances. During Department office hours (i.e., 8:00 a.m. to 5:00 p.m., Monday through Friday, except holidays), notification shall be made to the Nebraska Department of Environmental Quality at telephone numbers (402) 471-2186 or (877) 253-2603 (toll free). When NDEQ cannot be contacted, the permittee shall report to the Nebraska State Patrol for referral to the NDEQ Emergency Response Team at telephone number (402) 471-4545. It shall be the permittee's responsibility to maintain current telephone numbers necessary to carry out the notification requirements set forth in this paragraph.

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 damage to private property or any invasion of personal rights nor any infringement of federal, state or local laws or regulations.

9. Severability

If any provision of this permit is held invalid, the remainder of this permit shall not be affected.

10. Other Rules and Regulations Liability

The issuance of this permit in no way relieves the obligation of the permittee to comply with other rules and regulations of the Department.

11. Inspection and Entry

The permittee shall allow the Director or his authorized representative, upon the presentation of his identification and at a reasonable time:

a. to enter upon the permittee's premises where a regulated facility or activity is located or conducted, or records are required to be kept under the terms and conditions of the permit,

b. to have access to and copy any records required to be kept under the terms and conditions of the permit,

c. to inspect any facilities, equipment (including monitoring and control), practices or operations regulated or required in the permit, and

d. to sample or monitor any substances or parameters at any location.

12. Penalties

Violations of the terms and conditions of this permit may result in the initiation of criminal and/or civil actions. Civil penalties can result in fines of up to $10,000.00 per day (Neb. Rev. Stat. §81-1508, as amended to date). Criminal penalties for willful or negligent violations of this permit may result in penalties of $10,000.00 per day or by imprisonment. Violations may also result in federal prosecution.

B. Management Requirements

1. Duty to Provide Information

The permittee shall furnish to the Department within a reasonable time, any information which the Department may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit; or to determine compliance with this permit. The permittee shall also furnish to the Department upon request, copies of records retained as a requirement of this permit.

2. **Duty to Reapply**

The permittee shall apply for a re-issuance of this permit, if an activity regulated by this permit is to be continued after the expiration date of this permit. The application shall be submitted at least 180 days before the expiration of this permit on an application form supplied by the Department, as set forth in NDEQ Titles 119, Chapter 5 002.

3. **Signatory Requirements**

All reports and applications required by this permit or submitted to maintain compliance with this permit, shall be signed and certified as set forth in this section.

a. Permit applications shall be signed by a cognizant official who meets the following criteria:
   i) for a corporation: by a principal executive officer of at least the level of vice-president,
   ii) for a partnership or sole proprietorship: by a general partner or the proprietor, respectively, or
   iii) for a municipality, state, federal or other public facility: by either a principal executive officer or highest ranking elected official.

b. Discharge monitoring reports and other information shall be signed by the **cognizant official** or by an **authorized representative**.

c. The cognizant official designates an authorized representative. The authorized representative is responsible for the overall operation of the facility (i.e., the WWTF Operator, the City Manager, the Public Utilities Superintendent or similar person).

d. Any change in the signatories shall be submitted to the Department, in writing, within 30 days after the change.

e. Certification. All applications, reports and information submitted as a requirement of this permit, shall contain the following certification statement:

> "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 gathered and evaluated 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."

C. Monitoring and Records

1. **Representative Sampling**

Samples and measurements taken as required within this permit shall be representative of the discharge. 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 waste stream, body of water or substance. Monitoring points shall not be changed without notification to the Department and with the written approval of the Director.

a. Composite sampling shall be conducted in one of the following manners:
   i) continuous discharge - a minimum of one discrete aliquot collected every three hours,
   ii) less than 24 hours - a minimum of hourly discrete aliquots or a continuously drawn sample shall be collected during the discharge, or
   iii) batch discharge - a minimum of three discrete aliquots shall be collected during each discharge.

b. Composite samples shall be collected in one of the following manners:
   i) the volume of each aliquot must be proportional to either the waste stream flow at the time of sampling or the total waste stream flow since collection of the previous aliquot,
   ii) a number of equal volume aliquots taken at varying time intervals in proportion to flow,
   iii) a sample continuously collected in proportion to flow, and
   iv) where flow proportional sampling is infeasible or nonrepresentative of the pollutant loadings, the Department may approve the use of time composite samples.

c. Grab samples shall consist of a single aliquot collected over a time period not exceeding 15 minutes.

d. All sample preservation techniques shall conform to the methods adopted in NDEQ Title 119, Chapter 21, 006 unless:
   i) in the case of sludge samples, alternative techniques are specified in the 40 CFR, Part 503, or
   ii) other procedures are specified in this permit.

2. Flow Measurements

Appropriate flow measurement devices and methods consistent with accepted scientific practices shall be used to insure the accuracy and reliability of measurements. The devices shall be installed, calibrated and maintained to insure that the accuracy of the measurements. The accepted capability shall be consistent with the type of that device. Devices selected shall be capable of measuring flows with a maximum deviation of +/- 10%. The amount of deviation shall be from the true discharge rates throughout the range of expected discharge volumes. Guidance can be obtained from the following references for the selection, installation, calibration and operation of acceptable flow measurement devices:

a. "Water Management Manual," U. S. Department of Interior, Bureau of Reclamation, Second Edition, Revised Reprint, 2001, 327 pp. Available from the National Technical Information Services (NTIS)

b. "NPDES Compliance Inspection Manual," U. S. Environmental Protection Agency, Office of Enforcement and Compliance Assurance, Publication EPA 300-B-94-014 September 1994. This document is available from the National Technical Information Services (NTIS).

3. Test Procedures

Test procedures used for monitoring required by this permit shall conform to the methods adopted in NDEQ Title 119, Chapter 21, 006 unless:

a. in the case of sludge samples, alternative techniques are specified in the 40 CFR, Part 503, or

b. other procedures are specified in this permit.

4. Averaging of Measurements

Averages shall be calculated as an arithmetic mean except:

a. bacterial counts which shall be calculated as a geometric mean, or

b. where otherwise specified by the Department.

5. Retention of Records

The permittee shall retain records of all monitoring activities for a period of at least three years (except five years for biosolids data) as set forth in NDEQ Titles 119, Chapter 14 001.02. The types of records that must be retained include, but are not limited to:

a. calibration and maintenance records,
b. original strip chart recordings,
c. copies of all reports required by this permit,
d. monitoring records and information, and
e. electronically readable data.

The permittee shall retain records of monitoring required by this permit that are related to biosolids use and disposal for a period of five years or longer, as required in NDEQ Titles 119, Chapter 14.

6. Record Contents

As set forth in NDEQ Title 119, Chapter 14, records of sampling or monitoring information shall include:

a. the date(s), exact place, time and methods of sampling or measurements,
b. the name(s) of the individual(s) who performed the sampling or measurements,
c. the date(s) the analyses were performed,
d. the individual(s) who performed the analyses,
e. the analytical techniques or methods used,
f. the results of such analyses, and
g. laboratory data, bench sheets and other required information.

D. Reporting Requirements

1. Immediate Notification

a. NPP permittees shall report immediately to the publicly owned treatment works (POTW), any discharge to the POTW that may result in a violation of NDEQ Title 119, Chapter 26.
b. All permittees shall report immediately to the NDEQ:
   i) discharges of oil or hazardous substances which threaten waters of the state or public health and welfare, and
   ii) discharges causing in-stream toxicity (i.e., a fish kill) or an immediate threat to human health.

Initial notification may be verbal. A written noncompliance notification shall be submitted as set forth in Section D. 3 of this Appendix.

2. Test Procedures

Test procedures used for monitoring required by this permit, shall conform to the methods adopted in NDEQ Title 119, Chapter 27 unless:

a. In the case of biosolids samples, alternative techniques are specified in the NDEQ Title 119, Chapter 14; or
b. Other procedures are specified in this permit.

3. 24-Hour Reporting

As set forth in NDEQ Title 119, Chapter 14 the permittee shall report to the NDEQ, within 24 hours of becoming aware of:

a. any noncompliance which may endanger the environment or human health or welfare,
b. any unanticipated bypass,
c. all upsets,
d. any discharge to a POTW that causes a violation of the prohibited discharge standards, or
e. any noncompliance of an effluent limitation in this permit.

Initial notification may be verbal. A written noncompliance notification shall be submitted as set forth in Section D. 3 of this permit.

As set forth in NDEQ Title 119, Chapter 26, if sampling performed by an industrial user (NPP permittee) indicates a permit effluent violation, the permittee shall notify the Department and the city within 24 hours of becoming aware of the violation. The permittee shall resample and have it analyzed. The results of the resampling analysis shall be submitted to the Department and the city within 30 days after becoming aware of the violation.

4. Written Noncompliance Notification

a. The permittee shall submit a written noncompliance report to the NDEQ:
   i) within five days of becoming aware of any noncompliance with the:
      (a) NPP effluent limitations or requirements set forth in this permit, or
      (b) NPDES toxic pollutant effluent limitations or requirements set forth in this permit.
   ii) within seven days of becoming aware of any other noncompliance with the NPDES requirements and/or effluent limitations set forth in this permit.
b. The written notification shall be submitted on a noncompliance form supplied by the Department and shall include:
   i) a description of the discharge and cause of noncompliance,
   ii) the period of noncompliance, including exact dates and times, or if not corrected, the anticipated time the noncompliance is expected to continue, and
   iii) the steps taken to reduce, eliminate and prevent the reoccurrence of the noncompliance.

The submittal of a written noncompliance report does not relieve the permittee of any liability from enforcement proceedings that may result from the violation of permit or regulatory requirements.

5. Quarterly Discharge Monitoring Reports (DMRs)

The permittee shall report the monitoring results required by this permit on a DMR form supplied or approved by the Department. Monitoring results shall be submitted on a quarterly basis using the reporting schedule set forth below, unless otherwise specified in this permit or by the Department.

Monitoring Quarters	DMR Reporting Deadlines
January - March	April 28
April - June	July 28
July - September	October 28
October - December	January 28

If the permittee monitors any pollutant more frequently than required by this permit, using procedures specified in this permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted on the DMR. The frequency of the analysis shall also be reported on the DMR.

6. Changes in Discharge

Any facility expansion, production increases or process modifications which will result in new or substantially increased discharges of pollutants or a change in the nature of the discharge of pollutants must be reported by the permittee 180 days prior to the expansion, increases or modifications, either by amending his original application or by submitting a new application. This permit may be modified or revoked and reissued as a result of this notification to maintain compliance with applicable state or federal regulations.

7. Changes in Toxic Discharges from Manufacturing, Commercial, Mining and Silvicultural Facilities

Permittees discharging from manufacturing, commercial, mining and silvicultural facilities shall report to the Department:

a. if any toxic pollutant not limited in this permit is discharged from any NPDES outfall as a result of any activity that will or has occurred and results in its routine or frequent discharge. The Department shall be informed if that discharge exceeds the following notification levels:
   - i) 100 micrograms per liter (0.1 mg/L) for any toxic pollutant,
   - ii) 200 micrograms per liter for acrolein and acrylonitrile (0.2 mg/L),
   - iii) 500 micrograms per liter for 2,4-dinitrophenol and for 2-methyl-4, 6-dinitrophenol (0.5 mg/L),
   - iv) 1000 micrograms per liter for antimony (1 mg/L),
   - v) five times the maximum concentration value reported for that pollutant in the permit application or
   - vi) an alternative level established by the Director, and

b. if any toxic pollutant not limited in this permit is discharged from an NPDES outfall as a result of any activity that will or has occurred and results in its nonroutine discharge. The Department shall be informed if that discharge exceeds the following notification levels:
   - i) 500 micrograms per liter (0.5 mg/L) for any toxic pollutant,
   - ii) 1000 micrograms for antimony (1 mg/L),
   - iii) ten times the maximum concentration value reported for that pollutant in the permit application, or
   - iv) an alternative level established by the Director.

8. Changes in Sludge Quality

The permittee shall provide written notice to the Department of any alteration or addition that results in a significant change in the permittee's sludge use or disposal practices. This permit may be modified or revoked and reissued as a result of this notification to maintain compliance with applicable state or federal regulations.

9. Changes of Loadings to Publicly Owned Treatment Work (POTW)

POTW's shall notify the Department of the following:

a. any new introduction of pollutants from dischargers subject to the categorical pretreatment discharge limitations set forth in NDEQ Title 119, Chapter 27, and

b. any substantial change in the volume or character of pollutants being introduced into the POTW.

Notification shall be made 180 days in advance whenever possible. Information on the quantity and quality of new discharges and their anticipated impact on the POTW shall be included.

10. Transfers

The permittee shall notify the Department at least 30 days prior to the proposed transfer of ownership of this permit or the permitted facility to another party. The Department may modify or revoke and reissue this permit as set forth in NDEQ Title 119, Chapter 24.

11. Compliance Schedules

The permittee shall submit a written report of compliance or noncompliance with any compliance schedule established in this permit. The written report shall be submitted within 14 days following all deadlines established in the compliance schedule. If compliance has not been achieved, the report shall include an alternative completion date, an explanation of the cause of the noncompliance and an explanation of the steps being taken to ensure future compliance. The submission of this report does not ensure the Department's acceptance of alternative compliance dates nor does it preclude the Department from initiating enforcement proceedings based upon the reported noncompliance.

E. Operation and Maintenance

1. Proper Operation and Maintenance

The permittee shall, at all times, maintain in good working order and operate as efficiently as possible, any facilities or systems of control installed by the permittee in order to achieve compliance with the terms and conditions of this permit. This would include, but not be limited to, effective performance based on designed facility removals, effective management, adequate operator staffing and training, adequate laboratory and process controls, and adequate funding which reflects proper user fee schedules.

2. Treatment System Failure and Upset

An upset is an affirmative defense to an enforcement action brought for noncompliance with technology-based permit effluent limitations if the permittee can demonstrate, through properly signed, operating logs or other relevant evidence, that:

a. an upset occurred and the specific cause was identified,

b. that the facility was properly operated and maintained at such time,

c. the Department was notified within 24 hours of the permittee becoming aware of the upset, and

d. the permittee took action to reduce, eliminate and prevent a reoccurrence of upset, including minimizing adverse impact to waters of the state.

3. **Bypassing**

Any diversion from or bypass of the treatment facilities is prohibited, unless:

a. It is unavoidable to prevent loss of life, personal injury or severe property damage;
   - i) No feasible alternative exists, i.e., auxiliary treatment facilities, retention of untreated wastes or maintenance during normal periods of equipment downtime;
   - ii) The permittee submits notice to the Department within 24 hours of becoming aware of the bypass or if the bypass is anticipated or should have been anticipated, the Department is notified at least ten days prior to the bypass; and
   - iii) The bypass is conducted under conditions determined to be necessary by the Director to minimize any adverse effects.

b. If the bypass is needed for regular preventative maintenance for which back-up equipment should be provided, the bypass will not be allowed. When a bypass occurs, the burden is on the permittee to demonstrate compliance with items "a" through "d" above.

c. Additionally, NPP permittees shall report any bypasses to the POTW. Unanticipated bypasses shall be reported immediately and anticipated bypasses shall be reported at least ten days in advance.

d. All NPDES permittees shall notify the general public that a bypass of the treatment system is occurring. The public notification shall include:
   - i) Location of the bypass;
   - ii) The date the bypass started;
   - iii) Anticipated length of time the bypass will occur; and
   - iv) An estimate of the total volume of wastewater bypassed.

4. **Removed Substances**

Solids, sludge, filter backwash or other pollutants removed in the course of treatment or control of wastewater shall be disposed of at a site and in a manner approved by the Nebraska Department of Environmental Quality. The disposal of nonhazardous industrial sludges shall conform to the standards established in or to the regulations established pursuant to 40 CFR, Part 257. The disposal of sludge shall conform to the standards established in or to the regulations established pursuant to 40 CFR, Part 503. If solids are disposed of in a licensed sanitary landfill, the disposal of solids shall conform to the standards established in NDEQ Title 132. Publicly owned treatment works shall dispose of sewage sludge in a manner that protects public health and the environment from any adverse effects which may occur from toxic pollutants as defined in Section 307 of the Clean Water Act. This permit may be modified or revoked and reissued to incorporate regulatory limitations established pursuant to 40 CFR, Part 503.

F. **Definitions**

Administrator: The Administrator of the USEPA.

Aliquot: An individual sample having a minimum volume of 100 milliliters that is collected either manually or in an automatic sampling device.

Biweekly: Once every other week.

Bimonthly: Once every other month.

Bypass: The intentional diversion of wastes from any portion of a treatment facility.

Daily Average: An effluent limitation that cannot be exceeded and is calculated by averaging the monitoring results for any given pollutant parameter obtained during a 24-hour day.

Department: Nebraska Department of Environmental Quality.

Director: The Director of the Nebraska Department of Environmental Quality.

Industrial Discharge: Wastewater that originates from an industrial process and / or is noncontact cooling water and / or is boiler blowdown.

Industrial User: A source of indirect discharge (a pretreatment facility).

Monthly Average: Is an effluent limitation that cannot be exceeded. It is calculated by averaging any given pollutant parameter monitoring results obtained during a calendar month.

Passive Discharge: A discharge from a POTW that occurs in the absence of an affirmative action and is not authorized by the NPDES permit (e.g. discharges due to a leaking valve, discharges from an overflow structure) and / or is a discharge from an overflow structure not designed as part of the POTW (e.g. discharges resulting from lagoon berm / dike breaches).

Publicly Owned Treatment Works (POTW): A treatment works as defined by Section 212 of the Clean Water Act (Public Law 100-4) which is owned by the state or municipality, excluding any sewers or other conveyances not leading to a facility providing treatment.

Semiannually: Twice every year

Significant Industrial Use (SIU): All industrial users subject to Categorical Pretreatment Standards or any industrial user that, unless exempted under Chapter 1, Section 115 of NDEQ Title 119, discharges an average of 25,000 gallons per day or more of process water; or contributes a process waste stream which makes up 5 percent or more of the average dry weather hydraulic or organic capacity of the POTW; or is designated as such by the Director on the basis that the industrial user has a reasonable potential for adversely affecting the POTW's operation or for violating any National Pretreatment Standard or requirement.

30-Day Average: Is an effluent limitation that cannot be exceeded. It is calculated by averaging any given pollutant parameter monitoring results obtained during a calendar month.

Total Toxic Organics (TTO): The summation of all quantifiable values greater than 0.01 milligrams per liter (mg/l) for toxic organic compounds that may be identified elsewhere in this permit. (If this term has application in this permit, the list of toxic organic compounds will be identified, typically in the Limitations and Monitoring Section(s) and/or in an additional Appendix to this permit.)

Toxic Pollutant: Those pollutants or combination of pollutants, including disease causing agents, after discharge and upon exposure, ingestion, inhalation or assimilation into an organism, either directly from the environment or indirectly by ingestion through food chains will, on the basis of information available to the administrator, cause death, disease, behavioral abnormalities, cancer, genetic mutations, physiological malfunction (including malfunctions in reproduction) or physical deformations, in such organisms or their offspring.

Upset: 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, excluding such factors as operational error, improperly designed or inadequate treatment facilities or improper operation and maintenance or lack thereof.

Volatile Organic Compounds (VOC): The summation of all quantifiable values greater than 0.01 milligrams per liter (mg/l) for volatile, toxic organic compounds that may be identified elsewhere in this permit. (See the definition for Total Toxic Organics above. In many instances, VOCs are defined as the volatile fraction of the TTO parameter. If the term "VOC" has application in this permit, the list of toxic organic compounds will be identified, typically in the Limitations and Monitoring Section(s) and/or in an additional Appendix to this permit.)

Weekly Average: Is an effluent limitation that cannot be exceeded. It is calculated by averaging any given pollutant parameter monitoring results obtained during a fixed calendar week. The permittee may start their week on any weekday but the weekday must remain fixed. The Department approval is required for any change of the starting day.

"X" Day Average: An effluent limitation defined as the maximum allowable "X" day average of consecutive monitoring results during any monitoring period where "X" is a number in the range of one to seven days.

G. Abbreviations

CFR: Code of Federal Regulations
kg/Day: Kilograms per Day
MGD: Million Gallons per Day
mg/L: Milligrams per Liter
NOI: Notice of Intent
NDEQ: Nebraska Department of Environmental Quality
NDEQ Title 115: *Rules of Practice and Procedure*
NDEQ Title 117: *Nebraska Surface Water Quality Standards*
NDEQ Title 118: *Ground Water Quality Standards and Use Classification*
NDEQ Title 119: *Rules and Regulations Pertaining to the Issuance of Permits under the National Pollutant Discharge Elimination System*
NDEQ Title 126: *Rules and Regulations Pertaining to the Management of Wastes*
NDEQ Title 132: *Integrated Solid Waste Management Regulations*
NPDES: National Pollutant Discharge Elimination System
NPP: Nebraska Pretreatment Program
POTW: Publicly Owned Treatment Works
μg/L: Micrograms per Liter
WWTF: Wastewater Treatment Facility

Nebraska Water Pollution Control Council
State Certification for
Federally Licensed Facilities or Activities

The Nebraska Water Pollution Control Council hereby issues a state certification to: The Nebraska Public Power District

for the purpose of conducting the following described activity: Circulation Of Missouri River Water Through A Condenser To Cool And Condense Steam From A Turbo-Generator, Warming Such Water A Maximum of 18 Degrees Fahrenheit At Point of Discharge

which may result in the following type or types of discharges: Missouri River Water Warmed A Maximum of 18°F At Point Of Discharge

into the following named navigable water flowing through or bordering the State of Nebraska The Missouri River (Near Missouri River Mile 532.5)

This activity shall be conducted at Brownville in the County of Nemaha in the State of Nebraska.

The issuance of this certification to the above named entity signifies that the Nebraska Water Pollution Control Council determined that there is reasonable assurance that the above described activity will be conducted in a manner which will not violate the water quality standards of the State of Nebraska.

CHAIRMAN, Nebraska Water Pollution Control Council

ATTEST:

T. A. Filipi

EXECUTIVE SECRETARY,
Nebraska Water Pollution Control Council

June 11, 1971
Date

NWPCC 51-1970

Nebraska Public Power District
"Always there when you need us"

K. Michael Krumland
Environmental Protection Supvr.
PH: 402-563-5329

Mr. John Bender
Nebraska Department of
Environmental Quality
P.O. Box 98922
Lincoln, NE 68509-8922

RE: Nebraska Public Power District – Cooper Nuclear Station
Clean Water Act Section 401 Certification – License Renewal

Dear Mr. Bender:

This is a quick note to confirm our conversation regarding the license renewal application the District plans to file later this year to extend the Cooper Nuclear Station operating term for another twenty years. Specifically, as we discussed, the existing Section 401 certification that the state previously issued on July 11, 1971, would remain effective throughout the renewed term of plant operation should the U.S. Nuclear Regulatory Commission grant the application. I have attached the existing certification to this letter.

Sincerely,

Kevin M. Krumland

Kevin M. Krumland
Environmental Protection Supervisor

Att.

cc: J. L. Citta, Jr. w/att.
L. M. McFarland w/att.

bc: R. Buckley/Entergy w/att.
K. M. Sutton/Morgan, Lewis & Bockius LLP w/att.
J. Lagace/Entergy w/att.

D. W. Bremer w/att.
File: ENV-705.0350

Nebraska Water Pollution Control Council
State Certification for
Federally Licensed Facilities or Activities

The Nebraska Water Pollution Control Council hereby issues a state certification to: The Nebraska Public Power District

for the purpose of conducting the following described activity: Circulation Of Missouri River Water Through A Condenser To Cool And Condense Steam From A Turbo-Generator, Warming Such Water A Maximum of 18 Degrees Fahrenheit At Point of Discharge

which may result in the following type or types of discharges: Missouri River Water Warmed A Maximum of 18°F At Point Of Discharge

into the following named navigable water flowing through or bordering the State of Nebraska The Missouri River (Near Missouri River Mile 532.5)

This activity shall be conducted at Brownville *in the County of* Nemaha in the State of Nebraska.

The issuance of this certification to the above named entity signifies that the Nebraska Water Pollution Control Council determined that there is reasonable assurance that the above described activity will be conducted in a manner which will not violate the water quality standards of the State of Nebraska.

CHAIRMAN, Nebraska Water Pollution Control Council

ATTEST:

T. G. Filipi

EXECUTIVE SECRETARY,
Nebraska Water Pollution Control Council

June 11, 1971
Date

NWPCC 51-1970

Attachment D

Miscellaneous Agency Correspondence

- J.L. Citta, Jr., NPPD, to D. Childers, Missouri Department of Natural Resources, January 15, 2008.
- J.L. Citta, Jr., NPPD, to M. Linder, Nebraska Department of Environmental Quality, March 6, 2008.
- J.L. Citta, Jr., NPPD, to A. Salomon Bleed, Nebraska Department of Natural Resources, March 6, 2008.
- S. McMaster, Nebraska Department of Natural Resources to J.L. Citta, Jr., NPPD, March 12, 2008.
- J.L. Citta, Jr., NPPD, to Colonel D.C. Press, U.S. Army Corps of Engineers, Omaha District, January 15, 2008.
- L.D. Janis, U.S. Army Corps of Engineers, Omaha District, to J.L. Citta, Jr., NPPD, February 11, 2008.
- J.L. Citta, Jr., NPPD, to Colonel R.A. Wilson, Jr., U.S. Army Corps of Engineers, Kansas City District, January 15, 2008.
- M.D. Frazier, U.S. Army Corps of Engineers, Kansas City District, to J.L. Citta, Jr., NPPD, February 8, 2008.

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Mr. Doyle Childers, Director
Missouri Department of Natural Resources
P.O. Box 176
Jefferson City, MO 65102

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Childers:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential environmental impacts from the continued operation of CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Rick Buckley (Entergy Nuclear) w/att.

Nebraska Public Power District

"Always there when you need us"

Joe L. Citta, Jr.
Environmental Manager
PH: 402-563-5355

March 6, 2008

Mr. Mike Linder, Director
Nebraska Department of Environmental Quality
P.O. Box 98922
Lincoln, NE 68509-8922

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Mr. Linder:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential environmental impacts from the continued operation of CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist. If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Rick Buckley (Entergy Nuclear) w/att.

bc: J. C. McClure w/o att.
R. L. Beilke w/o att.
K. M. Krumland w/o att.
D. W. Bremer w/o att.
L. D. Linder w/o att.
C. O. Stipp w/o att.
L. M. McFarland w/o att.
ENV-705-0350 / E40 w/att.

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Environmental Manager
PH: 402-563-5355

March 6, 2008

Ms. Ann Salomon Bleed, Director
Nebraska Department of Natural Resources
301 Centennial Mall South
P.O. Box 94676
Lincoln, NE 68509-4676

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Ms. Bleed:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the NRC approves the application, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5 (Figure 1). Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site that includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the operation of CNS will continue to have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that impacts are adequately addressed, we are requesting from your office pertinent information regarding concerns, if any, that you may have regarding potential environmental impacts from the continued operation of CNS.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist. If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Rick Buckley (Entergy Nuclear) w/att.

bc: J. C. McClure w/o att.
R. L. Beilke w/o att.
K. M. Krumland w/o att.
D. W. Bremer w/o att.
L. D. Linder w/o att.
C. O. Stipp w/o att.
L. M. McFarland w/o att.
ENV-705-0350 / E40 w/att.

NOTE: Same attachments as NDEQ's letter.

STATE OF NEBRASKA

Dave Heineman
Governor

DEPARTMENT OF NATURAL RESOURCES
Ann Bleed
Director

March 12, 2008

IN REPLY TO:

Joe Citta, Jr.
NPPD
1414 15th Street
PO Box 499
Columbus, NE 68602-0499

RE: Cooper Nuclear Station

Dear Mr. Citta:

By itself, a license renewal does not constitute an action which would trigger a review for resources under NDNR's review authority: floodplain management, surface water, and ground water. In addition, since your letter states that no new ground will be disturbed and no new water resources will be developed or changed, this means that the Nebraska Department of Natural Resources has no comment.

If you have any questions about this letter, please call me at (402) 471-3957.

Sincerely,

Steve McMaster
Natural Resources Planner Coordinator

RECEIVED
MAR 13 2008

Dam Safety-Flood Plain/McMaster

301 Centennial Mall South, 4th Floor • P.O. Box 94676 • Lincoln, Nebraska 68509-4676 • Phone (402) 471-2363 • Telefax (402) 471-2900

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Colonel David C. Press, Commander
U.S. Army Corps of Engineers
Omaha District
106 South 15th Street
Omaha, NE 68102-1618

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Colonel Press:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the application is approved by the NRC, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5, an area referred to by the Corps of Engineers as the Lower Brownville Bend. Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site, which includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the continued operation of CNS will have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that potential impacts are adequately addressed, we are requesting from the Omaha and Kansas City Districts pertinent information regarding any concerns or issues, if any, that you may have about potential impacts from the continued operation of CNS, and information regarding any proposed changes in the future operation and maintenance of the Missouri River that could affect the CNS facility.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: Maps & Photographs

cc: Randal K. Petersen (ACOE) w/att.
Rick Buckley (Entergy Nuclear) w/att.

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, OMAHA DISTRICT
106 SOUTH 15TH STREET
OMAHA NE 68102-1618

REPLY TO
ATTENTION OF

February 11, 2008

RECEIVED
FEB 14 2008

Planning, Programs, and Project Management Division

Mr. Joe Citta
Nebraska Public Power District
P.O. Box 499
Columbus, Nebraska 68602-0499

Dear Mr. Citta:

The U.S. Army Corps of Engineers, Omaha District (Corps) has reviewed your letter dated January 15, 2008 regarding the renewal of the operating license for the Cooper Nuclear Station. The Corps offers the following comments:

There are no flood plain or environmental comments regarding the above mentioned license renewal, however if your plans include additional construction you should coordinate with the U.S. Environmental Protection Agency, which is currently involved in a program to protect ground water resources. In addition, it would be recommended that you consult with the U.S. Fish and Wildlife Service, Nebraska Game and Parks Commission, Iowa Department of Natural Resources, Kansas Department of Wildlife and Parks, and the Missouri Department of Conservation regarding fish and wildlife resources if new construction is to take place.

If future construction activities will involve any work in waters of the United States, a Section 404 permit may be required. For a detailed review of permit requirements, preliminary and final project plans should be sent to:

For Iowa:
U.S. Army Corps of Engineers
Rock Island District
Attention: Regulatory Branch
P.O. Box 2004
Clock Tower Building
Rock Island, Illinois 61204-2004

For Kansas and Missouri:
U.S. Army Corps of Engineers
Kansas City District
Attention: CENWK-OD-R
700 Federal Building
601 East 12th Street
Kansas City, MO 64106-2896

For Nebraska:
U.S. Army Corps of Engineers
Wehrspann Regulatory Office
Attention: CENWO-OD-R-NE/Moeschen
8901 South 154th Street
Omaha, Nebraska 68138-3621

If you have any questions, please contact Mr. Dave Crane of my staff at (402) 221-4882.

Sincerely,

Larry D. Janis, Chief
Environmental, Economics, and
Cultural Resources Section
Planning Branch

Nebraska Public Power District
"Always there when you need us"

Joe L. Citta, Jr.
Corporate Environmental Mgr.
PH: 402-563-5355

January 15, 2008

Colonel Roger A. Wilson, Jr., Commander
U. S. Army Corps of Engineers
Kansas City District
601 E. 12th St., Rm. 736
Kansas City, MO 64106

RE: Nebraska Public Power District
Cooper Nuclear Station

Dear Colonel Wilson:

Nebraska Public Power District (NPPD) is preparing an application to the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Cooper Nuclear Station (CNS). The current 30-year operating license for the station expires in 2014. If the application is approved by the NRC, NPPD will have the option to continue operating CNS until 2034.

CNS is located in Nemaha County, Nebraska, on the west bank of the Missouri River at river mile 532.5, an area referred to by the Corps of Engineers as the Lower Brownville Bend. Coordinates for the station are 40°21'43" North latitude and 95°38'29" West longitude. CNS is located on approximately 55 acres of a 1,351-acre site, which includes 205 acres located on the east bank of the Missouri River in Atchison County, Missouri. Approximately 150 miles of transmission lines were constructed to connect the station to the regional electric power grid.

As part of the license renewal process, the NRC requires that the applicant assess the impact of the proposed license renewal action. This assessment, which is contained in the Environmental Report, addresses specific environmental issues related to the continued operation of the station. NPPD is confident that the continued operation of CNS will have no significant environmental impacts.

There are no plans to alter current operations during the 20-year license renewal period. Any maintenance activities necessary to support continued operation of CNS will be limited to currently developed areas of the site. No expansion of existing facilities is planned and no additional land disturbance is anticipated in support of license renewal.

To ensure that potential impacts are adequately addressed, we are requesting from the Omaha and Kansas City Districts pertinent information regarding any concerns or issues, if any, that you may have about potential impacts from the continued operation of CNS, and information regarding any proposed changes in the future operation and maintenance of the Missouri River that could affect the CNS facility.

After your review, we would appreciate your office responding by letter detailing any concerns you may have or confirmation that no concerns exist.

If you have any questions or need additional information, please feel free to contact me at (402) 563-5355.

Thank you,

Joe L. Citta, Jr.
NPPD Corporate Environmental Manager

Att.: Maps & Photographs

cc: Scott Young (ACOE) w/att.
Rick Buckley (Entergy Nuclear) w/att.

DEPARTMENT OF THE ARMY
KANSAS CITY DISTRICT, CORPS OF ENGINEERS
700 FEDERAL BUILDING
KANSAS CITY, MISSOURI 64106-2896

February 8, 2008

RECEIVED
FEB 11 2008

REPLY TO
ATTENTION OF:

Regulatory Branch
(Project 2008-00155)

Joe L. Citta, Jr., Environmental Manager
Nebraska Public Power District
P.O. Box 499
Columbus, Nebraska 68602-0449

Dear Mr. Citta:

This is in response to your letter dated January 15, 2008, concerning your renewal application with the U.S. Nuclear Regulatory Commission for operation of your Cooper Nuclear Station located adjacent to the Missouri River (River mile 532.5) in Nemaha County, Nebraska.

This portion of the Missouri River navigation channel is within the Omaha District's area of review. To address any current environmental issues, identified in your Environmental Report, or for review of any future activities you should contact Mr. Stephen Earl, Omaha District, at 402-221-7325. In addition, for any future activities involving the discharge of dredged or fill material into waters of the United States, including wetlands, you should contact the Omaha District, Regulatory Branch at 402-896-0896 and/or for activities in the State of Missouri please contact the Kansas City District, Regulatory Branch at 816-389-3990.

We have reviewed the information provided and we have contacted the Omaha District, regarding this request, and at this time the Corps of Engineers has no issues or concerns with your application for continued operations at the Cooper Nuclear Station. We have provided a copy of this letter to the Omaha District for their records.

If you have any questions concerning this matter, please feel free to write me or call Mr. Douglas R. Berka, Regulatory Project Manager, at 816-389-3657.

Sincerely,

Mark D. Frazier
Chief, Regulatory Branch
Operations Division

Attachment E

Severe Accident Mitigation Alternatives Analysis

Attachment E contains the following sections.

E.1 – Evaluation of CNS PSA Model

E.2 – Evaluation of CNS SAMA Candidates

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LIST OF ACRONYMS

Acronym	Definition
AC	Alternating Current
ADS	Automatic Depressurization System
AOV	Air Operated Valve
ASDS	Alternate Shutdown System
ATWS	Anticipated Transient Without Scram
BOC	Break Outside of Containment
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owners Group
CB	Control Building
CCF	Common Cause Failure
CDF	Core Damage Frequency
CET	Containment Event Tree
CNS	Cooper Nuclear Station
CRD	Control Rod Drive
CS	Core Spray
CST	Condensate Storage Tank
DC	Direct Current
DFP	Diesel Fire Pump
DG	Diesel Generator
DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System
ECST	Emergency Condensate Storage Tank
EDG	Emergency Diesel Generator

Acronym	**Definition**
EOP	Emergency Operating Procedure
EPG	Emergency Procedure Guidelines
FIVE	Fire Induced Vulnerability Evaluation
FPS	Fire Protection System
HCLPF	High Confidence Low Probability of Failure
HPCI	High Pressure Coolant Injection
HVAC	Heating Ventilation and Air Conditioning
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination of External Events
ISLOCA	Interfacing Systems Loss of Coolant Accident
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOOP	Loss of Off-site Power
LPCI	Low Pressure Coolant Injection
MAAP	Modular Accident Analysis Program
MACCS2	Melcor Accident Consequences Code System 2
MCC	Motor Control Center
MSIV	Main Steam Isolation Valve
NBPP	No Break Power Panel
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
OECR	Off-site Economic Cost Risk
OSP	Off-site Power
PCPL	Primary Containment Pressure Limit
PDR	Population Dose Risk
PDS	Plant Damage State

Acronym	**Definition**
PSA	Probabilistic Safety Assessment
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWCU	Reactor Water Clean Up
SAMA	Severe Accident Mitigation Alternative
SAMG	Severe Accident Management Guidance
SBO	Station Blackout
SLC	Standby Liquid Control
SMA	Seismic Margin Assessment
SORV	Stuck Open Relief Valve
SPC	Suppression Pool Cooling
SQUG	Seismic Qualification Utility Group
SRV	Safety Relief Valve
SW	Service Water
SWBP	Service Water Booster Pump
TAF	Top of Active Fuel
TBCCW	Turbine Building Closed Cooling Water
TEC	Turbine Equipment Cooling
THPV	Torus Hard Pipe Vent
WW	Wetwell

ATTACHMENT E.1

EVALUATION OF CNS PSA MODEL

E.1 EVALUATION OF CNS PROBABILISTIC SAFETY ANALYSIS MODEL

The severe accident risk was estimated using the Probabilistic Safety Analysis (PSA) model and a Level 3 model developed using the most recent version (version 1.13.1) of the MELCOR Accident Consequences Code System version 2 (MACCS2 code). The CAFTA code was used to develop the CNS PSA Level 1 and Level 2 models. This section provides the description of CNS PSA levels 1, 2, and 3 analyses, Core Damage Frequency (CDF) uncertainty, Individual Plant Examination of External Events (IPEEE) analyses, and PSA model peer review.

E.1.1 PSA Model—Level 1 Analysis

The PSA model (Level 1 and Level 2) used for the SAMA analysis was the most recent internal events risk model for CNS (2007TM model, Rev. 1). This model is an updated version of the model used in the IPE and reflects the CNS configuration and design as of December 2007. It uses component failure and unavailability data as of March 2006. The CNS model adopts the small-event-tree / large-fault-tree approach and uses the CAFTA code for quantifying CDF.

The PSA model has had five major revisions since the IPE due to the following.

- Equipment performance: as data collection progresses, estimated failure rates and system unavailability data change.
- Plant configuration changes: plant configuration changes are incorporated into the PSA model.
- Modeling changes: the PSA model is refined to incorporate the latest state of knowledge and recommendations from internal and industry peer reviews.

The PSA model contains the major initiators leading to core damage with baseline CDFs listed in Table E.1-1. A separate breakdown of the top flood scenarios is given in Table E.1-2.

The CNS 2007TM model, Rev. 1, was reviewed to identify those potential risk contributors that made a significant contribution to CDF. CDF-based Risk Reduction Worth (RRW) rankings were reviewed down to 1.005. Events below this point would influence the CDF by less than 0.5% and are judged to be highly unlikely contributors for the identification of cost-beneficial enhancements. These basic events, including component failures, operator actions, and initiating events, were reviewed to determine if additional SAMA actions may need to be considered.

Table E.1-3 provides a correlation between the Level 1 RRW risk significant events (component failures, operator actions, and initiating events) down to 1.005 identified from the CNS PSA model and the SAMAs evaluated in Section E.2.

Table E.1-1
CNS PSA Model CDF Results by Major Initiators

Initiating Event Group	CDF (/ry)	% of Total CDF
Inadvertent ADS	4.48E-10	0.00
LOCA	1.37E-06	14.79
Internal Flood	2.62E-07	2.82
Interfacing System LOCA	5.14E-08	0.55
Loss of Offsite Power	6.52E-07	7.03
Transients	3.01E-06	32.44
Loss of AC Buses	2.62E-07	2.83
Loss of DC Power	2.06E-06	22.24
Loss of Feedwater	1.00E-06	10.83
Loss of Service Water	6.00E-07	6.47
Total CDF	**9.27E-06**	**100.00**
Total ATWS(1)	2.59E-07	2.79
Total SBO(1)	2.58E-07	2.78

1. Because SBO and ATWS may occur following multiple initiators, their contributions to CDF are listed separately.

Table E.1-2
Level 1 Flooding Contributions

Flooding Event	CDF (/ry)	% of Total Flood CDF	Description
%FLSWCB7AM	1.32E-07	50.41	Moderate SW pipe rupture in the control building basement (comp 7a)
%FLSWRBM	5.43E-08	20.74	Moderate SW rupture (RB-859' or above)
%FLSWCB7AL	2.57E-08	9.82	Large SW pipe rupture in the control building basement (comp 7a)
%FLSWRBL	9.71E-09	3.71	Large SW rupture (RB-859' or above)
%FLCWTB11L	9.34E-09	3.57	Large CW pipe rupture in turbine building basement (loss of FW, cond, MC)
%FLFPCB8DM	8.75E-09	3.34	Moderate fire water pipe rupture in control building ground floor corridor (CB-903')
%FLFPCB7AL	4.05E-09	1.55	Large fire water pipe rupture in the control building basement
%FLECRBM	2.97E-09	1.13	Moderate ECCS rupture (RB-859' or above)
%FLFPCB8DL	2.83E-09	1.08	Large fire water pipe rupture in control building ground floor corridor (CB-903')
%FLFPRBL	2.44E-09	0.93	Large fire water pipe rupture (RB-859' or above)
%FLECRB1DM	2.29E-09	0.87	Moderate ECCS rupture in quad 1D/1E (SW)
%FLFPCB7AM	2.26E-09	0.86	Moderate fire water pipe rupture in the control building basement
Other	5.19E-09	1.98	
Total	2.62E-07	100.00	

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

Event Name	Probability	RRW	Event Description	Disposition
%TDCA	5.25E-04	1.19	Loss of 125 VDC A	This term represents an initiating event caused by loss of 125V DC bus A. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21, for enhancing DC system availability and reliability, were evaluated.
EDC-XHE-FO-RSTRA	7.10E-01	1.19	Failure to restore DC power within 30 min. (data based)	This term represents operator failure to restore DC power in train A within 30 min. when DC power has been lost. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21, for enhancing DC system availability and reliability, were evaluated.
%TF	1.35E-01	1.121	Loss of feedwater	This term represents the initiating event for loss of feedwater. A modification to significantly reduce the potential for loss of feedwater by upgrading to a digital feedwater control system has already been installed. Phase II SAMAs 33, 34, and 75, to further reduce the potential for loss of feedwater, were evaluated.
DEP-XHE-FO-ERLY3	2.51E-06	1.11	Operator fails to initiate ADS & fails to initiate ECCS & RHR (early)	This term represents the combination of human failure events ADS-XHE-FO-COND, ECS-XHE-FO-TRANS, and RHR-XHE-FO-RHRE to account for dependencies. These three events represent operator failure to initiate ADS following failure of ECCS initiation, failure to initiate ECCS, and failure to initiate early suppression pool cooling. Phase II SAMAs 28, 29, 46, 47, 52, 71, 73, and 77, to improve the probability of successful injection and depressurization, to improve reliability of ECCS auto-start features, and to improve suppression pool cooling were evaluated.
%TC	1.16E-01	1.102	Loss of condenser vacuum	This term represents the loss of condenser vacuum initiator. Phase II SAMAs 75 and 76, to reduce initiating event frequencies by implementing generation risk assessment and to prevent inadvertent MSIV closure, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
%S2-WA	3.59E-03	1.102	Small break LOCA, below core inside drywell	This term represents an initiating event caused by a small break LOCA below the core inside of the drywell. Phase II SAMAs 22, 23, 24, 25, 28, 32, 67, and 78, to enhance high or low pressure injection systems and reduce the core damage frequency contribution from a LOCA, were evaluated.
SWS-XHE-FO-WNDML	1.00E+00	1.102	Operator does not use RHRSW without a SWBP (windmilling)	This term represents operator failure to use the RHRSW without a SWBP even though it has this capability. Phase II SAMA 79, to modify procedures to enhance the probability that the operator will use RHRSW without a SWBP, was evaluated.
FPS-XHE-FO-RHR25A	1.00E+00	1.095	Operator fails to manually open RHR-MO-25A locally	This term represents operator failure to manually open RHR-MO-25A which leads to a failure of fire water for RPV injection. Phase II SAMA 78, to improve training on alternate injection via the fire water system, was evaluated.
%MS	1.44E+00	1.086	Manual shutdown	This term represents the manual shutdown initiating event. Phase II SAMA 75, to reduce initiating event frequencies by implementing generation risk assessment, was evaluated.
ADS-XHE-FO-TRANS	3.90E-04	1.078	Operator failure to depressurize with SRVs	This term represents operator failure to depressurize with the safety relief valves following a transient. Phase I SAMAs to improve plant procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 26, 27, 43, and 44, to improve SRV availability and reliability, were evaluated.
EAC-ACB-CF-1F&G	2.64E-07	1.077	Common cause failure of 4160V AC buses 1F & 1G	This term represents common cause failure of 4160V AC buses 1F and 1G. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
%LOOP	1.86E-02	1.076	Loss of offsite power	This term represents the loss of offsite power initiating event. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
NBI-PIS-TM-PS52D	8.47E-03	1.071	Test or maintenance of PS-52D	This term represents pressure switch PS-52D unavailable due to testing or maintenance, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
%TSW	2.08E-04	1.069	Loss of service water	This term represents the initiating event of a complete loss of the service water system. Enhancements to prevent or mitigate loss of service water system components were evaluated in Phase II SAMAs 30 and 31. Phase II SAMA 75, to reduce initiating event frequencies by implementing generation risk assessment, was also evaluated.
%TT	7.30E-01	1.066	Turbine trip	This term represents the turbine trip initiating event. Phase II SAMA 75, to reduce initiating event frequencies by implementing generation risk assessment, was evaluated.
NBI-PIS-TM-P52B	7.32E-03	1.06	Test or maintenance of PS-52B (6.2CSCS.303)	This term represents pressure switch PS-52B unavailable due to testing or maintenance, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
PCI-CNT-FF-PREEX	2.70E-03	1.056	Pre-existing containment failure	This term represents a pre-existing containment failure leading to loss of NPSH to the ECCS pumps. Phase II SAMAs 22, 28, 46, and 47, providing independent or passive high and low pressure systems, were evaluated.
OSP-SYS-LP-LOCA	2.40E-02	1.054	Conditional probability of LOOP (LOCA signal)	This term represents the conditional probability that offsite power is lost as the result of a transient which also causes ECCS actuation. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
SPC-XHE-FO-RCVR	4.80E-01	1.054	Failure to recover/repair SPC before vent (transient/ IORV)	This term represents failure to recover suppression pool cooling before venting during a transient. Phase II SAMAs 30, 46, 71, and 73 to improve suppression pool cooling, were evaluated.
FPS-XHE-FO-RPVIN	1.00E-01	1.049	Operator fails to align fire protection system for RHR loop A injection	This term represents operator failure to align the fire protection system for RHR loop A injection. Phase II SAMA 78, to improve training on alternate injection via the fire water system, was evaluated.
SWS-XHE-FO-SWBPS	7.70E-03	1.049	Human error failure to manually initiate service water booster pump system	This term represents human failure to manually initiate the service water booster pump system. Phase II SAMA 79, to modify procedures to enhance the probability that the operator will use RHRSW without a SWBP, was evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
%TIA	8.84E-03	1.048	Loss of instrument air	This term represents an initiating event caused by loss of the instrument air system. Phase II SAMAs 41, 42, 45, to improve the availability and reliability of the instrument air system, were evaluated. Phase II SAMA 75, to reduce initiating event frequencies by implementing generation risk assessment, was also evaluated.
DEP-XHE-FO-ERLY7	2.20E-05	1.046	Operator fails to initiate ADS & bypass HPCI high temperature trip	This term represents the combination of human failure events ADS-XHE-FO-TRANS and HCI-XHE-FO-BYPTP to account for dependencies. These basic events represent operator failure to depressurize with the safety relief valves following a transient and failure to bypass the HPCI high temperature trip. Phase II SAMAs 22, 23, 26, 27, 43, and 44, to improve SRV availability and reliability and to provide additional high pressure injection, were evaluated.
NBI-XHE-CF-PS52	8.00E-05	1.046	Common cause failure to restore PS52A2 and PIS52B or PS52C2 and PIS52D	This term represents common cause failure to restore PS52A2 and PIS52B or PS52C2 and PIS52D, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
ADS-XHE-FO-COND	1.40E-01	1.045	Conditional probability of moderate dependence between injection initiation & depressurization	This term represents the probability of moderate dependence between injection initiation failure and operator failure to initiate ADS. Phase II SAMAs 28, 29, 47, 52, and 77, to improve the probability of successful injection and depressurization, were evaluated.
%TDC	7.88E-07	1.044	Loss of both DC buses	This term represents the loss of both DC buses initiating event. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
EDC-XHE-FO-RSTR	5.00E-01	1.044	Failure to restore a single DC bus within 30 min. (data based)	This term represents operator failure to restore a single DC bus within 30 minutes when both DC buses fail. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
LOOP-IE-SW	2.10E-01	1.043	Conditional probability due to weather related LOOP event	This term represents the conditional probability of a weather related LOOP event. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
HCI-TDP-SS-TP	1.30E-02	1.038	Standby turbine driven pump HPCI-P-MP fails to start	This term represents random failure of the standby turbine driven pump to start. Phase II SAMAs 22, 23, 67, and 77, to enhance high pressure injection, were evaluated.
PCV-XHE-FO-233MV	1.00E-01	1.035	Operator fails to manually open PC-MOV-233MV on loss of electrical power	This term represents operator failure to manually open torus vent valve PC-MOV-233MV on loss of electrical power. Phase II SAMA 20, to provide redundant power to the direct torus vent valves, was evaluated.
EAC-XHE-FO-MCCRA	1.00E+00	1.035	Operator fails to switch MCC-RA to alternate power source	This term represents operator failure to switch MCC-RA to an alternate power source. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
HVC-PHE-FF-CB7A	1.00E+00	1.034	Phenomenological requirement for CB7A HVAC	This term represents the phenomenological HVAC requirement for CB7A which affects the SW booster pumps. Phase II SAMA 35, to provide a redundant train of ventilation, was evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
HVC-XHE-FO-CB7A	2.40E-02	1.034	Operator fails to provide alternative cooling to CB basement (RHRSWBP)	This term represents operator failure to provide alternative cooling to the control building basement which affects the SW booster pumps. Phase II SAMA 35, to provide a redundant train of ventilation, was evaluated.
EAC-DGN-TM-DG2	1.97E-02	1.034	Diesel generator DG2 unavailable due to maintenance	This term represents diesel generator DG2 being unavailable due to maintenance. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EAC-TRN-TM-SU	6.30E-03	1.034	Test or maintenance unavailability of startup service transformer	This term represents the startup service transformer unavailable due to testing or maintenance. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
OSPR30MIN-GR	8.25E-01	1.031	Failure to recover OSP within 30 minutes (grid related LOOP event)	This term represents operator failure to recover a grid related LOOP event within 30 minutes. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
RCI-TDP-SS-TP	1.30E-02	1.031	Standby turbine driven pump RCIC-P-MP fails to start	This term represents random failure of the standby turbine driven RCIC pump to start. Phase II SAMAs 22, 23, 24, 25, 67, and 77, to enhance high pressure injection, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
HCI-SYS-TM-HPCI	1.15E-02	1.03	HPCI unavailable due to test and maintenance	This term represents HPCI unavailability during testing or maintenance. Phase I SAMAs to improve availability and reliability of the HPCI system that have already been implemented include raising backpressure trip set points and proceduralizing intermittent operation. Additional improvements for the HPCI system were evaluated in Phase II SAMAs 22, 23, 67, and 77.
DFP-FAIL-NOT	7.50E-01	1.029	DFP successful	This term represents successful injection via the diesel fire pump. Sequences containing this event fail due to loss of DC power. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21, for enhancing DC system availability and reliability, were evaluated.
DEP-XHE-FO-ERLY4	2.10E-05	1.029	Operator fails to initiate ADS & control HPCI to prevent level 8 trip	This term represents the combination of human failure events ADS-XHE-FO-TRANS and HCI-XHE-FO-LVL8 to account for dependencies. These basic events represent operator failure to depressurize with the safety relief valves following a transient and failure to control HPCI to prevent reaching the high level trip. Phase II SAMAs 22, 23, 26, 27, 43, and 44, to improve SRV availability and reliability and to provide additional high pressure injection, were evaluated.
%TM	3.46E-02	1.028	MSIV closure	This term represents an initiating event caused by MSIV closure. A Phase I SAMA to develop procedures to re-open MSIVs is already in place. Phase II SAMAs 27, 44, and 75, to improve SRV and MSIV availability and reliability and to reduce initiating event frequencies by implementing generation risk assessment, were evaluated.
RHR-MDP-TM-RHRD	7.38E-03	1.027	Test or maintenance unavailability: RHR pump D	This term represents unavailability of RHR pump D due to testing and maintenance. Phase II SAMAs 30, 46, and 73, to improve suppression pool cooling, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
RPS-SYS-CF-MECH	2.10E-06	1.027	CCF of RPS mechanical scram components	This term represents common cause failure of RPS mechanical scram components, which leads to failure to scram. Phase II SAMA 44, to improve SRV and MSIV availability and reliability, was evaluated.
RCI-SYS-TM-RCIC	1.25E-02	1.026	RCIC unavailable due to test or maintenance	This term represents RCIC unavailable due to testing or maintenance. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements for the RCIC system were evaluated in Phase II SAMAs 22, 23, 24, 25, 67 and 77.
SWS-MDP-TM-SWPB	1.62E-02	1.026	Test or maintenance unavailability: SW pump B	This term represents the unavailability of SW pump B due to testing or maintenance. Enhancements to prevent or mitigate loss of service water system components were evaluated in Phase II SAMAs 30 and 31.
SWS-MDP-TM-SWPD	1.62E-02	1.026	Test or maintenance unavailability: SW pump D	This term represents the unavailability of SW pump D due to testing or maintenance. Enhancements to prevent or mitigate loss of service water system components were evaluated in Phase II SAMAs 30 and 31.
ECS-XHE-FO-TRANS	3.30E-04	1.025	Manual ECCS initiation with a transient	This term represents operator failure to manually initiate ECCS following a transient and ECCS auto-start failure. Phase II SAMA 77, to improve reliability of ECCS auto-start features, was evaluated.
EAC-DGN-TM-DG1	1.45E-02	1.022	Diesel generator DG1 unavailable due to maintenance	This term represents EDG DG-1 unavailable due to maintenance. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
DEP-XHE-FO-SPTDV	5.00E-07	1.021	Operating staff fails to initiate both SPC and torus drywell vent	This term represents operator failure to initiate both SPC and the torus drywell vent. Phase II SAMAs 46, 52, and 73, providing independent suppression pool cooling and passive overpressure relief and maintaining a lower normal suppression pool temperature, were evaluated.
%TDCB	5.25E-04	1.02	Loss of 125 VDC B	This term represents an initiating event caused by loss of 125VDC bus B. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
EDC-XHE-FO-RSTRB	7.10E-01	1.02	Failure to restore DC power within 30 min. (data based)	This term represents operator failure to restore DC power in train B within 30 min. when DC power has been lost. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
NBI-XHE-MC-P52B	1.70E-03	1.02	Human error: miscalibration of pressure switch PS-52B	This term represents miscalibration of pressure switch PS-52B, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
NBI-XHE-MC-P52D	1.70E-03	1.02	Human error: miscalibration of pressure switch PS-52D	This term represents miscalibration of pressure switch PS-52D, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
NBI-ACT-TM-RCIC	8.20E-03	1.019	Test or maintenance unavailability: RCIC actuation relays	This term represents RCIC actuation relays unavailable due to testing or maintenance which prevents RCIC initiation. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements for the RCIC system were evaluated in Phase II SAMAs 22, 23 and 77.
OSPR65HR-SW	2.93E-01	1.019	Failure to recover OSP within 6.5 hrs (weather related LOOP event)	This term represents operator failure to recover a weather related LOOP event within 6.5 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
%TACF	1.28E-03	1.019	Loss of 4160 VAC F	This term represents an initiating event caused by loss of 4160V AC bus 1F. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
OSPR65HR-GR	7.08E-02	1.018	Failure to recover OSP within 6.5 hrs (grid related LOOP event)	This term represents operator failure to recover a grid related LOOP event within 6.5 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
ACP-XHE-FO-11HR	2.26E-01	1.017	Onsite AC power not recovered within 11.5 hrs (data based)	This term represents failure to recover onsite AC power within 11.5 hours. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ADS-SRV-CF-ADSRV	7.40E-05	1.017	Common cause failure of a sufficient number of safety relief valves	This term represents common cause failure of a sufficient number of SRVs to cause failure of the ADS system. Phase II SAMAs 26, 43, and 44, to improve SRV availability and reliability, were evaluated.
EAC-TRN-TM-E	1.00E-02	1.017	Test or maintenance unavailability of emergency service transformer	This term represents the emergency service transformer being in testing or maintenance. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
%S2-ST	2.88E-03	1.016	Small break LOCA, above core inside drywell	This term represents an initiating event caused by a small break LOCA above the core inside the drywell. Phase II SAMAs 22, 23, 24, 25, 28, 32, 67, and 78, to enhance high or low pressure injection systems and reduce the core damage frequency contribution from a LOCA, were evaluated.
PCS-MDP-CF-TRIP	1.00E-02	1.016	Common cause trip of circulating water pumps	This term represents common cause trip of the circulating water pumps, resulting in failure to remove heat from the reactor. SAMAs that improve suppression pool cooling will help mitigate this event. Phase II SAMAs 46, 71, and 73, to improve suppression pool cooling, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
OSPR11HR-SW	2.03E-01	1.016	Failure to recover OSP within 11 hrs (weather related loop event)	This term represents operator failure to recover a weather related LOOP event within 11 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ACP-XHE-FO-65HR	3.53E-01	1.016	Onsite AC power not recovered within 6.5 hrs (data based)	This term represents failure to recover onsite AC power within 6.5 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
HVC-PHE-FF-RHRQD	1.00E+00	1.015	Phenomenological room cooling requirement for quads	This term represents the phenomenological room cooling requirement for the quads. Phase II SAMA 35, to provide a redundant train of ventilation, was evaluated.
HVC-XHE-FO-ALTQC	4.30E-03	1.015	Operator fails to initiate alternate room cooling	This term represents operator failure to initiate alternate room cooling to the quads when needed. Phase II SAMA 35, to provide a redundant train of ventilation, was evaluated.
RPT-PIP-RP-SEALL	5.00E-02	1.015	Conditional probability of large recirc seal LOCA given SBO	This term represents the conditional probability of a large recirc seal LOCA given that a SBO has occurred. Phase II SAMAs 24 and 25, to extend HPCI/RCIC operation, were evaluated.
RHR-XHE-FO-RHRE	4.50E-03	1.015	Operator action: initiate SPC (early)	This term represents failure to initiate early suppression pool cooling. Phase II SAMAs 30, 46, 71, and 73, to improve suppression pool cooling, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
LOOP-IE-GR	2.93E-01	1.015	Conditional probability LOOP due to grid related event	This term represents the conditional probability of a grid related LOOP event. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
%FLSWCB7A M	5.06E-05	1.014	Moderate SW pipe rupture in the control bldg. basement (comp 7A)	This term represents the moderate SW pipe rupture in the control building basement initiator. Phase II SAMA 62, to improve internal flooding procedures, was evaluated along with SAMA 30 to help mitigate loss of service water.
ACP-XHE-FO-NONE	1.00E+00	1.014	No onsite AC power recovery	This term represents no onsite AC power recovery. This basic event is used to keep on-site AC power recoveries from being applied to cutsets when there is an EDG available. Since this term does not represent a component failure, no Phase II SAMAs were evaluated.
OSPR11HR-GR	2.22E-02	1.014	Failure to recover OSP within 11 hrs (grid related loop event)	This term represents operator failure to recover a grid related LOOP event within 11 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
HCI-HOV-CC-HO10	4.86E-03	1.013	Normally closed hydraulic operated valve HO10 fails closed	This term represents random failure of normally closed hydraulic operated valve HO10 which causes a failure of the turbine driven pump. Phase II SAMAs 22 and 23 were evaluated to add additional high pressure injection systems.

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

Event Name	Probability	RRW	Event Description	Disposition
IAS-XHE-FO-COOL	1.60E-01	1.013	Human error failure to align emergency compressor cooling	This term represents human error failure to align emergency air compressor cooling. Phase II SAMAs 42 and 45, to upgrade air compressors and to add a portable air compressor, were evaluated.
ADS-SRV-OO-RECLF	1.50E-01	1.012	SRVs fail to re-close on reduced pressure	This term represents failure of the SRVs to re-close on reduced pressure. Phase II SAMA 44, to improve SRV and MSIV pneumatic components, was evaluated.
PCV-XHE-FO-AOV	1.00E-01	1.012	Human error: fail to locally open HPV AOVs, PC-AOV-237AV and PC-AOV-32AV.	This term represents failure to locally open hard pipe vent AOVs, PC-AOV-237AV and PC-AOV-32AV, which results in failure to depressurize. Phase II SAMAs 41, 42, and 45, to improve the availability and reliability of the instrument air system, and Phase II SAMA 20, to provide redundant power to the hard pipe vent valves, were evaluated.
IAS-XHE-FO-CST	3.10E-01	1.012	Operator fails to isolate CST from the hotwell	This term represents operator failure to isolate the CST from the hotwell which allows the CST to drain to the hotwell. Phase II SAMA 72, to prevent drain-down of the CST to the hotwell, was evaluated.
FPS-XHE-FO-DFPAL	1.00E-01	1.012	Crew fails to align DFP under SBO conditions (> 2 hrs. available)	This term represents operator failure to align the DFP under SBO conditions for injection when greater than 2 hours is available. Phase II SAMA 78, to improve training on alternate injection via the fire water system, was evaluated.
LOOP-IE-SWYD	4.03E-01	1.012	Conditional probability LOOP due to switchyard event	This term represents the conditional probability of a switchyard centered LOOP event. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
RHR-HTX-TM-HXB	8.12E-03	1.011	Test or maintenance unavailability: RHR heat exchanger B	This term represents unavailability of RHR heat exchanger B due to testing or maintenance. Phase II SAMAs 30, 46, and 73, to improve suppression pool cooling, were evaluated.
RHR-MDP-TM-RHRA	9.49E-03	1.011	Test or maintenance unavailability: RHR pump A	This term represents unavailability of RHR pump A due to testing or maintenance. Phase II SAMAs 30, 46, and 73, to improve suppression pool cooling, were evaluated.
%TRLA	2.24E-03	1.011	Reactor water reference leg 3A line break	This term represents a reactor water reference leg 3A line break initiating event. Phase II SAMA 80, to install additional instrumentation to assist in identifying a reference leg leak-down, was evaluated.
FPS-XHE-FO-RBENV	1.00E+00	1.011	RB local access for alignment unavailable	This term represents the probability that reactor building local access for alignment of injection from the fire water system is unavailable due to adverse conditions. Phase II SAMAs 22, 23, 24, 25, 28, 32, 67, and 78, to enhance high or low pressure injection systems, were evaluated.
NBI-XHE-MC-P52C2	1.70E-03	1.01	Human error miscalibration of pressure switch PS-52C2	This term represents miscalibration of pressure switch PS-52C2, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
NBI-PIS-TM-P52A2	7.32E-03	1.01	Test or maintenance of PS-52A2 (6.1CSCS.303)	This term represents pressure switch PS-52A2 unavailable due to testing or maintenance, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
NBI-PIS-TM-P52C2	7.32E-03	1.01	Test or maintenance of PS-52C2 (6.1CSCS.303)	This term represents pressure switch PS-52C2 unavailable due to testing or maintenance, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
NBI-LIS-TM-101A	8.20E-03	1.009	Test or maintenance of reactor level switch NBI-LIS-101A (6.1RPS.307)	This term represents reactor level switch NBI-LIS-101A unavailable due to testing or maintenance. This causes failure of RCIC to trip on high reactor water level. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements were evaluated in Phase II SAMAs 22 and 23.
NBI-LIS-TM-101C	8.20E-03	1.009	Test or maintenance of reactor level switch NBI-LIS-101C (6.1RPS.307)	This term represents reactor level switch NBI-LIS-101C unavailable due to testing or maintenance. This causes failure of RCIC to trip on high reactor water level. Phase I SAMAs to improve availability and reliability of the RCIC system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements were evaluated in Phase II SAMAs 22 and 23.
SPC-SYS-TM-TRNB	8.95E-03	1.009	Test or maintenance of SPC train B equipment	This term represents test or maintenance of the SPC train B equipment. Phase II SAMAs 30, 46, 71, and 73, to improve suppression pool cooling, were evaluated.
DEP-XHE-FO-ERLYA	7.85E-06	1.009	Operator fails to initiate ADS, ECCS, RHR (early) and control HPCI to prevent level 8 trip	This term represents the combination of human failure events ADS-XHE-FO-COND, ECS-XHE-FO-TRANS and HCI-XHE-FO-LVL8 to account for dependencies. These three events represent operator failure to initiate ADS following failure of ECCS initiation, failure to initiate ECCS, and failure to control HPCI to prevent reaching the high level trip. Phase II SAMAs 22, 23, 28, 29, 47, 52, and 77, to improve the probability of successful injection and depressurization, to improve reliability of ECCS auto-start features, and to provide additional high pressure injection, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
PCS-SYS-RP-DWFAIL	4.30E-01	1.009	Large drywell containment failure causes loss of injection	This term represents a large drywell containment failure causing a loss of injection. Phase II SAMAs 22, 23, 28, and 46, to improve the probability of successful injection and depressurization, were evaluated.
NBI-XHE-MC-P52A2	1.70E-03	1.009	Human error miscalibration of pressure switch PS-52A2	This term represents miscalibration of pressure switch PS-52A2, impacting initiation of core spray and RHR. Phase II SAMAs 28, 29 and 47, to enhance low pressure system availability and reliability, were evaluated.
FPS-XHE-FO-DISEL	1.90E-02	1.009	No fuel oil makeup provided within 8 hours	This term represents operator failure to make-up fuel oil to diesel fire pump 1D within 8 hours. Phase II SAMA 78, to improve training on alternate injection via the fire water system, was evaluated.
ADS-SRV-CO-ISOL	5.40E-02	1.009	Probability of SORV for isolation initiators	This term represents the probability of a stuck open relief valve following a loss of offsite power or a non-turbine trip transient initiator. Phase II SAMA 44, to improve SRV and MSIV pneumatic components, was evaluated.
RCI-TDP-SR-TP24	4.25E-03	1.009	Standby turbine driven pump RCIC-P-MP fails to continue running (24 hrs)	This term represents random failure of the standby turbine driven RCIC pump to continue to run. Phase II SAMAs 22, 23, 24, 25, and 67, to enhance high pressure injection, were evaluated.
HCI-TDP-SR-TP24	4.25E-03	1.008	Standby turbine driven pump HPCI-P-MP fails to continue running (24 hrs)	This term represents random failure of the standby turbine driven pump to continue to run. Phase II SAMAs 22, 23, and 67, to enhance high pressure injection, were evaluated.
HVC-ACU-FS-DG_1C	2.63E-03	1.008	DG1 room air cooling unit HV-DG-1C fails to start	This term represents random failure of DG1 room air cooling unit HV-DG-1C. Phase II SAMAs 36, 38, 39, and 40, to enhance diesel room HVAC, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
NBI-LIS-TM-101B	6.71E-03	1.008	Test or maintenance of reactor level switch NBI-LIS-101B (6.2RPS.307)	This term represents the reactor level sensor NBI-LIS-101B unavailable due to testing or maintenance. This leads to failure of HPCI to trip on high reactor water level. Phase I SAMAs to improve availability and reliability of the HPCI system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements were evaluated in Phase II SAMAs 22 and 23.
NBI-LIS-TM-101D	6.71E-03	1.008	Test or maintenance of reactor level switch NBI-LIS-101D (6.2RPS.307)	This term represents the reactor level sensor NBI-LIS-101D unavailable due to testing or maintenance. This leads to failure of HPCI to trip on high reactor water level. Phase I SAMAs to improve availability and reliability of the HPCI system that have already been implemented include proceduralizing intermittent operation and manual initiation of HPCI and RCIC given auto initiation failure. Additional improvements were evaluated in Phase II SAMAs 22 and 23.
EAC-CRB-CC-1FS	2.55E-03	1.008	Normally closed circuit breaker 1FS fails to open	This term represents failure of circuit breaker 1FS to open. This leads to no power to bus 1F from diesel generator DG1. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
SLC-SYS-FF-SUCCE	7.32E-01	1.007	Early SLC success	This term represents early SLC success. Phase II SAMA 58, 59, 60, and 61 for enhancing ATWS mitigation capabilities, were evaluated.
HVC-ACU-FS-DG_1D	2.63E-03	1.007	DG2 room air cooling unit HV-DG-1D fails to start	This term represents random failure of DG2 room air cooling unit HV-DG-1D. Phase II SAMAs 36, 38, 39, and 40, to enhance diesel room HVAC, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
EDC-DCB-LP-125A	9.19E-06	1.007	125V DC bus 1A failure	This term represents loss of 125V DC bus 1A. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
EAC-CRB-CC-1GS	2.55E-03	1.007	Normally closed circuit breaker 1GS fails to open	This term represents failure of circuit breaker 1GS to open. This leads to no power to bus 1G from diesel generator DG2. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ADS-XHE-FO-3ALEG	9.50E-03	1.007	Failure of cognitive recognition of leakdown	This term represents the failure of cognitive recognition of leakdown after a reference leg break. Phase II SAMA 80, to install additional instrumentation to assist in identifying a reference leg leak-down, was evaluated.
OSP-SYS-LP-TRANS	2.40E-03	1.006	Transient induced LOOP	This term represents the transient induced LOOP event. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
%S1-WA	1.77E-04	1.006	Other medium break LOCA, below core	This term represents an initiating event caused by a medium break LOCA below the core but not in the LPCI line or drywell. Phase II SAMAs 22, 23, 24, 25, 28, 32, 67 and 78, to enhance high or low pressure injection systems and reduce the core damage frequency contribution from a LOCA, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
HCI-XHE-FO-BYPTP	5.40E-03	1.006	Failure to bypass HPCI high temperature trip	This term represents failure to bypass the HPCI high temperature trip. Phase II SAMAs 22 and 23, to provide additional high pressure injection, were evaluated.
%TACG	1.28E-03	1.006	Loss of 4160 VAC G	This term represents the loss of 4160 VAC bus G initiating event. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ADS-XHE-FO-S2W	4.70E-04	1.006	Operator failure to depressurize with SRVs (small water LOCA)	This term represents operator failure to depressurize with the SRVs following a small break LOCA below the core inside of the drywell. Phase I SAMAs to improve plant procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 26, 27, and 43, to improve SRV availability and reliability, were evaluated.
ALT-PHE-FF-BOCIN	1.00E+00	1.006	Alternate low pressure injection unavailable	This term represents unavailability of the alternate low pressure injection system (not including CS/LPCI). Phase II SAMAs 28, 29, 30, 32, and 78, to enhance alternate injection methods, were evaluated.
RHR-XHE-MC-TRIPD	1.70E-03	1.006	Miscalibration failure of position switches causes RHR pump D to trip	This term represents miscalibration of position switches causing RHR pump D to trip. Phase II SAMAs 30, 46, and 73, to improve suppression pool cooling, were evaluated.
%S1-LP	1.52E-04	1.006	Medium break LOCA, below core in LPCI line	This term represents an initiating event caused by a medium break LOCA below the core in the LPCI line. Phase II SAMAs 22, 23, 24, 25, 28, 32, 67, and 78, to enhance high or low pressure injection systems and reduce the core damage frequency contribution from a LOCA, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
SWS-XHE-FO-SWPS	1.40E-02	1.006	Operator fails to start SW pump following LOSP	This term represents operator failure to start the SW pump following a LOSP. Phase II SAMAs 9 and 12, were evaluated to reduce the likelihood of a LOSP.
%FLSWRBM	1.43E-04	1.006	Moderate SW rupture (RB-859' or above)	This term represents the moderate SW pipe rupture in the RB 859' or above initiating event. Phase II SAMA 62, to improve internal flooding procedures was evaluated, along with SAMA 30 to help mitigate loss of service water.
LCS-XHE-FO-BOCL8	2.00E-01	1.006	Operator controls level given a BOC	This term represents operator failure to control level given a break outside containment. Phase II SAMA 28, to add a diverse low pressure injection system, was evaluated.
EAC-DGN-FR-DG1	1.91E-03	1.006	Diesel generator DG1 fails to continue running	This term represents random failure of emergency diesel generator DG-1 to continue to run. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ADS-XHE-FO-ADSHP	4.90E-02	1.005	Failure to inhibit ADS with HPCI injecting	This term represents operator failure to inhibit ADS when HPCI is injecting. Phase II SAMA 44, to improve SRV and MSIV pneumatic components to reduce the likelihood of a stuck-open relief valve, was evaluated.
ADS-XHE-FO-RFLEG	3.50E-02	1.005	Failure of cognitive recognition of the leakdown given both	This term represents operator failure to recognize that both reactor water reference legs have failed. Phase II SAMA 80, to install additional instrumentation to assist in identifying a reference leg leak-down, was evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
%A-ST	1.60E-05	1.005	Large break LOCA, above top of the active fuel	This term represents the initiating event of a large break LOCA above the top of the active fuel. Phase II SAMA 66, to install a digital large break LOCA protection system, was evaluated.
RHR-XHE-FO-ISRPF	9.50E-01	1.005	Operator fails to isolate ISLOCA (pipe rupture)	This term represents operator failure to isolate the ISLOCA pipe rupture. Phase II SAMAs 54, 56, and 57, to improve ISLOCA identification and mitigation, were evaluated.
HVC-FAN-FS-DG_1A	1.79E-03	1.005	DG1 room exhaust fan EF-DG-1A fails to start	This term represents random failure of the DG1 room exhaust fan EF-DG-1A which leads to a failure of DG1. Phase II SAMAs 36, 38, 39, and 40, to enhance diesel room HVAC, were evaluated.
PCV-SYS-TM-VENT	2.43E-03	1.005	Test or maintenance of hard pipe vent system	This term represents unavailability of the hard pipe vent system due to testing or maintenance. Phase II SAMAs 50, 52 and 53 were evaluated for the hard pipe vent system.
SLC-XHE-FO-SLC1P	3.00E-02	1.005	Operator fails to initiate SLC with one pump in required time	This term represents operator failure to initiate SLC with one pump in the required time. Phase II SAMAs 58, 59, 60, and 61, for enhancing ATWS mitigation capabilities, were evaluated.
OSPR30MIN-SWYD	5.95E-01	1.005	Failure to recover OSP within 30 min. (switchyard centered event)	This term represents operator failure to recover a switchyard centered LOOP event within 30 minutes. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
EAC-CRB-CF-1FLS	6.00E-03	1.005	4160V bus 1F load shed breaker independent failures (12 bkrs.)	This term represents 4160V bus 1F load shed breaker failure. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EAC-DGN-FR-DG2	1.91E-03	1.005	Diesel generator DG2 fails to continue running	This term represents random failure of emergency diesel generator DG-2 to continue to run. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ADS-XHE-FO-S2S	4.70E-04	1.005	Operator failure to depressurize with SRVs (small steam LOCA)	This term represents operator failure to depressurize with the SRVs following a small break LOCA above the core inside the drywell. Phase I SAMAs to improve plant procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 26, 27, and 43, to improve SRV availability and reliability, were evaluated.
EAC-CRB-CC-1AN	2.55E-03	1.005	Normally closed circuit breaker 1AN fails to open	This term represents random failure of circuit breaker 1AN to open. This leads to failure of fast transfer for division I power and loss of power from the startup service transformer. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
PCV-XHE-FO-HPV	1.90E-03	1.005	Operator fails to operate primary containment hard pipe vent system	This term represents operator failure to operate the primary containment hard pipe vent system. Phase II SAMAs 52 and 53 were evaluated for the hard pipe vent system.

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

Event Name	Probability	RRW	Event Description	Disposition
EAC-DGN-CF-DGR	5.39E-05	1.005	Common cause failure to run for diesel generators	This term represents common cause failure of both EDGs to continue to run. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 12, 13, 14, 15, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDC-CHG-CF-125V	1.71E-06	1.005	Common cause failure of 125V DC chargers	This term represents common cause failure of the 125V DC chargers. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
HVC-FAN-FS-DG_1B	1.79E-03	1.005	DG2 room exhaust fan EF-DG-1B fails to start	This term represents random failure of the DG2 room exhaust fan EF-DG-1B which leads to a failure of DG2. Phase II SAMAs 36, 38, 39, and 40, to enhance diesel room HVAC, were evaluated.
EAC-CRB-CF-1GLS	6.00E-03	1.005	4160V bus 1G load shed breaker independent failures (12 bkrs.)	This term represents 4160V bus 1G load shed breaker failure. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

CDF Uncertainty

The uncertainty associated with CDF was estimated from the 2007TM model, Rev. 1. The ratio of the 95th percentile CDF to the mean is about 1.86. An uncertainty factor of 3 was conservatively selected to determine the "internal and external benefit with uncertainty" described in Section 4.21.5.4.

E.1.2 PSA Model – Level 2 Analysis

E.1.2.1 Containment Performance Analysis

The CNS Level 2 PSA model used for the SAMA analysis (2007TM model, Rev. 1) is the most recent internal events risk model, which is an updated version of the model used in the IPE. The Level 2 PSA model used for the SAMA analysis reflects the CNS operating configuration and design as of December 2007.

The CNS Level 2 model includes two types of considerations: (1) a deterministic analysis of the physical processes for a spectrum of severe accident progressions, and (2) a probabilistic analysis component in which the likelihood of the various outcomes are assessed. The deterministic analysis examines the response of the containment to the physical processes during a severe accident. This response is performed by

- utilization of the Modular Accident Analysis Program MAAP 4.0.5 code to simulate severe accidents that have been identified as dominant contributors to core damage in the Level 1 analysis, and

- reference calculation of several hydrodynamic and heat transfer phenomena that occur during the progression of severe accidents. Examples include debris coolability, pressure spikes due to ex-vessel steam explosions, scoping calculation of direct containment heating, molten debris filling the pedestal sump and flowing over the drywell floor, containment bypass, deflagration and detonation of hydrogen, thrust forces at reactor vessel failure, liner melt-through, and thermal attack of containment penetrations.

The Level 2 analysis examined the dominant accident sequences and the resulting plant damage states (PDS) defined in Level 1. The Level 1 analysis involves the assessment of those scenarios that could lead to core damage.

A full Level 2 model was developed for the 2007TM model and completed at the same time as the Level 1 model. The Level 2 model consists of containment event trees (CETs) with functional nodes that represent phenomenological events and containment protection system status. The nodes were quantified using subordinate trees and logic rules. A list of the CET functional nodes and descriptions, used for the Level 2 analysis is presented in Table E.1-4.

The Large Early Release Frequency (LERF) is an indicator of containment performance from the Level 2 results because the magnitude and timing of these releases provide the greatest potential for early health effects to the public. The frequency calculated is approximately 2.44E-6/ry. Figure E.1-1 and Figure E.1-2 summarize the Level 2 results.

LERF represents a fraction (~21%) of all release end states. Table E.1-5 provides a correlation between the Level 2 RRW risk significant events (severe accident phenomenon, initiating events, component failures and operator actions) down to 1.005 identified from the CNS 2007TM Revision 1 PSA LERF model and the SAMAs evaluated in Section E.2.

Table E.1-4
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Containment Isolation (IS)	The success of the containment isolation node (IS) is satisfied if the containment penetrations that communicate between the drywell (or wetwell) atmosphere and the reactor building (or environment) are "closed and isolated." The criteria used to satisfy this requirement of "closed or isolated" is that no line, hatch, or penetration has an opening greater than 2 inches in diameter that communicates with the atmosphere outside of containment. This implies that all containment penetrations are adequately sealed and isolated during the entire accident progression until either (1) a safe stable state is reached, or (2) the accident conditions exceed the ultimate capability of containment as determined in the plant specific evaluation.	Failure size (> 2-inch dia.)
RPV Depressurization (OP)	This function questions whether the RPV is depressurized after core damage but before vessel breach. Success of this action would allow low pressure injection, if available, and would minimize the challenge to containment due to a high pressure RPV rupture. The functional success criterion for this node is defined as having the RPV depressurized (i.e., less than 100 psig) until core melt is arrested in-vessel or until the RPV is breached by debris attack. The success of the depressurization function for the RPV is similar to the criterion established in the Level 1 analysis, i.e., prior to core damage. However, there are additional phenomena (i.e., non-condensible gas generation contributing to a high containment pressure that prevents SRV operation, and potentially very high containment temperatures which could fail electrical and mechanical components of the SRVs) which can occur during the accident progression beyond core damage and pose further challenge to the operator's ability to depressurize the RPV.	RPV Pressure (< 100 psig)

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
RPV Depressurization (OP) (cont'd)	The success criterion is to depressurize the RPV to less than 100 psig. The success criteria, in terms of systems, is the following: • any single SRV[(1)] is opened, or • failure of the primary system due to high temperature during core melt progression,[(2)] or • a large or medium LOCA (NEDO-24708A). Other alternatives[(3)] may be available but are not credited in this analysis.	
Arrest Core Melt Progression In-vessel (RX)	In-vessel recovery or arrest of core melt progression addresses the ability of the operating staff to restore adequate core cooling from the time the end state of the Level 1 PRA occurs (i.e., core nodal temperature > 1800°F) until restoration of water injection make-up cannot prevent the breach of the RPV bottom head by debris. As part of the definition of success, it is also useful to define what constitutes failure to maintain the RPV intact. The two primary failure modes that have been identified in the literature include: • Local penetration seal failure due to debris heat up and local failure at welds • Creep rupture failure of the entire bottom head.	> 1/2 core relocation calculated by MAAP.

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Arrest Core Melt Progression In-vessel (RX) (cont'd)	Preventing the core melt from progressing outside the reactor pressure vessel requires the timely introduction of water onto the debris and intact fuel assemblies. Both timing and system requirements must be defined as part of the success criteria. There are differences in-core melt progression models regarding the ability to recover adequate cooling under different circumstances. These vary from no credit for retention of debris in-vessel after core melting has begun (MAAP), to substantial credit for recovery even after debris has accumulated in the bottom head (MARCH). The best estimate success criteria used in this evaluation are based on the time available from the initiation of core degradation until just before substantial core relocation occurs. This typically is on the order of 30-40 minutes. This basis is documented in the success criteria discussion of the RX node in Appendix C. In terms of system requirements, coolant injection is assumed necessary to re-flood the RPV to above 1/3 core height. It is judged, based on deterministic calculations, that this can be accomplished using makeup systems (identified in the EOPs) with capability greater than approximately 1000 gpm.(4)	
Combustible Gas Venting (GV Node)	The functional success criterion at this node is that the containment vent and purge lines are opened to allow combustible gas mixtures to be removed from containment. The downward path of GV in the CET implies that combustible gas venting has not been initiated. Therefore, on the downward path either of two conditions may exist: • the containment is inerted,(5) or • a combustible gas mixture is present.	Vent opened.

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Combustible Gas Venting (GV Node) (cont'd)	The probabilistic evaluation of these two states on the downward branch is treated in the Containment Remains Intact Early (CZ) node. Hydrogen combustion that could lead to containment failure is prevented by either of the following: • deinerted operation with no oxygen intrusion during the accident, or • combustible gas purging and venting through the purge and vent lines. If both of these success paths fail, the hydrogen deflagration or detonation is assumed to occur, resulting in containment failure. The location of the failure is assumed to be in the drywell head region and is classified as a large failure. <u>Failure</u> • Radionuclide release: Assumed High magnitude (conservative) • Containment Failure Location: Assumed DW Head (conservative) <u>Success</u> Radionuclide Release: Same as Drywell Vent	
Containment Remains Intact (CZ)	The functional success criteria for the containment intact node are that the containment retains its pressure capability and that no early containment failure modes compromise the containment integrity. The early containment failures modeled by the CZ node are characterized by phenomenological events (e.g., steam explosions, missile generation, direct containment heating) that are estimated to challenge containment integrity relatively quickly following core melt. Late containment failures, modeled in subsequent nodes, are characterized by extreme pressure and temperature conditions that develop slowly over the course of the accident due to inadequate	No energetic containment failure pressure < 178 psig.

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Containment Remains Intact (CZ) (cont'd)	containment heat removal. Note that successful prevention of early containment failure does not necessarily preclude late containment failure. Therefore, successful prevention of early containment failure requires the following. • No direct containment heating (direct containment heating is precluded if the RPV is already depressurized). • No ex-vessel steam explosion. • No failure of vapor suppression (i.e., the suppression pool is not bypassed and no more than 1 drywell-to-wetwell vacuum breaker fails open). • No in-vessel steam explosion (in-vessel steam explosions are precluded if either the RPV is at high pressure, e.g., greater than 100 psig, or the core does not fragment into fine particles before dropping onto the bottom head). • No high pressure spike sufficient to cause containment failure occurs at the time of vessel melt-through (extreme pressure spikes are precluded if the RPV bottom head penetration fails locally or the RPV remains at low pressure). • No hydrogen deflagration or detonation (if the containment remains inert or effective combustible gas vent was operated successfully, then hydrogen detonation or deflagration is guaranteed not to occur). • No RPV blowdown from high pressure with the suppression pool temperature above 260°F. • No recriticality due to an unusual core configuration that may be achieved during the melt progression.	

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Containment Remains Intact (CZ) (cont'd)	If these failure modes cannot be prevented, containment failure is assumed to occur. The failure location is assumed to be in the drywell head region and is classified as a large failure with no Reactor Building effectiveness.	
Injection Established to RPV or Drywell (SI)	Success at this node requires that water is available (greater than 1000 gpm) to the core debris at the time of vessel failure. Continuous water injection either directed into the failed RPV or into the drywell will provide for the following: • reduced likelihood for drywell shell failure, • mitigation of high drywell gas temperatures, • water overburden to scrub fission products resulting from possible core concrete interaction, and • potential for debris coolability. These are considered substantially mitigated if on a best estimate basis a continuous water supply is available to the debris with a flow rate of greater than 1000 gpm. The two active mitigation methods that may provide coolant injection to the debris bed include continued make-up to the RPV and initiation of drywell sprays. These effects would influence the integrity of containment. Note that inadequate water injection will be modeled for the purposes of consequence evaluation as inducing a drywell failure high in the containment.	Flow > 1000 gpm to the debris

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Injection Established to RPV or Drywell (SI) (cont'd)	However, there are some models that indicate that concrete attack and non-condensible gas generation will not be terminated even if substantial water injection is available to the debris. The temperatures in the drywell will be acceptable, but continued non-condensible gas generation will occur. MAAP sensitivity analyses with minimum heat transfer between debris and water indicate this is not a LERF contributor. In addition, shell failure can occur relatively quickly (i.e., minutes) following RPV failure if water is not available to cool the core debris. It is assumed in the model that the core debris will come in contact with and fail the drywell shell if water is not available.	
Containment Flooding Initiated (FC)	Success at this node implies that the containment flooding contingency procedure has been initiated by the operating staff and that a system of adequate flow capacity from external sources is available to implement the procedure. In addition to these two requirements, the instrumentation must be available to initiate the flood operation. This node evaluates the possibility that the operator suspends containment flooding because the staff is unable to maintain containment conditions within prescribed limits described in the SAMGs. Success at FC includes drywell venting. Since it is presumed that containment pressurization will occur during the latter stage of flooding as a result of a diminishing drywell volume, the operator will be required to establish a drywell vent path (i.e., > 4 inch equivalent diameter).	External flow > 1000 gpm Vent > 6 inch dia.

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Containment Flooding Initiated (FC) (cont'd)	Drywell venting can have varying degrees of releases associated with it depending on the following: • when in the containment flood process drywell venting is required, and • whether success of RHR suppression pool cooling and injection is effective in controlling containment pressure. Success at this juncture in the model is defined as the continuation of the flooding evolution with containment conditions remaining within the limits of the Primary Containment Pressure Limit (PCPL). MAAP calculations indicate that containment flooding through the RPV or drywell sprays results in a low radionuclide release [MAAP CN060504, CN060515, CN060527, CN060528 for transient and large LOCAs.].	
Containment Pressure Control (see node descriptions HR and VC below)	Successful containment pressure control is achieved if either of two functional nodes are successfully satisfied: 1. RHR containment heat removal, or 2. containment venting. Because these have different potential impacts on the radionuclide releases they are treated in separate nodes.	1. Cont. pressure < 178 psig 2. Cont. pressure < 62 psig

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination

1. RHR Containment Heat Removal (HR)	Successful containment pressure control is unattainable using RHR[(6)] suppression pool cooling if either of the following conditions occur:
	• No debris cooling (in-vessel or ex-vessel)
	• Early containment failure modes
	RHR has the capability to remove heat from containment through the RHR heat exchangers. This capability requires
	• a flow path from the suppression pool,
	• one RHR pump,
	• one RHR pump heat exchanger,
	• SW to cool the heat exchanger,
	• a return flow path to
	  ▸ The suppression pool
	  ▸ The RPV
	  ▸ The drywell spray (wetwell spray flow rate is considered too low)
	• bypass of the low RPV water level (2/3 core height) interlock if not using RPV return.
	Failure at this juncture in the sequence implies insufficient containment heat rejection to the environment and that the continued decay heat generation could subject the containment to continued pressurization. This condition may eventually cause structural failure, which could subsequently threaten continued successful core coolant injection.	

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
1. RHR Containment Heat Removal (HR) (cont'd)	Note that RHR success is a moot point if adequate injection to the core or debris has failed. This is because of high temperatures from debris radiative heating or high pressure from non-condensable gases will cause drywell failure.	
2. Containment Venting (VC)	The capability to vent the containment is a valuable supplement to the containment pressure control systems. As pressure and temperature increase, there is decreasing confidence in the ability to maintain the integrity of the containment pressure boundary. By instituting a controlled vent of the containment atmosphere, it is possible to maintain long-term containment integrity by providing a viable means of containment pressure control and heat removal. Venting also constitutes a viable mitigative action to minimize the source term released to the environment. Containment venting is successful if it can remove the excess heat and non-condensable gases from the containment and, thereby, maintain the containment pressure within acceptable limits. Adequate pressure control can be obtained by containment venting if the following conditions are satisfied: • reactivity control exists, • no "early" containment failure modes occur, • containment flooding does not eliminate the venting pathways, • vent pathways can be opened and controlled.	Cont. Press < 62 psig

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
2. Containment Venting (VC) (cont'd)	Based upon deterministic calculations, a containment vent of approximately 8 inches in diameter will provide sufficient vent capability to prevent containment failure for sequences involving the loss of containment heat removal or severe accidents. Currently, no vent capability is considered successful for unmitigated failure to scram events.	
No Suppression Pool Bypass (SP)	This node in the CET is used to characterize the magnitude of radionuclides that may escape the containment if wetwell failure or venting occurs. Success means that radionuclides are directed through the suppression pool. Subsequent headings address specific release paths. Success in preventing suppression pool bypass requires that • vacuum breakers remain closed; • the suppression pool water level remains above the bottom of the downcomers; and • the downcomers do not rupture or fail due to debris attack.	Bypass path < 6 inch dia.

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
No Large Containment Failure (NC)	This event examines the size of containment leakage that may be induced by extreme pressure and temperature conditions. The downward path at this event tree node is defined as large leakage or failure, while the upward path depicts either no leakage or the existence of drywell leak paths that prevent further containment pressurization. Any failure of the containment structure greater than 1 ft^2 is considered to be a large containment failure and is modeled as a 2 ft^2 break in the MAAP runs. A small break is assumed to be 1 ft^2 or less in size, and is modeled in MAAP with a leak size of 27 in^2. A small containment breach may be characterized by any of the following breach of containment: • electrical penetration leak, • hatch seal leak, • bellows seal leak, or • drywell head seal leak: ‣ thermal degradation ‣ inadequate pre-load Leak sizes up to 3 in^2 equivalent area are assumed to present a negligible impact on the course of the accident. The downward branch of the “No Large Containment Failure” node is probabilistically based on the plant-specific structure analysis. However, there are certain cases in which failure (i.e., large break) is guaranteed. These cases include the following: • failure to scram sequences with continued injection and no effective SLC, • No Injection to containment, causing high temperature induced failure,	Break <1 $ft.^2$

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
No Large Containment Failure (NC) (cont'd)	• Any early containment failure (e.g., steam explosion, etc.), or • LOCAs plus failure of vapor suppression.	
Coolant Makeup Remains Available Post Containment Failure (MU)	This event node is used to examine the availability of water injection to the drywell and RPV following containment failure. Failure of coolant makeup to the debris results in delayed fission product release due to heat up and revaporization of fission products on the RPV internals and containment structures. Releases are reduced if coolant injection can be maintained. The success of coolant makeup following containment failure may be compromised by any of the following: • harsh environment in reactor building, • steam binding of pumps, • disruption of injection pathways due to catastrophic containment failure. The same success criteria established for accomplishing the ex-vessel debris coolability (node "SI") influence the analysis of whether functional success is achieved at this node. Alignment of the following injection sources external to the reactor building may be used to achieve success (these systems are not hindered by steam binding or harsh conditions in the reactor building). • condensate • fire protection (not credited) • LPCI/CS from CST (not credited) • SW cross tie	Flow > 1000 gpm

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Drywell Intact (DI)	Containment failure has already been asked in the CET. If containment failure has not occurred, this node is bypassed. If containment failure is determined to have occurred, then, the "DI" node is included to distinguish whether the failure occurred in the drywell (downward branch) or wetwell (upward branch). The probabilistic determination of the location of the failure is determined based on the Quad Cities structural analysis for slow overpressure events. Additional guidance is also provided for other accident scenarios as follows: • high temperature induced failures result in drywell failures, • rapid or energetic failure modes are assumed to occur in the drywell (e.g., steam explosions, etc.).	No DW release path > 2-inch diameter

Table E.1-4 (Continued)
Notation and Definitions for CNS CET Functional Nodes Description

CET Functional Node	Success Criteria	Parameter Monitored for Success Determination
Wetwell Airspace Failure (WW) (Scrubbed Release)	This node appears after the Drywell Intact (DI) node. If the DI node determines that the containment failure occurred in the drywell this node is bypassed. If containment failure occurred in the wetwell, this node distinguishes whether the wetwell failure occurred above or below the wetwell water line. As in the previous node, successfully avoiding a large containment failure requires successful containment heat removal. The probabilistic determination of the location of the failure is determined based on the plant specific structural analysis for slow overpressurization events.	No WW water release path > 2-inch diameter
Reactor Building Effectiveness (RB)	The reactor building provides a substantial capability to remove particulate fission products from the release pathway for scenarios where the containment has failed. Success of the reactor building to provide a substantial radionuclide reduction (i.e., a factor of 5 to 10 reduction in the radionuclide release magnitude) is based upon any of the following: • very small containment failures (i.e., 6 inch equivalent diameter) for which the reactor building remains substantially intact; • primary containment failures low in the reactor building for which the release pathway consists of a tortuous route through the reactor building and no other failures are induced due to hydrogen combustion; • cases in which substantial fire protection spray is occurring during the release (not credited due to limited area coverage by the fire sprays in the Reactor Building, i.e., cable trays only). The RB node is not currently credited in the CNS calculation of radionuclide release frequency.	Not used.

1. A plant-specific assessment of the CNS response to a high pressure core melt with a single ADS valve opened when the RPV level reaches TAF supports this criterion. This was illustrated in MAAP Case CN060501.
2. Primary system failure may be induced by very high internal temperatures generated by molten debris in an uncooled state within the RPV. Such high temperatures coincident with high RPV pressures may lead to localized failures at weak points high within the RPV.
3. Opening MSIVs and the use of HPCI steam line are not credited because no calculations are available to demonstrate sufficient capacity to lead to depressurization.
4. The 1000 gpm criterion is an approximation. There is a comparatively large degree of uncertainty surrounding this issue. However, ORNL and GE calculations seem to indicate that an injection rate close to 1000 gpm initiated at thirty minutes may be sufficient.
5. For this situation, the containment remains inerted and venting would not have been required. Therefore, in this case, the down branch is not considered as a failure of combustible gas venting but as a continuation of the sequence.
6. Other modes of containment heat removal are not considered effective because of interlocks or procedural restrictions under severe accident conditions. (e.g., RWCU, Main Condenser).

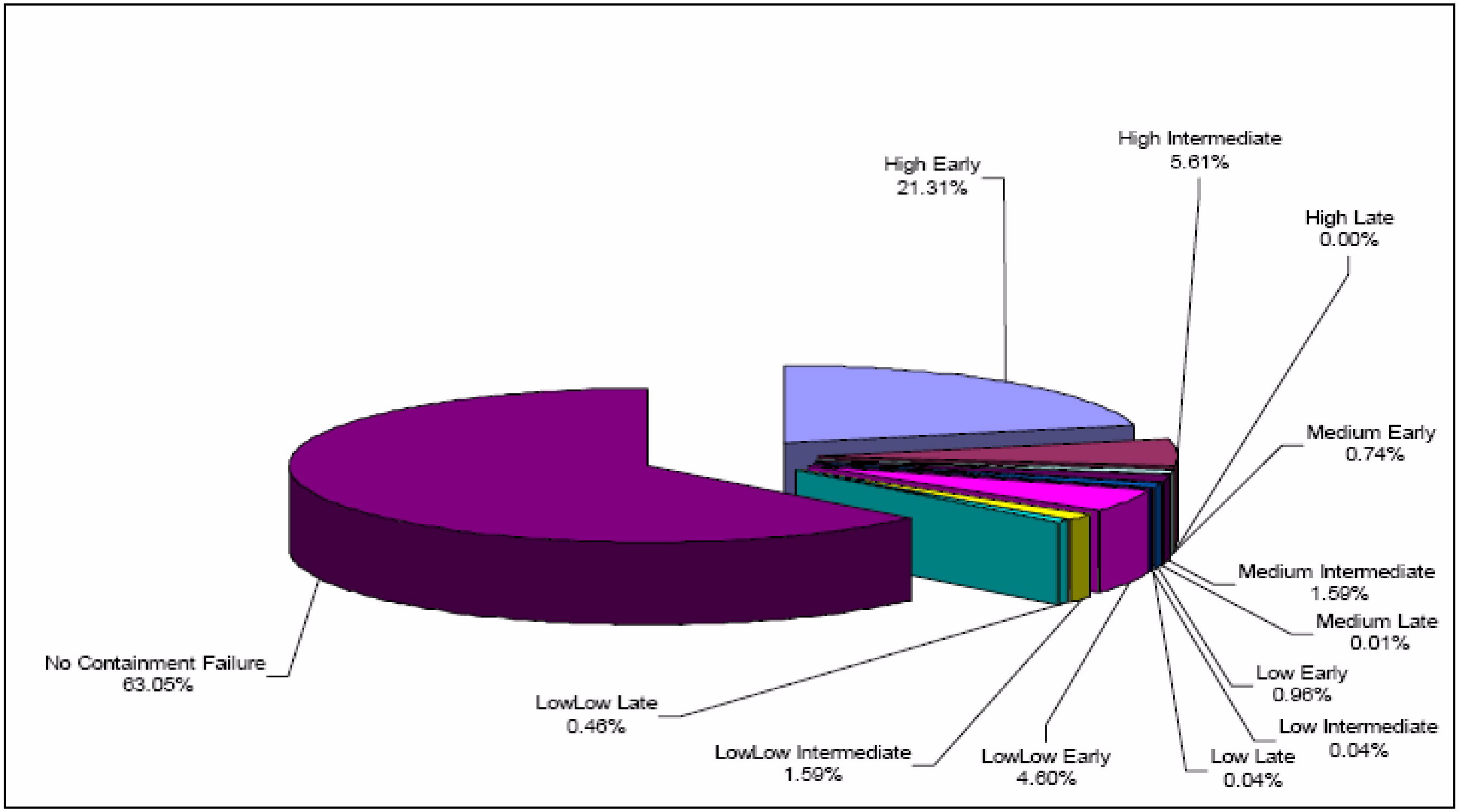
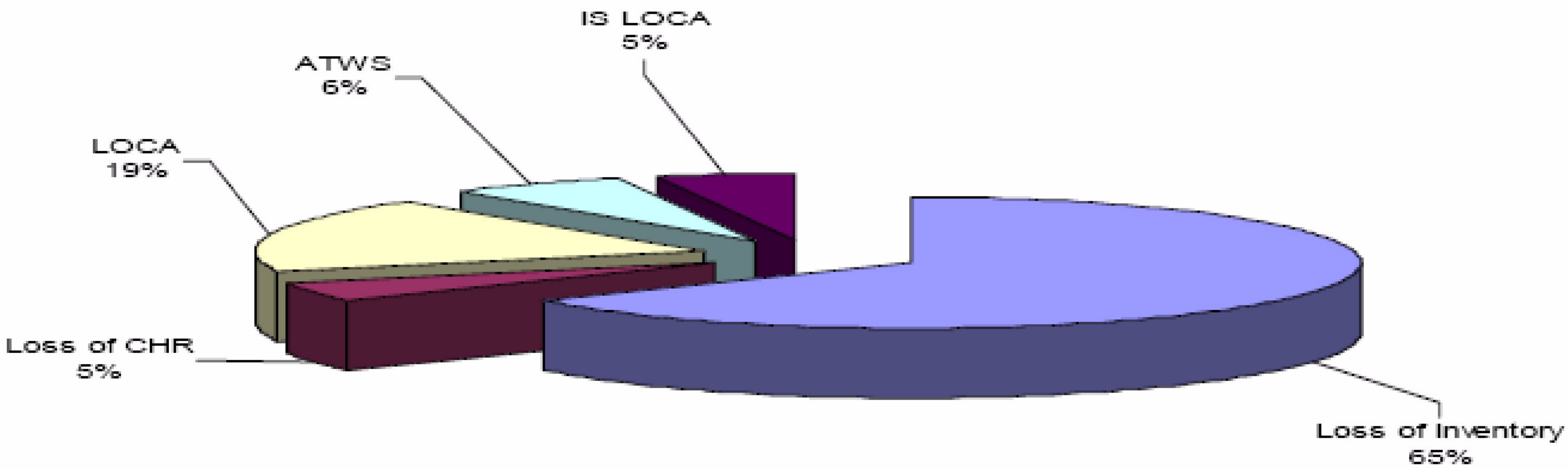


Figure E.1-1
CNS Radionuclide Release Category Summary



Note: The contribution of SBO to LERF is 0.43%. SBO is not a unique LERF accident class, thus the contribution is listed separately.

Figure E.1-2
Accident Class Contributions to LERF

Table E.1-5
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
CGS-PHE-FF-INERT	9.90E-01	3.417	Containment inerted; venting not required	This term represents the containment being inerted when combustible gas venting fails or is not required and AC power is available. A Phase I SAMA to implement venting procedures with respect to timing, path selection, and technique has already been installed. Phase II SAMA 70, to install a curb to prevent debris from spreading across the floor and contacting the shell, was evaluated.
CNT-SMP-FF-MLTOF	1.00E+00	2.181	Melt overflows sump	This event models the possibility that even though water is present on the drywell floor the debris in the sump is not coolable. The likelihood of this occurring is relatively high considering the depth of the debris accumulated in the sump. Phase II SAMA 70, to install a curb to prevent debris from spreading across the floor and contacting the shell, was evaluated.
RPV-DWV-FO-BARIS	1.00E+00	2.181	Drywell barriers fail to prevent debris from contacting shell	This term represents the possibility that barriers are present to block the debris from reaching the steel shell. This event is a result of the proposed Mark I containment modification which suggested installing a curb to prevent debris from spreading across the floor and contacting the shell. Phase II SAMA 70, to install a curb to prevent debris from spreading across the floor and contacting the shell, was evaluated.
CNT-MDL-FF-WTRCV	9.00E-01	2.181	Failure to recover a water system	This term represents failure to recover a water system at time of RPV breach (~ 3 hours). No repairs are currently credited in the model due to potential adverse environmental conditions. Phase II SAMAs 22, 23, 24, 25, 28, 29, 67, 77, and 78 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.

**Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)**

Event Name	Probability	RRW	Event Description	Disposition
RPV-XHE-FO-L2REC	9.00E-01	1.814	Operator fails to recover injection before RPV melt	This term represents operator failure to recover an injection method before RPV melt. The failure probability for system recovery is assumed to be quite high. If failed systems have not been repaired or restored at this point in the accident, it is judged relatively unlikely that the system(s) will be restored before RPV melt-through. Phase II SAMAs 22, 23, 24, 25, 28, 29, 67, 77, and 78 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.
RPV-MDL-FF-RXFLS	1.00E+00	1.749	Failure of RX (Classes ID, IE (OP=F), II, IIIA, IIIC, IIID, IV)	This term represents the probability of core melt progression causing in-vessel fuel degradation, vessel failure, and the discharge of molten debris from the reactor vessel. Phase II SAMAs 22, 23, 24, 25, 28, 29, 67, 77, and 78 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.
RPV-MDL-SC-C1A1E	7.00E-01	1.335	Successful RPV depressurization (Class IA, IE)	This term represents RPV depressurization during accident sequences involving loss of inventory makeup in which the reactor pressure remains high. Phase II SAMAs 26, 27, 43, and 44, to enhance depressurization, were evaluated.
RPV-MDL-FF-HITMP	7.00E-01	1.29	High primary system temperature does not cause failure of RCS pressure boundary	This term represents a time when failure of RCS pressure boundary is not caused by high primary system temperature. Phase II SAMA 70, to install a curb to prevent debris from spreading across the floor and contacting the shell, was evaluated.
RPV-MDL-FF-TRPRS	8.00E-01	1.29	Pressure transient does not fail mechanical systems	This term represents the case where pressure transient does not fail mechanical systems. The main contributor to LERF during this sequence is failure of the AC buses. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
RPV-MDL-FO-ALTDP	1.00E+00	1.29	Alternate depressurization methods not credited	This term represents alternate methods of depressurization not being credited. Because the MSIVs are assumed to not be able to be re-opened in sufficient time in a severe accident and the HPCI and RCIC steam exhaust lines and the steam line drains do not have analyses to support their adequacy as the sole means to depressurize the RPV, it is concluded that these alternative methods of depressurization would not be effective under the extreme conditions of high radiation, low reactor water level, and elevated reactor pressure. Phase II SAMA 44, to improve SRV and MSIV pneumatic components, was evaluated.
RPV-SRV-FO-CSORV	5.50E-01	1.29	SRVs do not fail open during core melt progression	This term represents the SRVs not failing open during adverse conditions. This leads to a failure to depressurize. Phase II SAMAs 44 and 52, to improve SRV and MSIV pneumatic components and to provide passive overpressure relief, were evaluated.
CNT-MDL-FF-LVL1F	1.00E+00	1.187	Large containment failure given containment failed in level 1 (Class II, IIID, IV)	This term represents a large containment failure given the containment failed in level 1. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
CNT-MDL-FF-SCTRM	1.00E+00	1.157	Reactor building ineffective in reducing source term	This term represents the failure of the reactor building to contain the event. Phase II SAMAs 48 and 49 were evaluated to improve fission product scrubbing during severe accidents.
RPV-MDL-SC-CLIII	1.00E+00	1.146	Successful RPV depressurization (Class III)	This term represents successful RPV depressurization. This basic event is driven by loss of the diesel generators and loss of offsite power. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
FPS-PHE-CF-FLOW	5.00E-01	1.127	In-vessel core melt arrest precluded by limited FPS flow	This term represents in-vessel core melt arrest precluded by limited FPS flow. Phase II SAMA 78 to improve training on alternate injection via the FPS was evaluated.
CNT-DWV-FF-MLTFL	1.00E+00	1.091	Drywell shell melt-through failure due to containment failure	This term represents drywell shell melt-through due to containment failure. Phase I SAMAs 121, 137, 138, 139, 141, 142, and 143 for enhancing containment integrity and cooling were investigated. Phase II SAMA 70, to install a curb to prevent debris from spreading across the floor and contacting the shell, was evaluated.
CNT-PHE-FO-HBFFS	1.00E+00	1.079	High pressure blowdown overwhelms vapor suppression	This term represents the high pressure blowdown overwhelming the vapor suppression. Phase II SAMAs 48, 49, and 51, to improve venting and fission product scrubbing, were evaluated.
CNT-DWV-SC-ATWSF	9.90E-01	1.066	Drywell intact for ATWS events (Class IV)	This term represents the drywell intact for ATWS events. Phase II SAMAs 58, 59, 60, and 61 for enhancing ATWS migration capabilities were evaluated.
CND-SYS-FF-LERF	1.00E+00	1.055	Conditional probability of a LERF (Class V)	This term represents the conditional probability of a LERF in an ISLOCA event. Phase II SAMAs 54, 56, and 57 were evaluated to reduce the risk from ISLOCAs.
PCV-WWV-FF-ATWSF	5.00E-01	1.051	WW water space fail. for ATWS events (Class IV)	This term represents a breach in the wetwell water space for ATWS events which may deplete the suppression pool water inventory and result in lowering the water level to below the downcomers. To successfully avoid a containment failure requires successful containment heat removal and containment pressure control. Phase II SAMAs 20 and 46 were evaluated to help mitigate failure of containment heat removal and increase vent capability.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
CGS-PHE-FF-STMIN	9.90E-01	1.049	Combustible gas venting not required (steam inerted - Class IIID)	This term represents combustible gas venting not required. Phase II SAMA 66 for installing digital large break LOCA protection was evaluated.
CNT-DWV-FF-NOVSS	1.00E+00	1.049	Drywell not intact for loss of vapor suppression (Class IIID)	This term represents the drywell not intact for loss of vapor suppression. This sequence is initiated by a LOCA thus Phase II SAMA 66 for installing digital large break LOCA protection was evaluated.
RPV-MDL-SC-CLSII	9.00E-01	1.044	Successful RPV depressurization (Class II)	This term represents successful RPV depressurization during Class II sequences. This term represents RPV depressurization during accident sequences involving loss of inventory makeup in which the reactor pressure remains high. This basic event is driven by loss of power to the hard pipe vent valves. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
RPV-MDL-SC-CLSIV	8.00E-01	1.038	Successful RPV depressurization (Class IV)	This term represents successful RPV depressurization. Improvements to the SLC system help mitigate this event. Phase II SAMAs 58, 59, and 60, to enhance boron injection, were evaluated.
CNT-DWV-SC-NODHR	5.50E-01	1.027	Drywell intact for loss of DHR events (Class II)	This term represents the drywell intact for loss of DHR events. Electrical power to the torus hard pipe vent system is very important in this sequence thus Phase II SAMA 20, to provide redundant power to the direct torus vent valves, helps mitigate this event.
CNT-DWV-FF-NODHR	4.50E-01	1.023	Drywell not intact for loss of DHR events (Class II)	This term represents failure of the drywell for decay heat removal events. Phase II SAMAs 46, 71, and 73, to enhance suppression pool cooling, were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
PCV-WWV-SC-LOTMP	7.80E-01	1.021	WW air space failure at low drywell temperature (CL I, III without RPV failure and CL II)	This term represents wet well air space failure at low drywell temperature. Electrical power to the torus hard pipe vent system is very important in this sequence thus Phase II SAMA 20, to provide redundant power to the direct torus vent valves, helps mitigate this event.
RPV-PHE-FF-RBEAL	5.00E-01	1.019	Adverse Rx building environment conditions cause failure	This term represents adverse reactor building environment conditions causing a failure. The location of the SRV logic and power control centers is in the reactor building. Therefore, failures of the containment or failure of isolation may result in adverse reactor building environment that can cause failure of the depressurization function. Phase II SAMAs 20 and 52, to provide redundant power to the direct torus vent valves and to provide passive overpressure relief, were evaluated.
CGS-PHE-SC-INERT	1.00E-02	1.015	Containment not inerted; Venting required	This term represents the containment not inerted and venting is required. A Phase I SAMA to implement venting procedures with respect to timing, path selection, and technique has already been installed. Phase II SAMAs 48, 49, 50, and 52, to improve venting and fission product scrubbing and to provide passive overpressure relief, were evaluated.
L2-OSP-15H-SW	7.99E-01	1.014	Conditional probability of failure to restore AC in l2 within 15 hrs in node SI	This term represents conditional probability of failure to restore AC in L2 within 15 hours when injection has been established. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
RHR-XHE-CF-TRIP	8.00E-05	1.014	Human error CCF to restore limit switches or to align interlocks	This term represents human CCF to restore limit switches or to align interlocks for the RHR system. Phase II SAMAs 28 and 29 to improve the LPCI system were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
CNT-PHE-FF-H2DFG	1.00E+00	1.014	Hydrogen deflagration occurs globally	This term represents the event in which hydrogen deflagration occurs globally. Phase II SAMA 49, to improve fission product scrubbing, was evaluated.
CNT-PHE-FF-O2DIN	1.00E-02	1.014	Operation deinerted or O2 introduced	This term represents the deinerting of containment. Phase II SAMA 49, to improve fission product scrubbing, was evaluated.
CNT-PHE-FF-STMIN	5.00E-01	1.014	Containment not steam inerted	This term represents the containment not being steam inerted. If the containment is steam inerted hydrogen deflagration will not occur. Phase II SAMA 49, to improve fission product scrubbing, was evaluated.
PCV-MDL-FF-CGVFL	1.00E+00	1.014	Combustible gas venting fails	This term represents failure of combustible gas venting. Phase II SAMA 49, to improve fission product scrubbing, was evaluated.
PCV-WWV-SC-ATWSF	5.00E-01	1.014	WW air space fails for ATWS events (Class IV)	This term represents a breach in the wetwell air space for ATWS events which may result in a release that passes through the suppression pool. To successfully avoid a containment failure requires successful containment heat removal and containment pressure control. Phase II SAMAs 20, 46, 71, and 73 were evaluated to help mitigate failure of containment heat removal and increase vent capability.
ADS-XHE-FF-RBENV	5.00E-01	1.013	Adverse reactor building environment conditions affect SRVs	This term represents the adverse reactor building environment conditions causing failure of the SRVs and depressurization. Phase II SAMAs 44 and 52, to improve SRV and MSIV pneumatic components and to provide passive overpressure relief, were evaluated.
%A-LP	1.01E-05	1.013	Large break LOCA, below TAF in LPCI line	This term represents a large break LOCA – below TAF in LPCI line. Phase II SAMA 66 to install a digital large break LOCA system was evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
%BOC-MS	1.06E-07	1.012	Main steam line BOC	This term represents a main steam line break outside of containment. Phase II SAMAs 22, 23, 28, and 47, to enhance injection, were evaluated.
FLD-XHE-FO-MSW7A	5.70E-04	1.011	Failure to isolate moderate flood late (terminate SW)	This term represents a failure to isolate a moderate pipe rupture in the control building basement. Phase II SAMA 62 to improve internal flooding procedures was evaluated along with SAMA 30 to help mitigate loss of service water.
SWS-PIP-BRK-TRNB	5.00E-01	1.01	Conditional probability That flood is in train B	This term represents the conditional probability that a flood is in train B rather than train A. No Phase II SAMAs were recommended.
%ISLOCA-HP	4.15E-06	1.009	ISLOCA initiator for HPCI injection line	This term represents the ISLOCA initiator for the HPCI injection line. Phase II SAMAs 54, 56, and 57 were evaluated to reduce the risk from ISLOCAs.
HPI-PIP-RP-ISLOC	5.52E-03	1.009	Pipe ruptures for HPCI injection line ISLOCA	This term represents the ISLOCA pipe rupture for the HPCI injection line. Phase II SAMAs 54, 56, and 57 were evaluated to reduce the risk from ISLOCAs.
FPS-DDP-TM-FPD	1.00E-02	1.009	Diesel-driven fire pump 1D unavailable due to test or maintenance	This term represents the diesel-driven fire pump 1D being unavailable due to testing or maintenance. Phase II SAMA 28, 29, and 47, to enhance injection, were evaluated.
%BOC-FW	8.06E-08	1.009	Feedwater line BOC	This term represents an unisolated feedwater line break outside of containment. Phase II SAMAs 22, 23, 28, and 47, to enhance injection, were evaluated.
SLC-EPV-CF-SQ14	1.40E-02	1.009	Common cause failure to open of squib valves SQ14A and SQ14B	This term represents the common cause failure to open of squib valves SQ14A and SQ14B. Phase II SAMAs 59 and 60, to provide alternate means of boron injection, were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
LCI-SYS-TM-LOOPA	9.49E-03	1.009	Test or maintenance unavailability: RHR (LPCI mode) loop A	This term represents the LPCI mode of RHR loop A unavailable due to testing or maintenance. Phase II SAMA 28, to add a diverse low pressure injection system, was evaluated.
EDC-DCB-CF-125AB	2.84E-07	1.008	Common cause failure of 125V DC buses 1A and 1B	This term represents common cause failure of the 125V DC buses 1A and 1B. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated.
SWS-XHE-FO-RPVIN	6.30E-02	1.008	Human error fail to operate RPV injection (level 1)	This term represents the human error fail to operate RPV injection (level 1). Phase II SAMAs 22, 23, 28, and 47, to enhance injection, were evaluated.
%A-CS	6.72E-06	1.008	Large break LOCA, above TAF in CS line	This term represents a large break LOCA above the TAF in the CS line. Phase II SAMA 66 to install a digital large break LOCA protection system was evaluated
%FLSWCB7AL	7.61E-06	1.008	Large SW pipe rupture in the control building basement	This term represents a large SW pipe rupture in the control building basement. Phase II SAMA 62 to improve internal flooding procedures was evaluated along with SAMA 30 to help mitigate loss of service water.
VSS-VAB-CO-NRV20	6.58E-03	1.008	Normally closed vacuum breaker NRV20 fails open	This term represents random failure of Vacuum breaker NRV20. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV21	6.58E-03	1.008	Normally closed vacuum breaker NRV21 fails open	This term represents random failure of Vacuum breaker NRV21. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV22	6.58E-03	1.008	Normally closed vacuum breaker NRV22 fails open	This term represents random failure of Vacuum breaker NRV22. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
VSS-VAB-CO-NRV23	6.58E-03	1.008	Normally closed vacuum breaker NRV23 fails open	This term represents random failure of Vacuum breaker NRV23. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV24	6.58E-03	1.008	Normally closed vacuum breaker NRV24 fails open	This term represents random failure of Vacuum breaker NRV24. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV25	6.58E-03	1.008	Normally closed vacuum breaker NRV25 fails open	This term represents random failure of Vacuum breaker NRV25. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV26	6.58E-03	1.008	Normally closed vacuum breaker NRV26 fails open	This term represents random failure of Vacuum breaker NRV26. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV27	6.58E-03	1.008	Normally closed vacuum breaker NRV27 fails open	This term represents random failure of Vacuum breaker NRV27. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV28	6.58E-03	1.008	Normally closed vacuum breaker NRV28 fails open	This term represents random failure of Vacuum breaker NRV28. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV29	6.58E-03	1.008	Normally closed vacuum breaker NRV29 fails open	This term represents random failure of Vacuum breaker NRV29. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
VSS-VAB-CO-NRV30	6.58E-03	1.008	Normally closed vacuum breaker NRV30 fails open	This term represents random failure of Vacuum breaker NRV30. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
VSS-VAB-CO-NRV31	6.58E-03	1.008	Normally closed vacuum breaker NRV31 fails open	This term represents random failure of Vacuum breaker NRV31. Phase II SAMA 51, to install redundant vacuum breakers, was evaluated.
RPV-MDL-SC-CMS1A	8.70E-01	1.007	Core melt arrested in-vessel (OP = S, Class IA)	This term represents core melt being arrested in-vessel. Phase II SAMAs 22, 23, 24, 25, 28, 29, 67, 77, and 78 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.
L2-OSP-10H-SW	7.36E-01	1.007	Conditional probability of failure to restore AC in l2 within 10.5 hrs in node SI	This term represents the conditional probability of failure to restore AC in 12 to within 10.5 hrs in node SI. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
OSP65HR-SW	2.94E-01	1.007	Failure to recover OSP within 6.5 hours (severe weather loop event)	This term represents operator failure to recover a weather related LOOP event within 6.5 hours. Phase I SAMAs to improve station blackout procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
SLC-XHE-FO-SLC2E	2.30E-01	1.007	Operator fails to initiate SLC with 2 pumps in required time	This term represents the failure of an operator to initiate SLC within 2 pumps in the required time. Phase II SAMAs 58, 59, 60, and 61 for enhancements to the SLC system were evaluated.
EAC-CRB-CF-LS-FG	8.82E-05	1.007	4160V bus 1F and 1G load shed breaker common cause failure	This term represents common cause failure of the 4160V buses 1F and 1G load shed breaker failures. This impacts power for division I and division II. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
%A-WA	5.51E-06	1.007	Large break LOCA, below TAF	This term represents a large break LOCA below the TAF. Phase II SAMA 66 to install a digital large break LOCA protection system was evaluated.
EAC-DGN-FS-DG1	1.52E-03	1.006	Diesel generator DG1 fails to start	This term represents random failure to start of emergency diesel generator DG-1. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
%BOC-RW	4.97E-08	1.006	RWCU BOC	This term represents an unisolated RWCU break outside of containment. Phase II SAMAs 22, 23, 28, and 47, to enhance injection, were evaluated.
EAC-DGN-FS-DG2	1.52E-03	1.005	Diesel generator DG2 fails to start	This term represents random failure to start of emergency diesel generator DG-2. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EAC-CRB-OO-EG1	1.29E-03	1.005	Normally open circuit breaker EG1 fails to close	This term represents random failure of normally open circuit breaker EG1. This causes no power to 4160V bus 1F from DG-1 Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
PCV-WWV-FF-LOTMP	2.20E-01	1.005	WW water space fails at low drywell temperature (CL I, III without RPV failure and CL II)	This term represents a WW water space fail at low drywell temperature. For this sequence to occur vessel injection must fail. Phase II SAMAs 22, 23, 24, 25, 28, 29, 67, 77, and 78 for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.

Table E.1-5 (Continued)
Correlation of Level 2 Risk-Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
ADS-SRV-CC-INDEP	7.71E-03	1.005	Independent failure to open (est.) (3 or more)	This term represents an independent failure to open three or more SRVs. Phases II SAMAs 44 and 52, to improve SRV and MSIV pneumatic components and to provide passive overpressure relief, were evaluated.
FLD-XHE-FO-LSW7A	1.40E-03	1.005	Failure to isolate large flood late (terminate SW)	This term represents failure to isolate the large flood in the control building basement. Phase II SAMA 62 to improve internal flooding procedures was evaluated along with SAMA 30 to help mitigate loss of service water.
%ISLOCA-CS	2.10E-06	1.005	ISLOCA initiator for core spray injection lines	This term represents the ISLOCA initiator for core spray injection lines. Phase II SAMAs 54, 56, and 57 were evaluated to reduce the risk from ISLOCAs.
%TI	1.93E-02	1.005	Inadvertently open relief valve	This term represents an inadvertently open relief valve initiating event. Phase II SAMAs 44 and 75, to improve SRV and MSIV pneumatic components and to implement trip/shutdown risk modeling, were evaluated.
EDC-DCB-LP-125B	9.19E-06	1.005	125V bus 1B failure	This term represents a 125V bus 1B failure. Phase II SAMAs 1, 2, 3, 13, 14, 15, 19, and 21 for enhancing DC system availability and reliability were evaluated
EAC-CRB-OO-EG2	1.29E-03	1.005	Normally open circuit breaker EG2 fails to close	This term represents normally open circuit breaker EG2 failure to close. This leads to no power to bus 1G from diesel generator DG-2. Phase II SAMAs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, and 21 for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Note: Basic events that are correlated in Table E.1-3 are not listed again in Table E.1-5.

E.1.2.2 Radionuclide Analysis

E.1.2.2.1 Introduction

A major feature of a Level 2 analysis is the estimation of the source term for every possible outcome of the CET. The CET end points represent the outcomes of possible in-containment accident progression sequences. These end points represent complete severe accident sequences from initiating event to release of radionuclides to the environment. The Level 1 and plant system information is passed through to the CET evaluation in discrete PDS. An atmospheric source term may be associated with each of these CET sequences. Because of the large number of postulated accident scenarios considered, mechanistic calculations (i.e., MAAP calculations) are not performed for every end-state in the CET. Rather, accident sequences produced by the CET are grouped or "binned" into a limited number of release categories each of which represents all postulated accident scenarios that would produce a similar fission product source term.

The criteria used to characterize the release are the estimated magnitude of total release and the timing of the first significant release of radionuclides. The predicted source term associated with each release category, including both the timing and magnitude of the release, is determined using the results of MAAP calculations.

E.1.2.2.2 Timing of Release

Timing completely governs the extent of radioactive decay of short-lived radioisotopes prior to an off-site release and, therefore, has a first-order influence on immediate health effects. CNS characterizes the release timing relative to the time at which the release begins, measured from the time of accident initiation. Three timing categories are used: early (less than 3.7 hours), intermediate (3.7 to 24 hours), and late (greater than 24 hours).

The definitions of the release timing categories are as follows.

- Early releases (E) are CET end-states involving containment failure less than 3.7 hours from declaration of a general emergency (i.e., prior to effective evacuation), for which minimal offsite protective measures have been observed to be performed in non-nuclear accidents.

- Intermediate releases (I) are CET end-states involving containment failure greater than or equal to 3.7 hours, but less than 24 hours from declaration of a general emergency, for which much of the offsite nuclear plant protective measures can be assured to be accomplished.

- Late releases (L) are CET end-states involving containment failure greater than or equal to 24 hours from declaration of a general emergency, for which offsite measures can be assumed to be fully effective.

E.1.2.2.3 Magnitude of Release

The CsI release fraction indicates the fraction of in-vessel radionuclides escaping to the environment. (Noble gas release levels are non-informative since release of the total core inventory of noble gases is essentially complete given containment failure).

The source terms were grouped into five distinct radionuclide release categories or bins according to release magnitude as follows.

(1) High (H): A radionuclide release of sufficient magnitude to have the potential to cause early fatalities. This implies a total integrated release of > 10% of the initial core inventory of CsI.

(2) Medium (M): A radionuclide release of sufficient magnitude to cause near-term health effects. This implies a total integrated release of between 1% and 10% of the initial core inventory of CsI.

(3) Low (L): A radionuclide release with the potential for latent health effects. This implies a total integrated release of between 0.1% and 1% of the initial core inventory of CsI.

(4) Low-Low (LL): A radionuclide release with undetectable or minor health effects. This implies a total integrated release of between 0% and 0.1% of the initial core inventory of CsI.

(5) Negligible (NCF): A radionuclide release that is less than or equal to the containment design base leakage.

The "total integrated release" as used in the above categories is defined as the integrated release within 36 hours after RPV failure. If no RPV failure occurs, then the "total integrated release" is defined as the integrated release within 36 hours after accident initiation.

E.1.2.2.4 Release Category Bin Assignments

Table E.1-6 summarizes the scheme used to bin sequences with respect to magnitude of release, based on the predicted CsI release fraction and release timing. The combination of release magnitude and timing produce seven distinct release categories for source terms. These are the representative release categories presented in Table E.1-7.

Table E.1-6
Release Severity and Timing Classification Scheme Summary

Release Severity		Release Timing	
Classification Category	**Cs Iodide % in Release**	**Classification Category**	**Time of Initial Release Relative to Time for General Emergency Declaration**
High (H)	Greater than 10	Late (L)	Greater than 24 hours
Medium or Moderate (M)	1 to 10	Intermediate (I)	3.7 to 24 hours
Low (L)	0.1 to 1	Early (E)	Less than 3.7 hours
Low-low (LL)	Less than 0.1		

Table E.1-7
CNS Release Categories

Time of Release	Magnitude of Release			
	H	**M**	**L**	**LL**
E	H/E	M/E	L/E	LL/E
I	H/I	M/I	L/I	LL/I
L	H/L	M/L	L/L	LL/L

E.1.2.2.5 Mapping of Level 1 Results into the Various Release Categories

PDS provide the interface between the Level 1 and Level 2 analyses (i.e., between core damage accident sequences and fission product release categories). In the PDS analysis, Level 1 results were grouped ("binned") according to plant characteristics that define the status of the reactor, containment, and core cooling systems at the time of core damage. This ensures that systems important to core damage in the Level 1 event trees, and the dependencies between containment and other systems are handled consistently in the Level 2 analysis. A PDS therefore represents a grouping of Level 1 sequences that defines a unique set of initial conditions that are likely to yield a similar accident progression through the Level 2 CETs and the attendant challenges to containment integrity.

From the perspective of the Level 2 assessment, PDS binning entails the transfer of specific information from the Level 1 to the Level 2 analyses.

- Equipment failures in Level 1. Equipment failures in support systems, accident prevention systems, and mitigation systems that have been noted in the Level 1 analysis are carried into the Level 2 analysis. In this latter analysis, the repair or recovery of failed equipment is not allowed unless an explicit evaluation, including a consideration of adverse environments where appropriate, has been performed as part of the Level 2 analysis.

- RPV status. The RPV pressure condition is explicitly transferred from the Level 1 analysis to the CET.

- Containment status. The containment status is explicitly transferred from the Level 1 analysis to the CET. This includes recognition of whether the containment is bypassed or is intact at the onset of core damage.

- Differences in accident sequence timing are transferred with the Level 1 sequences. Timing affects such sequences as: SBO, internal flooding, and containment bypass (ISLOCA).

This transfer of information allows timing to be properly assessed in the Level 2 analysis.

Based on the above criteria, the Level 1 results were binned into PDS's. These PDS define important combinations of system states that can result in distinctly different accident progression pathways and therefore, different containment failure and source term characteristics. Table E.1-8 provides a description of the CNS PDS that are used to summarize the Level 1 results.

Table E.1-8
Summary of CNS Core Damage Accident Sequences Plant Damage States

Accident Class Designator	Subclass	Definition	CDF (/ry)
Class I	A	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.	IA 1.26E-6 IAL 2.35E-6
	B	Accident sequences involving a station blackout and loss of coolant inventory makeup.	IBE 2.26E-7 IBL 6.88E-7
	C	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	1.93E-8
	D	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	ID 5.82E-7 IDL 1.30E-6
	E	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high and DC power is unavailable.	5.11E-7

Table E.1-8 (Continued)
Summary of CNS Core Damage Accident Sequences Plant Damage States

Accident Class Designator	Subclass	Definition	CDF (/ry)
Class II	A	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	6.75E-7
	L	Accident sequences involving a loss of containment heat removal with the RPV breached but no initial core damage; core damage induced post containment failure.	5.43E-9
	V	Class IIA and III except that the vent operates as designed; loss of makeup occurs at some time following vent initiation. Suppression pool saturated but intact.	3.72E-8
Class III (LOCA)	A	Accident sequences leading to core damage conditions initiated by vessel rupture where the containment integrity is not breached in the initial time phase of the accident.	0
	B	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	3.97E-7
	C	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	7.14E-7
	D	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with subsequent failure of makeup systems.	1.16E-7
Class IV (ATWS)	A	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	1.91E-7
	L	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially breached (e.g. LOCA or SORV); core damage induced post containment failure.	3.16E-8
Class V	---	Unisolated LOCA outside containment.	1.26E-7
		Total CDF	**9.23E-6**

Note: The total is not the same as the baseline CDF due to non-minimal cutsets created when quantifying at the sequence level.

E.1.2.2.6 Process Used to Group the Source Terms

The approach used to evaluate radionuclide releases and develop release categories is similar to that applied in the NUREG-1150 analysis [Reference E.1-17]. The objectives were to establish the timing of the first significant release of radionuclides and estimate the magnitude of the total release.

The CNS Level 3 analysis requires, as an input, the frequency, type, timing and amount of fission products released to the environment during the core damage accidents postulated by the CNS Level 2 PRA analyses. In order to simplify the large number of potential release scenarios, a representative set of release fractions was chosen for each containment event tree end state along with an end state frequency.

The PDS designators listed in Table E.1-8 represent the core damage end state categories from the Level 1 analysis that are grouped together as entry conditions for the Level 2 analysis. The Level 2 accident progression for each of the PDS is evaluated using a CET to determine the appropriate release category for each Level 2 sequence. Note, however, that since all the Level 2 sequences associated with each Level 1 plant damage state may not be assigned to the same release category, there is no direct link between a specific Level 1 core damage PDS and Level 2 release category. Rather, the sum of the Level 2 end state frequencies assigned to each release category determines the overall frequency of that release category.

The CNS Level 2 PSA Analysis describes which CNS specific MAAP analyses are representative of each CET end state. It also bins each CET sequence into one of the release categories depicted in Table E.1-7.

For each CET sequence, a value for each of the release-to-environment mass fractions was obtained from the representative MAAP calculation. These mass fractions were then weighed according to the contribution of that sequence to the sum of the sequences in the end state bin. The final mass fraction representing the end state bin was the sum of these individual weighed mass fractions for each species.

To evaluate the Level 2 model results in a manner that provided the above information, each Level 2 CET sequence was linked to its respective CET end state (H/E, H/I, H/L, etc.). The release fraction and timing data for all sequences associated with a particular CET end state was weighed according to the sequence weight for that end state and summed to obtain a representative release fraction and release timing for that end state.

Table E.1-9 summarizes the results of the CET quantification and identifies the total annual release frequency for each Level 2 release category.

Table E.1-9
Summary of Containment Event Tree Quantification
CNS 2007TM Model Revision 1

Release Category (Magnitude/Timing)	Release Frequency (/ry)
H/E	2.46E-06
H/I	6.48E-07
H/L	0.00
M/E	8.58E-08
M/I	1.83E-07
M/L	9.20E-10
L/E	1.11E-07
L/I	4.63E-09
L/L	4.12E-09
LL/E	5.31E-07
LL/I	1.84E-07
LL/L	5.37E-08
NCF	7.28E-06
Total	1.16E-05

Nomenclature

Timing (time between General Emergency Declaration and initial release):

Late (L): Greater than 24 hours
Intermediate (I): 3.7 to 24 hours
Early (E): Less than 3.7 hours

Magnitude

NCF (little to no release)	- Much less than 0.1% CsI release fraction
Low-Low (LL)	- Less than 0.1% CsI release fraction
Low (L)	- 0.1% to 1% CsI release fraction
Medium (M)	- 1% to 10% CsI release fraction
High (H)	- Greater than 10% CsI release fraction

E.1.2.2.7 Consequence Analysis Source Terms

Input to the Level 3 CNS model from the Level 2 model is a combination of radionuclide release fractions, timing of radionuclide releases, and frequencies at which the releases occur. This combination of information is used in conjunction with CNS site characteristics in the Level 3 model to evaluate the off-site consequences of a core damage event.

Source terms were developed for the release categories identified in Table E.1-7. Table E.1-10 provides a summary of the Level 2 results that were used as Level 3 input for the CNS SAMA analysis (the baseline analysis case).

Consequences corresponding to each of the release categories are developed in the CNS Level 3 model, which is discussed in Section E.1.5.

E.1.2.2.8 Release Magnitude Calculations

The MAAP computer code is used to assign both the radionuclide release magnitude and timing based on the accident progression characterization. Specifically, MAAP provides the following information:

- containment pressure and temperature (time of containment failure is determined by comparing these values with the nominal containment capability);
- radionuclide release timing and magnitude for a large number of radioisotopes; and
- release fractions for radionuclide species.

Table E.1-10
CNS Release Category Source Terms

Release Mode (CET End State)	Frequency (/year)	Warning Time (sec)	Elevation (m)	Release Start (sec)	Release Duration (sec)	Release Energy (W)
H/E	2.46E-06	7.37E+03	35	1.63E+04	4.32E+04	1.30E+07
H/I	6.48E-07	9.20E+04	35	1.23E+05	1.12E+05	7.70E+06
H/L	0.00	N/A	N/A	N/A	N/A	N/A
M/E	8.58E-08	7.20E+03	35	7.20E+03	1.30E+05	1.30E+07
M/I	1.83E-07	4.03E+03	35	4.90E+04	1.10E+05	7.70E+06
M/L	9.20E-10	2.41E+03	35	9.00E+04	2.49E+04	2.50E+05
L/E	1.11E-07	2.90E+03	35	1.46E+04	3.76E+04	1.30E+07
L/I	4.63E-09	2.41E+03	35	8.78E+04	2.80E+03	7.70E+06
L/L	4.12E-09	2.41E+03	35	1.01E+05	3.25E+04	2.50E+05
LL/E	5.31E-07	2.41E+03	35	1.44E+04	9.96E+04	1.30E+07
LL/I	1.84E-07	2.41E+03	35	8.78E+04	2.64E+04	7.70E+06
LL/L	5.37E-08	2.41E+03	35	1.04E+05	2.63E+04	2.50E+05

Table E.1-10 (Continued)
CNS Release Category Source Terms

Release Mode (CET End State)	Release Fractions								
	NG	I	Cs	Te	Sr	Ru	La	Ce	Ba
H/E	8.83E-01	3.50E-01	3.50E-01	2.57E-01	9.21E-03	8.13E-03	3.25E-04	4.56E-03	1.24E-02
H/I	1.00E+00	3.46E-01	3.46E-01	2.35E-01	9.33E-03	1.34E-04	1.84E-04	4.91E-03	4.39E-03
H/L	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
M/E	1.00E+00	1.51E-01	1.51E-01	2.79E-05	6.42E-03	1.11E-02	3.55E-04	3.40E-03	1.36E-02
M/I	1.00E+00	1.00E-01	1.00E-01	9.46E-02	3.17E-03	3.30E-04	5.85E-05	1.28E-03	1.92E-03
M/L	1.00E+00	9.08E-02	9.08E-02	1.21E-01	1.03E-05	1.83E-07	1.25E-07	4.76E-06	7.78E-06
L/E	9.90E-01	6.05E-03	6.05E-03	3.25E-03	7.54E-04	2.32E-07	5.03E-06	2.11E-04	3.45E-04
L/I	1.00E+00	9.40E-03	9.40E-03	2.16E-02	1.62E-05	2.88E-07	1.23E-07	4.64E-06	8.05E-06
L/L	9.98E-01	6.17E-03	6.17E-03	1.82E-03	3.14E-04	5.40E-08	2.12E-06	8.82E-05	1.44E-04
LL/E	9.12E-01	1.70E-04	1.70E-04	3.55E-06	9.02E-09	5.51E-08	8.76E-10	1.05E-09	6.56E-08
LL/I	1.00E+00	6.44E-06	6.44E-06	5.73E-06	3.68E-07	2.39E-08	2.54E-09	4.95E-08	1.94E-07
LL/L	1.00E+00	5.65E-04	5.65E-04	5.25E-04	4.92E-04	1.28E-07	2.25E-06	6.54E-05	2.18E-04

E.1.3 IPEEE Analysis

E.1.3.1 Seismic Analysis

The seismic portion of the IPEEE was completed in conjunction with the SQUG program [References E.1-2 and E.1-3]. CNS performed a seismic margin assessment (SMA) following the guidance of NUREG-1407, *Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities*, June 1991 [Reference E.1-4], and EPRI NP-6041-SL, Revision 1, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin," August 1991 [Reference E.1-5]. The SMA approach is a deterministic and conservative evaluation that does not calculate risk on a probabilistic basis. Therefore, its results should not be compared directly with the best-estimate internal events results.

The conclusions of the CNS IPEEE seismic margin analysis are as follows.

(1) The overall plant HCLPF (High Confidence Low Probability of Failure) capacity at CNS is 0.3g PGA. All major plant structures (e.g., primary containment, reactor building, control building, diesel generator building, turbine building superstructure, and intake structure) have seismic capacities in excess of the HCLPF.

(2) No unique decay heat removal vulnerabilities to seismic events were found.

(3) Seismic-induced flooding and fires do not pose major risks.

(4) No unique seismic-induced containment failure mechanisms were identified.

A number of plant improvements were identified as described in NUREG-1742, *Perspectives Gained from the IPEEE Program*, Final Report, April 2002 [Reference E.1-6]. These improvements were implemented or were evaluated as SAMAs. Phase II SAMA 69, "Upgrade the seismic capacity of the diesel fire pump fuel tank and water supply tank," was evaluated to reduce the seismic/fire interaction upon the diesel fire pump.

E.1.3.2 Fire Analysis

The CNS internal fire risk model was performed in 1996 as part of the IPEEE submittal report. The CNS fire analysis was performed using EPRI's Fire PRA Implementation Guide [Reference E.1-7]. The EPRI Fire Induced Vulnerability Evaluation method was used for the initial screening, for treatment of transient combustibles, and as the source of fire frequency data [Reference E.1-8].

Table E.1-11 presents the results of the current CNS IPEEE fire analysis. These values reflect the re-evaluation of the IPEEE fire CDF results to include responses to NRC questions regarding fire-modeling progression.

Two plant improvements were identified as described in NUREG-1742, *Perspectives Gained from the IPEEE Program*, Final Report, April 2002. It was determined that an improvement to install additional features to allow control of switchyard breakers remote from control room board C and vertical board F, or to have a pre-planned recovery/repair action for control of the switchyard breakers following a fire that completely disables the control room boards, would result in less than a 0.5% decrease in overall plant CDF. Therefore, this improvement was not implemented or evaluated as a SAMA. The improvement to provide the service water system with water supplies that are diverse from pumps in the service water pump room is evaluated under Phase II SAMA 68, "Proceduralize the ability to cross-connect the circulating water pumps and the service water going to the TEC heat exchangers." Also, Phase II SAMA 63, "Add automatic fire suppression systems to the dominant fire zones," and Phase II SAMA 65, "Upgrade the ASDS panel to include additional system controls for opposite division," were evaluated to reduce fire CDF in dominant fire zones without suppression and in the control room.

Generic conservatisms in the IPEEE fire analysis methods mentioned in NEI 05-01, "Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document," that are applicable to the CNS fire analysis include the following.

- The frequency and severity of fires were generally conservatively overestimated. A revised NRC fire events database indicates a trend toward lower frequency and less severe fires. This trend reflects improved housekeeping, reduction in transient fire hazards, and other improved fire protection steps at utilities.

- There is little industry experience with crew actions following fires. This led to conservative characterization of crew actions in the IPEEE fire analysis. Because CDF is strongly correlated with crew actions, this conservatism has a profound effect on fire results.

- The peer review process for fire analyses is less well developed than for internal events PSAs. For example, no industry process, such as NEI 00-02, exists for the structured peer review of a fire PSA.

Plant-specific conservative assumptions in the CNS IPEEE fire analysis include the following.

- Cable failure due to fire damage was assumed to arise from open circuits, hot shorts circuits, and short circuits to ground. In damaging a cable, the fire was always assumed to induce the conductor failure mode of concern.

- Manual fire suppression was only credited in the control room and non-essential switchgear room evaluations.

- Generic fire frequencies were used.

- Hardware repair activities were not credited.

E.1.3.3 Other External Hazards

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

- high winds and tornadoes;
- external flooding; and
- ice, hazardous chemical, transportation, and nearby facility incidents.

The CNS Individual Plant Examination of External Events (IPEEE) concluded for high winds, floods, and other external events that no undue risks are present that might contribute to CDF with a predicted frequency in excess of 1E-06/ry except for the design-basis tornado and a lightning strike to the control building. As these events are not dominant contributors to external event risk and quantitative analysis of these events is not practical, they are considered negligible.

Table E.1-11
CNS Fire IPEEE
Five Phase 2 Screening Results

Fire Compartment	Fire Compartment Description	Total Compartment CDF (/ry)	Screened?
1A	RCIC & CS Room	9.05E-08	Y
1B/1G	CS and CRD Room	1.03E-07	Y
1C	RHR Pump 1A and 1C Room	5.74E-08	Y
1D/1E	RHR Pump 1B and 1D, and HPCI Room	8.40E-08	Y
1F	Suppression Pool Area	1.73E-07	Y
2A/2C	Reactor Building El. 903'-6" - CRD Units - North/South	8.16E-07	Y
2B	RHR Hx 1A Compartment	1.29E-08	Y
2D	RHR Hx 1B Compartment	1.30E-08	Y
2E	Steam Tunnel	4.88E-08	Y
3A	Swgr Room 1F	1.11E-06	N
3B	Swgr Room 1G	2.72E-06	N
3C/3D/3E	Reactor Building El. 932'-6" - REC	2.73E-07	Y
4A/4C/4D	Reactor Building El. 958'-3" - Fuel Pool Hx/ Lube Oil	5.37E-07	Y

Table E.1-11 (Continued)
CNS Fire IPEEE
Five Phase 2 Screening Results

Fire Compartment	Fire Compartment Description	Total Compartment CDF (/ry)	Screened?
5B	Reactor Building El. 976'-0" - RRMG Set	8.04E-08	Y
7A	RHRSW Booster and Service Air Compressor	5.58E-07	Y
7B	ECST Area	2.79E-08	Y
8A	Auxiliary Relay Room	3.66E-07	Y
8B	RPS Room 1B	7.30E-07	Y
8C	RPS Room 1A	6.52E-08	Y
8D	Seal Water Pump Area	4.86E-08	Y
8E	Battery Room 1A	1.77E-07	Y
8F	Battery Room 1B	6.73E-07	Y
8G	DC Swgr Room 1B	7.90E-07	Y
8H	DC Swgr Room 1A	3.36E-07	Y
9A	Cable Spreading Room	8.23E-07	Y
9B	Cable Expansion Room	3.45E-07	Y
10B	Control Room and SAS Corridor	3.73E-06	N
8-1	Condenser Pit Area	9.68E-07	Y
12D	Turbine Building Floor - North 903'-6" El.	1.41E-07	Y
13B	Non-Critical Swgr Room	3.32E-07	Y
13C	Electric Shop	4.19E-08	Y
13D	I&C Shop	4.36E-08	Y
14A	EDG 1A Room	6.08E-07	Y
14B	EDG 1B Room	6.08E-07	Y
14C	EDG 1A Day Tank Room	1.32E-08	Y
14D	EDG 1B Day Tank Room	1.32E-08	Y
20A	Service Water Pump Room	1.73E-06	N
		1.93E-05	

E.1.4 PSA Model Revisions and Peer Review Summary

The summary of the CNS PSA models CDF and LERF is presented in the table below.

Summary of Major PSA Models

PSA Model	CDF (/ry)	LERF (/ry)
(IPE) 1995	7.97×10^{-5}	$< 1 \times 10^{-6}$
1996b	1.33×10^{-5}	(not updated)
2001a	1.25×10^{-5}	5.63×10^{-7}
2005TM	1.12×10^{-5}	(not updated)
2006TM	1.43×10^{-5}	(not updated)
2007TM (Rev. 1)	9.27×10^{-6}	2.44×10^{-6}

E.1.4.1 Major Differences between the 1996b PSA Model and the IPE Model

In the IPE model, the contributors in order of dominance were station blackout (35 percent), transient induced LOCAs (30 percent), loss of coolant injection (18 percent), loss of containment heat removal (11 percent), ATWS (5 percent), and LOCA (1 percent).

The 1996b model CDF (1.33×10^{-5}/ry) represents a reduction from the CDF determined from the IPE model (7.97×10^{-5}/ry).

In the 1996b model, the contributors in order of dominance were loss of offsite power (49 percent), loss of condenser (14 percent), reactor trip (6 percent), loss of instrument air (6 percent), inadvertent open relief valve (6 percent), loss of service water (5 percent), loss of DC bus (3 percent), loss of AC bus (2 percent), small LOCA (< 1 percent), recirculation pump seal LOCA (< 1 percent). From an accident contribution standpoint SBO contributes 41 percent, ATWS contributes 19 percent, and ISLOCA contributes < 1 percent.

The major changes in the 1996b model can be summarized as follows.

- Revised human reliability analysis to incorporate revisions to emergency operating procedures.
- Added newly installed torus hard pipe vent.
- Corrected conservative thermal hydraulic analysis of SRV flow.
- Improved loss of offsite power model.

E.1.4.2 Major Differences between the 2001a Model and the 1996b Model

The 2001a model CDF (1.25×10^{-5}/ry) represents a slight reduction from the CDF determined from the 1996b model (1.33×10^{-5}/ry).

In the 2001a model, the contributors in order of dominance were loss of offsite power (49 percent), loss of condenser (19 percent), LOCA (8 percent), reactor trip (6 percent), loss of instrument air (6 percent), inadvertent open relief valve (6 percent), loss of service water (5 percent), loss of DC bus (3 percent), and loss of AC bus (2 percent).

Changes in the 2001a model can be summarized as follows.

- Minor improvements stemming from the 9/97 peer review (see Section E.1.4.6 for more information on the peer review).
- Updated component failure and unavailability database.
- LERF model was developed to include the torus hard pipe vent, incorporate revisions to emergency operating procedures, and a LERF translation matrix from the Level 1 results was implemented.

E.1.4.3 Major Differences between the 2005TM Model and the 2001a Model

The 2005TM model CDF (1.12×10^{-5}/ry) represents a slight reduction from the CDF determined from the 2001a model (1.25×10^{-5}/ry).

In the 2005TM model, the contributors in order of dominance were loss of offsite power (28 percent), reactor trip (23 percent), loss of AC bus (15 percent), loss of condenser (11 percent), loss of service water (11 percent), inadvertent open relief valve (3 percent), loss of instrument air (2 percent), loss of DC bus (2 percent), loss of TBCCW (< 1 percent), and LOCA (< 1 percent).

Changes in the 2005TM model can be summarized as follows.

- Updated initiating event frequencies to reflect information in NUREG/CR-6890.

E.1.4.4 Major Differences between the 2006TM Model and the 2005TM Model

The 2006TM model CDF (1.43×10^{-5}/ry) represents an increase from the CDF determined from the 2005TM model (1.12×10^{-5}/ry).

In the 2006TM model, the contributors in order of dominance were loss of offsite power (34 percent), loss of condenser (20 percent), loss of service water (16 percent), loss of AC bus (11 percent), reactor trip (8 percent), loss of instrument air (3 percent), loss of DC bus (3 percent), loss of TBCCW (2 percent), inadvertent open relief valve (1 percent), and LOCA (< 1 percent).

Changes in the 2006TM model can be summarized as follows.

- Updated to support MSPI and maintenance rule update.

E.1.4.5 Major Differences between the 2007TM (Rev. 1) Model and the 2006TM Model

The 2007TM model Rev. 1 CDF (9.27×10^{-6}/ry) represents a decrease from the CDF determined from the 2006TM model (1.43×10^{-5}/ry). The 2007TM model Rev. 1 LERF (2.44×10^{-6}) represents an increase from the 2007TM model LERF (5.63×10^{-7}). [The 2007TM model (Rev. 0) was revised immediately after it was received to correct various inaccurate pipe break and EDG start and run frequencies that were significantly skewing the model results. The 2007TM model (Rev. 0) was never used and the "Rev. 1" was added strictly for tracking.]

In the 2007TM Rev. 1 model, the contributors in order of dominance are transients (32 percent), loss of DC power (22 percent), LOCA (15 percent), loss of feedwater (11 percent), loss of offsite power (7 percent), loss of service water (6 percent), loss of AC bus (3 percent), internal flood (3 percent), and ISLOCA (< 1 percent). There were no specific initiators for SBO but the percentage contributions due to SBO and ATWS are 2.78 percent and 2.79 percent respectively.

Changes in the 2007TM Rev. 1 model can be summarized as follows.

- Internal flooding was added to the Level 1 model.
- Operator action dependencies were accounted for.
- The treatment of common cause failures was expanded.
- A more detailed Containment Event Tree and new Level 2 fault trees were developed.
- New Level 1 system models were added including severe accident mitigation strategies such as firewater injection.
- The PRA data was updated.
- Initiator fault trees were developed and used to calculate some initiating event frequencies such as loss of TEC.

The 2007TM model Rev. 1 LERF represents an increase from the previous LERF value. This difference is attributed to the following.

- Contributors to plant damage states leading to LERF were changed by revisions to the Level 1 model mentioned above, especially addition of internal flooding and revision of initiating event fault trees and frequencies (particularly DC power initiating events).

- MAAP 4.0.5 deterministic calculations were used to provide more realistic success criteria and timings. These timings were used in the human reliability analysis (HRA) which was also revised to use the EPRI HRA Calculator.

- MAAP 4.0.5 radionuclide release calculations were used to replace fission product transport calculations using MAAP 3.0B.

E.1.4.6 PSA Model Peer Review

The 1996b model was peer reviewed in September 1997 using Boiling Water Reactor Owners Group process. Facts and Observation sheets documented the certification team's insights and potential level of significance. There were no Level A findings (for which immediate model changes would have been appropriate) from the peer review. Although a number of minor model corrections were made following the peer review, no significant changes were made to the model structure or underlying assumptions.

The model changes in the 2001a, 2005TM and 2006TM models were peer reviewed for accuracy and consistency by members of the CNS staff not directly involved in their implementation. In addition, cognizant departments (licensing, operations, maintenance, training, planning & scheduling, system engineering, and design engineering) were provided with the final results and insights derived from each study for an expert panel review.

The 2007TM model, Revision 1 was peer reviewed by members of the Boiling Water Reactor Owners Group in May 2008 using the NEI 05-04 [Reference E.1-18] process and the ASME PRA Standard [Reference E.1-19] along with the NRC clarifications provided in Regulatory Guide 1.200, Rev. 1 [Reference E.1-20]. The peer review was a full-scope review of all the technical elements of the internal events, at-power PRA. These elements are initiating events analysis, accident sequence analysis, success criteria, systems analysis, human reliability analysis, data analysis, internal flooding, quantification, and LERF analysis. The week-long peer review also addressed PRA configuration control.

The review team found that, of the 301 ASME PRA Standard supporting requirements applicable to CNS, approximately 94% are supportive of capability category II or greater. Nine best practices, 47 suggestions, and 33 findings were noted by the review team. The "best practices" identify PRA strengths, i.e., items that represent best industry practice. The "suggestions" identify changes desirable to maintain maximum flexibility for PRA applications and consistency with industry practices. Failing to resolve a suggestion should have no significant impact on the PRA results or the integrity of the PRA. "Findings" are observations that should be addressed to ensure the technical adequacy of the PRA relative to a capability category, the capability/ robustness of the PRA update process, or the process for evaluating the necessary capability of the PRA technical elements.

CNS review of the preliminary peer review findings determined that resolution of the findings would not result in significant impact on the PRA results. The areas considered "not met" or capability category I have negligible effect on the baseline CDF. In addition, with respect to this application, the issue regarding treatment of uncertainty on SAMA candidates is explicitly evaluated and reported. Therefore the "not met" characterization of the nine SRs related to uncertainty has limited impact. Generally the PRA model is documented extensively and peer review comments were related to thoroughness rather than specific deficiencies when assigning capability to each SR. It is anticipated that several of the findings will be revised or resolved prior to finalizing the peer review report. Therefore, use of the 2007TM model, Revision 1 for the SAMA analysis is appropriate.

No plant modifications or procedure changes have occurred since the freeze date of the 2007TM Revision 1 model that could have a significant impact on the results of the PSA or the SAMA analysis.

E.1.5 The MACCS2 Model – Level 3 Analysis

E.1.5.1 Introduction

SAMA evaluation relies on Level 3 PRA results to measure the effects of potential plant modifications. A Level 3 PRA model using version 1.13.1 of the MELCOR Accident Consequences Code System Version 2 (MACCS2) [Reference E.1-1] was created for CNS. This model, which requires detailed site-specific meteorological, population, and economic data, estimates the consequences in terms of population dose and offsite economic cost. Risks in terms of population dose risk (PDR) and offsite economic cost risk (OECR) were also estimated in this analysis. Risk is defined as the product of consequence and frequency of an accidental release.

This analysis considers a base case and two sensitivity cases to account for variations in data and assumptions for postulated internal events. The base case uses estimated time and speed for evacuation. Sensitivity case 1 is the base case with delayed evacuation. Sensitivity case 2 is the base case with lower evacuation speed.

PDR was estimated by summing over all releases the product of population dose and frequency for each accidental release. Similarly, OECR was estimated by summing over all releases the product of offsite economic cost and frequency for each accidental release. Offsite economic cost includes costs that could be incurred during the emergency response phase and costs that could be incurred through long-term protective actions.

E.1.5.2 Input

The following sections describe the site-specific input parameters used to obtain the off-site dose and economic impacts for cost-benefit analyses.

E.1.5.2.1 Projected Total Population by Spatial Element

The total population within a 50-mile radius of CNS was estimated for the year 2034, the end of the proposed license renewal period, for each spatial element by combining total resident population projections with transient populations. The 2034 permanent population values are based on the county-level projections obtained from the University of Nebraska Bureau of Business Research from 2000–2020, Woods & Poole Economics, Inc. for Iowa from 2000–2030, Darrel Eklund et al. for Kansas from 2000–2040, and the Missouri Census Data Center from 2000–2025 [References E.1-11, E.1-12, E.1-13 and E.1-14]. Regression methods were used to extrapolate population projections to 2034. For the counties with population in decline, the population value for 2014 was used as the 2034 estimate. Table E.1-12 shows the estimated population distribution.

Table E.1-12
Estimated Population Distribution within a 50-mile Radius

Wind Direction	0 to 10 miles	11 to 20 miles	21 to 30 miles	31 to 40 miles	41 to 50 miles	Total
N	148	1,580	1,970	2,770	14,771	21,239
NNE	81	189	1,387	7,433	5,607	14,697
NE	231	248	975	1,047	6,803	9,304
ENE	1,498	2,100	588	1,481	1,974	7,641
E	103	816	272	4,580	9,984	15,755
ESE	51	255	471	1,240	2,455	4,472
SE	9	499	1,675	1,842	3,027	7,052
SSE	40	292	824	1,830	2,047	5,033
S	62	505	5,257	5,005	3,611	14,440
SSW	311	532	427	3,776	2,569	7,615
SW	237	638	1,192	897	2,532	5,496
WSW	108	230	646	1,391	837	3,212
W	90	2,021	2,615	709	1,951	7,386
WNW	104	2,646	1,308	1,641	3,654	9,353
NW	140	507	1,346	5,333	5,788	13,114
NNW	1,183	232	10,239	2,728	19,674	34,056
Totals	4,396	13,290	31,192	43,703	87,284	179,865

E.1.5.2.2 Land Fraction

The land fraction for each spatial element was estimated within the 50 mile radius area. The National Hydrography Dataset was used to estimate the extent of land and surface water coverage [Reference E.1-15].

E.1.5.2.3 Watershed Class

Watershed Index is defined by MACCS2 as areas drained by rivers (Class 1) or large water bodies (Class 2). No spatial elements were treated as large water bodies for CNS.

E.1.5.2.4 Regional Economic Data

Region Index

Each spatial element was assigned to an economic region, defined in this report as a county. Where a spatial element covers portions of more than one county, it was assigned to that county having the most area within the element.

Regional Economic Data

County level economic data were obtained from the US Department of Agriculture for 2002 [Reference E.1-16].

VALWF – Value of Farm Wealth

MACCS2 requires an average value of farm wealth (dollars/hectare) for the 50-mile radius area around CNS. The county-level farmland property value was used as a basis for deriving this value. VALWF is $3,701/hectare.

VALWNF– Value of Non-Farm Wealth

MACCS2 also requires an average value of non-farm wealth. The county-level non-farm property value was used as a basis for deriving this value. VALWNF is $104,504/person.

Other economic parameters and their values are shown below. The values were obtained by adjusting the economic data given in Reference E.1-1 with the consumer price index of 201.6, which is the average value for the year 2006, as appropriate.

Variable	Description	Value
EVACST	Daily cost for a person who has been evacuated ($/person-day)	49.7
POPCST	Population relocation cost ($/person)	9197
RELCST	Daily cost for a person who is relocated ($/person-day)	49.7
CDFRM0	Cost of farm decontamination for the various levels of decontamination ($/hectare)	1035 2299
CDNFRM	Cost of non-farm decontamination for the various levels of decontamination ($/person)	5518 14715
DLBCST	Average cost of decontamination labor ($/person-year)	64380

DPRATE	Property depreciation rate (per year)	0.2
DSRATE	Investment rate of return (per year)	0.12

E.1.5.2.5 Agriculture Data

The source of regional crop information is the 2002 Census of Agriculture [Reference E.1-16]. The crops listed for each county within the 50-mile area were summed and mapped into the seven MACCS2 crop categories.

E.1.5.2.6 Meteorological Data

The MACCS2 model requires meteorological data for wind speed, wind direction, atmospheric stability, accumulated precipitation, and atmospheric mixing heights. The required data was obtained from the CNS meteorological monitoring system and regional National Weather Service stations.

Site Specific Data

The CNS meteorological monitoring system includes both primary and backup systems. The primary meteorological system was the data source for the MACCS2 analysis. Based on a review of annual meteorological data collected at the site between 2002 and 2006, data from calendar years 2002 through 2006 were averaged for the MACCS2 input file. The data included 43,824 (one leap year) consecutive hourly values of wind speed, wind direction, precipitation, and temperature recorded at the CNS meteorological tower from January 2002 to December 2006. Missing data for parameters of interest were estimated using data substitution methods. These methods include substitution of missing data with valid data from the previous hour, removal of data from the average calculation, and substitution of valid data collected from other elevations on the meteorological tower.

Regional Mixing Height Data

Mixing height is defined as the height of the atmosphere above ground level within which a released contaminant will become mixed (from turbulence) within approximately one hour. Regional mixing heights were estimated using ground level and upper-air data collected at National Weather Service Station No. 94980 in Valley, NE (approximately 76 miles NNW of CNS) and Station No. 72553 in Falls City/Brenner, NE (approximately 19 miles S of CNS). These two weather stations were selected by staff meteorologists at the National Climatic Data Center to calculate seasonal mixing height values for the CNS area.

E.1.5.2.7 Emergency Response Assumptions

Detailed analysis of evacuation scenarios for the EPZ were addressed in the CNS evacuation travel time estimate studies for the Nebraska [Reference E.1-9] and Missouri [Reference E.1-10] portions of the EPZ. The Nebraska study, dated January 1992, was conducted by the Nebraska Civil Defense Agency in conjunction with the Civil Defense organizations in Nemaha and

Richardson Counties. The Missouri Study, dated August 1991, was conducted by the Missouri State Emergency Management Agency and the Nebraska Public Power District. The studies provide an analysis of the range and variation of public reaction to the evacuation notification process. They are the latest reports available and are still valid because the population in the 10-mile EPZ area has been in decline since the studies were conducted. The reports present conservative estimates of the time needed to evacuate the total population from the 10-mile EPZ.

Evacuation Delay Time

The elapsed time between the issuance of an evacuation notification and the beginning of the public evacuation is 2 hours and 15 minutes in Nebraska, 1 hour and 45 minutes in Missouri. The baseline delay time (2 hours) for an evacuation from the EPZ was calculated by averaging the delay times identified in both the Missouri and Nebraska evacuation time estimate studies. A sensitivity case that assumes 4.0 hours for evacuees to begin evacuation was considered in this study to evaluate consequence sensitivities due to uncertainties in delay time.

Evacuation Speed

Evacuation travel speed ranges from 23.8 miles/hour (10.6 meters/second) to 10.9 miles/hour (4.9 meters/second) in Nebraska. In Missouri the evacuation travel speed ranges from 28.6 miles/hour (12.8 meters/second) under normal conditions to 14.5 miles/hour (6.5 meters/second) under adverse conditions. The average evacuation speed was estimated to be approximately 19.5 miles/hour (8.7 meters/second). A sensitivity case that assumes a lower evacuation speed of 1.0 meter/second was considered in this study to evaluate consequence sensitivities due to uncertainties in evacuation speed.

E.1.5.2.8 Core Inventory

The estimated CNS core inventory (Table E.1-13) used in the MACCS2 input is based on a power level of 2429 MW(t). The core inventory was derived from isotope generation and depletion code ORIGEN2 for a bounding reload core immediately following shutdown. The core inventory values were calculated for an assumed power level of 2429 MWt (102% of the 2381 MWt licensed power level) to provide margin for possible Measurement Uncertainty Recapture (MUR) power uprate.

Table E.1-13
Estimated CNS Core Inventory (Becquerels)[1]

Nuclide	Inventory	Nuclide	Inventory
Co-58	1.38E+16	Te-131m	3.56E+17
Co-60	1.64E+16	Te-132	3.46E+18
Kr-85	3.29E+16	I-131	2.44E+18
Kr-85m	6.12E+17	I-132	3.53E+18

Table E.1-13 (Continued)
Estimated CNS Core Inventory (Becquerels)[(1)]

Nuclide	Inventory	Nuclide	Inventory
Kr-87	1.17E+18	I-133	4.95E+18
Kr-88	1.64E+18	I-134	5.43E+18
Rb-86	6.28E+15	I-135	4.64E+18
Sr-89	2.19E+18	Xe-133	4.73E+18
Sr-90	2.61E+17	Xe-135	1.67E+18
Sr-91	2.79E+18	Cs-134	6.07E+17
Sr-92	3.04E+18	Cs-136	1.94E+17
Y-90	2.70E+17	Cs-137	3.64E+17
Y-91	2.85E+18	Ba-139	4.40E+18
Y-92	3.05E+18	Ba-140	4.23E+18
Y-93	3.56E+18	La-140	4.38E+18
Zr-95	4.00E+18	La-141	4.01E+18
Zr-97	4.05E+18	La-142	3.86E+18
Nb-95	4.03E+18	Ce-141	4.02E+18
Mo-99	4.60E+18	Ce-143	3.69E+18
Tc-99m	4.06E+18	Ce-144	3.29E+18
Ru-103	3.86E+18	Pr-143	3.61E+18
Ru-105	2.72E+18	Nd-147	1.62E+18
Ru-106	1.56E+18	Np-239	5.27E+19
Rh-105	2.49E+18	Pu-238	1.15E+16
Sb-127	2.71E+17	Pu-239	1.16E+15
Sb-129	8.03E+17	Pu-240	1.59E+15
Te-127	2.74E+17	Pu-241	4.80E+17
Te-127m	3.65E+16	Am-241	6.17E+14
Te-129	7.90E+17	Cm-242	1.55E+17
Te-129m	1.17E+17	Cm-244	9.98E+15

1. From CNS specific data for a power level of 2429 MWth

E.1.5.2.9 Source Terms

Eleven release categories, corresponding to internal event sequences, were part of the MACCS2 input. The High Late (H/L) category has zero release frequency and is not considered. Section E.1.2.2.6 provides details of the source terms for postulated internal events. A linear release rate was assumed between the time the release started and the time the release ended.

E.1.5.3 Results

Risk estimates for one base case and two sensitivity cases were analyzed with MACCS2. The base case assumes 2.0 hours delay and 8.7 meter/sec speed of evacuation. Sensitivity case 1 is the base case with delayed evacuation of 4.0 hours. Sensitivity case 2 is the base case with an evacuation speed of 1.0 meter/sec. Table E.1-14 shows estimated base case mean risk values for each release mode. The estimated mean values of PDR and offsite OECR for CNS are 2.14 person-rem/yr and $7,010/yr, respectively.

Table E.1-14
Base Case Mean PDF and OECR Values

Release Mode	Frequency (/yr)	Population Dose (person-sv)(1)	Offsite Economic Cost ($)	Population Dose Risk (PDR) (person-rem/yr)	Offsite Economic Cost Risk (OECR) ($/yr)
H/E	2.46E-06	6.46E+03	2.13E+09	1.59E+00(2)	5.24E+03
H/I	6.48E-07	6.11E+03	2.10E+09	3.96E-01	1.36E+03
M/E	8.58E-08	4.51E+03	1.55E+09	3.87E-02	1.33E+02
M/I	1.83E-07	3.88E+03	1.33E+09	7.11E-02	2.44E+02
M/L	9.20E-10	3.59E+03	1.13E+09	3.30E-04	1.04E+00
L/E	1.11E-07	2.08E+03	2.26E+08	2.31E-02	2.51E+01
L/I	4.63E-09	1.33E+03	2.77E+08	6.15E-04	1.28E+00
L/L	4.12E-09	2.11E+03	1.77E+08	8.68E-04	7.29E-01
LL/E	5.31E-07	3.62E+02	3.51E+06	1.92E-02	1.86E+00
LL/I	1.84E-07	2.18E+01	4.16E+05	4.00E-04	7.64E-02
LL/L	5.37E-08	8.49E+02	2.04E+07	4.56E-03	1.09E+00
			Totals	2.14E+00	7.01E+03

1. 1 sv = 100 rem
2. 1.59E+00 (person-rem/yr) = 2.46E-06 (/yr) x 6.46E+03 (person-sv) x 100 (rem/sv)

Results of sensitivity analyses indicate that a delayed evacuation or a lower evacuation speed would not have any significant effects on the offsite consequences or risks determined in this study. Table E.1-15 summarizes offsite consequences in terms of population dose (person-sv) and offsite economic cost ($) for the base case and the sensitivity cases. Comparison of the consequences indicates that the maximal deviation is less than 2% between the base case population dose and the Sensitivity Case 1 population dose for release mode M/E.

Table E.1-15
Summary of Offsite Consequence Sensitivity Results

	Population Dose (person-sv)			Offsite Economic Cost ($)		
Release Mode	**Base Case**	**4-hr Delayed Evacuation**	**Lower Speed of Evacuation**	**Base Case**	**4 –hr Delayed Evacuation**	**Lower Speed of Evacuation**
H/E	6.46E+03	6.48E+03	6.53E+03	2.13E+09	2.13E+09	2.13E+09
H/I	6.11E+03	6.11E+03	6.11E+03	2.10E+09	2.10E+09	2.10E+09
M/E	4.51E+03	4.53E+03	4.56E+03	1.55E+09	1.55E+09	1.55E+09
M/I	3.88E+03	3.88E+03	3.88E+03	1.33E+09	1.33E+09	1.33E+09
M/L	3.59E+03	3.59E+03	3.59E+03	1.13E+09	1.13E+09	1.13E+09
L/E	2.08E+03	2.08E+03	2.08E+03	2.26E+08	2.26E+08	2.26E+08
L/I	1.33E+03	1.33E+03	1.33E+03	2.77E+08	2.77E+08	2.77E+08
L/L	2.11E+03	2.11E+03	2.11E+03	1.77E+08	1.77E+08	1.77E+08
LL/E	3.62E+02	3.62E+02	3.62E+02	3.51E+06	3.51E+06	3.51E+06
LL/I	2.18E+01	2.18E+01	2.18E+01	4.16E+05	4.16E+05	4.16E+05
LL/L	8.49E+02	8.49E+02	8.49E+02	2.04E+07	2.04E+07	2.04E+07

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ATTACHMENT E.2

EVALUATION OF CNS SAMA CANDIDATES

E.2 EVALUATION OF CNS SAMA CANDIDATES

This section describes the generation of the initial list of potential SAMA candidates, screening methods, and the analysis of the remaining SAMA candidates.

E.2.1 SAMA List Compilation

A list of SAMA candidates was developed by reviewing industry documents and considering other plant-specific enhancements not identified in published industry documents. Since CNS is a BWR, considerable attention was paid to the SAMA candidates from SAMA analyses for other BWR plants. Industry documents reviewed include the following.

- NEI 05-01, Severe Accident Mitigation Alternatives Analysis [Reference E.2-1]
- James A. FitzPatrick Nuclear Power Plant SAMA Analysis [Reference E.2-2]
- Vermont Yankee Nuclear Power Station SAMA Analysis [Reference E.2-3]
- Pilgrim Nuclear Power Station SAMA Analysis [Reference E.2-4]
- Oyster Creek Nuclear Generating Station SAMA Analysis [Reference E.2-5]
- Monticello Nuclear Generating Plant SAMA Analysis [Reference E.2-6]
- Brunswick Steam Electric Plant, Units 1 and 2 SAMA Analysis [Reference E.2-7]
- NUREG-1742, *Perspectives Gained from the Individual Plant Examination of External Events (IPEEE) Program* [Reference E.2-8]

In addition to SAMA candidates from review of industry documents, additional SAMA candidates were obtained from plant-specific sources, such as the CNS IPE [Reference E.2-9] and the CNS IPEEE [Reference E.2-10]. In the IPE and IPEEE several enhancements related to severe accident insights were recommended. These enhancements are included in the comprehensive list of Phase I SAMA candidates. Table E.2-1 lists the IPE and IPEEE Phase I SAMA candidates for the SAMA analysis and indicates which have been implemented, which have been incorporated in the model used for the SAMA analysis, and which have been retained for further evaluation in Phase II of the SAMA analysis. The current CNS PSA levels 1 and 2 models were also used to identify plant-specific modifications for inclusion in the comprehensive list of SAMA candidates. The risk significant terms from the current PSA model were reviewed for similar failure modes and effects that could be addressed through a potential enhancement to the plant. The correlation between SAMAs and the risk significant events are listed in Tables E.1-3 and E.1-5.

The comprehensive list contained a total of 244 Phase I SAMA candidates and is available in onsite documentation.

E.2.2 Qualitative Screening of SAMA Candidates (Phase I)

The purpose of the preliminary SAMA screening was to identify the subset of candidate SAMAs that would reduce severe accident risk at CNS and would therefore warrant a detailed cost-benefit evaluation. Potential SAMA candidates were screened out if they modified features not applicable to CNS, if they had already been implemented at CNS, or if they were similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate. During this process, 49 of the Phase I SAMA candidates were screened out because they were not applicable to CNS, 24 of the Phase I SAMA candidates were screened out because they were similar in nature and could be combined with another SAMA candidate, and 91 of the Phase I SAMA candidates were screened out because they had already been implemented at CNS, leaving 80 SAMA candidates for further analysis. The final screening process involved identifying and eliminating those items whose implementation cost would exceed their benefit as described below. Table E.2-2 provides a description of each of the 80 Phase II SAMA candidates.

E.2.3 Final Screening and Cost Benefit Evaluation of SAMA Candidates (Phase II)

A cost/benefit analysis was performed on each of the remaining SAMA candidates. If the implementation cost of a SAMA candidate was determined to be greater than the potential benefit (i.e., there was a negative net value) the SAMA candidate was considered not to be cost beneficial and was not retained as a potential enhancement.

The expected cost of implementation of each SAMA was established from existing estimates of similar modifications. Most of the cost estimates were developed from similar modifications considered in previously performed SAMA. In particular, these cost-estimates were derived from the following sources.

- Pilgrim SAMA Analysis [Reference E.2-4]
- Vermont Yankee SAMA Analysis [Reference E.2-3]
- James A. FitzPatrick SAMA Analysis [Reference E.2-2]
- Peach Bottom SAMA Analysis [Reference E.2-12]
- Quad Cities SAMA Analysis [Reference E.2-13]
- Susquehanna Steam Electric Station SAMA Analysis [Reference E.2-14]
- Monticello SAMA Analysis [Reference E.2-6]
- Browns Ferry, Units 1, 2, and 3 SAMA Analysis [Reference E.2-15]
- Brunswick, Units 1 and 2 SAMA Analysis [Reference E.2-16]
- Oyster Creek SAMA Analysis [Reference E.2-5]
- Nine Mile Point, Units 1 and 2 SAMA Analysis [Reference E.2-17]

The cost estimates did not include the cost of replacement power during extended outages required to implement the modifications. 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.

The benefit of implementing a SAMA candidate was estimated in terms of averted consequences. The benefit was estimated by calculating the arithmetic difference between the total estimated costs associated with the four impact areas for the baseline plant design and the total estimated impact area costs for the enhanced plant design (following implementation of the SAMA candidate).

Values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the NUREG/BR-0184 [Reference E.2-11] conversion factor of $2,000 per person rem and discounted to present value. Values for avoided off-site economic costs were also discounted to present value.

As this analysis focuses on establishing the economic viability of potential plant enhancement when compared to attainable benefit, detailed cost estimates often were not required to make informed decisions regarding the economic viability of a particular modification. Several of the SAMA candidates were clearly in excess of the attainable benefit estimated from a particular analysis case.

For less clear cases, engineering judgment on the cost associated with procedural changes, engineering analysis, testing, training, and hardware modification was applied to determine if a more detailed cost estimate was necessary to formulate a conclusion regarding the economic viability of a particular SAMA. Cost input to the engineering judgment was obtained from project engineers experienced in performing design changes at the facility and these values were compared, where possible, to estimates developed and used at plants of similar design and vintage. Therefore, based on a review of previous SAMA evaluations and an evaluation of expected implementation costs at CNS, the following estimated costs for each potential element of the proposed SAMA implementation are used.

Type of Change	Estimated Cost Range
Procedural only	$25K-$50K
Procedural change with engineering required	$50K-$200K
Procedural change with engineering and testing/training required	$200K-$300K
Hardware modification	$100K to >$1000K

In most cases, more detailed cost estimates were not required, particularly if the SAMA called for the implementation of a hardware modification. Nonetheless, the cost of each unscreened SAMA candidate was conceptually estimated to the point where conclusions regarding the economic viability of the proposed modification could be adequately gauged. The cost benefit comparison and disposition of each of the 80 Phase II SAMA candidates is presented in Table E.2-2.

Bounding evaluations (or analysis cases) were performed to address specific SAMA candidates or groups of similar SAMA candidates. These analysis cases overestimated the benefit and thus were conservative calculations. For example, one SAMA candidate suggested installing digital large break LOCA protection; the bounding calculation estimated the benefit of this improvement by total elimination of risk due to large break LOCA (see analysis of Phase II SAMA 66 in Table E.2-2). This calculation obviously overestimated the benefit, but if the inflated benefit indicated that the SAMA candidate was not cost beneficial, then the purpose of the analysis was satisfied.

A description of the analysis cases used in the evaluation follows.

Case 1: DC Power

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of DC power (e.g., increasing battery capacity, portable power supplies, or using fuel cells). It was assumed that battery life could be extended to 24 hours to simulate additional battery capacity. This enhancement would extend HPCI and RCIC operability and allow more credit for AC power recovery. A bounding analysis was performed by changing the time available to recover offsite power before HPCI and RCIC are lost to 24 hours during station blackout scenarios in the level 1 PSA model. This resulted in an internal and external benefit (with uncertainty) of approximately $96,836. This analysis case was used to model the benefit of Phase II SAMAs 1, 2, 13, and 21.

Case 2: Improve Charger Reliability

This analysis case was used to evaluate the change in plant risk from improving DC battery charging reliability by adding an additional battery charger or by changing procedures to allow the charger high-voltage trip circuit to be disabled when the batteries are disconnected from the DC circuit, thereby preventing the trip and allowing the chargers to remain online. A bounding analysis was performed by setting the common cause failure contribution due to loss of DC battery chargers to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $7,018. This analysis case was used to model the benefit of Phase II SAMAs 3 and 15.

Case 3: Add DC System Cross-ties

This analysis case was used to evaluate the change in plant risk from adding DC bus cross-ties to improve DC power availability and reliability. The 125V distribution panels and starter racks can be powered from either bus, thus the 125V buses are cross-tied. However, the 250V buses are not cross-tied. A bounding analysis was performed by setting the 250V DC buses to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $0. This analysis case was used to model the benefit of Phase II SAMA 4.

Case 4: Improve Existing DC System Cross-ties

This analysis case was used to evaluate the change in plant risk from enhancing procedures to make use of the existing 125V DC bus cross-tie to improve DC power availability and reliability. A bounding analysis was performed by setting failure of the operator to use the 125V DC bus cross-tie to zero in the Level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $5,997. This analysis case was used to model the benefit of Phase II SAMA 19.

Case 5: Provide Backup DC Power to the 120 V Vital AC Bus

This analysis case was used to evaluate the change in plant risk from improving injection capability by auto-transfer of AC bus control power to a standby DC power source upon loss of the normal DC source. A bounding analysis was performed by eliminating failure of DC power to the no break power panel, which resulted in an internal and external benefit (with uncertainty) of approximately $1,395. This analysis case was used to model the benefit of Phase II SAMA 5.

Case 6: Increase Availability of the 120 V Vital AC Bus

This analysis case was used to evaluate the change in plant risk from improving injection capability by auto-transfer of AC bus control power to a standby power source upon loss of the normal power source. A bounding analysis was performed by setting failure to transfer the RPS panels to their alternate power source to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $0. This analysis case was used to model the benefit of Phase II SAMA 6.

Case 7: Increase Availability of On-Site AC Power

This analysis case was used to evaluate the change in plant risk from improving the diversity of on-site AC power. A bounding analysis was performed by setting failure of the EDGs to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $425,016. This analysis case was used to model the benefit of Phase II SAMAs 7 and 10.

Case 8: Provide Backup EDG SW Cooling

This analysis case was used to evaluate the change in plant risk from increasing EDG reliability by adding a backup source of diesel cooling. A bounding analysis was performed by eliminating failure of SW cooling to the EDGs, which resulted in an internal and external benefit (with uncertainty) of approximately $134,213. This analysis case was used to model the benefit of Phase II SAMA 11.

Case 9: Increase EDG Reliability

This analysis case was used to evaluate the change in plant risk from providing a portable EDG fuel oil transfer pump. A bounding analysis was performed by eliminating failure of the EDG fuel oil transfer pumps, which resulted in an internal and external benefit (with uncertainty) of approximately $18,687. This analysis case was used to model the benefit of Phase II SAMA 16.

Case 10: Improve AC Power

This analysis case was used to evaluate the change in plant risk from improving the 4.16-kV buses by adding cross-ties or by providing alternate feeds to essential loads directly from an alternate emergency bus. A bounding analysis was performed by eliminating the loss of the 4.16-kV buses, which resulted in an internal and external benefit (with uncertainty) of approximately $106,470. This analysis case was used to model the benefit of Phase II SAMAs 8 and 17.

Case 11: Reduce Loss of Off-Site Power During Severe Weather

This analysis case was used to evaluate the change in plant risk from burying existing or additional power lines to reduce the probability of loss of off-site power during severe weather. A bounding analysis was performed by eliminating the weather centered loss of off-site power initiating event, which resulted in an internal and external benefit (with uncertainty) of approximately $129,710. This analysis case was used to model the benefit of Phase II SAMAs 9 and 12.

Case 12: Reduce Plant-Centered Loss of Off-Site Power

This analysis case was used to evaluate the change in plant risk from reducing the loss of off-site power by protecting the transformers from explosive failure. A bounding analysis was performed by eliminating the plant centered loss of offsite power initiating event, which resulted in an internal and external benefit (with uncertainty) of approximately $1,843. This analysis case was used to model the benefit of Phase II SAMA 18.

Case 13: Redundant Power to Torus Hard Pipe Vent (THPV) Valves

This analysis case was used to evaluate the change in plant risk from adding redundant power supplies to the hard pipe direct torus vent valve control circuits. A bounding analysis was performed by setting failure of power to the hard pipe torus vent valves to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $232,320. This analysis case was used to model the benefit of Phase II SAMA 20.

Case 14: High Pressure Injection System

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of high pressure injection (e.g., installing a high pressure injection system independent of AC power, passive high pressure injection system, or additional power to the HPCI system). The proposed modification for SAMA 14 includes using an available skid mounted portable AC generator and adding electrical wall penetrations in the control building. It would also require procedure revisions, training and maintenance of the portable generator to ensure availability. A bounding analysis was performed by setting the CDF contribution due to unavailability of the HPCI system to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $905,481. This analysis case was used to model the benefit of Phase II SAMAs 14, 22, and 23.

Case 15: Extend RCIC Operation

This analysis case was used to evaluate the change in plant risk from raising or bypassing the RCIC backpressure trip set-point. A bounding analysis was performed by eliminating failures due to the RCIC backpressure trip, which resulted in an internal and external benefit (with uncertainty) of approximately $86,079. This analysis case was used to model the benefit of Phase II SAMAs 24 and 25.

Case 16: Improve ADS System

This analysis case was used to evaluate the change in plant risk from adding larger accumulators to the ADS components to increase reliability during a SBO. A bounding analysis was performed by eliminating failure of the ADS accumulators, which resulted in an internal and external benefit (with uncertainty) of approximately $0. This analysis case was used to model the benefit of Phase II SAMA 26.

Case 17: Reliability of SRVs

This analysis case was used to evaluate the change in plant risk from installing additional signals to automatically open the SRVs in an MSIV closure transient. This improvement would reduce the likelihood of SRVs failing to open, thereby reducing the consequences of LOCAs. A bounding analysis was performed by setting the probability of SRVs failing to open when required by reactor pressure vessel overpressure conditions to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $406,113. This analysis case was used to model the benefit of Phase II SAMA 27.

Case 18: Low Pressure Injection System

This analysis case was used to evaluate the change in plant risk from adding an additional low pressure injection system. A bounding analysis was performed by eliminating failure of the low pressure injection system, which resulted in an internal and external benefit (with uncertainty) of approximately $1,811,968. This analysis case was used to model the benefit of Phase II SAMA 28.

Case 19: ECCS Low Pressure Interlock

This analysis case was used to evaluate the change in plant risk from installing a bypass switch to allow operators to bypass the low reactor pressure interlock circuitry. A bounding analysis was performed by eliminating failure of the low pressure interlock circuitry in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $570,904. This analysis case was used to model the benefit of Phase II SAMA 29.

Case 20: Improve Reliability of HPCI and RCIC

This analysis case was used to evaluate the change in plant risk from improving the reliability of the HPCI and RCIC systems by upgrading their control systems. A bounding analysis was performed by eliminating failure of the HPCI and RCIC turbine driven pumps, which resulted in an internal and external benefit (with uncertainty) of approximately $125,987. This analysis case was used to model the benefit of Phase II SAMA 67.

Case 21: Main Condenser

This analysis case was used to evaluate the change in plant risk from improving steam tunnel HVAC reliability/redundancy to prevent inadvertent group 1 isolations. A bounding analysis was performed by eliminating failure of the condenser to remove heat and eliminating the group 1 isolation initiator, which resulted in an internal and external benefit (with uncertainty) of approximately $79,550. This analysis case was used to model the benefit of Phase II SAMA 76.

Case 22: Improve Reliability of ECCS Equipment

This analysis case was used to evaluate the change in plant risk from improving reliability of auto-start features for the ECCS equipment. A bounding analysis was performed by eliminating the failure of the auto-start features for the ECCS equipment, which resulted in an internal and external benefit (with uncertainty) of approximately $27,895. This analysis case was used to model the benefit of Phase II SAMA 77.

Case 23: Improve Injection Via Fire Water System

This analysis case was used to evaluate the change in plant risk from improving training on alternate injection via fire water system. A bounding analysis was performed by reducing operator actions that could be improved via training for alternate injection via the fire water system by a factor of 2, which resulted in an internal and external benefit (with uncertainty) of approximately $157,816. This analysis case was used to model the benefit of Phase II SAMA 78.

Case 24: RHR Heat Exchangers

This analysis case was used to evaluate the change in plant risk from revising procedures to allow manual alignment of the fire water system to RHR heat exchangers. A bounding analysis was performed by eliminating failure of the SW to provide cooling to the RHR heat exchangers, which resulted in an internal and external benefit (with uncertainty) of approximately $599,907. This analysis case was used to model the benefit of Phase II SAMA 30.

Case 25: Emergency Service Water System Reliability

This analysis case was used to evaluate the change in plant risk from installing an additional service water pump. A bounding analysis was performed by setting the events for the common cause contribution due to service water system pumps to zero in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $9,456. This analysis case was used to model the benefit of Phase II SAMA 31.

Case 26: Reduce Valve Failure, Fire Water System

This analysis case was used to evaluate the change in plant risk from enhancing alternate injection reliability by including the fire water cross-tie valves in the maintenance program. A bounding analysis was performed by eliminating the CDF contribution due to the fire water cross-tie valves, which resulted in an internal and external benefit (with uncertainty) of approximately $1,073. This analysis case was used to model the benefit of Phase II SAMA 32.

Case 27: Alternate Water Supply for the TEC Heat Exchangers

This analysis case was used to evaluate the change in plant risk from proceduralizing the ability to cross-connect the circulating water pumps with the service water going to the turbine equipment cooling (TEC) heat exchangers. A bounding analysis was performed by eliminating failure of service water to provide cooling to the TEC heat exchangers, which resulted in an internal and external benefit (with uncertainty) of approximately $533,364. This analysis case was used to model the benefit of Phase II SAMA 68.

Case 28: Increase Availability of Feedwater and Condensate

This analysis case was used to evaluate installation of emergency connections of existing or alternate water sources to feedwater/condensate. A bounding analysis was performed by eliminating the CDF contribution due to failure of alternate injection from feedwater/condensate, which resulted in an internal and external benefit (with uncertainty) of approximately $1,295,174. This analysis case was used to model the benefit of Phase II SAMA 33.

Case 29: Main Feedwater System Reliability

This analysis case was used to evaluate the change in plant risk from installing a motor-driven feedwater pump. A bounding analysis was performed by setting failure of the feedwater turbine driven pumps to zero, which resulted in an internal and external benefit (with uncertainty) of approximately $267. This analysis case was used to model the benefit of Phase II SAMA 34.

Case 30: Increase Availability of the CST

This analysis case was used to evaluate the change in plant risk from providing a means of automatically preventing draindown of the CST to the hotwell during a SBO. A bounding analysis was performed by eliminating the CDF contribution from operator failure to prevent CST inventory drain-down to the hotwell, which resulted in an internal and external benefit (with uncertainty) of approximately $62,671. This analysis case was used to model the benefit of Phase II SAMA 72.

Case 31: Increase Availability of Room Cooling

This analysis case was used to evaluate the change in plant risk from providing a redundant means of ventilation to the CS pump rooms, RHR pump rooms, RHRSW booster pump rooms, SW pump rooms, or HPCI pump room. Room cooling to each of the rooms was eliminated individually. The RHRSW booster pump rooms had the largest benefit. Therefore, a bounding analysis was performed by eliminating failure of room cooling to the RHRSW booster pump rooms [basic event HVC-PHE-FF-CB7A was set to zero], which resulted in an internal and external benefit (with uncertainty) of approximately $115,493. This analysis case was used to model the benefit of Phase II SAMA 35.

Case 32: Increase Availability of the EDG System

This analysis case was used to evaluate the change in plant risk from installing a diverse set of fan actuation logic, installing an additional fan and louver pair, adding a diesel building high temperature alarm, or operator procedure revisions to provide additional space cooling to the EDG room. A bounding analysis was performed by eliminating failure of EDG HVAC, which resulted in an internal and external benefit (with uncertainty) of approximately $99,480. This analysis case was used to model the benefit of Phase II SAMAs 36, 38, 39, and 40.

Case 33: Improve Diagnosis of a Loss of Switchgear HVAC

This analysis case was used to evaluate the change in plant risk from adding a switchgear room high temperature alarm. A bounding analysis was performed by eliminating failure of room cooling to the critical switchgear rooms in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $0. This analysis case was used to model the benefit of Phase II SAMA 37.

Case 34: Increase Reliability of Instrument Air

This analysis case was used to evaluate the change in plant risk from improving the reliability of the instrument air system, by modifying procedures to allow alignment of diesel power to more air compressors, by replacing the compressors with more reliable models, or by using a portable compressor. A bounding analysis was performed by eliminating failure of the instrument air compressors in the level 1 PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $499,350. This analysis case was used to model the benefit of Phase II SAMAs 41, 42, and 45.

Case 35: Extend SRV Operation Time

This analysis case was used to evaluate the change in plant risk from installing nitrogen bottles as backup gas supply for safety relief valves. A bounding analysis was performed by eliminating the failure of loss of nitrogen and air to the SRVs, which resulted in an internal and external benefit (with uncertainty) of approximately $0. This analysis case was used to model the benefit of Phase II SAMA 43.

Case 36: Improve Availability of SRVs and MSIVs

This analysis case was used to evaluate the change in plant risk from improving SRV and MSIV pneumatic components. A bounding analysis was performed by eliminating failure of nitrogen, air, and accumulators for the SRVs and MSIVs, which resulted in an internal and external benefit (with uncertainty) of approximately $574,974. This analysis case was used to model the benefit of Phase II SAMA 44.

Case 37: Decay Heat Removal Capability, Torus Cooling

This analysis case was used to evaluate the change in plant risk from installing an additional decay heat removal system or upgrading the existing decay heat removal system for torus cooling. Enhancements of decay heat removal capability decrease the consequences of loss of containment heat removal. The system upgrade recommended in SAMA 71 would require new penetrations, piping, valves, heat exchanger, cooling capability and increased storage in the radwaste system. The additional means of suppression pool cooling recommended in SAMA 73 would involve installation of a chiller in the yard with piping and valves installed with penetrations through the reactor building. A heat exchanger would be required in the reactor building to transfer heat from the torus water to the chiller water. Pipe penetrations would be needed on the torus to allow for water circulation to the heat exchanger. A bounding analysis was performed by setting the events for loss of the torus cooling mode of the RHR and RHRSW systems to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $1,122,355. This analysis case was used to model the benefit of Phase II SAMAs 46, 71, and 73.

Case 38: Decay Heat Removal Capability, Drywell Spray

This analysis case was used to evaluate the change in plant risk from installing an additional decay heat removal system for drywell sprays. Enhancements of decay heat removal capability decrease the probability of loss of containment heat removal. A bounding analysis was performed by setting the events for loss of the drywell sprays mode of the RHR and RHRSW systems to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $957,021. This analysis case was used to model the benefit of Phase II SAMA 47.

Case 39: Filtered Vent

This analysis case was used to evaluate the change in plant risk from installing a filtered containment vent or to enhance the fire protection system/standby gas treatment system hardware and procedures to provide fission product scrubbing. A bounding analysis was performed by reducing the baseline accident progression source terms by a factor of 2 (excluding noble gases) to reflect the additional filtered capability. Reducing the releases from the vent path resulted in an internal and external benefit (with uncertainty) of approximately $267,367. This analysis case was used to model the benefit of Phase II SAMAs 48 and 49.

Case 40: Controlled Containment Venting

This analysis case was used to evaluate the change in plant risk from changing the containment venting procedure to establish a narrow pressure control band. This would prevent rapid containment depressurization when venting, thus avoiding adverse impact on the ability of the low pressure ECCS injection systems to take suction from the torus. A bounding analysis was performed by eliminating operator failure to control the venting evolution in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $106. This analysis case was used to model the benefit of Phase II SAMA 50.

Case 41: Vacuum Breakers

This analysis case was used to evaluate the change in plant risk from improving the reliability of vacuum breakers by installing redundant valves in each line. A bounding analysis was performed by setting the vacuum breaker failure probability to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $68,671. This analysis case was used to model the benefit of Phase II SAMA 51.

Case 42: Passive Containment Overpressure Relief

This analysis case was used to evaluate the change in plant risk from providing a passive containment overpressure relief pathway during severe accidents. This SAMA will prevent catastrophic failure of the containment by controlled relief through a selected vent path, which has a greater potential for reducing the release of radioactive material than through a random break. A bounding analysis was performed by eliminating hard pipe vent failure in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $383,762. This analysis case was used to model the benefit of Phase II SAMAs 52 and 53.

Case 43: Barriers to Block Debris from Reaching the Steel Shell

This analysis case was used to evaluate the change in plant risk from installing a curb to prevent debris from spreading across the floor and contacting the shell. A bounding analysis was performed by eliminating the CDF contribution due to failure of the DW barriers to prevent debris from contacting the shell, which resulted in an internal and external benefit (with uncertainty) of approximately $682,341. This analysis case was used to model the benefit of Phase II SAMA 70.

Case 44: ISLOCA

This analysis case was used to evaluate the change in plant risk from reducing the probability of an ISLOCA by increasing the frequency of valve leak testing or improving ISLOCA identification or coping. A bounding analysis was performed by setting the ISLOCA initiators to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $25,669. This analysis case was used to model the benefit of Phase II SAMAs 54, 56, and 57.

Case 45: MSIV Design

This analysis case was used to evaluate the change in plant risk from improving MSIV design to decrease the likelihood of containment bypass scenarios. A bounding analysis was performed by eliminating failure of the MSIVs to close or remain closed, which resulted in an internal and external benefit (with uncertainty) of approximately $8,169. This analysis case was used to model the benefit of Phase II SAMA 55.

Case 46: SLC System

This analysis case was used to evaluate the change in plant risk from increasing boron concentration in the SLC system. A bounding analysis was performed by eliminating the contribution due to failure to initiate SLC and failures due to the boron concentration being too low in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $37,086. This analysis case was used to model the benefit of Phase II SAMA 58.

Case 47: Improve Availability of Boron Injection

This analysis case was used to evaluate the change in plant risk from providing an additional method of boron injection (e.g., add an independent boron injection system or use CRD for alternate boron injection). A bounding analysis was performed by eliminating failure of the SLC system in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $67,455. This analysis case was used to model the benefit of Phase II SAMAs 59 and 60.

Case 48: SRV Reseat

This analysis case was used to evaluate the change in plant risk from improving the reliability of the SRVs to reseat to address the risk associated with boron dilution. A bounding analysis was performed by setting failure of the SRVs to reseat to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $32,202. This analysis case was used to model the benefit of Phase II SAMA 61.

Case 49: Internal Flooding

This analysis case was used to evaluate the change in plant risk from improving internal flooding procedures. A bounding analysis was performed by eliminating operator failures related to flood mitigation in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $51,711. This analysis case was used to model the benefit of Phase II SAMA 62.

Case 50: Fire Water Pipe Break

This analysis case was used to evaluate the change in plant risk from providing flow diversion to help mitigate the fire water pipe break in the control building ground floor corridor. A bounding analysis was performed by eliminating failure to isolate the large and medium fire water pipe breaks in the control building ground floor corridor, which resulted in an internal and external benefit (with uncertainty) of approximately $6,108. This analysis case was used to model the benefit of Phase II SAMA 74.

Case 51: Increase Reliability of the Fire Water System

This analysis case was used to evaluate the change in plant risk from upgrading the seismic capacity of the diesel fire pump fuel tank and water supply tank or proceduralizing the use of a fire pumper truck to pressurize the fire water system. A bounding analysis was performed by eliminating failure of the diesel-driven fire pump in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $82,395. This analysis case was used to model the benefit of Phase II SAMAs 64 and 69.

Case 52: Add Fire Suppression

This analysis case was used to evaluate the change in plant risk from adding automatic fire suppression systems to the dominant fire zones. The dominant fire zones reported in the IPEEE for CNS are the control room, switchgear rooms, and SW pump room. The control room has no automatic suppression system. The switchgear rooms have no automatic suppression system. The SW pump room has an automatic suppression system which is a total flooding halon system.

For the main control room, an automatic suppression system would not provide a significant safety benefit. The sensing devices used for fires include both fuse elements that melt given high temperature and smoke detectors. These types of actuation devices would only actuate after the fire has progressed to a point that would cause evacuation of the control room. Even if the auto suppression system actuated prior to evacuation, the consequences of actuation would require evacuation. Halon or CO_2 systems would asphyxiate any personnel remaining in the main control room and water would damage the control equipment. Given that the main control room fire risk is dominated by failure to shut down the reactor from outside the control room, extremely limited benefit is judged to exist for auto suppression systems in the main control room.

A bounding analysis was performed as described below, which resulted in an internal and external benefit (with uncertainty) of approximately $347,908. This analysis case was used to model the benefit of Phase II SAMA 63.

SAMA analysis case 52 (adding automatic fire suppression systems to the critical switchgear rooms) is an external events SAMA, which would not mitigate internal event risk. A bounding analysis was performed by assuming the SAMA would eliminate the contribution to fire CDF from fires in the critical switchgear rooms. Since the total fire CDF is 1.93E-05/yr [Table E.1-11] and the critical switchgear rooms fire CDF is 1.11E-06 + 2.72E-06 = 3.83E-06/yr, fires in the critical switchgear rooms contribute 19.84% of the total fire CDF.

The internal events model cannot be used to assess the benefit from this external event SAMA. However, the consequences resulting from fire-induced core damage and internal event-induced core damage would be comparable. Since we have already estimated the maximum benefit from removing all internal event risk, the maximum benefit of removing all fire risk was estimated by reducing the maximum internal event benefit by the ratio of the total fire CDF to the internal event CDF. Since SAMA analysis case 52 would eliminate 19.84% of the total fire risk, the benefit for SAMA analysis case 52 was estimated to be 19.84% of the total fire benefit as shown below.

Given,

Maximum internal benefit is $351,319

Total fire CDF = 1.93E-05/rx-yr [Table E.1-11]

Internal events CDF = 1.16E-05/rx-yr

Maximum fire benefit = Maximum internal benefit x Total fire CDF/Internal events CDF

Maximum fire benefit = $351,319(1.93E-5/1.16E-5)

SAMA case 52 benefit = 19.84% x (Maximum fire benefit) = 0.1984 x $351,319(1.93E-5/1.16E-5)

SAMA case 52 benefit = $115,969

Applying the uncertainty factor of 3,

SAMA case 52 benefit with uncertainty = $115,969 x 3 = $347,908.

Case 53: Reduce Risk from Fires that Require Control Room Evacuation

This analysis case was used to evaluate the change in plant risk from upgrading the ASDS panel to include additional system controls for division I equipment. A bounding analysis was performed as described below, which resulted in an internal and external benefit (with uncertainty) of approximately $338,964. This analysis case was used to model the benefit of Phase II SAMA 65.

SAMA analysis case 53 (Reduce Risk from Fires that Require Control Room Evacuation) is an external events SAMA, which would not mitigate internal event risk. A bounding analysis was performed by assuming the SAMA would eliminate the contribution to fire CDF from fires in the control room. Since the total fire CDF is 1.93E-05/yr [Table E.1-11] and the control room fire CDF is 3.73E-06, fires in the control room contribute 19.33% of the total fire CDF.

The internal events model cannot be used to assess the benefit from this external event SAMA. However, the consequences resulting from fire-induced core damage and internal event-induced core damage would be comparable. Since we have already estimated the maximum benefit from removing all internal event risk, the maximum benefit of removing all fire risk was estimated by reducing the maximum internal event benefit by the ratio of the total fire CDF to the internal event CDF. Since SAMA analysis case 53 would eliminate 19.33% of the total fire risk, the benefit for SAMA analysis case 53 was estimated to be 19.33% of the total fire benefit as shown below.

Given,

Maximum internal benefit is $351,319

Total fire CDF = 1.93E-05/rx-yr [Table E.1-11]

Internal events CDF = 1.16E-05/rx-yr

Maximum fire benefit = Maximum internal benefit x Total fire CDF/Internal events CDF

Maximum fire benefit = $351,319(1.93E-5/1.16E-5)

SAMA case 53 benefit = 19.33% x (Maximum fire benefit) = 0.1933 x $351,319(1.93E-5/1.16E-5)

SAMA case 53 benefit = $112,988

Applying the uncertainty factor of 3,

SAMA case 53 benefit with uncertainty = $112,988 x 3 = $338,964

Case 54: Large Break LOCA

This analysis case was used to evaluate the change in plant risk from installing a digital large break LOCA (LBLOCA) protection system. A bounding analysis was performed by setting the LBLOCA initiators to zero in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $57,704. This analysis case was used to model the benefit of Phase II SAMA 66.

Case 55: Trip/Shutdown Risk

This analysis case was used to evaluate the change in plant risk from including Generation Risk Assessment (trip and shutdown risk modeling) in plant activities. It is assumed that this would reduce the frequency of plant trips and shutdowns. A bounding analysis was performed by reducing all initiating events except pipe breaks, floods, and LOOP by a factor of 2, which resulted in an internal and external benefit (with uncertainty) of approximately $1,183,332. This analysis case was used to model the benefit of Phase II SAMA 75.

Case 56: Improve RHRSW System

This analysis case was used to evaluate the change in plant risk from modifying procedures to allow use of the RHRSW system without a SWBP. A bounding analysis was performed by eliminating failure to use the RHRSW system without a SWBP, which resulted in an internal and external benefit (with uncertainty) of approximately $331,699. This analysis case was used to model the benefit of Phase II SAMA 79.

Case 57: Improve Plant Identification of Reference Leg Leakdowns

This analysis case was used to evaluate the change in plant risk from installing additional instrumentation to assist in identifying a reference leg leakdown. A bounding analysis was performed by eliminating failure of cognitive recognition of a leakdown of the reference legs in the PSA model, which resulted in an internal and external benefit (with uncertainty) of approximately $15,917. This analysis case was used to model the benefit of Phase II SAMA 80.

E.2.4 Sensitivity Analyses

Two sensitivity analyses were conducted to gauge the impact of assumptions upon the analysis. The benefits estimated for each of these sensitivities are presented in Table E.2-3.

A description of each sensitivity case follows.

Sensitivity Case 1: Years Remaining Until End of Plant Life

The purpose of this sensitivity case was to investigate the sensitivity of assuming a 26-year period for remaining plant life (i.e., six years on the original plant license plus the 20-year license renewal period), rather than the 20-year license renewal period used in the base case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

Sensitivity Case 2: Conservative Discount Rate

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the discount rate. The discount rate of 7.0% used in the base case analyses is conservative relative to corporate practices. Nonetheless, a lower discount rate of 3.0% was assumed in this case to investigate the impact on each analysis case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

E.2.5 References

E.2-1 NEI 05-01, "Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document," Revision A, November 2005.

E.2-2 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding James A. FitzPatrick Nuclear Power Plant,* Supplement 31, Final Report, January 2008.

E.2-3 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Vermont Yankee Nuclear Power Station*, Supplement 30, Final Report, August 2007.

E.2-4 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Pilgrim Nuclear Power Station*, Supplement 29, Final Report, July 2007.

E.2-5 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Oyster Creek Nuclear Generating Station*, Supplement 28, Final Report, January 2007.

E.2-6 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Monticello Nuclear Generating Plant*, Supplement 26, Final Report, August 2006.

E.2-7 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Brunswick Steam Electric Plant, Units 1 and 2*, Supplement 25, Final Report, April 2006.

E.2-8 U.S. Nuclear Regulatory Commission, NUREG-1742, *Perspectives Gained From the Individual Plant Examination of External Events (IPEEE) Program*, Volumes 1 & 2, Final Report, April 2002.

E.2-9 "Cooper Nuclear Station Probabilistic Risk Assessment (IPE) Level 1 and Level 2," March 1993.

E.2-10 Nebraska Public Power District, "Cooper Nuclear Station Individual Plant Examination for External Events," October 1996, Revision 0.

E.2-11 U.S. Nuclear Regulatory Commission, NUREG/BR-0184, *Regulatory Analysis Technical Evaluation Handbook*, January 1997.

E.2-12 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Peach Bottom Atomic Power Station, Units 2 and 3*, Supplement 10, Final Report, January 2003.

E.2-13 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Supplement 16 Regarding Quad Cities Nuclear Power Station, Units 1 and 2*, Supplement 16, June 2004.

E.2-14 Attachment E, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal for the Susquehanna Steam Electric Station, September 2006.

E.2-15 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Browns Ferry Nuclear Plant, Units 1, 2, and 3*, Supplement 21, Final Report, June 2005.

E.2-16 Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal for the Brunswick Steam Electric Plant, October 2004.

E.2-17 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Nine Mile Point Nuclear Station, Units 1 and 2*, Supplement 24, Final Report, May 2006.

Table E.2-1
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
61	Modify automatic depressurization system components to improve reliability.	Reduced frequency of high pressure core damage sequences.	Retain (Phase II SAMA 26)	The CNS SRVs use an electro-pneumatic control system for automatic depressurization. Two redundant 125 VDC power supplies power a solenoid-operated pilot valve that controls pneumatic pressure to an activator valve, which in turn operates the SRV. Each SRV has a dedicated accumulator tank sized for approximately five actuations of its associated SRV against atmospheric pressure or two actuations against 70 percent of drywell design pressure. This SAMA is being retained to add larger accumulators, thus increasing reliability during SBOs.
67	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	Already installed	The CNS diesel-driven fire pump can be used for alternate injection.
120	Cross-tie open cycle cooling system to enhance drywell spray system.	Increased availability of containment heat removal.	Already installed	CNS has an RHR/RHRSW crosstie that can be aligned for vessel injection flow and for drywell spray header flow. This would use the untreated water from the RHRSW loops.
123	Install a passive drywell spray system.	Improved drywell spray capability.	Retain (Phase II SAMA 47)	CNS does not contain a passive drywell spray system.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
124	Use the fire water system as a backup source for the drywell spray system.	Improved drywell spray capability.	Already installed	This operator action is taken in the event that containment heat removal via the RHR system (suppression pool cooling and drywell spray) is unavailable.
182	Modify safety-related condensate storage tanks	Improved availability of ECSTs following a seismic event and reduced potential for flooding from ECSTs following a seismic event.	Already installed	Emergency condensate storage tanks (CM-TK-ECSA, B) were evaluated and determined to be acceptable for the 0.3g RLE, without modification.
203	Increase training and operating experience feedback to improve operator response.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Already installed	Operator response has been a focus at CNS over the past decade. Training has been improved and training reference materials and procedures have been updated in an ongoing effort to improve operator reliability.
206	Develop a procedure outlining improved battery loading schemes associated with a load study demonstrating potential extended battery life.	Improved availability of DC power system.	Already installed	DC load-shedding procedures are in place to increase the probability of successful load shed under SBO conditions.
207	Develop a procedure to bypass the AC solenoid valve on the nitrogen supply to the SRVs.	Reduced failure to depressurize during station blackout scenarios.	Already installed	Actions to bypass the AC solenoid valve on the nitrogen supply to the SRVs have been implemented in procedure 2.3_9.3.1 page 45.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
208	Improve the reliability of the HPCI and RCIC systems by upgrading their control systems.	Improved reliability of HPCI and RCIC systems.	Retain (Phase II SAMA 67)	A sensitivity study using the 1997 PSA model showed a 16% decrease in both CDF and LERF. Improvement was not implemented because existing risk estimates did not present an outlier in the industry and no associated vulnerability was identified.
209	Enhance the reactor pressure vessel depressurization system reliability.	Reduced frequency of high pressure core damage sequences.	N/A	A sensitivity study using the 1997 PSA model showed a CDF reduction of 1% and the LERF was unaffected. Due to the low CDF contribution this SAMA has been determined not to be cost beneficial.
210	Provide a backup for the service water pumps via equipment modifications and procedure changes.	Continued use of the power conversion system after service water is lost.	Similar item is addressed under other proposed SAMAs	See Phase I SAMA 212 (Phase II SAMA 68).
211	Provide a low pressure source of cooling water (i.e., diesel fire water pump) which is not dependent on AC power.	Extended recovery time during station blackout scenarios.	Already Installed	The CNS diesel-driven 3000 gpm fire pump can be used for alternate injection.
212	Proceduralize the ability to cross-connect the circulating water pumps and the service water going to the turbine equipment cooling (TEC) heat exchangers.	Continued use of the power conversion system after service water is lost.	Retain (Phase II SAMA 68)	A sensitivity study using the 1997 PSA model showed a 3% decrease for CDF and no change in LERF.

**Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights**

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
213	Provide an alternate water supply for the drywell spray.	Increased availability of containment heat removal.	Similar item is addressed under other proposed SAMAs	A sensitivity study using the 1997 PSA model showed a LERF reduction of 19%, but this impact was considered to be significantly reduced by the EOP revisions in Phase I SAMA 215 since the latest EPGs have added cues to increase the probability that drywell sprays will be actuated for the mitigation of core melt progression. See Phase II SAMA 47.
214	Provide alternate cooling in the HPCI quad room.	Increased availability of the HPCI system.	Similar item is addressed under other proposed SAMAs	See Phase I SAMA 101 (Phase II SAMA 35).
215	Upgrade emergency operating procedures (EOP's) to the latest revision of the Boiling Water Reactor Owners Group Emergency Procedure Guidelines (EPG's).	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Already installed	The CNS EOP's incorporated Rev. 4 of the EPG's around the time the IPE was being performed. CNS has also incorporated the latest revision of the EPG's and reviews every new revision of the EPG's.
216	Implement emergency procedures and training.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Already Installed	See Phase I SAMA 215.
217	Upgrade relays identified as outliers in the A-46 program.	Increased reliability of relays that may chatter at low seismic levels.	N/A	The ten relays identified as potential outliers in the A-46 program were resolved analytically.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
218	Relocate or upgrade anchorage for equipment located adjacent to control room panels.	Increased availability of control room panels following a seismic event.	Already installed	Control room ceiling diffusers were secured to the supporting grid using plastic ties. Procedure 7.2.79, Securing Control Room Ceiling Diffuser Panels, ensures the ties are replaced when ceiling panels are removed for periodic maintenance. Outlier cabinets, a table, and a copier were resolved by increasing anchorage or by removing the items.
219	Eliminate the interaction hazard vulnerability caused by the concrete beam and hanging lights near 480V control switchgear 1G.	Increased reliability of essential relays in 480V control switchgear 1G.	Already installed	Outliers were resolved by attaching a brace between the switchgear and the concrete beam to prevent pounding, and relocating the lights.
220	Remove potential seismic interaction hazards from transformers EE-XFMR-RPS1A and B.	Improved reliability of EE-XFMR-RPS1A and B during a seismic event.	N/A	Outlier resolved analytically. Further evaluation determined that these transformers are not required to achieve and maintain hot shutdown for 72 hours. Thus, they were removed from the safe shutdown equipment list.
221	Eliminate the interaction hazard with adjacent rack posed on jet pump instrument rack A (LRP-PNL-{25-51}).	Improved reliability of jet pump instrument rack A during a seismic event.	N/A	Outlier resolved analytically. Further evaluation showed that the gap between the jet pump instrument rack and the adjacent rack is sufficient to preclude interaction.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
222	Eliminate the interaction hazard vulnerability of the auxiliary relay room panels (LRP-PNL-9-32, 33, 41, 42, 45) which contain a significant number of essential (chatter-sensitive) relays.	Improved reliability of auxiliary relay room panels LRP-PNL-9-32, 33, 41, 42, and 45 during a seismic event.	Already installed	Outlier resolved by upgrading anchorage of auxiliary relay room panels LRP-PNL-9-32, 33, 41, 42, and 45.
223	Upgrade the braced Unistrut trapeze frame (hanger 89) in the NE corner of elevation 903' of the reactor building (suspended from elevation 931')	Improved reliability of hanger 89 during a seismic event.	Already installed	Outlier was resolved by upgrading hanger 89 anchorage and evaluating the surrounding similar hangers.
224	Upgrade seismic capacity of the SE and NE quad recirculation fans (HV-FAN-FC-R-1E and F).	Improved availability of the vibration-isolated air handling systems following a seismic event.	N/A	Outlier resolved analytically. Further evaluation determined that HV-FAN-FC-1E and F are not required to achieve and maintain hot shutdown for 72 hours. Thus, they were removed from the safe shutdown equipment list.
225	Upgrade seismic capacity of service water pump B&D strainer control panel (LRP-PNL-S192) by tightening loose bolt securing one corner of interior panel.	Improved seismic capacity of service water pump B&D strainer control panel (LRP-PNL-S192).	Already installed	Minor maintenance item was resolved by tightening the loose bolt securing one corner of the service water pump B&D strainer control panel.
226	Upgrade seismic capacity of hanger 144 in the cable spreading room which has cross pieces overstressed in dead weight.	Improved seismic capacity of hanger 144.	N/A	Outlier resolved analytically. Further evaluation determined that gross failure of the hanger will not occur following a seismic event.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
227	Upgrade seismic capacity of the recirculation pump motor generator set lube oil cooler heat exchangers.	Reduced potential for release of combustible fluid following a seismic event.	N/A	Outlier resolved analytically. The Fire IPEEE considered this source of oil in its evaluation of the fire area. The fire area screened with a fire CDF of < 1E-6/yr. Therefore, the benefit from this improvement is not considered adequate to justify the cost of potential modifications.
228	Upgrade the seismic capacity of the diesel fire pump fuel tank and water supply tank.	Improved availability of water-based fire protection following a seismic event.	Retain (Phase II SAMA 69)	The water-based fire protection systems are vulnerable to a seismic event because the electric fire pumps are dependent on offsite power and the diesel fire pump is dependent on its fuel tank and water supply tank, both of which have seismic vulnerability. Upgrading the seismic capacity of the tanks would decrease the vulnerability.
229	Install additional features to allow control of switchyard breakers remote from control room board C and vertical board F, or have a pre-planned recovery/repair action for control of the switchyard breakers following a fire that completely disables the control room boards.	Allows for control of switchyard breakers following a control room fire that completely disables board C and vertical board F.	N/A	Further evaluation concluded that this improvement would result in less than a 0.5% decrease in overall plant CDF. The minor reduction in overall plant CDF is not considered adequate to justify the cost of potential modifications.

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE and IPEEE Insights

Phase I SAMA ID number	SAMA Title	Result of Potential Enhancement	Screening Results	SAMA Disposition
230	Provide the service water system with water supplies that are diverse from pumps in the service water pump room.	Improved availability of the service water system following a fire in the pump house that disables all the service water pumps.	Similar item is addressed under other proposed SAMAs	See Phase I SAMAs 210 and 212 (Phase II SAMA 68).
231	Reduce the potential vulnerability of the control building to a lightning induced loss of offsite power that also affects the station batteries.	Reduced probability of a lightning induced non-recoverable loss of offsite power.	N/A	Further evaluation concluded that the control building is not vulnerable to a lightning induced loss of offsite power that also affects the station batteries.
232	Protect the diesel generator exhaust system from postulated tornado-generated missiles.	Improved availability of the EDG system.	Already installed	A modification completed in 1998 removed the diesel generator muffler bypass valves, thereby eliminating the failure mode and significantly improving protection of the diesel generator exhaust system from tornado generated missiles.

Table E.2-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
DC Power	Changed the time available to recover offsite power before HPCI and RCIC are lost to 24 hours during station blackout scenarios in the level 1 PSA model.	3.14%	2.80%	3.00%	$32,279	$96,836		
1 - Provide additional DC battery capacity.	The cost for implementing this SAMA was specifically estimated for Pilgrim and FitzPatrick.						$500,000	Not cost effective
2 - Replace lead-acid batteries with fuel cells.	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$1,000,000	Not cost effective
13 - Portable generator for DC power to supply the battery chargers.	The cost for implementing this SAMA was specifically estimated for Susquehanna.						$203,000	Not cost effective
21-Modify plant procedures to allow use of a portable power supply for battery chargers.	Part of SAMA 13						Part of SAMA 13 cost estimate	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve Charger Reliability	The common cause failure contribution due to loss of DC battery chargers to zero in the level 1 PSA model.	0.34%	0.00%	0.00%	$2,339	$7,018		
3 - Add battery charger to existing DC system.	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$90,000	Not cost effective
15 - Proceduralize battery charger high-voltage shutdown circuit inhibit.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$50,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Add DC System Cross-ties	The 250V DC buses were set to zero in the level 1 PSA model.	0.00%	0.00%	0.00%	$0	$0		
4 - Provide DC bus cross-ties [The 125V distribution panels and starter racks can be powered from either bus, thus the 125V buses are cross-tied. However the 250V buses are not cross-tied].	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$300,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve Existing DC System Cross-ties	The failure of the 125V DC bus cross-tie was set to zero in the level one PSA model.	0.29%	0.00%	0.00%	$1,999	$5,997		
19 - Modify plant procedures to use DC bus cross-ties [This SAMA will enhance procedures to use the existing 125V DC bus cross-ties].	The cost for implementing this SAMA was specifically estimated for Pilgrim.						$25,000	Not cost effective
Provide Backup DC Power to the 120 V Vital AC Bus	Eliminate the failure of DC power to the NBPP.	0.07%	0.00%	0.00%	$465	$1,395		
5 - Provide additional DC power to the 120/240V vital AC system.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Availability of the 120 V Vital AC Bus	The time available to recover offsite power before HPCI and RCIC are lost was changed to 24 hours during station blackout scenarios in the level 1PSA model.	0.00%	0.00%	0.00%	$0	$0		
6 - Add an automatic feature to transfer the 120V vital AC bus from normal to standby power.	The cost for implementing this SAMA was specifically estimated for Pilgrim, Vermont Yankee, and FitzPatrick.						$500,000	Not cost effective
Increase Availability of On-Site AC Power	The contribution of the EDGs was set to zero in the level 1 PSA model.	13.06%	14.02%	14.27%	$141,672	$425,016		
7 - Provide an additional diesel generator.	The cost for implementing this SAMA was specifically estimated for Monticello.						$20,000,000	Not cost effective
10 - Install a gas turbine generator.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$2,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Provide Backup EDG SW Cooling	Eliminate failure of SW cooling to the EDGs.	4.71%	3.27%	3.42%	$44,738	$134,213		
11 - Add a new backup source of diesel cooling.	The cost for implementing this SAMA was specifically estimated for Browns Ferry.						$2,000,000	Not cost effective
Increase EDG Reliability	Eliminate failure of the EDG fuel oil transfer pumps.	0.58%	0.47%	0.71%	$6,229	$18,687		
16 - Provide a portable EDG fuel oil transfer pump.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$100,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve AC Power	Eliminate the loss of the 4.16-kV buses.	2.62%	4.67%	4.85%	$35,490	$106,470		
8 - Improve 4.16-kV bus cross-tie ability.	The cost for implementing this SAMA was specifically estimated for Susquehanna.						$656,000	Not cost effective
17 - Provide alternate feeds to essential loads directly from an alternate emergency bus.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$217,388	Not cost effective
Reduce Loss of Off-Site Power During Severe Weather	Eliminate the weather centered loss of off-site power initiating event.	4.26%	3.74%	3.85%	$43,237	$129,710		
9 - Install an additional, buried off-site power source.	The cost for implementing this SAMA was specifically estimated for CNS.						$2,485,000	Not cost effective
12 - Bury off-site power lines.	The cost for implementing this SAMA was specifically estimated for CNS.						$1,140,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Reduce Plant-Centered Loss of Off-Site Power	Eliminate the plant centered loss of offsite power initiating event.	0.09%	0.00%	0.00%	$614	$1,843		
18 - Protect transformers from failure.	The cost for implementing this SAMA was specifically estimated for Oyster Creek.						$780,000	Not cost effective
Redundant Power to Torus Hard Pipe Vent (THPV) Valves	Set failure of power to the hard pipe torus vent valves to zero in the PSA model.	4.16%	13.08%	13.55%	$77,440	$232,320		
20 - Provide redundant power to direct torus hard pipe vent valves to improve the reliability of the direct torus vent valves and enhance the containment heat removal capability.	The cost for implementing this SAMA was specifically estimated for CNS.						$714,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
High Pressure Injection System	Set the CDF contribution due to unavailability of the HPCI system to zero in the level 1 PSA model.	31.93%	22.43%	22.40%	$301,827	$905,481		
14 - Portable generator for DC power to supply the individual panels.	The cost for implementing this SAMA was specifically estimated for CNS.						$714,000	Retain
22 - Install an independent active or passive high pressure injection system.	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$1,000,000	Not cost effective
23 - Provide an additional high pressure injection pump with independent diesel.	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$1,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Extend RCIC Operation	Eliminate failures due to the RCIC backpressure trip.	3.93%	0.47%	0.43%	$28,693	$86,079		
24 - Raise HPCI/ RCIC backpressure trip set points [HPCI backpressure trip setpoint has already been raised. This SAMA will evaluate raising the RCIC backpressure trip set point].	The cost for implementing this SAMA was specifically estimated for CNS.						>200K	Not cost effective
25 - Revise procedure to allow bypass of RCIC turbine exhaust pressure trip [This SAMA will revise EOP 5.8.20 to give direction to allow bypass of RCIC turbine exhaust pressure trip].	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve ADS System	Eliminate failure of the ADS accumulators.	0.00%	0.00%	0.00%	$0	$0		
26 - Modify automatic depressurization system components to improve reliability [This SAMA will add larger accumulators thus increasing reliability during SBOs].	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Reliability of SRVs	Set the probability of SRVs failing to open when required by reactor pressure vessel overpressure conditions to zero in the level 1 PSA model.	19.17%	0.93%	0.86%	$135,371	$406,113		
27 - Add signals to open safety relief valves automatically in an MSIV closure transient.	The cost for implementing this SAMA was specifically estimated for Pilgrim and Vermont Yankee.						$1,500,000	Not cost effective
Low Pressure Injection System	Eliminate failure of the low pressure injection.	54.58%	62.66%	62.34%	$603,989	$1,811,968		
28 - Add a diverse low pressure injection system.	The cost for implementing this SAMA was specifically estimated for Monticello.						$8,800,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
ECCS Low Pressure Interlock	Eliminate failure of the low pressure interlock circuitry in the level 1 PSA model.	24.47%	6.07%	5.85%	$190,301	$570,904		
29 - Install a bypass switch to allow operators to bypass the low reactor pressure interlock circuitry.	The cost for implementing this SAMA was specifically estimated for Pilgrim and Vermont Yankee.						$1,000,000	Not cost effective
Improve Reliability of HPCI and RCIC	Eliminate failure of the HPCI and RCIC turbine driven pumps.	5.95%	0.00%	0.43%	$41,996	$125,987		
67 - Improve the reliability of the HPCI and RCIC systems by upgrading their control systems.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$434,775	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Main Condenser	Eliminate failure of the steam tunnel HVAC.	2.96%	1.40%	1.85%	$26,517	$79,550		
76 - Improve steam tunnel HVAC reliability/ redundancy to prevent inadvertent group 1 isolations.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective
Improve Reliability of ECCS Equipment	Eliminate the failure of the auto-start features for the ECCS equipment.	1.35%	0.00%	0.00%	$9,298	$27,895		
77 - Improve reliability of auto-start features for the ECCS equipment.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective
Improve Injection Via Fire Water System	Reduce operator actions that could be improved via training for alternate injection via the FPS by a factor of 2.	5.29%	4.21%	4.56%	$52,605	$157,816		
78 - Improve training on alternate injection via FPS.	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
RHR Heat Exchangers	Eliminate failure of the SW to provide cooling to the RHR heat exchangers.	20.62%	15.89%	15.83%	$199,969	$599,907		
30 - Revise procedures to allow manual alignment of the fire water system to RHR heat exchangers.	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain
Emergency Service Water System Reliability	Set the events for the common cause contribution due to service water system pumps to zero in the level 1 PSA model.	0.36%	0.00%	0.29%	$3,152	$9,456		
31 - Add a service water pump to reduce the impact of common cause failures on the SW system.	The cost for implementing this SAMA was specifically estimated for Quad Cities.						$5,900,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Reduce Valve Failure – Fire Water System	Eliminate the CDF contribution due to the fire service water cross-tie valves that are not contained in the maintenance program.	0.05%	0.00%	0.00%	$358	$1,073		
32 - Enhance alternate injection reliability by including the residual heat removal service water and fire water cross-tie valves in the maintenance program.	The cost for implementing this SAMA was specifically estimated for Monticello.						$50,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Alternate Water Supply for the TEC Heat Exchangers	Eliminate failure of the service water to provide cooling to the TEC heat exchangers.	15.39%	19.63%	19.69%	$177,788	$533,364		
68 - Proceduralize the ability to cross-connect the circulating water pumps and the service water going to the TEC heat exchangers.	The cost for implementing this SAMA was specifically estimated for Browns Ferry.						$50,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Availability of Feedwater and Condensate	Eliminate the CDF contribution due to loss of the feedwater and condensate systems as alternate injection paths in the PSA model.	38.31%	45.79%	46.08%	$431,725	$1,295,174		
33 - Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Main Feedwater System Reliability	Set the events for failure of the feedwater turbine driven pumps to zero in the level 1 PSA model.	0.01%	0.00%	0.00%	$89	$267		
34 - Add a motor-driven feed water pump to increase the availability of injection subsequent to MSIV closure.	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$1,650,000	Not cost effective
Increase Availability of the CST	Eliminate the CDF contribution from operator failure to prevent CST inventory drain-down to the hotwell.	2.00%	1.87%	2.00%	$20,890	$62,671		
72 - Provide a means of automatically preventing draindown of CST to hotwell during a SBO.	The cost for implementing this SAMA was specifically estimated for Monticello.						$230,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Availability of Room Cooling	Eliminate failure of room cooling to the RHRSW booster pump rooms.	4.04%	2.80%	3.00%	$38,498	$115,493		
35 - Provide a redundant train or means of ventilation.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$2,202,725	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Availability of the EDG System	Eliminate failure of the EDG HVAC.	2.94%	3.27%	3.71%	$33,160	$99,480		
36 - Add a diesel building high temperature alarm or redundant louver and thermostat.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$1,304,700	Not cost effective
38 - Diverse EDG HVAC logic.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$100,000	Not cost effective
39 - Install additional fan and louver pair for EDG heating, ventilation, and air conditioning.	The cost for implementing this SAMA was specifically estimated for Browns Ferry.						$6,000,000	Not cost effective
40 - Operator procedure revisions to provide additional space cooling to the EDG room via the use of portable equipment.	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve Diagnosis of a Loss of Switchgear HVAC	Eliminate failure of room cooling to the critical switchgear rooms in the level 1 PSA model.	0.00%	0.00%	0.00%	$0	$0		
37 - Add a switchgear room high temperature alarm.	The cost for implementing this SAMA was specifically estimated for Browns Ferry.						$400,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Reliability of Instrument Air	Eliminate failure of the instrument air compressors in the level 1 PSA model.	16.79%	13.55%	14.12%	$166,450	$499,350		
41 - Modify procedure to provide ability to align diesel power to more air compressors.	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$1,200,000	Not cost effective
42 - Replace service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.	The cost for implementing this SAMA was specifically estimated for CNS.						$1,394,598	Not cost effective
45 - Provide an alternate means of supplying the instrument air header.	The cost for implementing this SAMA was specifically estimated for CNS.						$100,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Extend SRV Operation Time	Eliminate the failure of loss of nitrogen and air to the SRVs.	0.00%	0.00%	0.00%	$0	$0		
43 - Install nitrogen bottles as backup gas supply for safety relief valves.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective
Improve Availability of SRVs and MSIVs	Eliminate failure of nitrogen/air/accumulators for the SRVs and MSIVs.	16.89%	20.56%	20.68%	$191,658	$574,974		
44 - Improve SRV and MSIV pneumatic components.	The cost for implementing this SAMA was specifically estimated for Pilgrim.						$1,500,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Decay Heat Removal Capability – Torus Cooling	Set the events for loss of the torus cooling mode of the RHR and RHRSW systems to zero in the PSA model.	34.64%	36.92%	37.23%	$374,118	$1,122,355		
46 - Install an independent method of suppression pool cooling.	The cost for implementing this SAMA was specifically estimated for Quad Cities.						$5,800,000	Not cost effective
71 - Upgrade existing equipment to transfer water from the torus to radwaste.	The cost for implementing this SAMA was specifically estimated for CNS.						$11,118,000	Not cost effective
73 - Provide ability to maintain suppression pool temperature lower.	The cost for implementing this SAMA was specifically estimated for CNS.						$1,275,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Decay Heat Removal Capability, Drywell Spray	Set the events for loss of the drywell sprays mode of the RHR and RHRSW systems to zero in the PSA model.	16.83%	55.05%	56.06%	$319,007	$957,021		
47 - Install a passive drywell spray system to provide a redundant drywell spray method.	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$5,800,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Filtered Vent	Reduce the baseline accident progression source terms by a factor of 2 (excluding noble gases) to reflect the additional filtered capability.	0.00%	24.77%	24.25%	$89,122	$267,367		
48 - Install a filtered containment vent to provide fission product scrubbing.	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$1,500,000	Not cost effective
49 - Enhance fire protection system and/or standby gas treatment system hardware and procedures.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$2,500,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Controlled Containment Venting	Eliminate operator failure to control the venting evolution in the PSA model.	0.01%	0.00%	0.00%	$35	$106		
50 - Control containment venting within a narrow band of pressure to prevent rapid containment depressurization when venting is implemented thus avoiding adverse impact on the low pressure ECCS injection systems taking suction from the torus.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$250,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Vacuum Breakers	Set the vacuum breaker failure probability to zero in the PSA model.	1.31%	3.74%	3.85%	$22,890	$68,671		
51 - Install improved vacuum breakers (redundant valves in each line).	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$500,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Passive Containment Overpressure Relief	Eliminate the hard pipe vent failure in the PSA model.	6.80%	21.50%	22.68%	$127,921	$383,762		
52 - Provide passive overpressure relief by changing the containment vent valves to fail open and improving the strength of the rupture disk.	The cost for implementing this SAMA was specifically estimated for Oyster Creek.						$1,000,000	Not cost effective
53 - Install alternate path to the torus hard pipe vent via the wet well using a rupture disk.	The cost for implementing this SAMA was specifically estimated for Susquehanna.						$5,700,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Barriers to Block Debris from Reaching the Steel Shell	Eliminate the CDF contribution due to failure of the DW barriers to prevent debris from contacting the shell.	11.59%	40.19%	40.66%	$227,447	$682,341		
70 - Install a curb to prevent debris from spreading across the floor and contacting the shell.	The cost for implementing this SAMA was specifically estimated for CNS.						$844,000	Not cost effective
ISLOCA	Set the ISLOCA initiator to zero in the PSA model.	0.44%	1.40%	1.57%	$8,556	$25,669		
54 - Increase frequency of valve leak testing to reduce ISLOCA frequency.	The cost for implementing this SAMA was specifically estimated for Vermont Yankee.						$100,000	Not cost effective
56 - Revise EOPs to improve ISLOCA identification.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$50,000	Not cost effective
57 - Improve operator training on ISLOCA coping.	The cost for implementing this SAMA was specifically estimated for CNS.						$112,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
MSIV Design	Eliminate failure of the MSIVs to close or remain closed.	0.25%	0.00%	0.43%	$2,723	$8,169		
55 - Improve MSIV design to decrease the likelihood of containment bypass scenarios.	The cost for implementing this SAMA was specifically estimated for Peach Bottom.						$1,000,000	Not cost effective
SLC System	Eliminate the contribution due to failure to initiate SLC along with the boron concentration being too low in the PSA model.	0.72%	1.87%	2.14%	$12,362	$37,086		
58 - Increase boron concentration in the SLC system [Reduced time required to achieve shutdown provides increased margin in the accident timeline for successful initiation of SLC].	The cost for implementing this SAMA was specifically estimated for CNS.						>50k	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve Availability of Boron Injection	Eliminate failure of the SLC system in the PSA model.	1.25%	3.74%	3.85%	$22,485	$67,455		
59 - Add an independent boron injection system.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective
60 - Provide ability to use control rod drive (CRD) for alternate boron injection.	The cost for implementing this SAMA was specifically estimated for Nine Mile Point.						$150,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
SRV Reseat	Set the failure of the SRVs to reseat to zero in the PSA model.	1.32%	0.47%	0.43%	$10,734	$32,202		
61 - Increase safety relief valve (SRV) reseat reliability to address the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.	The cost for implementing this SAMA was specifically estimated for FitzPatrick.						$2,200,000	Not cost effective
Internal Flooding	Eliminate operator failures related to flood mitigation in the PSA model.	1.52%	1.87%	1.85%	$17,237	$51,711		
62 - Improve internal flooding procedures.	The cost for implementing this SAMA was specifically estimated for CNS.						$460,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Fire Water Pipe Break	Eliminate failure to isolate the large and medium fire water pipe breaks in the control building ground floor corridor.	0.20%	0.00%	0.29%	$2,036	$6,108		
74 - Provide flow diversion to help mitigate the fire water pipe break in the control building ground floor corridor.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Increase Reliability of the Fire Water System	Eliminate failure of the diesel-driven fire pump in the PSA model.	2.67%	2.34%	2.57%	$27,465	$82,395		
64 - Proceduralize the use of a fire pumper truck to pressurize the fire water system.	The cost for implementing this SAMA was specifically estimated for Monticello.						$50,000	Retain
69 - Upgrade the seismic capacity of the diesel fire pump fuel tank and water supply tank.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective
Add Fire Suppression[1]	Eliminate fire CDF from the critical switchgear rooms.	n/a	n/a	n/a	$115,969	$347,908		
63 - Add automatic fire suppression systems to the dominant fire zones.	The cost for implementing this SAMA was specifically estimated for Brunswick.						$375,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Reduce Risk from Fires that Require Control Room Evacuation[1]	Eliminate fire CDF from the main control room.	n/a	n/a	n/a	112,988	$338,964		
65 - Upgrade the ASDS panel to include additional system controls for opposite division.	The cost for implementing this SAMA was specifically estimated for Monticello.						$786,991	Not cost effective
Large Break LOCA	Set the LBLOCA initiators to zero in the PSA model.	1.01%	3.27%	3.42%	$19,235	$57,704		
66 - Provide digital large break LOCA protection to identify symptoms/ precursors of a large break LOCA (a leak before break).	The cost for implementing this SAMA was specifically estimated for Pilgrim.						$100,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Trip/Shutdown Risk	Reduce the initiating events that could be improved by the GRA by a factor of 2.	38.76%	34.58%	35.09%	$394,444	$1,183,332		
75 - Generation Risk Assessment implementation into plant activities.	The cost for implementing this SAMA was specifically estimated for CNS.						$500,000	Retain
Improve RHRSW System	Eliminate failure to use the RHRSW system without a SWBP.	10.75%	9.81%	10.13%	$110,566	$331,699		
79 - Modify procedures to allow use of the RHRSW system without a SWBP.	The cost for implementing this SAMA was specifically estimated for CNS.						$25,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Analysis Case (Bold) SAMA Number and Title	Assumptions	CDF Reduction	PDR Reduction	OECR Reduction	Internal and External Benefit	Internal and External Benefit with Uncert	CNS Cost Estimate	Conclusion
Improve Plant Identification of Reference Leg Leakdowns	Eliminate failure of cognitive recognition of a leakdown of the reference legs in the PSA model.	0.77%	0.00%	0.00%	$5,306	$15,917		
80 - Install additional instrumentation to assist in identifying a reference leg leakdown.	The cost for implementing this SAMA was specifically estimated for CNS.						> 100k	Not cost effective

1. These analysis cases only impact external events and have been evaluated differently as shown in Section E.2.3 (analysis cases 52 and 53).

Table E.2-3
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
DC Power	$32,279	$39,487	$39,221	
1 - Provide additional DC battery capacity.				$500,000
2 - Replace lead-acid batteries with fuel cells.				$1,000,000
13 - Portable generator for DC power to supply the battery chargers.				$203,000
21-Modify plant procedures to allow use of a portable power supply for battery chargers.				Part of SAMA 13 cost estimate
Improve Charger Reliability	$2,339	$2,988	$2,631	
3 - Add battery charger to existing DC system.				$90,000
15 - Proceduralize battery charger high-voltage shutdown circuit inhibit.				$50,000
Add DC System Cross-ties	$0	$0	$0	
4 - Provide DC bus cross-ties [The 125V distribution panels and starter racks can be powered from either bus, thus the 125V buses are cross-tied. However the 250V buses are not cross-tied].				$300,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Improve Existing DC System Cross-ties	$1,999	$2,554	$2,249	
19 - Modify plant procedures to use DC bus cross-ties [This SAMA will enhance procedures to use the existing 125V DC bus cross-ties].				$25,000
Provide Backup DC Power to the 120 V Vital AC Bus	$465	$593	$523	
5 - Provide additional DC power to the 120/240V vital AC system.				> 100k
Increase Availability of the 120 V Vital AC Bus	$0	$0	$0	
6 - Add an automatic feature to transfer the 120V vital AC bus from normal to standby power.				$500,000
Increase Availability of On-Site AC Power	$141,672	$172,502	$173,475	
7 - Provide an additional diesel generator.				$20,000,000
10 - Install a gas turbine generator.				$2,000,000
Provide Backup EDG SW Cooling	$44,738	$55,143	$53,680	
11 - Add a new backup source of diesel cooling.				$2,000,000
Increase EDG Reliability	$6,229	$7,585	$7,623	
16 - Provide a portable EDG fuel oil transfer pump.				$100,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Improve AC Power	$35,490	$42,467	$44,679	
8 - Improve 4.16-kV bus cross-tie ability.				$656,000
17 - Provide alternate feeds to essential loads directly from an alternate emergency bus.				$217,388
Reduce Loss of Off-Site Power During Severe Weather	$43,237	$52,957	$52,430	
9 - Install an additional, buried off-site power source.				$2,485,000
12 - Bury off-site power lines.				$1,140,000,000
Reduce Plant-Centered Loss of Off-Site Power	$614	$784	$690	
18 - Protect transformers from failure.				$780,000
Redundant Power to Torus Hard Pipe Vent (THPV) Valves	$77,440	$90,889	$100,406	
20 - Provide redundant power to direct torus hard pipe vent valves to improve the reliability of the direct torus vent valves and enhance the containment heat removal capability.				$714,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
High Pressure Injection System	$301,827	$372,216	$361,864	
14 - Portable generator for DC power to supply the individual panels.				$714,000
22 - Install an independent active or passive high pressure injection system.				$1,000,000
23 - Provide an additional high pressure injection pump with independent diesel.				$1,000,000
Extend RCIC Operation	$28,693	$36,403	$32,726	
24 - Raise HPCI/RCIC backpressure trip set points [HPCI backpressure trip setpoint has already been raised. This SAMA will evaluate raising the RCIC backpressure trip set point].				> 200K
25 - Revise procedure to allow bypass of RCIC turbine exhaust pressure trip [This SAMA will revise EOP 5.8.20 to give direction to allow bypass of RCIC turbine exhaust pressure trip].				$25,000
Improve ADS System	$0	$0	$0	
26 - Modify automatic depressurization system components to improve reliability [This SAMA will add larger accumulators thus increasing reliability during SBOs].				> 100k

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Reliability of SRVs	$135,371	$172,481	$153,207	
27 - Add signals to open safety relief valves automatically in an MSIV closure transient.				$1,500,000
Low Pressure Injection System	$603,989	$734,195	$741,607	
28 - Add a diverse low pressure injection system.				$8,800,000
ECCS Low Pressure Interlock	$190,301	$239,635	$220,027	
29 - Install a bypass switch to allow operators to bypass the low reactor pressure interlock circuitry.				$1,000,000
Improve Reliability of HPCI and RCIC	$41,996	$53,513	$47,519	
67 - Improve the reliability of the HPCI and RCIC systems by upgrading their control systems.				$434,775
Main Condenser	$26,517	$32,872	$31,507	
76 - Improve steam tunnel HVAC reliability/ redundancy to prevent inadvertent group 1 isolations.				> 100k
Improve Reliability of ECCS Equipment	$9,298	$11,883	$10,462	
77 - Improve reliability of auto-start features for the ECCS equipment.				> 100k

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Improve Injection Via Fire Water System	$52,605	$64,556	$63,587	
78 - Improve training on alternate injection via FPS.				$25,000
RHR Heat Exchangers	$199,969	$245,994	$240,745	
30 - Revise procedures to allow manual alignment of the fire water system to RHR heat exchangers.				$25,000
Emergency Service Water System Reliability	$3,152	$3,920	$3,722	
31 - Add a service water pump to reduce the impact of common cause failures on the SW system.				$5,900,000
Reduce Valve Failure – Fire Water System	$358	$456	$402	
32 - Enhance alternate injection reliability by including the residual heat removal service water and fire water cross-tie valves in the maintenance program [The residual heat removal service water cross-tie valves (CNS-1-SW-MOV-36MV and CNS-2-SW-MOV-37MV) are essential and in the maintenance rule program. The fire water cross-tie valves are not in the maintenance program. This SAMA will evaluate including the fire water cross-tie valves].				$50,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Alternate Water Supply for the TEC Heat Exchangers	$177,788	$215,342	$219,563	
68 - Proceduralize the ability to cross-connect the circulating water pumps and the service water going to the turbine equipment cooling (TEC) heat exchangers.				$50,000
Increase Availability of Feedwater and Condensate	$431,725	$523,994	$531,403	
33 - Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.				$25,000
Main Feedwater System Reliability	$89	$113	$99	
34 - Add a motor-driven feed water pump to increase the availability of injection subsequent to MSIV closure.				$1,650,000
Increase Availability of the CST	$20,890	$25,520	$25,439	
72 - Provide a means of automatically preventing draindown of CST to hotwell during a SBO.				$230,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Increase Availability of Room Cooling	$38,498	$47,436	$46,219	
35 - Provide a redundant train or means of ventilation [This SAMA examines implementing a redundant means of ventilation to the CS pump rooms, RHR pump rooms, RHRSW booster pump rooms, SW pump rooms, and HPCI pump room].				$2,202,725
Increase Availability of the EDG System	$33,160	$40,239	$40,827	
36 - Add a diesel building high temperature alarm or redundant louver and thermostat.				$1,304,700
38 - Diverse EDG HVAC logic.				$100,000
39 - Install additional fan and louver pair for EDG heating, ventilation, and air conditioning.				$6,000,000
40 - Operator procedure revisions to provide additional space cooling to the EDG room via the use of portable equipment.				$25,000
Improve Diagnosis of a Loss of Switchgear HVAC	$0	$0	$0	
37 - Add a switchgear room high temperature alarm.				$400,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Increase Reliability of Instrument Air	$166,450	$204,331	$201,094	
41 - Modify procedure to provide ability to align diesel power to more air compressors.				$1,200,000
42 - Replace service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.				$1,394,598
45 - Provide an alternate means of supplying the instrument air header.				$100,000
Extend SRV Operation Time	$0	$0	$0	
43 - Install nitrogen bottles as backup gas supply for safety relief valves.				> 100k
Improve Availability of SRVs and MSIVs	$191,658	$232,481	$236,137	
44 - Improve SRV and MSIV pneumatic components.				$1,500,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Decay Heat Removal Capability – Torus Cooling	$374,118	$455,722	$457,795	
46 - Install an independent method of suppression pool cooling.				$5,800,000
71 - Upgrade existing equipment to transfer water from the torus to radwaste.				$11,118,000
73 - Provide ability to maintain suppression pool temperature lower.				$1,275,000
Decay Heat Removal Capability – Drywell Spray	$319,007	$374,060	$414,194	
47 - Install a passive drywell spray system to provide a redundant drywell spray method.				$5,800,000
Filtered Vent	$89,122	$99,126	$124,533	
48 - Install a filtered containment vent to provide fission product scrubbing.				$1,500,000
49 - Enhance fire protection system and/or standby gas treatment system hardware and procedures.				$2,500,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Controlled Containment Venting	$35	$44	$39	
50 - Control containment venting within a narrow band of pressure to prevent rapid containment depressurization when venting is implemented thus avoiding adverse impact on the low pressure ECCS injection systems taking suction from the torus.				$250,000
Vacuum Breakers	$22,890	$26,952	$29,534	
51 - Install improved vacuum breakers (redundant valves in each line).				$500,000
Passive Containment Overpressure Relief	$127,921	$150,053	$165,996	
52 - Provide passive overpressure relief by changing the containment vent valves to fail open and improving the strength of the rupture disk.				$1,000,000
53 - Install alternate path to the torus hard pipe vent via the wet well using a rupture disk.				$5,700,000
Barriers to Block Debris from Reaching the Steel Shell	$227,447	$266,226	$296,088	
70 - Install a curb to prevent debris from spreading across the floor and contacting the shell.				$844,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
ISLOCA	$8,556	$10,024	$11,121	
54 - Increase frequency of valve leak testing to reduce ISLOCA frequency.				$100,000
56 - Revise EOPs to improve ISLOCA identification.				$50,000
57 - Improve operator training on ISLOCA coping.				$112,000
MSIV Design	$2,723	$3,318	$3,327	
55 - Improve MSIV design to decrease the likelihood of containment bypass scenarios.				$1,000,000
SLC System	$12,362	$14,567	$15,930	
58 - Increase boron concentration in the SLC system [Reduced time required to achieve shutdown provides increased margin in the accident timeline for successful initiation of SLC].				> 50k
Improve Availability of Boron Injection	$22,485	$26,433	$29,078	
59 - Add an independent boron injection system.				> 100k
60 - Provide ability to use control rod drive (CRD) for alternate boron injection.				$150,000

**Table E.2-3 (Continued)
Sensitivity Analysis Results**

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
SRV Reseat	$10,734	$13,450	$12,517	
61 - Increase safety relief valve (SRV) reseat reliability to address the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.				$2,200,000
Internal Flooding	$17,237	$20,905	21,240	
62 - Improve internal flooding procedures.				$460,000
Fire Water Pipe Break	$2,036	$2,494	$2,466	
74 - Provide flow diversion to help mitigate the fire water pipe break in the control building ground floor corridor.				> 100k
Increase Reliability of the Fire Water System	$27,465	$33,602	$33,365	
64 - Proceduralize the use of a fire pumper truck to pressurize the fire water system.				$50,000
69 - Upgrade the seismic capacity of the diesel fire pump fuel tank and water supply tank.				> 100k

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Add Fire Suppression[1]	N/A	N/A	N/A	
63 - Add automatic fire suppression systems to the dominant fire zones.				$375,000
Reduce Risk from Fires that Require Control Room Evacuation[1]	N/A	N/A	N/A	
65 - Upgrade the ASDS panel to include additional system controls for opposite division.				$786,991
Large Break LOCA	$19,235	$22,547	$24,982	
66 - Provide digital large break LOCA protection to identify symptoms/precursors of a large break LOCA (a leak before break).				$100,000
Trip/Shutdown Risk	$394,444	$483,039	$478,471	
75 - Generation Risk Assessment implementation into plant activities (trip/shutdown risk modeling).				$500,000
Improve RHRSW System	$110,566	$135,263	$134,344	
79 - Modify procedures to allow use of the RHRSW system without a SWBP.				$25,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Analysis Case (Bold) SAMA Number and Title	Internal and External Benefit, 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1, 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2, 20 yrs Remaining, 3% Discount Rate	CNS Cost Estimate ($)
Improve Plant Identification of Reference Leg Leakdowns	$5,306	$6,780	$5,969	
80 - Install additional instrumentation to assist in identifying a reference leg leakdown.				> 100k

1. These analysis cases only impact external events and have been evaluated differently as shown in Section E.2.3 (analysis cases 52 and 53).