Document Type: EA-Administrative Record
Index Field: **Final** EA
Project Name: Shawnee Fossil Plant Units 1 and 4
Project Number: 2015-2

SHAWNEE FOSSIL PLANT UNITS 1 AND 4
West Paducah, Kentucky

FINAL ENVIRONMENTAL ASSESSMENT

Prepared by:
TENNESSEE VALLEY AUTHORITY
Knoxville, Tennessee

December 2014

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Table of Contents

List of Tables

List of Figures

Symbols, Acronyms, and Abbreviations

APE	Area of potential effects
APH	Air pre-heater
BMP	Best management practice
CAA	Clean Air Act
CCC	Chronic criterion concentration
CCR	Coal combustion residuals
CCW	Condenser cooling water
CDS	Circulating dry scrubber
CO	Carbon monoxide
CO_2	Carbon dioxide
dB	Decibel
dBA	A-weighted decibel
DOE	Department of Energy
DSI	Dry sorbent injection
EA	Environmental assessment
EIS	Environmental impact statement
FGD	Flue gas desulfurization
GHG	Greenhouse gas
GWh	Gigawatt-hour
ILB	Illinois Basin
IRP	Integrated Resource Plan
KDEP	Kentucky Department for Environmental Protection
KPDES	Kentucky Pollutant Discharge Elimination System
LBC	Little Bayou Creek
MATS	Mercury and Air Toxics Standards
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NH_3	Ammonia
NO_2	Nitrogen dioxide
NO_x	Nitrogen oxide
NRHP	National Register of Historic Places
PM	Particulate matter
PRB	Powder River Basin
RGA	Regional Gravel Aquifer
SCR	Selective catalytic reduction
SHF	Shawnee Fossil Plant
SHPO	State Historic Preservation Officer
SO_2	Sulfur dioxide
TVA	Tennessee Valley Authority
USACE	United States Army Corps of Engineers
USEC	U.S. Enrichment Corporation
USEPA	United States Environmental Protection Agency

CHAPTER 1

1. PURPOSE AND NEED FOR ACTION

Introduction

In April 2011, the Tennessee Valley Authority (TVA) and the U.S. Environmental Protection Agency (USEPA) entered into a Federal Facilities Compliance Agreement to resolve a dispute over how the Clean Air Act (CAA)'s New Source Review program applied to maintenance and repair activities at TVA's coal-fired power plants (USEPA 2011a). TVA also entered into a judicial consent decree with four states and three environmental advocacy organizations (USEPA 2011b). The consent decree is substantively similar to the compliance agreement. These agreements (collectively the "USEPA Clean Air Agreements") require TVA to, among other things, reduce emissions from its coal-fired power plants. At its Shawnee Fossil Plant (SHF) Units 1 and 4, TVA must decide whether to install and continuously operate selective catalytic reduction (SCR) and flue gas desulfurization (FGD) systems, repower the units to burn renewable biomass, or retire the units by December 31, 2017. TVA must inform USEPA and the other consent decree parties of its decision for Units 1 and 4 by December 31, 2014. If TVA decides to control the units or convert them to biomass, the agreements provide TVA the discretion to change the decision to retirement later.

TVA proposes to comply with the USEPA Clean Air Agreements provisions for SHF Units 1 and 4 by installing and operating SCR systems to reduce nitrogen oxide (NO_x) emissions and FGD systems to reduce sulfur dioxide (SO_2) emissions.

The purpose and need of the proposed action is to:

- Comply with the USEPA Clean Air Agreements by reducing NO_x and SO_2 emissions from SHF Units 1 and 4.
- Achieve and maintain a balanced portfolio of generation resources.

TVA completed its Integrated Resource Plan (IRP) and associated programmatic environmental impact statement (EIS) in 2011 (TVA 2011a, 2011b). The IRP described how TVA would meet the electric power demands of its service area for the next 20 years while fulfilling its mission of providing low-cost, reliable power; environmental stewardship; and economic development. One of the goals of the IRP was to rely on more balanced (diverse) generation resources to reduce supply and price risks. This environmental assessment (EA) describes the anticipated environmental impacts of installing and operating the SCR and FGD systems on SHF Units 1 and 4. It tiers from the 2011 IRP EIS (TVA 2011b) and has been prepared to comply with the National Environmental Policy Act (NEPA) and regulations promulgated by the Council on Environmental Quality and TVA for implementing NEPA.

1.2 Shawnee Fossil Plant

SHF is located on 1,696 acres adjacent to the Ohio River about 10 miles northwest of Paducah, Kentucky (Figure 1-1).

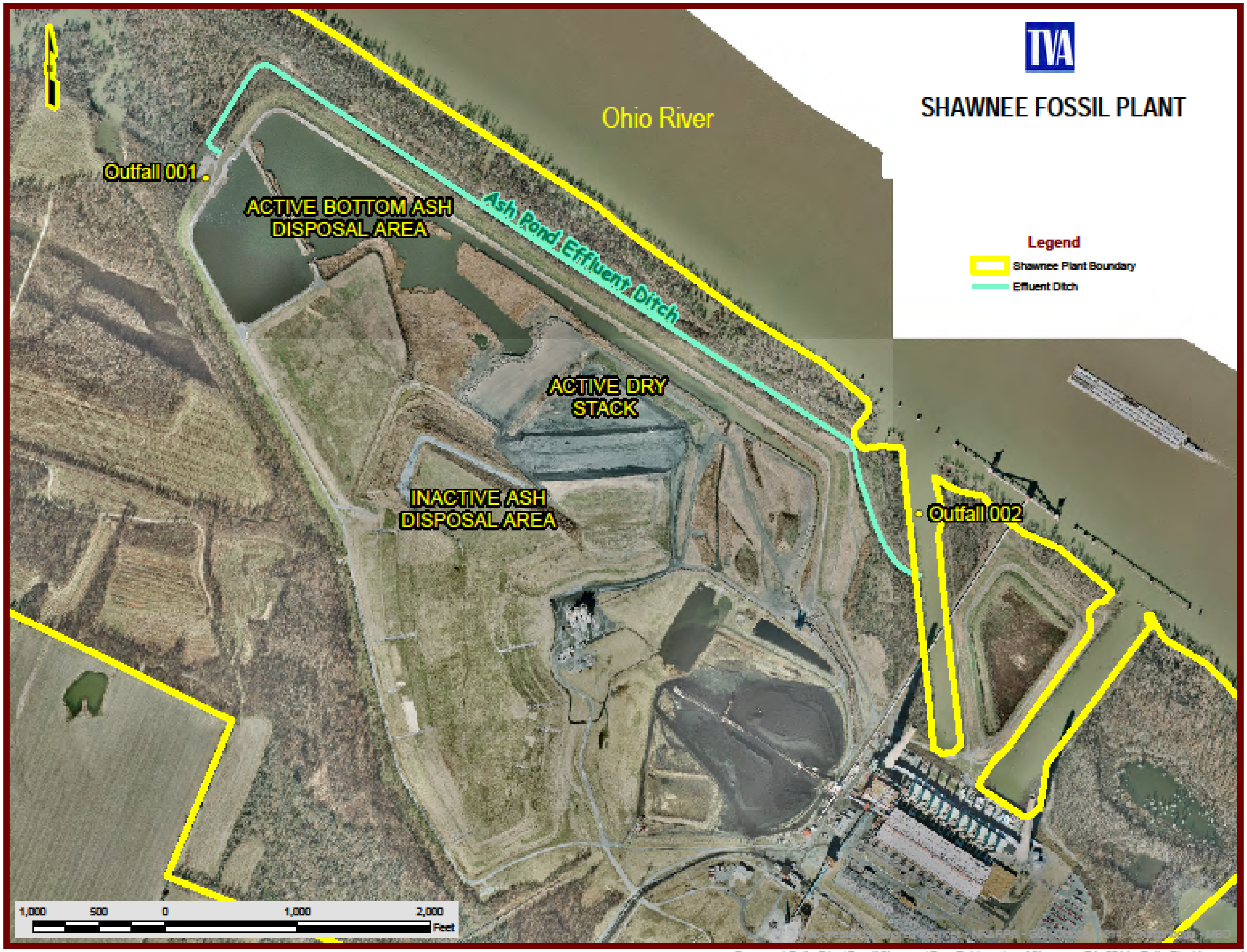

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Figure 1-1. Shawnee Fossil Plant Existing Site Layout Map

Construction of the ten similar pulverized coal units began in 1951 and all units were operating by October 1956. Unit 10 was converted from a pulverized coal boiler to a 124-MW atmospheric fluidized bed boiler in the 1980s; it was removed from service in 2010 and formally retired in 2014. The nine active coal-fired generating units have a summer net capability of 1,206 megawatts and can generate about 8 billion kilowatt-hours of electricity a year, enough to supply 540,000 homes. Emissions of air pollutants are controlled by the following:

- Use of low-sulfur coal for reducing SO_2 emissions
- Use of low-NO_x burners for reducing NO_x emissions
- Use of fabric filter baghouses to reduce particulate emissions
- Use of dry sorbent injection (DSI) systems to reduce emissions of acid gases for compliance with the 2011 Mercury and Air Toxics Standards (MATS). These systems are currently being installed and will be fully operational in 2015. They will use a calcium-based sorbent.

After exiting the baghouses, emissions are released through two stacks, one serving Units 1-5 and one serving Units 6-9.

SHF burns about 9,600 tons of coal a day, a blend of about 75 percent Powder River Basin (PRB) subbituminous coal and 25 percent Colorado bituminous coal. Coal combustion residuals (CCRs), primarily ash, are stored in an on-site landfill (for fly ash) and an on-site ash pond (for bottom ash).

The relatively small generating units at SHF, approximately 134 MW each, are operated on Automatic Generation Control and can be started up and shut down relatively quickly to respond to changes in energy demand. They provide TVA the flexibility to operate SHF for base-load power, when the units operate at or close to their maximum capacity most of the time, and intermediate-load power, when the units change their output as energy demand increases and decreases over time (usually during the course of a day). The TVA system benefits from the small, flexible, and load-following resource characteristics of these units.

SHF Units 1 and 4 are not needed for reliability purposes in the Paducah area. TVA could retire the two units without having to build or obtain replacement capacity to maintain reliable service in the Paducah area. However, the two units do help meet the growing demand for energy and capacity on the TVA system, and this enhances their value.

1.3 Related Environmental Reviews and Consultation Requirements

The following EIS and EAs prepared by TVA are relevant to the proposed action. Several environmental reviews have been prepared for actions related to the proposed construction and operation of FGD and SCR systems at TVA coal fired plants.

- *Environmental Impact Statement and Record of Decision, TVA's Integrated Resource Plan* (TVA 2011b). This programmatic EIS and the associated Integrated Resource Plan describe how TVA will meet demands for electric power in its service area for the next 20 years and the environmental impacts resulting from meeting those demands. TVA is in the process of updating the 2011 IRP. This EA tiers from the 2011 IRP EIS.

- *Installation of Air Pollution Control Equipment and Associated Facilities at Gallatin Fossil Plant – Environmental Assessment* (TVA 2013). This EA evaluates the impacts of installing and operating SCR and FGD systems, as well as a new CCR disposal landfill at TVA's Gallatin Fossil Plant. The Gallatin SCR and FGD systems are generally similar in their operation to those proposed at SHF.

- *Supplemental Environmental Assessment Selective Catalytic Reduction Optimization Systems* (TVA 2008). This EA assesses the impacts of operating SCR units at high ammonia injection rates while still meeting the environmental requirements for NO_x reduction in plant permits and USEPA's interstate transport rule.

- *NOxOUT Selective Noncatalytic Reduction Demonstration Shawnee Fossil Plant – Unit 1 Final Environmental Assessment* (TVA 2005). This EA evaluates the installation of a selective noncatalytic NO_x emissions reduction system on Shawnee Unit 1.

The findings in these documents related to this EA are utilized in Chapter 3 for each environmental resource and incorporated by reference as appropriate.

1.4 Scope of the Environmental Assessment

The proposed SCR and FGD systems would be constructed on the SHF reservation and would not require an expansion of the area currently occupied by the powerhouse and adjacent emissions control equipment. The additional CCRs produced during operation of the FGD systems, scrubber residue primarily consisting of calcium salts, would be stored in the existing onsite CCR landfill.

TVA determined the resources listed below are potentially impacted by the alternatives considered.

- Air Quality and Climate Change
- Noise
- Visual Resources
- Groundwater
- Surface Water
- Cultural and Historic Resources
- Solid and Hazardous Waste
- Socioeconomics and Environmental Justice
- Transportation

Because the proposed SCR and FGD systems and associated infrastructure would be installed in areas already occupied by components of the generating plant or otherwise heavily disturbed and the future Unit 1 and 4 waste streams would be processed and/or stored in existing on-site facilities, there is no potential for impacts to the following resources:

- Wetlands/Floodplains

- Geology
- Endangered and Threatened Species
- Vegetation and Wildlife
- Natural Areas, Parks, and Recreation
- Land Use and Prime Farmland

TVA‘s action would satisfy the requirements of Executive Orders 11988 (Floodplains Management), 11990 (Protection of Wetlands), 12898 (Environmental Justice), 13112 (Invasive Species), and 13653 Preparing the United States for the Impacts of Climate Change; and applicable laws including the National Historic Preservation Act, Endangered Species Act, Clean Water Act, and Clean Air Act (CAA).

Public and Agency Involvement

TVA conducted a 3-week public scoping period from October 20, 2014, to November 10, 2014, to solicit comments on the alternatives and environmental resources to be considered in the EA. The scoping period was announced by advertisements in Paducah-area media, by news releases, by a notice on the TVA website, and by notices sent to potentially interested agencies and organizations. TVA received 85 individual comment letters/emails/online submissions from members of the public and other interested parties/agencies/organizations. Twenty-one of the comments were form letters distributed by the International Brotherhood of Boilermakers Local Lodge 40.

An overwhelming majority of comments were in support of installing the emission controls and continuing to operate the two units. Primary topics of support focused on employment benefits, economic stimulation, electric reliability and rates, the uncertainty of natural gas as an energy source, and environmental stewardship. In addition to general concerns regarding the level of environmental assessment being performed, other commenters requested that TVA consider 1) retiring all SHF units, 2) retiring Units 1 and 4 and, if necessary, replacing the energy they generate with energy efficiency, renewable energy, or purchased power, 3) converting Units 1 and 4 to biomass, 4) adding SCR and FGD systems to all nine SHF units, and 5) updating the current facility best management practices (BMPs).

In their scoping comments, the U.S. Fish and Wildlife Service raised concerns about potential impacts to endangered and threatened species, to wildlife using the ash pond and other water bodies associated with SHF, to aquatic resources, and to fish- and wildlife-related recreational activities. Although at least 13 species listed or proposed for listing under the Endangered Species Act have been reported in the vicinity of SHF, none of the alternative actions would affect these species. As described in Sections 3.5 and 3.7, there would be no structural changes to the ash pond and changes to water chemistry in the pond and the plant discharges would be minimal. None of the construction activities would occur in the immediate vicinity of fish- and wildlife-oriented recreational activities in the plant area.

TVA also received comments on the requirement that it use least-cost planning in making the decision on SHF Units 1 and 4. The TVA Act directs TVA to deliver low-cost, reliable power to the Valley while also promoting economic prosperity and the wise use and conservation of the natural resources of the region. In addition, § 113 of the Energy Policy Act of 1992 requires TVA to conduct a least-cost system planning program for the selection of new energy resources. This requires more than a simple comparison of construction and fuel costs for specific energy resources. TVA is directed to take into account such things as diversity of resources, reliability, and risk factors on a system-wide basis in order to provide its customers "adequate and reliable electric service" at the lowest system cost. TVA evaluates all generation types in the context of the overall resource portfolio to ensure that it meets the needs of the TVA system at the lowest feasible cost. TVA's IRP processes implement these least-cost system planning requirements. TVA's IRPs and associated EISs provide the foundation for its specific energy resource proposals, such as the proposal to control or retire SHF Units 1 and 4. Section 113 also directs TVA to provide the public an opportunity to comment before it selects a new energy resource. Controlling or retiring Units 1 and 4 would not involve the selection of a new energy resource so this provision of § 113 does not apply. However, TVA decided to provide the public an opportunity to comment on this EA.

On November 25, 2014, TVA issued the draft of this EA for public comment. Its availability was announced by advertisements in Paducah-area media, by news releases, by a notice on the TVA website, and by notices sent to potentially interested agencies and organizations, as well as those who submitted scoping comments. The comment period closed December 9, 2014. TVA received 589 comments on the draft EA. These were carefully reviewed and the text of the EA was edited as appropriate. Appendix A contains the comments on the draft EA and TVA's responses to those comments.

1.5 Necessary Permits or Licenses

TVA holds the permits necessary for the current operation of SHF. To implement the proposed action, TVA would have to obtain or seek amendments to the following permits:

- Modification of SHF's existing Title V air operating permit would be needed to reflect the new plant configuration and associated emissions.
- Modifications to the Integrated Pollution Prevention Plan would be made for any switchyard modifications.
- A Risk Management Plan would be developed for the addition of new ammonia handling facilities required for SCR operations.
- An updated flow schematic for hydrostatic testing would be submitted to the Kentucky Division of Water, if necessary, for pipe system integrity testing.
- SHF Best Management Plan would be revised to include management of precipitation into secondary containment for ammonia tanks.
- A modification of SHF's Special Waste permit would be needed to store the scrubber residue in the on-site landfill.

2. ALTERNATIVES

Description of Alternatives

This chapter describes the alternatives TVA evaluated in detail for this review. Alternatives evaluated in detail include:

- Alternative A – No Action Alternative (i.e., Continue Operation of SHF Units 1 and 4 with No Additional Controls)
- Alternative B – Retire SHF Units 1 and 4
- Alternative C – Install SCR and FGD Systems on SHF Units 1 and 4

This chapter also discusses the alternatives that TVA considered, but rejected from detailed analysis because they did not meet the Purpose and Need of TVA's proposed action, or were otherwise unreasonable.

2.1.1 Alternative A – The No Action Alternative

Under the No Action Alternative, TVA would continue the current operation of SHF Units 1 and 4 without implementing measures to further reduce SO_2 and NO_x emissions to comply with the USEPA Clean Air Agreements. Unless the USEPA Clean Air Agreements were changed, TVA could not continue to operate these two units without violating those agreements. To stay in compliance, TVA would have to retire the units by December 31, 2017. This alternative would not meet the Purpose and Need for this proposed action and therefore is not considered viable or reasonable. It does provide, however, an appropriate benchmark or baseline for determining the environmental impacts of Alternatives B and C, the proposed action.

2.1.2 Alternative B – Retire SHF Units 1 and 4

Under this alternative, TVA would retire SHF Units 1 and 4 by December 31, 2017. This alternative, like Alternative C, is included in the USEPA Clean Air Agreements. Following the retirement of SHF Units 1 and 4, TVA would take necessary measures to stabilize and maintain them. Components of the two units could be removed for use at other generating units. TVA would eventually have to decide on their long-term future treatment, including whether to leave them in place or to partially or fully dismantle or demolish them. This future decision is outside the scope of this EA. TVA is not required to dismantle or demolish retired coal units and it has taken more than 25 years to do this in the past. Due to the arrangement of Units 1 and 4 in relation to the other seven units, TVA would likely not consider demolishing the two units while the other units are still operating. Any future component removal, dismantling, or demolishing actions would done in compliance with applicable environmental regulations.

Retiring SHF Units 1 and 4 would not require TVA to procure or build replacement energy resources in the Paducah area to maintain reliability. There is a general system need for more generation in the future, but this is not needed at SHF. Continued operation of these two units would help meet this general need. The addition of new energy resources on the TVA system is addressed in TVA's 2011 IRP and EIS, both of which are being updated. TVA's least-cost system planning analysis in its IRP will help guide its selection(s) of the type and amount of new energy resources in the future.

2.1.3 Alternative C – Install and Operate SCR and FGD Systems on SHF Units 1 and 4

Under Alternative C, TVA would install and operate FGD and SCR systems on SHF Units 1 and 4. The location and arrangement of the major components associated with Alternative C are illustrated in Figures 2-1 and 2-2. The SCR systems would be constructed in the location of the non-operational electrostatic precipitators which would be removed and sold for scrap metal. The 250-foot tall original emission stacks for Units 1 and 4 would be demolished and the new FGD systems would be located in the area of these stacks. The demolition material from the stacks would either be disposed of in a permitted landfill or utilized as fill or stabilization material such as rip-rap. Additional actions would include potential changes to the dry fly ash piping systems to allow segregation of the new scrubber CCRs, extensions of on-site electrical components, and ancillary facilities such as haul roads, stock piles, and laydown areas. The total land disturbance anticipated under Alternative C to support operations is negligible as all of the proposed additions are on areas already heavily impacted by plant operations.

TVA currently burns low-sulfur coal, primarily from the PRB, at SHF. TVA would conservatively design the FGD system to accommodate a blend of at least 50 percent higher-sulfur Illinois Basin (ILB) coal and 50 percent PRB coal. Designing the FGD systems to burn higher-sulfur coal gives TVA the flexibility to switch coals in the future to take advantage of changing market conditions while maintaining compliance with applicable regulations. SHF currently has the ability to receive and blend coal from different sources and a change to use of ILB coal would not require modifications to coal receiving and blending equipment.

FGD Systems

FGD systems inject a calcium-based reagent into the flue gas stream from the boiler. The reagent reacts with the SO_2 in the flue gas to form calcium sulfite and/or calcium sulfate compounds. The calcium sulfite and/or calcium sulfate, as well as any unreacted reagent, is then captured by the particulate control system and either stored in a landfill or recycled for beneficial uses. TVA operates FGD systems on several of its coal plants; these systems use a wet scrubber process which uses limestone as the reagent mixed with large volumes of water to remove SO_2. Wet FGD systems work well, but produce a wet CCR that can pose more difficult management and regulatory challenges than dry FGD systems. TVA is currently installing a newer design dry scrubbing system on its Gallatin Fossil Plant and proposes to install dry scrubbing systems at SHF.

Dry FGD systems, known generically as “dry scrubbers,” force maximum contact between flue gas and a scrubber reagent. Most often, the reagent used in dry scrubbers is calcium hydroxide [$Ca(OH)_2$], also known as hydrated lime, slaked lime, and pebble lime. Dry scrubbers typically use high rates of recirculation of the reaction product. A majority of the reacted calcium is collected as calcium sulfite ($CaSO_3$). A dry scrubber generally requires a precipitator or fabric filter/baghouse to collect the dry product particulate generated from the reaction. Particulate collection is typically downstream of the scrubber and the particulate consists of a mixture of the calcium salts and fly ash.

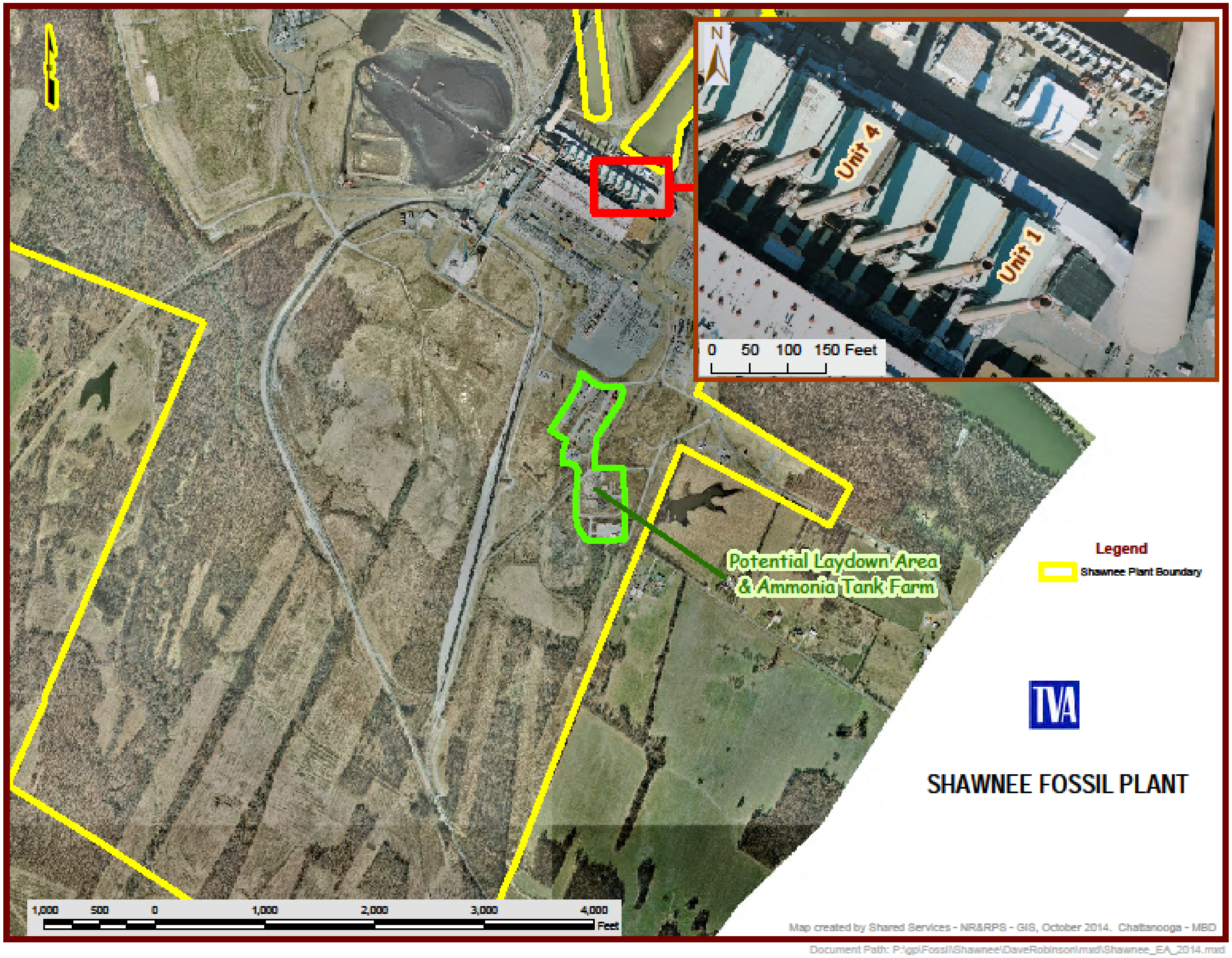

Figure 2-1. Location of Units 1 and 4 and Construction Laydown Area and Ammonia Tank Farm

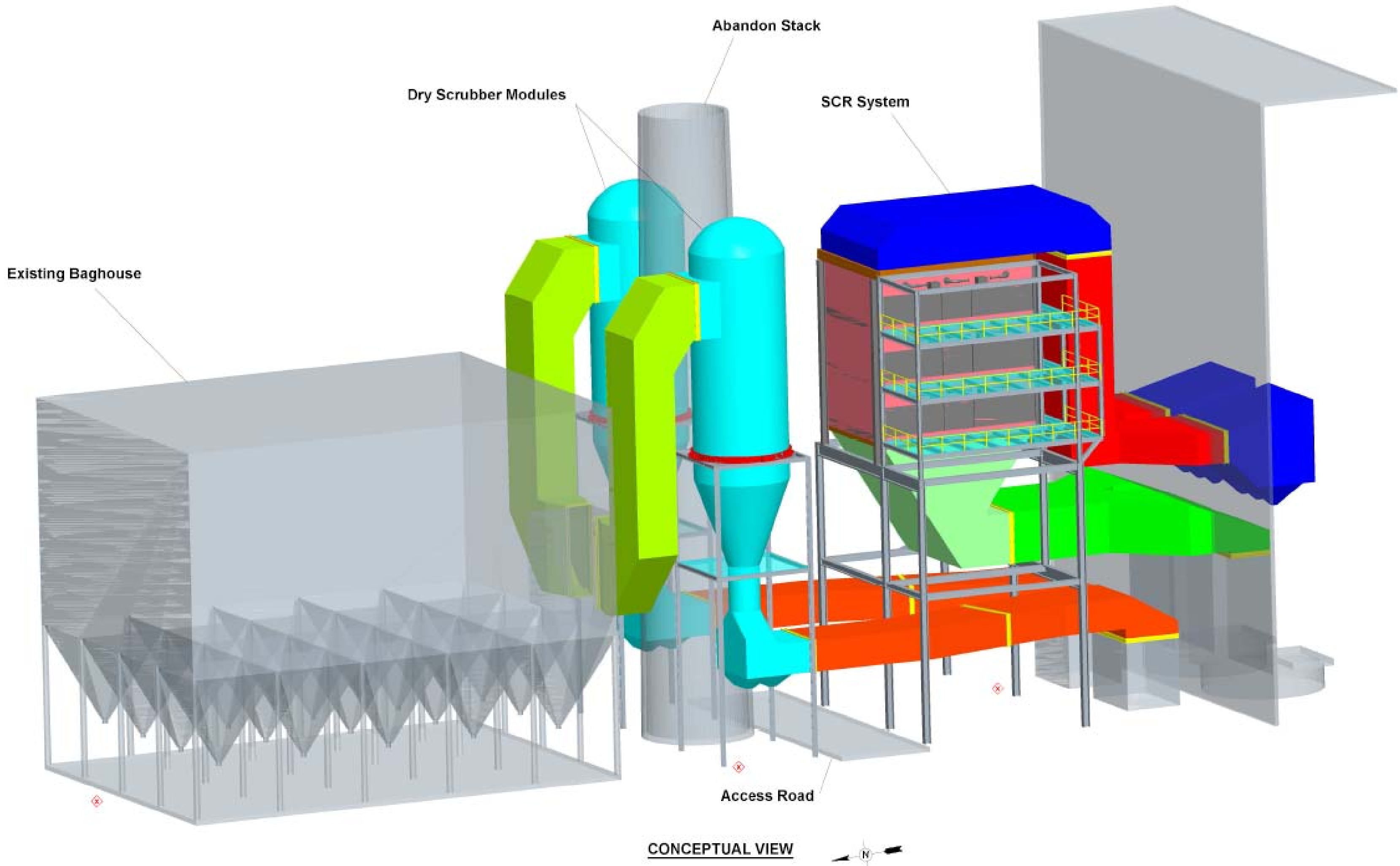

Figure 2-2. Layout of Major Components

A dry FGD system, utilizing lime, would be installed to control SO_2 and acid gases and to enhance mercury capture by the fabric filter PM control device. Dry scrubber costs have continued to decrease, largely because of technical innovations, and are increasingly being recognized as an important part of a comprehensive air control program. The following dry FGD systems were evaluated:

- Spray drying absorber (SDA)
- Circulating dry scrubber (CDS)
- Novel integrated desulfurization

TVA identified the dry scrubber technologies as suitable for SHF, and has not yet determined which is preferred. All three systems would utilize lime as the base reagent to remove SO_2. In the CDS system, dry lime and water are injected into the scrubber modules. In the SDA system, a mixture of lime and water is injected into the scrubber modules. Upon injection, the hydrated lime bonds with SO_2 in the flue gas and fly ash to produce calcium sulfite and water. The calcium salts and fly ash are disposed of by transfer to a landfill.

The fundamental scrubbing reaction is as follows:

$CaO + H_2O \rightarrow Ca(OH)_2$ $Ca(OH)_2 + SO_2 \rightarrow CaSO_3 + H_2O$

The basic schematic for the SCR and FGD systems is represented in Figure 2-2. Lime would be mixed with raw water in the hydrator/mixer. The hydrated lime is injected into the flue gas stream to a react with the SO_2. The FGD systems would utilize the existing baghouse to separate the gas from the solid material. T he process includes a disposal bin for small quantity, short-term storage of CCRs. The amount of water added to FGD systems is minimal, allowing the dry handling of CCRs. Raw water from the Ohio River would be used from a process water supply line for each unit.

Continued operation of the existing SHF Units 1 and 4, as proposed in Alternative C, would result in the generation of up to about 180,000 tons per year of CCRs, an increase over the 73,000 tons per year currently produced by Units 1 and 4. The CCRs would consist of comingled FGD residue and fly ash collected in the baghouses, as well as the segregated bottom ash. The quantity of CCRs potentially produced was estimated based on the units running at full load 75% of the time and burning coals with a range of 0.64–3.1 pounds of sulfur per million British Thermal Units. The quantity of bottom ash produced by Units 1 and 4 would not change.

Dry FGD Reagent Delivery and Storage

Lime would be delivered to SHF by trucks equipped with a pneumatic unloading blower. The hydrated lime would be unloaded and conveyed to existing storage silos (one silo per unit) that are currently being installed for the Unit 1 and 4 DSI systems. These DSI systems would no longer be required for Units 1 and 4 after installation of the FGD systems. A self-contained vent filter mounted on each silo roof would control fugitive dust during receiving operations.

Dry FGD Reagent Preparation and Feed

The lime would be conveyed from the silos to the FGD bins or to the scrubber vessels using a positive-pressure pneumatic conveying system. Lime from the bins would then be gravity fed to a hydrator/mixer where raw water is added to form the $Ca(OH)_2$.

FGD Residue Handling and Storage

Mixed fly ash and FGD residue (primarily calcium salts), would be collected from the FGD exhaust stream by the existing baghouses. It would then be conveyed utilizing pneumatic conveying systems to existing byproduct storage silos. CCRs would then be loaded into trucks and transported to the dry stack for disposal.

SCR Equipment

Units 1 and 4 would be retrofitted with SCR system designed to reduce NO_X emissions by approximately 90 percent, given an inlet NO_X concentration of 0.46 pounds/million Btu of heat input to the boilers. The SCR systems (Figure 2-2) are designed to convert NO_X in the boiler flue gas to nitrogen gas and water vapor. The reduction is accomplished by a chemical reaction, using ammonia facilitated by a catalyst. The SCR systems inject ammonia into the flue gas stream upstream of the scrubbers. The flue gas – ammonia mix passes through a catalyst bed where NO_X in the flue gas stream reacts with the ammonia to form nitrogen and water vapor. New duct systems would connect the flue gas exiting the SCR reactors to the FGD systems.

The emission of unreacted ammonia is caused by the incomplete reaction of injected ammonia with NO_x present in the flue gas. SCR catalysts gradually deactivate, resulting in the incomplete reaction of ammonia and NOx, increased NOx emissions, and emissions of unreacted ammonia. The catalysts are therefore periodically replaced or rejuvenated during scheduled unit outages to maintain the needed NOx reduction. To retain optimal NOx removal between scheduled outages, the ammonia injection rate may need to be gradually increased to make up for catalyst deactivation. Increasing the amount of ammonia injected can increase the amount of unreacted ammonia that slips through the system, which could increase the ammonia-on-ash concentration. SCR optimization programs at TVA's Colbert, Cumberland, Kingston, Paradise, and Widows Creek Fossil Plants have enabled TVA to sustain high NOx removal rates while extending the SCR catalyst life until the next scheduled outage. This is accomplished by increasing slip up to values that do not cause violations of applicable opacity standards. TVA would employ a comparable process for SCR optimization at SHF.

Anhydrous Ammonia Delivery and Storage

To support SCR system operations, a new anhydrous ammonia tank farm and vaporizer system would be constructed. The new tank farm and vaporizer system would consist of two 18,000-gallon tanks, ammonia liquid forwarding pumps and vaporizers mounted on skids, and associated truck unloading equipment, piping, valves, and instrumentation. The anhydrous ammonia would be delivered to the tank farm by truck. Any liquid including runoff from the unloading operations area would be contained in a compacted-earth catch basin surrounding the storage tank and unloading area. The containment would be sized for storm water runoff from a 10-year, 24-hour event, the content of one tank and the deluge system associated with catastrophic release. Following testing, any spilled material would be handled and disposed of as required by applicable regulations.

Anhydrous Ammonia Preparation and Feed

Anhydrous ammonia vapor from the tank farm vaporizers would be piped to an ammonia injection grid where the vapor and dilution air would be injected into the SCR reactor inlet duct. A device to control ammonia flow would be provided for each unit's SCR to control the vaporized ammonia flow.

Electrical System Components

Initial studies indicate that operating the proposed FGD and SCR systems would require approximately 955kW of 480-V or lower voltage power. Based on this projected power requirement, TVA expects sufficient electrical capacity can be provided by a combination of the existing power feed and distribution system serving the operating units and the power feed and distribution system that previously served Unit 10. In the event that detailed engineering studies show the need for a new power source to serve the SCR and FGD systems, a subsequent tiered environmental review would be conducted as necessary. Any new power supply system would likely be constructed in the immediate vicinity of the powerhouse and switchyard.

TVA is refining its capital cost estimates for installing the proposed SCR and FGD systems on SHF Units 1 and 4. Current total capital costs are estimated at $175 to $225 million.

2.1.4 Alternatives Considered but Eliminated From Further Discussion

Shawnee Units 1 and 4 provide approximately 268 MWs of capacity. The units are small and flexible and have the ability to provide needed regulation services to the power system. The generation from these units is part of the overall TVA system which includes resources of various fuel types designed to achieve the balanced portfolio goal in the 2011 IRP.

Repower Units 1 and 4 to Burn Renewable Biomass Fuel

One of the options listed in the USEPA Clean Air Agreements is to convert Units 1 and 4 from burning coal to burning 100 percent biomass fuel. TVA has previously considered converting various coal-fired units, including units at SHF, to burn 100 percent biomass, but did not proceed with those projects because of capital and operating cost considerations. It is estimated it would cost $1,000 to $3,000 per kilowatt to convert these units to burn 100 percent biomass. The major components of this cost are the boiler modifications, environmental controls, and new biomass fuel handling equipment.

Converting a unit that was designed to burn coal to burn 100 percent biomass would reduce the capacity of that unit by 35 to 50 percent and increase the heat rate of the unit. Heat rate is the amount of energy needed to produce a given quantity of energy, and measures the efficiency of the generating unit. A higher heat rate indicates less efficient generation. Such a loss in generation would increase the need for additional energy resources that TVA projects will be needed to serve future demand on the TVA power system. Since the biomass would likely cost more than coal on a dollar per unit of heat basis, the higher fuel cost combined with the increase in the net heat rate would increase the dispatch cost of the unit (the operational cost).

Approximately two to three million tons of green biomass (at 50 percent moisture by weight) would be needed annually if there was no reduction in capacity as a result of the repowering. The USEPA Clean Air Agreements define the types of biomass that can be used to in the repowered units, and this eliminates a few potential biomass sources. A biomass supply assessment conducted a few years ago showed that a sufficient quantity was likely available, but there were several concerns over cost and reliability of the supply. In addition to sourcing from nearby suppliers (i.e., within a 100- to 150-mile radius), delivery of biomass by barge from more distant sourcing areas would likely be necessary.

Due to the high cost of converting the units to burn biomass and uncertainties over the fuel supply, this alternative was considered unreasonable and was eliminated from detailed consideration.

Retire Units 1 and 4, Rely on Energy Efficiency or Renewable Energy

TVA received a number of comments during the scoping period asking that this EA evaluate replacing generation from SHF Units 1 and 4 with energy efficiency or renewable energy resources (solar or wind). As discussed above, SHF Units 1 and 4 are not needed to meet the real and reactive power needs of the Paducah area. If TVA retired these units, it would not be necessary to replace them with new generation at or near Shawnee. However, TVA demand forecasts indicate that there will be a general need for more generation on the TVA system in the future. TVA's 2011 IRP and EIS address future demands for electricity from the TVA power system, energy resources that could be used to address those demands, and the environmental impacts associated with those resources. TVA is in the process of updating the 2011 IRP and EIS and expects to issue both in draft for comment in early 2015 and in final in late summer 2015.

The energy resources that could be used to address future generation needs somewhere on the TVA system include traditional resources like nuclear and natural gas generation as well as renewable energy resources and energy efficiency. Both the 2011 IRP EIS and the supplement to it currently being prepared are programmatic in nature. Site specific impacts of the energy resources that TVA may propose to meet future generation needs would be addressed in a proposal- and site-specific environmental review. That cannot be done at this time because TVA has not yet made such a proposal.

2.2 Comparison of Alternatives

The environmental impacts of Alternatives A, B, and C are analyzed in detail in this EA and are summarized in Table 2-1. These summaries are derived from the information and analysis provided in the Affected Environment and Environmental Consequences sections of each resource in Chapter 3. As the baseline for analysis, the No-Action Alternative presumes continued operation of Units 1 and 4 even though this would violate the USEPA Agreements unless those are changed. In all likelihood, TVA would not be able to continue to operate the units legally; hence the impacts of Alternative A actually would be the same as Alternative B.

Table 2-1.
Summary and Comparison of Alternatives by Resource Area

Resource Area	Impacts from the No Action Alternative A	Impacts from Action Alternative B	Impacts from Action Alternative C
Air Quality and Climate Change	Emissions continue at current levels, unless or until the units cease operating	SHF emissions would be reduced 22 percent	Insignificant short-term increase in fugitive dust and CO_2 emissions during construction. Beneficial impact from ca. 22 percent reduction in SHF emissions of NOx and SO2. Insignificant impacts from increase in direct and indirect GHG emissions.
Noise	No change in area sound environment until Units 1 and 4 cease operation, then slight reduction in noise	Slight reduction in noise following retirement of Units 1 and 4	Short-term, minor increase in noise during construction. Negligible effect on noise levels during plant operations.
Visual Resources	No change in appearance of SHF	Same as Alternative A	Small change in appearance of SHF due to demolition of two stacks. Other construction activities result in negligible change.
Groundwater	Negligible effect on groundwater	Same as Alternative A	No impacts on nearby groundwater users. Insignificant impact on receiving streams from slight increase in ammonia and nitrogen transported by groundwater into receiving streams.
Surface Water	No change until Units 1 and 4 unless or until the units cease operating	An approximate 22 percent reduction in water withdrawals and discharges	Minor temporary impacts during construction. Small operational change in water consumption and no change in thermal discharge. Insignificant impact on water quality with implementation of design and permit requirements.
Cultural and Historic Resources	No effects on historic properties	Same as Alternative A	Adverse effect on historic property from demolition of two original stacks, will be mitigated

Table 2-1.
Summary and Comparison of Alternatives by Resource Area

Resource Area	Impacts from the No Action Alternative A	Impacts from Action Alternative B	Impacts from Action Alternative C
Solid and Hazardous Waste	No change until Units 1 and 4 unless or until the units cease operating	An approximate 22 percent reduction in water withdrawals and discharges	SHF CCR production increased by ca. 40 percent with reduction in CCR beneficial reuse. Impacts from CCR handling and on-site storage insignificant.
Socioeconomics and Environmental Justice	No change until Units 1 and 4 unless or until the units cease operating	Insignificant impacts from reduction in direct and indirect employment. No disproportionate adverse effects on minority or low income populations	Short-term beneficial impacts from construction-related employment and related economic activity. Minor long-term beneficial impacts during operation. No disproportionate adverse effects on minority or low income populations.
Transportation	No change until Units 1 and 4 unless or until the units cease operating	Small reduction in traffic on area roadways	Insignificant impacts from increased traffic during construction and operation

2.3 Identification of Mitigation Measures

Mitigation measures identified in Chapter 3 to avoid, minimize, or reduce adverse impacts to the environment are summarized below. TVA‘s analysis of selected alternatives includes mitigation, as required, to reduce or avoid adverse effects. Project-specific BMPs for Alternative C are also identified.

- Clean Air Act Title V operating permit conditions would be implemented.
- Fugitive dust emissions from site preparation and construction would be controlled by wet suppression and BMPs.
- Project specific BMPs would be developed as required, to ensure that all surface waters are protected from construction and operational impacts.
- Waste streams would be further characterized after operation of installed controls commences to ensure permit limits would be met, as required.
- Consistent with Executive Order 13112, disturbed areas would be revegetated with native or non- native, non-invasive plant species to avoid the introduction or spread of invasive species.

- BMPs would be used during construction activities to minimize and restore areas disturbed during construction.
- If necessary, emissions from construction areas, paved, and unpaved roads would be mitigated using wet suppression. From roadways and unpaved areas, wet suppression can reduce fugitive dust emissions by as much as 95 percent.
- TVA will implement one or more of the following mitigation measures as necessary to limit the potential impacts to surface water quality from ammonia discharges:
  - Adjusting pH in the Ash Pond - As compounds containing ammonia dissolve, and as natural microbial and algal processes for assimilating ammonia proceed, pH changes could occur. To ensure that the ash pond discharges meet the Kentucky Pollutant Discharge Elimination System permit limits for both pH and acute toxicity, and to ensure that the effluent being discharged to the Ohio River would not exceed the chronic criterion concentration for ammonia, the existing carbon dioxide system could be utilized to control the pH. Additional potential measures for managing ammonia discharges include the following:
  - Baffling the Ash Pond - Installation of baffles in the ash pond would improve mixing of the ash pond inflow with the free water volume of the pond. Mixing of 75 percent to 100 percent could be attained. Baffling the ash pond would increase the retention time of the water, which would improve mixing, and allow more time for chemical degradation and/or biological uptake of the ammonia.
  - Combining Mitigation Measures and/or Use of Other Treatment Systems - A combination of the mitigation methods could be used to effectively control the ammonia concentrations at Outfalls 001 and 002. Other options include, but are not limited to, passive treatment systems, such as constructed wetlands; addition of media for enhancing growth of nitrifying microorganisms in the ash pond; installation of aeration devices to improve dissolved oxygen concentrations to enhance aerobic microbial degradation of ammonia; and installation of conventional treatment systems, such as air stripping, trickling filters, recirculating sand filters, or biological treatment systems.
- Implement the measures stipulated in the Memorandum of Agreement with the Kentucky State Historic Preservation Office for mitigation of the adverse effect on historic properties.

2.4 The Preferred Alternative

TVA has identified Alternative C - Install and Operate SCR and FGD Systems on SHF Units 1 and 4 - as its preferred alternative. By implementing this alternative, TVA would comply with the USEPA Clean Air Agreements consistent with TVA's mission to provide reliable and affordable power and TVA's goal of maintaining a balanced portfolio of generation resources. These small coal-fired units have enhanced value on the TVA system because of their load following capabilities. The costs of installing the proposed SCR and FGD systems—$175 to $225 million—also are relatively low compared to those of emission controls installed at other TVA plants.

3. AFFECTED ENVIRONMENT AND ENVIRONMENTAL CONSEQUENCES

Air Quality and Climate Change

3.1.1 Affected Environment

Air Quality

Through its passage of the Clean Air Act, Congress has mandated the protection and enhancement of our nation’s air quality resources through various programs including the promulgation and attainment of National Ambient Air Quality Standards (NAAQS) (40 *CFR* Part 50). USEPA has established NAAQS to protect the public health and welfare for the following "criteria" pollutants:

- Sulfur dioxide (SO_2)
- Ozone
- Nitrogen dioxide (NO_2)
- Particulate matter less than or equal to 10 micrometers [µm] (PM_{10})
- Particulate matter less than or equal to 2.5 µm ($PM_{2.5}$)
- Carbon monoxide (CO)
- Lead

There are two types of NAAQS: primary standards (set to protect public health) and secondary standards (set to protect public welfare, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings). Primary and secondary standards are listed in Table 3-1.

Air quality in the Ohio Valley and the nation has steadily improved following the enactment of the Clean Air Act, subsequent amendments to that Act, and the promulgation of increasingly strict regulations by USEPA and the States. This has resulted in significant emission reductions from industrial and other categories of sources such as motor vehicles. Levels of all criteria pollutants have significantly decreased (USEPA 2013a). For example, from 1980 to 2013, nationwide ozone levels (8-hour) have decreased 33 percent. NO_x levels (annual) and SO_2 levels (24 hour) have decreased 60 percent and 81 percent, respectively. There has been a 34 percent reduction in 24-hour and annual levels of fine particulates from 2000 to 2013. Regional trends are similar to these national trends. These air quality improvements have resulted from the significant reductions in relevant emissions. Air quality is better today than it has been for decades and it will continue to get better as emission sources continue to make reductions.

The air quality in McCracken County in which SHF is located meets applicable federal and state air quality standards. McCracken County and the surrounding counties (Ballard, Carlisle, Graves, Marshall and Livingston) are all in attainment with applicable NAAQS. Table 3-2 lists the pollutant concentration values from monitors in McCracken County and from the Mammoth Cave area. These concentrations, which represent air quality from monitoring sites near SHF,

Table 3-1.
National Ambient Air Quality Standards (NAAQS)

Pollutant		Primary/ Secondary	Averaging Time	Level	Form	Final rule
Carbon Monoxide (CO)		Primary	8-hour	9 ppm	Not to be exceeded more than once per year	76 FR 54294, (Aug. 31, 2011)
			1-hour	35 ppm		
Lead		Primary and secondary	Rolling 3 month average	0.15 $\mu g/m^3$ [(1)]	Not to be exceeded	73 FR 66964, (Nov. 12, 2008)
Nitrogen Dioxide (NO_2)		Primary	1-hour	100 ppb	98th Percentile, averaged over 3 years	75 FR 6474, (Feb. 9, 2010)
		Primary and secondary	Annual	53 ppb [(2)]	Annual mean	61 FR 52852, (Oct. 8, 1996)
Ozone		Primary and secondary	8-hour	75 ppb [(3)]	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years	73 FR 16436, (Mar. 27, 2008)
Particulate Matter	$PM_{2.5}$	Primary and secondary	Annual	15 $\mu g/m^3$	Annual mean, averaged over 3 years	71 FR 61144, (Oct. 17, 2006)
			24-hour	35 $\mu g/m^3$	98th Percentile, averaged over 3 years	
	PM_{10}	Primary and secondary	24-hour	150 $\mu g/m^3$	Not to be exceeded more than once per year on average over 3 years	
Sulfur Dioxide (SO_2)		Primary	1-hour	75 ppb [(4)]	99th Percentile of 1-hour daily maximum concentrations, averaged over 3 years	75 FR 35520, (Jun. 22, 2010)
		Secondary	3-hour	0.5 ppm	Not to be exceeded more than once per year on average over 3 years	38 FR 25678, (Sept. 14, 1973)

FR = Federal Register; $\mu g/m^3$ = micrograms per cubic meter; PM = particulate matter; ppb = parts per billion; ppm = parts per million.

(1) The 1978 lead standard (1.5 micrograms per cubic meter [$\mu g/m^3$] as a quarterly average) remains in effect until one year after an area is designated for the 2008 standard, except that in areas designated nonattainment for the 1978 standard, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 standard are approved.

(2) The official level of the annual NO_2 standard is 0.053 parts per million (ppm), equal to 53 parts per billion (ppb), which is shown here for the purpose of clearer comparison to the 1-hour standard.

(3) The 1997 ozone standard (0.08 ppm, annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years) and related implementation rules remain in place. In 1997, the USEPA revoked the 1-hour ozone standard (0.12 ppm, not to be exceeded more than once per year) in all areas, although some areas have continued obligations under that standard (“anti-backsliding”). The 1-hour ozone standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is less than or equal to 1.

(4) The 1971 annual and 24-hour SO_2 standards were revoked in this rulemaking. However, they remain in effect until one year after an area is designated for the 2010 standard, except in areas designated nonattainment for the 1971 standards, where the 1971 standards remain in effect until implementation plans to attain or maintain the 2010 standard are approved.

Table 3-2.
Air Quality in the Vicinity of Paducah, KY

Monitor Location	Pollutant and Form	Concentration	Years
Mammoth Cave[(1)]	8-hour carbon monoxide	0.3 ppm	2012
Mammoth Cave[(1)]	1-hour carbon monoxide	0.3 ppm	2012
McCracken County, KY[(2)]	8-hour ozone 4th highest	87 ppb	2012
McCracken County, KY[(3)]	24-hour $PM_{2.5}$ 4th highest	17.8 µg/m^3	2012
McCracken County, KY[(2)]	1-hour SO_2 2nd highest	21 ppb	2012

United States Environmental Protection Agency Ambient Monitoring Data, Web site available: http://www.epa.gov/airquality/airdata/ad_maps.html.
µg/m^3 = micrograms per cubic meter; PM = particulate matter; ppb = parts per billion; ppm = parts per million; SO_2 = sulfur dioxide.

From Kentucky Division for Air Quality Annual report (KDAQ 2014).
[(1)] Mammoth Cave, Edmondson County, KY – closest carbon monoxide monitoring station to SHF.
[(2)] 2901 Powell Street, Paducah.
[(3)] 342 Lone Oak Road, Paducah.

are in the form used to determine attainment with NAAQS. Aside from the 8-hour ozone standard, the monitored pollutant concentrations are well below the standards. All areas in Kentucky have attained the old 1-hour ozone standard.

Individual States address NAAQS attainment through regulations and specific limits in permits issued to sources of emissions for the relevant pollutant. The Kentucky Division for Air Quality has issued TVA a Title V permit to operate the SHF coal-fired units and associated material handling operations and TVA has put in place equipment and practices at SHF to meet permit requirements.

The nine operating coal units at SHF emitted 27,211 tons of SO_2, 12,094 tons of NOx, and 180 pounds of mercury in 2013. Although not classified as a criteria pollutant and subject to NAAQS, mercury is considered a hazardous air pollutant and emissions are regulated by the 2011 MATS. Units 1 and 4 emitted a total of 6,253 tons of SO_2 and 2,905 tons of NO_x in 2013 (USEPA 2014a). Unit 1 and 4 mercury emissions in 2013 were about 2/9 of the total plant mercury emissions.

The DSI systems, presently being installed to reduce emissions of acid gases for compliance with MATS, are expected to reduce emissions of the acid gas hydrogen chloride by 80 – 90 percent. Prior to being injected into the flue gas ducts, the hydrated lime will be stored in silos and transferred by pneumatic conveyors. The operation of the DSI systems will result in a slight increase (about 3 tons/year each for total suspended particulates, PM_{10}, and $PM_{2.5}$) of particulate emissions.

Climate Change

Global climate change comprises the changes in the global environment (including alterations in climate, land productivity, oceans or other water resources, atmospheric chemistry, and ecological systems) that may alter the capacity of Earth to sustain life (U.S. Global Change Research Act 1990). The globally averaged combined land and ocean surface temperature data as calculated by a linear trend, show a warming of 0.85 [0.65 to 1.06] degrees Celsius (°C), over the period 1880 to 2012 (IPCC 2013).

The SHF region transitions between a humid yet cooler climate during winter months and a humid subtropical warmer climate during summer months. This provides the region with generally mild temperatures on average (i.e., a limited number of days with temperature extremes), ample rainfall for agriculture and water resources, vegetation-killing freezes from mid-autumn through early spring, occasional severe thunderstorms, infrequent snow, and infrequent impacts – primarily in the form of heavy rainfall – from tropical storms. The seasonal climate variation induces a dual-peak in annual power demand, one for winter heating and a second for summer cooling. Rainfall does not fall evenly throughout the year, but tends to peak in late winter/early spring and again in mid-summer. Winds over the region are generally strongest during winter and early spring and lightest in late summer and early autumn. Solar radiation varies seasonally with the maximum sun elevation above the horizon and longest day length in summer. However, solar radiation is moderated by frequent periods of cloud cover typical of a humid climate.

Greenhouse Gases

Human activities, such as fossil fuel combustion and land use changes, and natural processes release carbon dioxide (CO_2) and other compounds, cumulatively considered greenhouse gases (GHGs). GHGs are effective in trapping infrared radiation that otherwise would have escaped the atmosphere, thereby warming the atmosphere, the oceans, and Earth's surface (IPPC 2013). GHGs include CO_2, methane (CH_4), nitrous oxide (N_2O), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and hydrofluorocarbons (HFCs). The most abundant man-made GHG is CO_2. The major U.S. anthropogenic emission sources of CO_2 include combustion of fossil fuels; noncombustion uses of fossil fuels in producing chemical feedstocks, solvents, lubricants, waxes, asphalt, and other materials; iron and steel production; cement production; and natural gas extraction and transportation systems. The major U.S. emission sources of methane are ruminant animals (cows and sheep), landfills, natural gas extraction and transportation systems, and coal mining. HFCs, PFCs, and SF_6 are all industrial chemicals with no natural sources and emitted by various industrial activities (IPPC 2013). GHGs are present in the atmosphere naturally, released by natural sources, or formed from secondary reactions taking place in the atmosphere. In the last 200 years, substantial quantities of GHGs have been released into the atmosphere by human activities. These extra emissions are increasing GHG concentrations in the atmosphere, enhancing the natural greenhouse effect, which is considered to be causing or contributing to global warming (IPPC 2013).

The primary GHG emitted by human activity is CO_2 produced by the combustion of coal and other fossil fuels. Coal- and gas-fired electric power plants and automobiles are major sources of CO_2 in the United States (EIA 2013a). Forests and other vegetated landforms represent sinks of CO_2. GHG emissions are also affected by development activities associated with land or forest clearing and land use changes, as well as construction activities involving use of fossil -fuel-powered equipment (e.g., bulldozers, loaders, haulers, trucks, generators).

In 2013, worldwide man-made annual CO_2 emissions were estimated at 36 billion tons, with the U.S. responsible for about 14 percent (Le Quéré et al. 2014). Electric utilities in the U.S., in turn, emit 2.039 billion tons, roughly 32 percent of the U.S. total (USEPA 2014b). TVA emitted 72 million tons of CO_2 during 2013, a 32 percent reduction from 2005. These emissions are forecast to continue decreasing (TVA 2011b).

GHG emissions from SHF since 2006 have averaged about 7.65 million CO_2-equivalent tons per year (Table 3-3). Over 99 percent of these emissions are comprised of CO_2; the other main constituents are methane (about 2,100 tons/year) and nitrous oxide (about 36,200 tons per year; USEPA 2013b). Both methane and nitrous oxide have much higher global warming potential than CO_2. Units 1 and 4 accounted for about 2/9 (22.2 percent) of these emissions.

Table 3-3.
Current and Future GHG Emissions from Coal Combustion

Emission Source	Avg. Emissions 2006-2012 (Tons/Year)	2013 Actual Emissions (Tons/Year)[2]	2014 Estimated Emissions (Tons/Yr.)
SHF Coal Combustion – Greenhouse Gas (GHG) CO_2 equivalent[1]	7,644,830	7,934,617	7,650,000

[1] Includes carbon dioxide, methane, and nitrous oxide.
[2] As reported under 40 CFR Part 98 – GHG Reporting Rule.

3.1.2 Environmental Consequences

Alternative A – No Action Alternative

Under the No Action Alternative, TVA would continue current operation of SHF Units 1 and 4 without implementing measures to further reduce SO_2 and NO_x emissions. Unless the USEPA Clean Air Agreements were changed, TVA could not continue to operate these two units without violating those agreements. To stay in compliance, TVA would have to retire the units, and thus halt their emissions of air pollutants, by December 31, 2017. Assuming no change in dispatch of the remaining seven operating units, annual emissions would decrease by about 2/9 (22.2 percent) to 21,170 tons of SO_2, 9,409 tons of NO_x, 140 pounds of mercury, and 5.95 million tons of CO_2 equivalent greenhouse gases. These reductions would have beneficial effects in the region.

Alternative B – SHF Unit Retirement

Under this alternative, the impacts would be the same as those described under Alternative A, in that Units 1 and 4 would be retired and cease emitting air pollutants by December 31, 2017. The reduction in emissions of air pollutants would be the same as the reduction that would eventually occur under Alternative A. This retirement would not affect the operation of SHF Units 2, 3, and 5-9.

Alternative C – Install and Operate SCR and FGD Systems on SHF Units 1 and 4

Construction Impacts – Priority Pollutants

The construction activity associated with Alternative C would result in transient air pollutant emissions. Site preparation, and vehicular traffic over unpaved roads and the construction site result in the emission of fugitive dust during site preparation and active construction periods. The largest fraction (greater than 95 percent by weight) of fugitive dust emissions would be deposited within the construction site boundaries.

There would also be fugitive emissions from the transport of equipment and supplies on paved and unpaved roads. Currently, TVA's Title V permit allows no more than five minutes per hour or twenty minutes per day of visible fugitive emissions (dust) beyond the SHF property line. Fugitive emissions from demolition and construction activities would produce particles that would primarily be deposited near the site of the activity. Ninety-five percent (by weight) of fugitive emissions from vehicular traffic over paved roads would also be deposited near the roadways (AP-42 Paved Road emission factors, USEPA 1995). The remaining fraction of the dust would be subject to transport beyond the property boundaries or roadway right-of-ways. A large fraction of fugitive emissions from vehicle traffic in unpaved areas would also be deposited near the unpaved areas. These areas are required by the SHF Title V air permit to use wet suppression for dust control.

Finally, there would be emissions from the exhaust of internal combustion engines powering the machinery used for removal of existing structures and construction of new equipment, concrete, and earthen structures. Combustion of gasoline and diesel fuels by internal combustion engines (vehicles, generators, construction equipment, etc.) would generate local emissions of PM, NO_X, CO, volatile organic compounds, and SO_2 during the site preparation and construction period. The total amount of these emissions would be small and would result in no off-site impacts.

The project would comply with Kentucky regulations for fugitive emissions and SHF's Title V air operating permit conditions. Air quality impacts from demolition of the old precipitators and stacks and construction would be temporary, minimal, and dependent on both manmade factors (e.g., intensity of activity, control measures) and natural factors (e.g., wind speed, wind direction, soil moisture). However, even under unusually adverse conditions, these emissions would have, at most, a minor, transient impact on off-site air quality and be well below the applicable ambient air quality standard. Overall, the impact to air quality of the construction resulting under Alternative C would not be significant.

<u>Construction Impacts – Greenhouse Gases/Climate Change</u>

GHG emissions from demolition and construction would be short-term and dependent on manmade factors (e.g., intensity of activity, control measures). Assuming that construction would involve diesel engines with a total output of 3,000 horsepower, operating 40 hours per week for two years, the GHG emissions would be approximately 11,000 tons total over a two-year period. The 2009 estimate of CO_2 emissions in the world was almost 30 billion tons. By comparison, the GHG emissions from construction-related activities for the proposed actions would not be significant and would have negligible effects on climate change.

<u>Operation Impacts – Priority Pollutants</u>

Alternative C would result in substantial reductions to the current emissions of acid gases, mercury, NO_X and SO_2 from SHF Units 1 and 4 and contribute to the significant improvement in air quality that has been occurring since at least 1980. SCR systems would be designed and installed to reduce NO_x emissions by approximately 90 percent. The FGD systems would be installed to reduce up to 96 percent of SO_2 emissions. These systems would also control acid gases and enhance mercury capture by the fabric filter baghouses. If necessary to meet the MATS, activated carbon injection would be deployed to capture mercury. The combination of SCR, FGD, and baghouse systems would remove at least 86 percent of mercury emissions. Tests would be conducted to determine if carbon injection would be needed to attain the required mercury emission limit of 1.2 lb per trillion British thermal units (TBtu) based on heat input or 0.013 lb per GWh based on power output.

Compared to emissions from SHF following the retirement of Units 1 and 4, total SHF emissions under Alternative C would be about 1.2 percent greater for SO_2, 3.2 percent greater for NO_x, and 4 percent greater for mercury.

Fugitive emissions are expected to increase slightly in the future due to the transport of reagents required for pollution control and the transport and disposal of CCR. Under the proposed action, the volume of CCR generated from this project would be less than those from the operation of the now-retired SHF Unit 10.

All reagents would be conveyed to the fly ash transfer silos while the exhaust gas exits through the common stack for Units 1-5. The excess fly-ash material is mixed with water to about 15-20% moisture in a dust conditioner and discharged into trucks. The trucks haul and dump the ash material on the dry ash stack where it is then graded, compacted and covered with dirt. Fugitive emissions from the hauling of reagent and CCR would be minimized by using wet dust suppression. Wind erosion from the active part of the landfill would be controlled by keeping the disturbed area as small as possible and using wet suppression. Fugitive emissions must be controlled under the plant's CAA operating permit. Among other things, visible fugitive emissions cannot cross plant boundaries for more than 20 minutes in any 24 hour period according to the permit.

The additional fugitive emissions from all the material handling operations would be less than prevention of significant deterioration significance levels of 25 tons per year (TPY) for total suspended particulate, 15 TPY for PM_{10} and 10 TPY for $PM_{2.5}$.

Operation Impacts – Greenhouse Gases/Climate Change

The Council on Environmental Quality (CEQ) has issued draft guidance intended to assist federal agencies in analyzing environmental effects of GHG emissions and climate change in a NEPA document (CEQ 2010). CEQ recommends that agencies assess the impacts on GHG emissions and climate change from proposed actions that would directly emit 25,000 metric tons or more of CO_2-equivalent (CO_2e) GHGs per year. CEQ also recommends that agencies consider opportunities to reduce GHG emissions caused by their proposed actions and adapt their actions to future changes in climate.

The operation of the proposed SCR and FGD systems would result in a small increase in the current CO_2 emissions rate (tons per megawatt-hour of electricity generated) due to the energy required to operate the emission controls. Assuming that the mix of coal used in Units 1 and 4 remains the same, the quantity of direct CO_2 emissions would not otherwise change. A change to using higher-sulfur Illinois Basin coal, made possible by the installation of the FGD systems, would result in a small reduction in CO_2 emissions due to the lower CO_2 emission factor of bituminous Illinois Basin coal compared to sub-bituminous PRB coal (EIA 2013a).

Indirect CO_2 emissions would increase from the production and transportation of the hydrated lime used in the FGD systems. The major sources of CO_2 during the production of hydrated lime are from the reduction of carbonate to CO_2 when limestone is heated in the kiln and from the coal or natural gas combusted to heat the kiln. CO_2 emission factors for the production of hydrated lime range from about 1.2 to 1.6 tons of CO_2 emitted per ton of lime produced and are higher for coal-fired kilns (USEPA 1995). As described elsewhere in this EA, the quantity of hydrated lime used in the FGD systems varies greatly with the sulfur content of the coal being burned. Indirect hourly CO_2 emissions from the production of hydrated lime for Units 1 and 4 operating at full capability range from about 2.4 – 3.2 tons when burning western low-sulfur coal to 14.4 – 19.2 tons when burning a high-sulfur blend. At 2013 generation rates, using western low-sulfur coal, these annual indirect CO_2 emissions would be between 7,900 and 10,600 tons.

As described in the 2011 IRP EIS (TVA 2011b), TVA's overall GHG emissions are projected to substantially decrease in the future. IRP analyses considered the retirement of between 2,400 and 7,000 MW of TVA coal-fired generating capacity. Recent TVA decisions are moving retirements toward the upper end of this range. Any small incremental change in GHG emissions resulting from the proposed action, or from the retirement of the two units, is not expected to have a noticeable effect on climate change. Future climate change is also expected to have little or no effect on the operation of the various facilities proposed under Alternative C.

Resource Specific Mitigation Measures/BMPs

In addition to the proper operation of pollution control devices and dust suppression methods for controlling fugitive emissions as required by the SHF air operating permit, the following mitigation measure is being considered for maintaining air quality:

- If necessary, emissions from construction areas, paved, and unpaved roads would be mitigated using wet suppression. From roadways and unpaved areas, wet suppression can reduce fugitive dust emissions by as much as 95 percent.

Summary of Impacts

Significant adverse impacts associated with air quality and GHG emissions have not been identified under either Action Alternative. Implementation of either of the action alternatives would result in substantial emission reductions at SHF and help continue air quality improvements in the region. Under the No Action Alternative, emissions would not be reduced, and any associated air quality improvements would not result unless TVA retired the units to stay in compliance with the USEPA agreements.

3.2 Noise

3.2.1 Affected Environment

Noise is defined as any unwanted sound. Defining characteristics of noise include sound level (amplitude), frequency (pitch), and duration. Each of these characteristics plays a role in determining a noise's intrusiveness and level of impact on a noise receptor. A noise receptor can be any person, animal, or object that hears or is affected by noise. Sound levels are described on a logarithmic decibel (dB) scale, reflecting the relative way in which the ear perceives differences in sound energy levels. Frequency is measured in Hertz (Hz), and most common environmental sounds are composed of a composite of frequencies. While a normal human ear can usually detect sounds within the range of 20 and 20,000 Hz, humans are most sensitive to frequencies between 500 and 4,000 Hz (Federal Interagency Committee on Noise [FICON] 1992).

Noise measurements are typically weighted to correspond to the frequencies heard best by the human year. This adjusted unit of measure is known as the A-weighted decibel (dBA). Noise exposure measurements are frequently weighted to account for day-night differences and expressed as Day/Night Average Sound Level (DNL). Although there are no federal, state, or local regulations for community noise in the vicinity of SHF, USEPA guidelines (USEPA 1974) recommend that, to protect public health with an adequate margin of safety, exterior noise levels should not exceed 55 dB in noise-sensitive locations. The Federal Interagency Committee on Noise took this into consideration when developing its recommendations on noise impacts (FICON 1980). TVA generally uses noise levels of 55 dBA day/night level at the nearest residence and 65 dBA at the property line in industrial areas to assess the noise impact of a proposed action. Additionally, TVA considers an increase of 3 dB an indication of potential impact that would require further analysis in areas with an existing day/night level of 65 dBA or less.

There are numerous noise sources at SHF. The main sources are coal delivery and unloading, ash-handling activities, and plant equipment such as induced draft fans, conveyors, and the ball mill. Although there are no recent noise measurements at SHF, measurements at other TVA coal plants (e.g., Paradise (TVA 2013)) show on-site noise levels of 59 to 78 dBA.

The SHF plant is bordered to the north by the Ohio River and to the east, south, and west by a mix of forest, farmland, and rural residences. The nearest off-site sensitive noise receptor is a residence 0.45 mile southeast of the powerhouse.

3.2.2 Environmental Consequences

Alternative A – No Action Alternative

Under Alternative A, there would be no change in noise levels until such time as Units 1 and 4 are retired. At that time, there would be a slight decrease in noise levels, although it may not be perceptible in the surrounding area because of the continued operation of the other seven units.

Alternative B – SHF Unit Retirement

The noise impacts of Alternative B would be the same as those described for Alternative A.

Alternative C – Install and Operate SCR and FGD Systems on SHF Units 1 and 4

Under Alternative C, the major demolition (of the old Unit 1 and 4 precipitators and stacks) and construction activities would occur in the immediate vicinity of existing, operating plant components. Demolition and construction activities would result in short-term impacts during the 18–24 month construction period. Most of the construction would occur during the day on weekdays, although construction could also occur at night or on weekends. Typical construction equipment noise levels range up to about 85 dBA (TVA 2013). Construction activities would increase traffic on roads near the plant, which would also increase intermittent noise at some area residences and other noise receptors. Although construction noise levels could exceed 55 dBA at the nearest sensitive receptor (the residence), any exceedance would be intermittent and short-term and unlikely to cause a prolonged adverse impact. The operation of the SCR and FGD systems and associated infrastructure would not introduce any new sources of noise that would have a noticeable effect on the current noise levels from plant operations and would have a negligible effect on off-site noise levels.

Summary of Impacts

Overall noise impacts from construction and operation of the proposed FGD and SCR systems would be insignificant.

3.3 Visual Resources

3.3.1 Affected Environment

SHF is located in a predominantly rural area adjacent to the Ohio River. The 1,696-acre plant reservation is bordered by the river on the north and a mix of forest, wetlands, and farmland on the east, south, and west. Adjacent lands to the west and south/south-west are part of the West Kentucky Wildlife Management Area. Immediately east of the plant is the Metropolis Lake State nature Preserve. These areas are accessible to the public for boating, fishing, hunting, and wildlife observation. The former U.S. Enrichment Corporation (USEC) / Department of Energy (DOE) gaseous diffusion plant, a large industrial complex, is located about 2 miles southwest of SHF.

The most prominent plant features visible from public accessible areas are the two 800-foot tall stacks, the nine 250-foot tall stacks, transmission lines and towers. Exhaust plumes from the stacks are visible under some weather conditions. The lower-profile main plant buildings and switchyard are also visible from some nearby areas.

3.3.2 Environmental Consequences

Alternative A – No Action Alternative

Under the No Action Alternative, there would be no immediate change in the appearance of SHF. The eventual retirement of Units 1 and 4 would not result in a noticeable change in the appearance of SHF as the other seven units would continue to operate.

Alternative B – SHF Unit Retirement

The impacts of Alternative B would be the same as those of Alternative A.

Alternative C – Install and Operate SCR and FGD Systems on SHF Units 1 and 4

The proposed SCR and FGD systems would be installed in the area of the 250-foot stacks for Units 1 and 4, between the main powerhouse building and the baghouses (Figure 2-1). The Unit 1 and 4 stacks would be demolished, which would alter the appearance of the main plant area. Otherwise, the change in the appearance of the main plant area would be minimal and not readily visible to the public. The proposed laydown area and ammonia tank farm site (Figure 2-1) is near the periphery of the plant site. It is largely paved and/or graveled and has been used as a surplus equipment and scrap storage area. Its use as a laydown area and ammonia tank farm would not detract from the overall appearance of the plant site.

3.4 Groundwater

3.4.1 Affected Environment

SHF lies at the northwestern limit of the Mississippi Embayment and within the Gulf Coastal Plain Physiographic Province. The predominant natural physiographic features of the site, most evident prior to plant construction, are the recent floodplain of the Ohio River and the low upland terrace developed on loess deposits (Kellberg 1951). The floodplain along the south bank of the river averages about 2,000 feet in width and generally lies at or above approximately 320 feet mean sea level (msl). The floodplain is characterized by a natural levee immediately adjacent to the river and a lower, locally swampy area, extending south of the levee to the base of the upland terrace. At the southern margin of the floodplain, the topography rises some 20 to 30 feet to a relatively flat upland terrace bench. Most of the plant facilities are situated on this terrace (TVA 2005).

The plant site is underlain by more than 300 feet of unconsolidated deposits of clay, silt, sand, and gravel, ranging from Cretaceous to Holocene in age. These deposits include, in descending stratigraphic order, Holocene alluvium within the floodplains of the Ohio River, Little Bayou, and Bayou Creeks; Pleistocene loess occupying the upland terrace region; Plio-Pleistocene alluvial terrace deposits; the McNairy formation (Upper Cretaceous); and the Tuscaloosa formation (Upper Cretaceous). Bedrock at the site consists of the Warsaw limestone (Mississippian) and lies at approximate elevation of 6 feet above mean sea level (Kellberg 1951). Bedrock surface dips to the southwest toward the axis of the Mississippi Embayment (Davis et al. 1973).

Because the dry ash stack is the primary focus of groundwater quality impacts presented later in this section, the remainder of the site description focuses on the hydrogeologic conditions in this region of the plant site.

Plio-Pleistocene-age alluvial terrace deposits lie directly below a large portion of the site, including the dry ash stack. Most if not all of the loess originally present above the terrace deposits is believed to have been removed during construction of the former ash pond. The upper portion of the terrace deposits are fine-grained and lenticular, consisting of variable mixtures of clay, silt, and fine sand. Thickness of the upper terrace sediments ranges from 4 – 25 feet and averages 9 feet in the landfill area. These sediments are distinct from the lower part of the terrace deposit, which is composed predominantly of rounded quartz (chert) gravel with sand and very small amounts of clay and silt. Occasional sand lenses occur within the gravel unit, and fairly continuous micaceous sand was encountered below the gravel layer at most borings. The lower gravel unit and associated sand layers are commonly referred to as the Regional Gravel Aquifer (RGA), the principal aquifer in the area. Historic borings in the landfill area indicate RGA thicknesses of 30 – 65 feet, with an average thickness of 47 feet. Regionally, the RGA is thinnest near the Ohio River, with thickness increasing with distance from the river (Boggs and Lindquist 2000).

The McNairy formation was encountered below the RGA at all borings in the dry stack area although penetration depths were 10 feet or less. The McNairy consists of lenticular deposits of green-to-gray sandy clay and fine micaceous sand.

The first occurrence of groundwater below the vicinity of the dry stack area is within the basal ash fill deposits of the underlying former ash pond. Boring data suggest that isolated regions of saturated ash form in areas where infiltrating water accumulates above an underlying clay or silt layer. These perched groundwater zones do not appear to be laterally continuous and do not constitute usable aquifers.

A June 2000 study that measured the potentiometric levels of groundwater in the upper RGA indicated mounding of the potentiometric surface in the dry stack area. The overall potentiometric surface configuration suggested that groundwater originating within the limits of the dry stack area ultimately discharges to Little Bayou Creek and to the Ohio River. (Boggs and Lindquist 2000). Because discharge is to these water bodies, there is no potential for contamination of any private groundwater supplies located on properties bordering SHF.

The current facility solid waste permit (permit number SW07300041) requires both groundwater sampling (twice per year) and surface water sampling (every 6 months). The sampling parameters required by this permit for groundwater are boron, total organic carbon, chemical oxygen demand, chloride, dissolved copper, fluoride, groundwater elevation, molybdenum, total dissolved solids, specific conductance, sulfate, temperature, vanadium, and pH. Copper and fluoride are the only two constituents that have upper limits while all other constituents must meet statistical limits or are report only. The sampling parameters required for surface water are boron, calcium, chloride, total suspended solids, sulfate, and pH. These samples are to be collected at four separate locations in the Ohio River and Little Bayou Creek (LBC). (TVA 2013a)

The SHF dry stack was placed in Groundwater Assessment Monitoring status in February 2011. This action resulted from statistical exceedances for several naturally occurring sample constituents. Elevated levels of turbidity, due to the retention of colloidal soil particles in collected groundwater samples, have been found in several SHF groundwater monitoring wells. These colloidal soil particles contain varying levels of naturally occurring elemental metals which when analyzed in groundwater samples can result in elevated levels of constituents in the laboratory analysis. Historical data collected from the site indicates there have been a few exceedances of regulatory maximum contaminant level (MCLs) but it appears these exceedances can be attributed to turbidity. Assessment monitoring at the site is on-going and requires the implementation of an assessment plan, which details more frequent monitoring to determine impacts of the CCR wastes in the dry stack. Elevated gross beta (a measurement of beta-particle emitting radionuclides) has been detected in a monitoring well up gradient of the SHF ash disposal facilities. This is attributed to historical contamination of the underlying RGA from a plume of technetium-99 originating up-gradient of SHF, likely from the USEC/DOE plant site. The SHF plant site lies within the DOE Water Policy Boundary, which restricts use of ground and surface water. Property owners residing within this boundary have agreed to use public water supplies to preclude potential health effects of the DOE contaminant plumes.

3.4.2 Environmental Consequences

Alternative A – No Action Alternative

Under the No Action Alternative, there would be no changes to groundwater while the plant continues to operate. As required by the USEPA Agreements, TVA would have to retire Units 1 and 4 by the December 31, 2017, USEPA Clean Air Agreement deadline. Because the other seven units would continue to operate and CCRs would be stored onsite, there would be little associated change in groundwater conditions following retirement of the two units.

Alternative B – SHF Unit Retirement

The impacts of Alternative B would be the same as those of Alternative A.

Alternative C – Install and Operate SCR and FGD Systems on SHF Units 1 and 4

Construction Impacts

Construction of the proposed SCR and FGD systems would require little excavation or other activities that would affect local groundwater resources. Therefore construction impacts to groundwater would be insignificant.

Operational Impacts

Ammonia-laden leachate from dry stacked ash produced by the Units 1 and 4 once the SCR systems are operating represents a potential source of groundwater contamination. Otherwise the additional CCRs generated by Units 1 and 4 would not vary significantly from waste previously generated from the recently retired Unit 10 and disposed of in the SHF special waste landfill. Dry ammoniated ash from Units 1 and 4 would be mixed in pug mills with ash from the other seven units and deposited on the active dry stack area. To limit ammonia loads from the dry stack, TVA would restrict the amount of dry fly ash exposed to 10 acres or less. The ammonia content of the mixed ash is estimated to be approximately 99.3 mg NH_3-N/kg ash (see Section 3.5.2). Interim cover consisting of bottom ash or vegetated soil would be applied to inactive stack surfaces to control dust. The ash stack would ultimately be capped and closed in accordance with facility permit requirements.

A hydrologic water budget analysis of the SHF dry ash stacking area reported by Lindquist et al. (1992) indicates that from 7 – 8 percent of precipitation contacting the stack surface would be expected to form leachate. Ammoniated leachate would seep downward through the partially saturated ash, exit through the base of the stack, and enter underlying older saturated ash deposits associated with a former ash pond. Once in the shallow saturated ash, Lindquist et al. (1992) indicate that part of the leachate would migrate horizontally with ambient groundwater flow to LBC, while the remaining leachate would be transported downward to the RGA where it would then migrate to the Ohio River. Ammoniated leachate migrating from the disposal site would not traverse private property regardless of whether flow is to LBC or the Ohio River. Consequently, there would be no impacts to existing or future groundwater users in the site vicinity.

Geochemical and hydrological studies of Lindquist et al. (1989 and 1992), Fryar et al. (2000), LaSage (2004), and Mukherjee (2003) indicate that the reach of LBC adjacent to the dry ash stack and ash pond areas receives shallow groundwater recharge from at least portions of the ash disposal areas. The estimated rate of ammoniated leachate seepage from the disposal area to LBC would be 2.5 cubic meters (m_3)/day based on groundwater flow modeling predictions of Lindquist et al. (1992). Assuming complete leaching of ammonia from the mixed ash by infiltrating precipitation, the NH_3-N concentration of the leachate would be approximately 128 mg/L. (This estimate assumes complete leaching of ammonia from a unit volume of ash by one pore volume of infiltrating precipitation, i.e., pore water NH_3-N concentration is equal to the ash NH_3-N content of 99.2 mg/kg multiplied by ash density of 0.71 kg/L divided by ash porosity of 0.55.) The ammonia loading to LBC would be approximately 0.32 kg/day assuming no transformation or attenuation of ammonia during groundwater transport.

Historical stream flow data for LBC are available for a United States Geological Survey (USGS) gauge located approximately 1.5 miles upstream of the proposed ammoniated-ash disposal site. These data, however, fail to account for the substantial influx of groundwater and spring water downstream of the gauge. Lindquist et al. (1992) reported additional stream flow measurements at a gauging site (LBC-1) situated about 0.5 mile downstream of the dry ash stack. Although the minimum daily flow reported at the USGS gauge is 930 m_3/day, Lindquist et al. (1992) measured downstream flows of approximately 2,400 m_3/day during "low flow conditions."

Bounding estimates of the NH3-N concentration in LBC under low flow conditions are 0.13 to 0.34 mg/L, assuming complete mixing of the NH3-N loading (0.32 kg/day) with the reported Lindquist et al. (1992) and USGS low flows, respectively. Concentration estimates are considered conservative because no allowance is made for dilution of leachate seepage as it mixes with ambient groundwater during transport to LBC. Furthermore, the analysis assumes the average daily ammonia load entering LBC is mixed with stream flow during low flow conditions. Under low stream flow conditions, the rate of leachate seepage into LBC would also be lower than average, since both stream flow and leachate generation rates respond similarly to periods of reduced precipitation. The pH of historical surface water samples is approximately 7.5 standard units (s.u.) and at a high temperature of 38 degrees Celsius the chronic criterion concentration (CCC) limit would be 0.98 mg/L. Therefore, the ammonia loading from groundwater sources is expected to have an insignificant toxicity impact on the LBC receiving stream.

The quantity of ammoniated ash leachate migrating to the Ohio River via groundwater was estimated from modeling results reported by Lindquist et al. (1992). Their water budget analysis of the dry stack indicated that the total rate of leachate generation ammoniated ash disposal area would average ~15.3 m^3/day. Subtracting the portion of leachate transported to LBC (i.e., 2.5 m^3/day) from the total leaves approximately 12.8 m^3/day of leachate that would ultimately discharge into the Ohio River. Assuming an NH_3-N concentration of 128 mg/L as before, the estimated average NH_3-N loading to the Ohio River would be approximately 1.63 kg/day. Impacts would be negligible due to the high dilution capacity of the river.

3.5 Surface Water

3.5.1 Affected Environment

The SHF site is located on the Ohio River, 35 miles upstream of its confluence with the Mississippi River (Ohio River Mile [ORM] 946). The plant is bordered by the Ohio River and Little Bayou Creek (LBC), which are both classified as warm water aquatic habitat. The 7Q10 flow (lowest stream flow for seven consecutive days that would be expected to occur once in ten years) at the SHF discharge points on the Ohio River is 46,300 cubic feet per second (cfs), and on the LBC is 0 cfs (KDEP 2005a).

The TVA SHF facility discharge is located between Lock and Dam 52 at ORM 938.9 and Lock and Dam 53 at ORM 962.6. These two locks and dams, under the control of and operated by the United States Army Corps of Engineers (USACE), are being replaced by the Olmstead Locks and Dam at ORM 964.4. Work on the new Olmstead locks is complete and work on the new dam is ongoing. Olmstead Dam does not currently provide any regulation of the river and in recent years there have been large swings in river elevations (USACE 2014). The average monthly stream flow is approximately 267,700 cfs. Generally, the Ohio River average depth is 24 feet and at its widest point is 1 mile across at Smithland Dam, about 27 miles upstream of SHF (ORSANCO 2014).

All of the Ohio River bordering Kentucky supports aquatic life use and drinking water use. Primary contact recreation is impaired for nearly 350 stream miles, or about 53 percent of the river in Kentucky. The pollutant causing this impairment is the pathogen indicator, E. coli. No reaches of the Ohio River fully support all assessed uses. This limited support is often a result of combined sewer overflows during and immediately following rainfall events along the riverfront and downstream of urban areas. All of the Ohio River only partially supports the fish consumption use because of polychlorinated biphenyls (PCBs) and dioxin, while methylmercury residue in fish tissue is a cause of less than full support in many of the river miles. The Ohio River segment associated with mercury-related impairment is the reach from just below Louisville to approximately 0.5-miles upstream of the Wabash River mouth (ORM 772.35-

843.1), or approximately 11 percent of the 664 Ohio River Miles (KDEP 2013). This stretch is well upstream of SHF.

Besides the State of Kentucky's statewide fish consumption advisory for mercury, long-standing fish consumption advisories remain in effect for the 7.2 miles of LBC. LBC is identified as not supporting warm water aquatic habitat due to pollutants including metals and radiation (KDEP 2013). The suspected sources of the pollutants are industrial point sources and waste disposal from the former USEC/DOE plant. A total maximum daily loading limit (TMDL) was put in place for PCBs for this stream segment in 2001. (KDEP 2001)

SHF withdraws an average of 543,019 million gallons per year (MGY) for use as condenser cooling water and plant process water (i.e., sluice water, fire protection, boiler feed water, safety eye wash and showers, and miscellaneous wash water). Approximately 98 percent of the water withdrawal is used for cooling, while approximately 2 percent is used for process water. Essentially all of the withdrawn water is returned to the river.

Existing Wastewaters

There are several existing wastewater streams at SHF permitted under KPDES Permit Number KY0004219 (KDEP 2005). The main plant area is drained by permitted storm water outfalls, wet weather conveyances (WWCs), the condenser cooling water (CCW) discharge (Outfall 002), the chemical treatment pond (Outfall 004), and process and storm water discharges from the ash pond system (Outfall 001). Potentially impacted onsite wastewater streams include the dry stack storm water discharge, CCW discharge channel, and ash pond discharge.

Because the ash pond discharge (Outfall 001) and the CCW discharge channel (Outfall 002) are the primary discharge points potentially affected by the proposed action, they are the main focus of discussion. About 25.75 million gallons per day (MGD) average are discharged from the ash pond through Outfall 001. Outfall 001 discharges into the CCW discharge channel. The ash pond currently receives wastewater from a number of sources, as listed in Table 3-4. The pH (a measure of acidity) of the ash pond discharge generally ranges from 6.91 to 8.96. The current SHF KPDES permit requires TVA to meet the ash pond effluent limits presented in Table 3-5. The permit contains limitations on the ash pond discharge for pH, oil and grease, total suspended solids, hardness, and acute toxicity. This permit also requires monitoring and reporting of 13 metals: antimony, arsenic, beryllium, cadmium, chromium, copper, lead, mercury, nickel, selenium, silver, thallium, and zinc.

Approximately 1490 MGD is discharged from the CCW discharge channel through KPDES Outfall 002. Outfall 002 discharges at ORM 946. The plant's permitted discharges from Outfall 002 are once-through cooling water. The CCW itself would not be affected by the proposed action. However, because the ash pond discharge (Outfall 001) discharges into the CCW discharge channel, Outfall 002 could be affected by this project by potential changes to Outfall 001. The current KPDES permit contains limitations on the CCW discharge for total residual chlorine and free available chlorine (no chlorine is added as part of normal operations), total residual oxidants and time of oxidant addition (no oxidants are added as part of normal operations), as well as thermal discharge (MBTU/hr). The permit also requires reporting of flow, intake temperature, and discharge temperature.

Table 3-4.
Sources and Quantities of Inflows to Ash Pond

Source	Average Annual Daily Inflow to Ash Pond (MGD)
Bottom Ash sluice water	19.44
Coal yard drainage basin (receives effluent from the chemical treatment pond and station sumps)	5.7105
Inactive and active ash disposal areas, dry ash stacking areas, coal/ash dredge cell	0.4101
Limestone storage area and sump	0.0084
Air preheater washing wastes	0.0040
Pressure washing waste, water treatment plant waste	0.1501
Portable hand wash stations	0.0001
Precipitation	0.1709
Ash pond seepage	- 0.017
Evaporation	- 0.1226
Total	**25.7545**

Source: February 2010 Wastewater Flow Schematic for KPDES Permit Number KY0004219 Permit Renewal

Table 3-5.
Outfall 001 Discharge Limitations and Requirements

Effluent Characteristics	Effluent Limitations				Monitoring Requirements	
	Monthly Average		Daily Maximum		Measurement Frequency	Sample Type
	Average Concentration (mg/L)	Average Amount (lb/day)	Average Concentration (mg/L)	Average Amount (lb/day)		
Flow	Report (MGD)		Report (MGD)		1/Week	Weir
pH	Range 6.0 – 9.0 (s.u.)				1/Week	Grab
Total Suspended Solids	30	--	75	--	1/Month	Grab
Oil and Grease	12	--	14	--	1/Month	Grab
Hardness (as mg/L of $CaCO_3$)	Report	--	Report	--	1/Quarter	Grab
Total Recoverable Metals	Report	--	Report	--	1/Quarter	Grab
Acute Toxicity*	N/A	--	1.00 TU_a	--	1/Quarter	2 Grabs

Source: KPDES Permit Number KY0004219 effective July 13, 2005
mg/L = milligrams per liter
lb/day = pounds per day
MGD = million gallons per day
s.u. = standard units
$CaCO_3$ = Calcium Carbonate
Total Recoverable Metals include: antimony, arsenic, beryllium, cadmium, chromium, copper, lead, mercury, nickel, selenium, silver, thallium, and zinc
*TU_a = acute toxicity unit; quarterly tests conducted the first year of the permit with annual tests in subsequent years.

Existing Coal Combustion Residuals Wastewater Treatment Facilities

SHF units each produce on average 36,000 tons of fly ash and 4,000 tons of bottom ash per year, on a dry basis. The fly ash is handled by a dry ash stacking system and the bottom ash is wet-sluiced to the ash pond.

As described in the following paragraphs, the CCR handling system at SHF includes the ash pond (Outfall 001); the chemical treatment pond (Outfall 004, which is currently not being used), which is pumped to the coal yard drainage basin and then pumped to the ash pond; and the dry ash stack area, which drains via storm water to the ash pond.

Ash Pond

The ash pond is permitted to receive combined wastewaters of ash sluice water, water treatment plant wastes, dry fly ash and limestone handling (for the now-retired Unit 10) facilities wastes, station sump discharges, effluent from the chemical treatment pond (this pond is no longer in use), air pre-heater (APH) washing wastes, and storm water runoff. The ash pond inflow sources and average annual daily flow rates are listed in Table 3-4.

The ash pond receives wet-sluiced bottom ash only; SHF has no capability to wet-sluice fly ash to the ash pond. The bottom ash collects in the bottom of the boiler and is washed from the boiler bottoms with jets of water and sluiced to a bottom ash dewatering area within the ash pond system. The bottom ash sluice water is discharged to the ash pond at a rate of 19.44 MGD.

The air pre-heaters (APHs) are washed during plant outages, typically once every three to four years. The wastewater from the cleaning of the APHs is discharged to the ash pond. In addition, the APHs are steam cleaned twice per week, removing an estimated 10 percent of the waste per steam cleaning that is collected on the interior surfaces. The wastes from the steam cleanings are disposed of at the dry ash stack area. Storm water runoff from the dry ash stack area flows to the ash pond.

Dry Ash Stack Area

SHF utilizes a dry fly ash handling system and fly ash is disposed of on the dry ash stack. The maximum active area of exposed fly ash at the dry fly ash stacking area is 10 acres. As stacking areas become inactive, they are stabilized with an interim cover, such as soil or bottom ash, for fugitive emission control, which is required on the unexposed or stabilized areas. The dry fly ash stack is graded at the end of each day to limit ponding and encourage sheet flow runoff. Runoff from the active dry fly ash stacking area flows to the ash pond.

3.5.2 Environmental Consequences

Alternative A - No Action Alternative

Under the No Action Alternative, current plant processes would continue and there would be no changes to surface water until the December 31, 2017 date in the USEPA Agreements when TVA would have to retire Units 1 and 4 unless those agreements are changed. Following retirement, there would be an approximately 2/9 (22.2 percent) reduction in SHF water withdrawal and discharge volumes. The quantities of metals and other constituents in the outfall discharges could decrease, but due to chemical reactions in the ash pond and elsewhere, any decrease would not necessarily be proportionate to the decrease in discharge volumes.

Alternative B – SHF Unit Retirement

Retirement of Units 1 and 4 could potentially alter the surface water intake and discharges. Depending on unit retirement/closure plans, short term, temporary impacts are possible, but ultimately surface water withdrawals and discharges from the site could be reduced.

Alternative C – Install and Operate SCR and FGD Systems on SHF Units 1 and 4

Construction Impacts

Wastewaters generated during construction of the proposed projects would include construction storm water runoff, dewatering of work areas, domestic sewage, non-detergent equipment washings, dust control liquids, and hydrostatic test discharges.

Surface Runoff
Soil disturbances associated with construction and demolition activities can potentially result in adverse water quality impacts. Soil erosion and sedimentation can clog small streams and threaten aquatic life. TVA would comply with all appropriate state and federal permit requirements. Construction and demolition activities would be located on the plant property that already supports heavy industrial uses. Appropriate BMPs would be followed, all proposed project activities would be conducted in a manner to ensure that waste materials are contained, and the introduction of pollution materials to the receiving waters would be minimized. The site BMP plan, part of the KPDES permit, would be updated to include project-specific BMPs. This plan would identify specific BMPs to address construction-related activities that would be adopted to minimize storm water impacts.

Where soil disturbance could occur, the area would be stabilized and vegetated with noninvasive grasses and mulched, as described in TVA (2012) or equivalent measures.

Additionally, impervious buildings and infrastructure prevent rain from percolating through the soil, which results in additional runoff of water and pollutants into storm drains, ditches, and streams. Because the installation of the SCR and FGD systems will be implemented in an area where semi-impervious or impervious cover already exists, there would only be a slight increase of impervious cover with the implementation of Alternative C. For this reason, this project is not expected to significantly increase the concentrated storm water flow from the project sites. This flow, however, would need to be properly treated with either implementation of the proper BMPs, or by diverting the storm water discharges to the ash pond for co-treatment or an onsite treatment facility. With proper implementation of these controls, only minor, temporary impacts to local surface waters are expected.

Equipment Washing and Dust Control
Equipment washing and dust control discharges would be handled in accordance with BMPs described in the BMP Plan required by the site’s KPDES Permit KY0004219 to minimize construction impacts to surface waters.

Hydrostatic Testing
Onsite hydrostatic testing will have the option to use potable or surface waters and would be covered under the current KPDES Permit KY0004219.

Sewage
Sanitary wastes generated during construction activities would be collected by the existing septic system or by means of portable toilets (i.e., portalets). These portable toilets would be located throughout construction areas and would have wastes removed as required by an approved contractor.

FGD Construction
As mentioned above, appropriate BMPs would be implemented in accordance with the KPDES BMP Plan to minimize construction storm water impacts. Additionally, KDEP would be notified of the addition of the FGD systems and the potential changes to the KPDES permit parameters. Because this project will not take place adjacent to or in Waters of the U.S. or State, no water quality certification or USACE permit would be required. With proper implementation and maintenance of BMPs, only minor, temporary impacts to local surface waters are expected.

SCR Construction
The proposed installation of the SCR systems would take place within the current plant footprint and little to no additional new soil disturbance would be associated with this task. Soil disturbances could potentially result from the clearing and grading of the project and laydown areas; creation of personnel offices and parking space; and the construction of the ammonia tank farm, containment pond, and drainage from the pond to the main plant. The drainage area associated with the ammonia tank farm site would be approximately 0.3 acres. The SCR containment pond site would be approximately 0.1 acres. As mentioned above, appropriate BMPs would be implemented in accordance with the plant's BMP Plan to minimize construction storm water impacts. Additionally, KDEP would be notified of the addition of the SCR systems and ammonia tank farm and the potential changes to the KPDES permit parameters. Because this project would not take place adjacent to or in Waters of the U.S. or State, no water quality certification or USACE permit would be required. With proper implementation and maintenance of BMPs, only minor, temporary impacts to local surface waters are expected.

<u>**Operational Impacts**</u>

Surface Water Withdrawal and Discharge
Withdrawal rates would increase slightly over present rates under Alternative C. Additionally, a wastewater stream would be added to the total discharge from SHF. This stream would be the discharge of the ammonia tank farm retention pond, which would primarily retain storm water, but would also be used in the case of an ammonia release to treat ammoniated water prior to release. However, this discharge would very rarely flow if at all. The installation of the SCR and FGD systems would require raw water for quick lime mixing, fogging system, wash-down activities, and CCR conditioning, along with minimal amounts of potable water (safety showers, eye washes and restroom facilities) to operate. The wash-down activities and CCR conditioning activities already take place and would be an existing need, but the flow rate may increase due to the need to condition a larger quantity of CCR.

Estimated water usage for the FGD system would be approximately 150 gallons per minute per unit which would be a total usage of 0.432 MGD of raw water. The withdrawal of this quantity represents less than one percent (0.001) of the total volume of water in the Ohio River moving past the plant at 7Q10 flow (29,922 MGD) and would not be significant. Between 3 and 20 gallons per minute of potable water would be used for safety showers, eye washes and restrooms. The SCR systems would have no continuous-use water streams other than potable water for eyewash and safety shower facilities and intermittent raw water needs (filling of two vaporizer tanks every 1–2 years and the use of the fogging system at the ammonia tanks). Up to 100 percent of the raw water utilized in the FGD systems would be consumed (evaporation and conditioning) and there would be no standard discharges from this system.

The main withdrawal usage plant-wide is for the CCW, which carries the majority (99.9%) of the thermal loading from SHF discharges out Outfall 002. The discharge thermal loading at Outfall 002 would not be changed by the current project. Thermal discharges from Outfall 001 would also not change. Raw and potable waters utilized in the SCR and FGD processes, and storm water flows associated with this project, would remain at ambient temperatures; therefore, no additional thermal impacts would be anticipated. Additionally, the discharge volume from this outfall would remain virtually unchanged during normal operating conditions.

TVA would maintain wet surface impoundments onsite as required to support SHF's operations and continued wastewater streams. When surface impoundments are closed, the closure would be regulated by the KPDES permit.

FGD Operational Impacts

The wastewater streams, which could change under this alternative, are:

- Surface runoff from the proposed byproduct silo areas
- Surface runoff from the FGD area
- Washes associated with FGD process equipment
- Dry stack discharges changes

Runoff Streams from the FGD

All industrial storm water associated with the FGD equipment would be routed to the ash pond that flows to the CCW discharge channel. This stream is expected to be a precipitation-driven intermittent storm water stream. This process storm water flow already exists, however the discharge may change slightly in the amount of flow and the composition of the flow to account for the placement of the FGD and SCR structures. This storm water could contain trace levels of ash, hydrated lime, calcium sulfite, and calcium. This stream has the potential to impact ash pond pH and metals concentrations. Hydrated lime is an acid neutralizer due to its alkaline nature. Currently, the SHF ash pond tends to have a neutral to slightly alkaline pH. A carbon dioxide diffuser is operated to help maintain ash pond pH below 9.0 standard units (s.u.). Addition of this run-off stream or any waste wash waters has a slight potential to increase the average alkalinity and pH of the ash pond effluent. This operational discharge would be permitted under the existing KPDES permit, and action and mitigation measures would be implemented as necessary to ensure that there would be no adverse impacts on water quality in the Ohio River. These mitigation measures may include, but are not limited to, implementing design controls, a cleaning and maintenance plan, and the installation of appropriate BMPs onsite to ensure this process waste stream is not discharged to the discharge channel.

FGD Process Waste and Outage Wash Waste Streams

The FGD system would be a circulating dry scrubber system, with no anticipated normal process water discharge. There is a possibility that a non-routine outage wash may be warranted of this system, but only in the unlikely event that the system develops a blockage. These wash waters would be evaluated for permitting under the KPDES permit and would either be managed onsite or would be trucked offsite by an approved vendor for proper disposal. If treated onsite, these waste streams are not expected to have any adverse effect on water quality in the Ohio River.

Effects on Wastewater and Surface Water

Metals Loading

The use of the dry FGD systems eliminates the water discharges from scrubber waste handling typical of wet scrubber systems. The addition of dry scrubbers is not expected to increase the overall wastewater discharges and pollutant loadings from SHF. The volume of discharges from Outfall 001 has the potential to be slightly higher when non-routine washes or conditions exist in the FGD and SCR systems. While they would not otherwise result in new process water waste streams, the composition of existing waste water streams may be slightly altered. The waste streams that may be altered are the active dry stack discharge, storm water run-off from the new FGD areas and ash silo drainage area. Newly created FGD waste streams are noted above.

The storm water process waste streams changes would likely be minimal, with good housekeeping practices; the quantity of the CCR in the process storm water waste stream would be negligible. The most notable change would be to the discharge from the dry stack, where fly ash from the recently retired Unit 10 was a main contributor to metals in the dry stack runoff. To estimate the concentration of metals in the ash pond discharge after receiving discharges from the active dry stack containing Unit 1 and 4 CCRs, the maximum Synthetic Precipitation Leaching Procedure (SPLP) data were used from acquired dry FGD residue mixed with a 52/48 PRB/ILB ash blend to produce the estimated results in Table 3-6. Depending on coal market conditions, TVA could change to a similar coal blend following completion of the FGD systems. The SPLP data were used instead of Toxicity Characteristic Leaching Procedure (TCLP) data because the SGLP data were deemed more appropriate due to the alkaline nature of the by-product. Additionally, this method allows for analysis of more parameters than the TCLP method.

In analyzing the anticipated discharges of pollutants, TVA assumed there would be no further discharges from Unit 10 and the new waste stream from the proposed FGD systems would begin. Historical data were used from previous permit applications and 2C forms to complete the following loading and mixing calculations. These loading mixing calculations were then compared with SHF KPDES permit effluent limits and KDEP water quality criteria.

Results of the mass balance analysis (Table 3-6) show that the concentrations of the constituents of concern at Outfalls 001 and 002 would be below KPDES effluent permit limits and KDEP water quality criteria. Additionally, the mixing concentration of the discharge from Outfall 002 with the Ohio River at 7Q10 flow was found to range orders of magnitude below the water quality standard. Neither the SCR nor the FGD systems are expected to significantly increase metals in the ash pond discharge.

The SHF units currently burn a blend of 75 percent PRB subbituminous coal and 25 percent Colorado bituminous coal. The change to a near 50/50 blend of the PRB/ILB would result in less ash generation and a less alkaline pH of the ash. The blending of the calcium carbonate from the FGD with the ash would add additional alkalinity to this CCR blend. The metals discharged from this blend were evaluated in Table 3-6 and the difference was found to be favorable.

Table 3-6.
Estimated Concentrations of Metals in SHF Discharges

Element	River Conc. mg/L	River Loading lbs/day	Ash Pond Conc. mg/L	Ash Pond Loading lbs/day	Previous Dry Stack Metals Conc.* mg/L	Previous Dry Stack Loading* lbs/day	New Dry Stack Conc. Estimates mg/L	Landfill Leachate Loading Estimates lbs/day	Projected Loading at DSN 001 lbs/day	Projected Conc. at DSN 001 mg/L	Projected Conc. At CCW Outfall 002 mg/l	Projected Loading at CCW Outfall 002 mg/l	Projected Mixing Conc. of Outfall 002 and Outfall mg/L	Total Discharge Conc. at Ohio River 7Q10 mg/L	KDEP*** Water Quality Based Effluent Standard Conc., mg/L
Antimony	<0.001	6.2111	0.002	0.43	<0.001	0.0013	<0.0010	0.001	0.425	0.00198	<0.001	6.116	0.00764	0.00084	0.64000
Arsenic	0.0011	13.6645	0.002	0.43	0.002	0.0050	0.0021	0.005	0.426	0.00198	0.0011	13.455	0.00823	0.00144	0.15000
Barium	0.047	583.8479	0.045	9.57	2.400	6.0120	2.400	6.012	9.570	0.04453	0.047	574.908	0.20701	0.05459	NL
Beryllium	<0.001	6.2111	0.002	0.43	<0.001	0.0013	<0.001	0.001	0.425	0.00198	<0.001	6.116	0.00764	0.00084	0.00400
Cadmium	<0.0005	3.1056	0.002	0.43	<0.0002	0.0003	<0.0005	0.001	0.426	0.00198	<0.0005	3.058	0.00740	0.00059	0.00029
Chromium	0.0031	38.5091	0.003	0.64	0.01	0.0135	0.15	0.376	1.000	0.00465	0.0031	37.919	0.01985	0.00389	NL
Copper	0.0026	32.2980	0.004	0.85	<0.0261	0.0327	<0.002	0.003	0.821	0.00382	0.0026	31.803	0.01634	0.00325	0.01012
Lead	0.0011	13.6645	0.002	0.43	<0.002	0.0025	<0.001	0.001	0.424	0.00197	0.0011	13.455	0.00821	0.00144	0.00359
Mercury	0.00000243	0.0302	0.0000012	0.00	<0.0002	0.0003	<0.0002	0.0003	0.000	0.00000	0.00000243	0.030	0.00001	0.000003	0.00077
Nickel	0.0032	39.7513	0.002	0.43	0.00	0.0063	0.0086	0.022	0.441	0.00205	0.0032	39.143	0.01055	0.00355	0.05654
Selenium	<0.001	6.2111	0.002	0.43	<0.001	0.0013	0.02	0.050	0.474	0.00221	<0.001	6.116	0.00846	0.00088	0.00500
Silver	<0.0005	3.1056	0.002	0.43	<0.001	0.0013	<0.001	0.001	0.425	0.00198	<0.0005	3.058	0.00739	0.00059	0.00446
Thallium	<0.001	6.2111	0.002	0.43	<0.001	0.0013	<0.001	0.001	0.425	0.00198	<0.001	6.116	0.00764	0.00084	NL
Zinc	0.0011	13.6645	0.011	2.34	0.01	0.0200	<0.010	0.013	2.332	0.01085	0.0011	13.455	0.04026	0.00296	0.12989

lbs/day = conc. in mg/L X flow in MGD X 8.34 lbs/gal.

Intake Flow	1487.7	MGD	River flow and data from SHF 2010 NPDES Permit renewal application, Data from 2C sampling
			application for Intake
Ash Pond Flow	25.47	MGD	Ash Pond flow from SHF 2010 NPDES Permit renewal applicaiton , Data from 2C data sampling of Ash PondOutfall 001
			application for DSN001 (Ash Pond)
Dry Stack Flow	0.3	MGD	run-off estimates for flow and chemical parameters taken from Water Extratction of dry FGD and Ash combo - Flow from KPDES Permit
			KPDES Permit application
CCW Flow	1490.39	MGD	CCW Flow from SHF KPDES Permit renewal application, data was taken from intake data and from 2C data sampling of Outfall 002
7Q10 River Flow	29922.3936	MGD	Flow to evaluate Human Health SHF Permit 2005
	110	mg/L	Ash pond discharge hardness as CaCO3 from 20101 permit renewal 2C samples
ln of hardness	4.700480366		

*Previous Stack Metal Data used from 1985-1986 data provided to KDEP of long term storm water characterazation of the AFBC dry stack. Antimony, Barium, Berlyllum, Silver and Thallium were not sampled at this time.
Antomony, Beryllium, Silver and Thallium were all assumed to be below detection since solid waste samples has these total concentratiosn on the ash as below detection. Barium was assumed to be the same as the new stack or higher.

DSN002 current concentrations from KIF 2008 NPDES Permit renewal application

**Mass Discharge and Loadings below detection were calculated using 0.5 of the Minimum Detection Limit

***KY Surface Water Standards, 401 KAR 10:31

Even after accounting for the impacts of the change from the dry stack, the impacts at Outfall 001 would be insignificant. TVA would conduct an operational characterization of the altered and new waste streams to confirm no significant impacts to the Ohio River are anticipated from this action. The waters would be analyzed for metals and other parameters. Additionally, no direct negative (toxic) impacts on the receiving stream Ohio River) would be anticipated because Outfall 001 would be required to meet KPDES Acute toxicity limits. Mitigative actions would be taken to meet requirements for ensuring that discharges meet KPDES and acute toxicity limits if necessary. These could include additional pH adjustment technology, installing curtains in the ash pond to create longer retention time for assimilation of metals, and reducing the exposed open area of the dry stack. Thus, the proposed FGD and SCR systems and the potential change to a combination of 50/50 ILB and PRB coal blend should have no significant impact on the aquatic environment of the Ohio River.

SCR Operational Impacts

Operational impacts are primarily dependent on the engineering features and safeguards of the proposed SCR systems. A number of assumptions concerning the proposed SCR systems and their operation are necessary to establish the basis for the potential environmental impacts. These assumptions are similar to the assumptions used in the environmental assessment for installation of emission control equipment at Gallatin Fossil Plant (TVA 2013), and are summarized below:

Design, Construction, and Operational Assumptions

1. Given an inlet of 0.46 lbs/mmBtu, a 90-percent NOx removal rate would be achieved under normal operations throughout the life of the system, excepting potential periods near the end of the catalyst life.
2. The SCR systems would operate year-round in order to meet air quality requirements.
3. No ammonia slip limits would be applied. Slip would be allowed to increase to a point that would not violate any water quality criteria for ammonia and/or nutrients, NPDES action levels, pH limits, or toxicity reference values (TRVs). Catalyst disposal would be managed by a catalyst contractor in compliance with applicable regulations.

Anhydrous Ammonia System

Design, Construction and Operational Assumptions

1. Two 18,000-gallon (nominal) storage tanks would be installed.
2. A water fogging system with both automatic and manual activation would protect both the storage tank and the truck off-loading area by limiting the hazard from large ammonia leaks or catastrophic tank failure.
3. The drainage from the proposed ammonia unloading and storage area would be configured to contain the ammonia generated by operation of the fogging system within the SCR containment pond adjacent to the ammonia unloading and discharge facility.
4. Discharges from the SCR containment pond would be treated prior to release, if an ammonia release occurs to the ash pond.
5. The applicable chemical accident prevention measures required under 40 CFR 68 would be implemented prior to filling of the anhydrous ammonia storage system or receipt of ammonia in quantities exceeding 10,000 pound-mass (lbm).

6. Appropriate personal protective equipment (respirators, self-contained breathing apparatus, and protective clothing) and training would be provided to operating personnel consistent with Occupational Safety and Health Administration regulations.

These features would control the probability and extent of accidental or unintentional releases of anhydrous ammonia to the environment. These potential releases and attendant impacts could be as follows:

- Excessive ammonia passing through the SCR reactors could result in ammonia contamination of the air heater wash, causing potential effluent toxicity and/or odor. Additionally, fly ash could become contaminated with ammonia and in turn, ammonia would be released to the ash pond from the dry stacking area, air pre-heater wash, and CCR silo storm water runoff, causing potential effluent toxicity.
- Accidental releases of anhydrous ammonia to the air from the storage and unloading system or truck could cause a potential hazard to plant operating personnel, the public, and the environment. Direct accidental releases of anhydrous ammonia to surface water could cause damage to aquatic life.

The parameters of concern with regard to wastewater discharge to surface waters are (1) the concentration of ammonia that is in the ash pond effluent (as opposed to the total annual amount discharged), and (2) the potential for this ammonia to cause toxicity to aquatic organisms.

Effects on Wastewater and Surface Water

To avoid higher ammonia concentrations at Outfalls 001 and 002, the four potential sources of ammonia to the ash pond (APH wash water, SCR containment pond purge, byproduct storm water runoff, and CCR silo runoff) would be characterized for operational knowledge. Any non-storm water releases from the SCR containment pond would be monitored and treated prior to discharge to the unwatering sump and ultimately the ash pond. If concentrations from these sources are deemed too high, then the streams would be released to the ash pond singularly, sent offsite for proper disposal, or new treatment options and BMPs would be explored and implemented within the ash pond.

No direct negative (toxic) impacts on water quality of surface waters are anticipated, based on historical and modeled data, and ultimately as a result of the fact that ash pond discharges would be required to meet KPDES limits. The engineered features of the SCR systems, including a containment pond for spills and emergency water fogging to minimize risk of direct releases of ammonia, are adequate to meet regulatory requirements and designed to ensure safe handling of ammonia. Therefore, direct impacts from accidental releases of ammonia to surface waters are not expected.

Dry Stack Operational Waste Streams

The composition of the surface runoff from the dry stack area could change substantively under this alternative. CCR samples from a FGD process were obtained from a system that was deemed comparable to the proposed FGD CCR. Raw dry FGD CCR, CCR mixed with 52/48 Powder River Basin/Illinois Basin(PRB/ILB) blend, and dry FGD CCR mixed with 100 percent PRB ash were evaluated for TCLP, metals, SPLP water extraction, sieve analysis, and other physical properties. This information was utilized to predict wastewater impacts from the dry stack operation. Since storm water flows from the site are currently entering the ash pond, the flow volumes would potentially be equivalent; however, difference in the CCR content will alter the contact runoff stream and could have the potential to be very alkaline in nature with higher ammonia levels. The assumptions utilized to produce this model are listed below:

Dry Stack Runoff

The dry stack storm water runoff would be an intermittent, precipitation-driven stream. Metals and ammonia in the dry fly ash have the potential to enter the wastewater stream during a rainfall event as runoff from the dry stack area. This runoff would be directed to the ash pond and ultimately discharged from the site at Outfall 002. In the event of wet pond closure, onsite water treatment or offsite disposal would be implemented. Minimal data are available on the projected concentration of ammonia in fly ash. Much of this data would be dependent on SCR process and plant specifics. To limit ammonia loads from the dry fly ash stack, it would be important to restrict the amount of dry fly ash exposed to 10 acres or less. The greater the surface area of exposed dry fly ash, the more ammonia there is available to run off or leach during a rain event. The dry stacking area was evaluated for potential impacts associated with both ammonia and metals in-stream loading.

Ammonia Model

An ammonia model was used to evaluate the maximum ammonia releases from the dry stack runoff. The model was based on extremely conservative assumptions regarding the amount of ammonia entering the river, the volume of ammoniated water released, and the flow of the river at the time of release.

Ammonia slip, the emission of unreacted ammonia (NH_3), is caused by the incomplete reaction of the ammonia with NO_x present in the flue gas. The unreacted NH_3 could react with available gaseous sulfuric acid to form ammonium bisulfate (NH_4HSO_4), a very sticky substance. Ammonia slip tends to adhere to or commingle with the fly ash, and/or build up on the APH interior surfaces. Formation of NH_4HSO_4 could accelerate the buildup inside the APHs, and make the periodic cleaning of the APHs more difficult.

$NH_3 + H_2O + SO_3 \Leftrightarrow NH_4HSO_4$

Approximately 20 percent of the NH_3 slip is expected to adhered to the heating surfaces in the APH, and about 80 percent adhered to the fly ash. The partitioning of ammonia slip between fly ash and APH heating surfaces will be determined by the specific equipment installed, actual fuel blends, and their operating characteristics. Best professional judgment was used in developing the estimates utilized in this EA.

This alternative includes the potential change to a 50/50 blend of PRB and ILB coal. Due to the presence of acid species in ILB coal ash and flue gas relative to PRB coal ash and flue gas, it is likely that the ammonia slip could react with gaseous acids or acids in the fly ash, causing an increase of ammonia on the ash and potentially forming ammonium fluoride, ammonium chloride, and/or ammonia-sulfur salts (ammonium bisulfate likely predominating) among other species. This acid-base neutralization reaction would likely keep the ammonia more stable in solid salt form or combined with fly ash and less susceptible to off-gassing as it would be in a more alkaline environment. If dissociated in water, the soluble ammonium would likely pair with soluble acids from the now more acidic fly ash and result in a more neutral pH, to the extent that such a small amount of gaseous ammonia slip can influence the pH of a much larger volume of water.

Ammonia Criteria

The current SHF KPDES permit requirements for the Outfall 001 discharge do not include limitations for ammonia concentrations; however, limits for acute toxicity are included and there are existing water quality criteria for ammonia. The acute criterion (criterion maximum concentration or CMC) for protection of aquatic life ammonia toxicity is defined as the 1-hour average concentration of total ammonia nitrogen (in mg N/L) that should not be exceeded more than once every 3 years on average. The CMC is not affected by temperature but does vary with pH. As the pH increases, the CMC decreases (Table 3-7). The CMC for ammonia must be met at the Outfall 001 discharge point in accordance with regulations and KPDES permit requirements.

Table 3-7.
Maximum Allowable Ammonia Concentrations to Protect Aquatic Life from Acute Effects at Typical pH Levels

Acute Criterion (mg NH_3-N/L)						
pH 6.0	pH 6.5	pH 7.0	pH 7.5	pH 8.0	pH 8.5	pH 9.0
54.99	48.83	36.09	19.89	8.41	3.20	1.32

Note: Assumes salmonids are absent

Similarly, the chronic criterion concentration (CCC) for ammonia must be met in the receiving stream to protect the aquatic biota of the Ohio River. The CCC is defined as the 30-day average concentration not to be exceeded more than once every 3 years. In addition, the highest 4-day average within the 30-day period should not exceed 2.5 times the CCC. The CCC is dependent on both temperature and pH. As temperature and/or pH increases, the CCC decreases (Table 3-8). In addition to the above criteria, KDEP water quality standards limits the concentration of unionized ammonia in receiving streams to 0.05 mg/L. (KDEP, 2014)

Table 3-8.
30-Day Average Allowable Ammonia Concentrations to Protect Aquatic Life from Chronic Effects at Selected pH Levels

Chronic Criterion Concentration (CCC) (mg NH_3-N/L)				
Temperature (°F)	pH 7.5	pH 8.0	pH 8.5	pH 9.0
70	2.85	1.59	0.71	0.32
75	2.38	1.33	0.6	0.27
80	1.99	1.11	0.5	0.22
82	1.86	1.03	0.46	0.21
84	1.73	0.96	0.43	0.19
86	1.61	0.90	0.4	0.18

Note: Assumes salmonids are absent

Storm Water Runoff Loading

The 10-year, 24-hour, 5-inch rainfall event would produce the worst-case ammonia mass loading to the ash pond from the dry ash stack area runoff. Total runoff from the dry stack for this event is estimated to be approximately 6.33 X 10^5 cfd (based on information provided in a personal communication with Mark Boggs for TVA's SHF SNCR EA [TVA 2005]). The ammoniated runoff rate from the active area is estimated at approximately $1.32x10^5$ cfd.

For the estimated maximum byproduct CCR analysis, it was assumed that a rainfall event which generated runoff from the dry stack area would be routed to the ash pond. Dry FGD residue mixed with 52/48 PRB/ILB fly ash blend was the test basis. Storm water would be routed through a ditch line to the ash pond. It was assumed that the exposed surface area of the stack had just reached maximum working capacity (10 acres) before having interim cover applied, and all of the ammonia stored in the top 1 centimeter of the exposed area would be released as runoff through the storm water pond and then the ash pond.

The leachate infiltration assumptions included the following:

- Twenty percent moisture content on the CCR.
- Particle density was assumed at 2.25 kg/L.
- One hundred percent of the ammonia would be released from the CCR.
- One pore volume of water dissolves all of the NH_3 in one unit volume of CCR.

Because the average concentration of ammonia in the fly ash is unknown for this process at this time, a maximum allowable concentration was back-calculated based on the USEPA ammonia criteria at the ash pond discharge and the Ohio River mixing zone. The initial concentration of ammonia in the Ohio River was taken from 2010 NPDES permit renewal USEPA Form 2C data. The concentration of the intake ammonia sample (<0.1 mg/L NH_3-N) was selected as the concentration based on available data, which results in an estimated maximum allowable concentration in the ash pond discharge of 1.32 mg/L. Since the intake concentration was below detection, half of the detection limit was utilized for this calculations (0.05 mg/L NH_3-N) If necessary, the ammonia-on-ash concentration would be restricted to ensure that the CMC would not be exceeded.

The average theoretical residence time for SHF's Ash Pond is approximately 2.2 days. Therefore, based on the findings of the winter ammonia study at Paradise Fossil Plant (TVA 2006), biochemical uptake rates of 50 percent during spring and summer and 20 percent during fall and winter are assumed for the SHF ash pond. It was also assumed that because of the size of the ponds, the discharge leachate/runoff would mix with 50 percent of each pond section before discharge.

Under these conditions, the ammonia-on-ash concentration must not exceed 266 mg NH_3-N/kg in the winter months and 434 mg NH_3-N/kg during the summer months, to ensure that the CMC would not be exceeded. At these ammonia ash concentrations, the estimated discharge concentration should be approximately 1.32 mg/L of NH_3-N into the CCW. Table 3-9 indicates higher ammonia-on-ash concentrations could be achievable if pH control could be safeguarded, and these higher concentrations would ensure that the ash pond pH is maintained in the lower portion of the range of 6.0 – 9.0 s.u.

Table 3-9.
Allowable Ammonia-on-Ash Concentrations to Protect Aquatic Life from Acute and Chronic Effects at Selected pH Levels during Winter Months

	pH (in standard units)						
	6	**6.5**	**7**	**7.5**	**8**	**8.5**	**9**
CMC (mg/L) at Outfall 001	54.99	48.83	36.09	19.89	8.41	3.2	1.32
NH3 -N on Ash (mg/kg)	11,601	10,300	7610	4188	1764	664	266
Conc. (mg/L) at CCW	2.28	2.02	1.49	0.824	0.348	0.11	0.053
Conc. (mg/L) at In OR	0.156	0.143	0.119	0.087	0.064	0.053	0.05

Outfall 001 effluent flows to the CCW discharge channel prior to entering the Ohio River. Complete mixing can be assumed in the discharge channel considering the turbulent conditions and the fact that the ash pond effluent enters the discharge channel approximately 1,270 feet upstream of the Ohio River. If the ammonia concentration at the Outfall 001 discharge is 1.32 mg NH_3-N/L due to storm water runoff, after mixing with the discharge channel flow (average flow of 1490 MGD) and the Ohio River (7Q10 flow: 29,910 MGD according to SHF KPDES Permit Number KY0004219), the concentration would be reduced to 0.049 mg NH_3-N/L. For all allowable pH levels at Outfall 002 (6.0 to 9.0 s.u.), and for very high water temperatures, the ammonia concentration at the Ohio River is less than the CCC (Table 3-4). Therefore, the worst-case ammonia loading from storm water runoff alone is expected to have an insignificant toxicity impact to the receiving stream.

In addition to assessing the 10 year, 24 hour storm flows in this model the same model was evaluated using the KPDES normal daily flow of approximately 0.32 MGD. Under these conditions, the ammonia-on-ash concentration must not exceed 2,568 mg NH_3-N/kg in the winter months and 4,113 mg NH_3-N/kg during the summer months, to ensure that the CMC would not be exceeded. If the 266 mg NH_3-N/kg worse case winter concentration on ash was preserved with the 0.32 MGD flow the discharge ammonia levels would yield greatly reduced concentrations, with the winter concentration of 0.14 mg/L and the summer concentration of 0.088 mg/L. This further reinforces the insignificance of the impacts of this waste stream on the receiving stream.

Further characterization of ammonia-on-ash would be performed after start up and operation of the FGD and SCR systems utilizing actual coal blends burned and SCR ammonia slips. An actual NPDES action target would be calculated to ensure that the CMC would not be exceeded at Outfall DSN 001. Mitigation measures would be implemented as needed.

APH Cleaning Wastewater Loading

The ammonia concentrations from APH wash water were evaluated in 2005 for the SHF SNCR EA (TVA 2005) with the prospective installation of an SNCR unit. The information from that analysis was utilized for the purposes of evaluating impacts and deemed still relevant, however only the 5 ppmv slip was the only scenario that was appropriate. The 5 ppm slip would be considered a worst case scenario for the purposes of this evaluation; as the slip from the SCRs is expected to be lower. The largest ammonia loading to the ash pond would occur during either the Unit 1 or Unit 4 APH cleaning, assuming the wastewater would be discharged directly to the ash pond, as is the current procedure. Each of these unit's APH wash scenario analyzed for this analysis assumes that there would be buildup of ammonia on the APH surfaces prior to being washed. This buildup would result in an ammonia loading of approximately 2,932 kg, assuming an ammonia slip rate of 5 ppmv, respectively. Steady release of the ammoniated material is assumed throughout the washing process, although it is likely that a more concentrated release would occur over a shorter time span at the beginning of the washing process.

Like the storm water runoff, the Unit 1 and 4 APH cleaning waste is assumed to completely mix with the ash pond inflow, and, due to short-circuiting, mix with only 50 percent of the ash pond free water volume. It is also assumed that the Units 1 and 4 would not be washed at the same time. In addition, no volatilization, chemical degradation, or biological uptake of the ammonia is assumed for purposes of estimating the ammonia discharges. Complete mixing of the Outfall 001 effluent is assumed in the discharge channel, considering the turbulent conditions, and the fact that the ash pond effluent enters the discharge channel approximately 1,270 feet upstream of the Ohio River.

As presented in Table 3-9, under these conditions for the direct release of either Unit 1 or Unit 4 APH waste wash water to the ash pond, the CMC is met only within specific pH ranges at Outfall 001 for both slip rates evaluated. Although the ash pond does have a pH control system, under all operating conditions the pH might not be able to be maintained below 8.0 s.u., much less be lowered to pH levels below 6.5 s.u. as needed during the Unit 1 and 4 APH cleaning. If a storm event occurred during the Unit 1 and 4 APH washing, runoff could contribute additional ammonia loading from the dry stack to the ash pond. Therefore, the Unit 1 and 4 APH wash water waste should be contained (in a pond, frac tanks, etc.), the ammonia concentration should be determined, and then the waste could be released over a number of days to ensure that the ammonia concentration at the Outfall 001 discharge remains at or below the CMC. Staging releases from the containment could also eliminate any risks of significant levels of ammonia being leached from the ash pond to LBC via groundwater flows. If either the Unit 1 or 4 APH wash water is contained then released in stages to ensure the effluent ammonia concentration remains at or below the CMC, no significant toxicity impacts are expected at the Outfall 001 discharge.

The ammonia concentration of the APH wash water waste after mixing with the discharge channel flow and the Ohio River is very low for both slip rates evaluated (Table 3-10). For all allowable pH levels at Outfall 002 (6.0 – 9.0 s.u.), and for very high water temperatures (greater than 86 degrees Fahrenheit), the ammonia concentration at the Ohio River is less than the CCC (Table 3-8). Over the past two years at SHF the maximum water temperature at the intake was 87 degrees Fahrenheit. Therefore, the discharge of Unit 1 and 4 APH waste wash water directly to the ash pond is expected to have an insignificant toxicity impact to the receiving stream.

Table 3-10.
Unit 1 Air Preheater Waste Wash Water Ammonia Concentrations

Ammonia Slip Rate (ppmv)	Ammonia Concentrations in mg NH_3-N/L	
	Outfall 001	Outfall 002
5	12.80	0.02

Resource-Specific Mitigation and Monitoring

The following mitigation measures are being considered for limiting the potential impacts to surface water quality:

- Adjusting pH in the Ash Pond - As compounds containing ammonia dissolve, and as natural microbial and algal processes for assimilating ammonia proceed, pH changes could occur. To ensure that the ash pond discharges meet the KPDES permit limits for both pH and acute toxicity, and to ensure that the effluent being discharged to the Ohio River would not exceed the CCC for ammonia, the existing carbon dioxide system could be utilized to control the pH.
- Baffling the Ash Pond - Installation of baffles in the ash pond would improve mixing of the ash pond inflow with the free water volume of the pond. Mixing of 75 percent to 100 percent could be attained. Baffling the ash pond would increase the retention time of the water, which would improve mixing, and allow more time for chemical degradation and/or biological uptake of the ammonia.
- Combining Mitigation Measures and/or Use of Other Treatment Systems - A combination of the mitigation methods could be used to effectively control the ammonia concentrations at Outfalls 001 and 002. Other options include, but are not limited to, passive treatment systems, such as constructed wetlands; addition of media for enhancing growth of nitrifying microorganisms in the ash pond; installation of aeration devices to improve dissolved oxygen concentrations to enhance aerobic microbial degradation of ammonia; and installation of conventional treatment systems, such as air stripping, trickling filters, recirculating sand filters, or biological treatment systems.

TVA would conduct a study to further evaluate the ammonia concentration at the ash pond inflow, midpoint, and discharge during the Unit 1 and 4 APH cleaning; in the Unit 1 fly ash; and in storm water runoff from the dry ash stacking area. TVA would ensure that all KPDES permit and other regulatory requirements for Outfalls 001 and 002 are met. As necessary, mitigation measures would be implemented to ensure that any ammonia released through Outfall 001 would have no significant impact. The following monitoring techniques are being considered for maintaining surface water quality:

- Staging Releases of the Unit 1 or Unit 4 APH Waste Wash Water to the Ash Pond - To reduce the NH_3-N concentration at the ash pond discharge (Outfall 001), the APH cleaning waste from the units with SCRs would be retained in a basin, frac tanks, or other containment and slowly released to the ash pond over a number of days. The number of days required for the staged release would depend on the ammonia concentration of the unit's APH wash water waste. The higher the ammonia concentration, the more days would be required to meter the waste to ensure the ammonia concentration at the Outfall 001 discharge remained below the CMC.

If the containment tank/basin does not have enough free volume to accept the APH cleaning waste, the tank/basin would be pumped prior to receiving the waste to ensure there would be enough available volume in the pond/basin to hold and slowly release the APH wastewater to minimize ash pond impacts. Complete mixing of the unit's APH wastewater in the containment by use of pumps would be recommended.

3.6 Cultural and Historic Resources

3.6.1 Affected Environment

Cultural resources include prehistoric and historic archaeological sites, districts, buildings, structures, and objects, as well as locations of important historic events that lack material evidence of those events. Cultural resources that are listed, or considered eligible for listing, on the National Register of Historic Places (NRHP) maintained by National Park Service are called historic properties. Historic properties are identified based on whether they meet the Secretary of the Interior's criteria for evaluation (36 *CFR* Part 60.4), which states that historic properties possess integrity of location, design, setting, materials, workmanship, feeling, and association. In addition, historic properties meet at least one of the following criteria of significance: (a) are associated with important historical events or are associated with the lives of significant historic persons; (b) embody distinctive characteristics of a type, period, or method of construction; (c) represent the work of a master, or have high artistic value; or (d) have yielded or may yield information important in history or prehistory.

Section 106 of the National Historic Preservation Act requires federal agencies to determine the impacts of their proposed actions on historic properties and must provide the Advisory Council on Historic Properties an opportunity to comment on those impacts. TVA determined that the proposed action is an undertaking for purposes of Section 106 compliance. Further, 36 CFR Part 800.3(a) requires agencies to consider whether the proposed undertaking is a type of activity that has the potential to cause effects on historic properties. If the undertaking is such an activity, then the agency must follow steps outlined in 36 CFR Part 800.4 through 800.13. These steps can be summarized as (1) involving the appropriate consulting parties; (2) defining the area of potential effects (APE); (3) identifying historic properties in the APE; (4) evaluating possible effects of the undertaking on historic properties in the APE; and (5) resolving adverse effects. At 36 CFR Part 800.16, APE is defined as the "geographic area or areas within which the undertaking may directly or indirectly cause alterations in the character or use of historic properties, if any such properties exist".

TVA has identified the APE for this undertaking as SHF and the area within a one-half mile radius surrounding Units 1 and 4. This is the area within which direct and indirect effects to historic architectural properties could occur as a result of the undertaking. Because the areas where physical work would take place were affected by significant ground disturbance during plant construction in the 1950s and subsequent activities, the potential for intact native soils or sediments there is nil. Therefore, TVA has determined the undertaking has no potential to affect archaeological resources.

TVA contracted Tennessee Valley Archaeological Research to carry out a Phase I historic architectural survey of the APE, including an assessment of SHF. No historic architectural properties had been identified previously within the APE. The survey identified one historic architectural resource, the SHF plant itself. SHF was originally constructed in 1952 and the units began commercial operation between April 1953 and October 1956. It was the first of the two coal-fired electrical generating plants that TVA built in Kentucky. SHF has been altered several times over the past 40 years through the construction of new auxiliary buildings and emission control equipment, most notably the two 800-ft smokestacks constructed ca. 1975, the modern emissions control equipment on the north elevation of the boiler bay, and the installation of the filter fabric baghouses. Despite those alterations, the original core complex of buildings associated with SHF remains extant and largely unaltered since the early 1950s. Based on the results of the architectural survey and assessment, TVA has determined that SHF is eligible for inclusion in the NRHP. The Kentucky State Historic Preservation Officer (SHPO) agreed with this determination by letter dated December 4, 2014.

3.6.2 Environmental Consequences

Alternative A - No Action Alternative

Under the No Action Alternative, it is assumed that Units 1 and 4 would continue to operate until December 31, 2017, at which time they would be retired. Due to their position relative to the other operating units at SHF, TVA would likely continue to perform essential maintenance on the structures and there would be no changes to the historic integrity or significance of SHF.

Alternative B – SHF Unit Retirement

The impacts of Alternative B on historic properties would be the same as the impacts of Alternative A.

Alternative C – Install and Operate SCR and FGD Systems on SHF Units 1 and 4

Alternative C would physically affect an area adjacent to the SHF powerhouse that has been extensively altered within the past 40 years. The original draft system equipment has already been removed in this area and replaced by the ca. 1980 baghouses and modern emissions control equipment. These actions have diminished the integrity of design, setting, and materials of SHF. Alternative C would have a visual effect on this area of SHF, but this visual effect would have no additive (i.e., cumulative) effect to SHF such that SHF could suffer any further diminution in its historic integrity. However, Alternative C would also result in a significant physical effect to original structures (removal of the 250-foot tall chimneys associated with Units 1 and 4). TVA finds that this effect would be adverse. The Kentucky Historical Commission (KHC) has verbally agreed with this finding. TVA is entering into a Memorandum of Agreement (MOA) with SHPO for the mitigation of the adverse effect. The MOA will stipulate measures that TVA will take. Specifically, TVA will mitigate the adverse effect by providing documentation (photographs, design drawings, and a report presenting the results of archival research) to the KHC. The documentation will meet the Kentucky SHPO standards for the mitigation of adverse effects to historic architectural properties as stipulated by the KHC's *Standard Mitigation Measures for Historic Structures* (2000), at a level to be determined by TVA and SHPO in consultation. The KHC has verbally agreed to enter into an MOA with TVA, and has also agreed that such documentation will adequately mitigate the adverse effect.

3.7 Solid and Hazardous Waste

3.7.1 Affected Environment

Coal Combustion Byproduct Generation, Marketing, and Handling

The nine coal units at SHF, should they all continue to operate, are expected to burn between 3.9 and 5.3 million tons of coal annually through at least 2021. These units currently burn a blend of 75 percent PRB subbituminous coal and 25 percent Colorado bituminous coal. The PRB coal ash content averages about 5.6 percent ash, and the Colorado coal averages about 8.7 percent ash.

Fly ash can be classified by its chemical composition. The chief difference between Class F and Class C fly ash is in the amount of calcium and the silica, alumina, and iron content in the ash (ASTM 1994). In Class F fly ash, total calcium typically ranges from 1 to 12 percent, mostly in the form of calcium hydroxide, calcium sulfate, and glassy components in combination with silica and alumina. In contrast, Class C fly ash may have reported calcium oxide contents as high as 30 to 40 percent (McKerall et al. 1982). Another difference between Class F and Class C is that the amount of alkalis (combined sodium and potassium) and sulfates (SO_4) are generally higher in the Class C fly ashes than in the Class F fly ashes. Because the predominant coal source currently is subbituminous coal, the fly ash produced from the blending of these coals is classified as a Class C coal ash. However, the presence of the Colorado coal causes the fly ash to contain less calcium than most ash produced solely from the combustion of subbituminous coal. Therefore, the resulting fly ash has a less alkaline pH than subbituminous coal ash. If the coal blend should change to nearly a 50/50 percent blend of PRB and ILB coal, then the fly ash could possibly be classified as Class C. That determination would be based on the properties of the coals blended and the fly ash meeting the requirements of ASTM C618 (USDOT 2012)

Total ash production from Units 1–9 has ranged from approximately 252,000 to 475,000 tons per year from 2009–2013. The ash is collected as either fly ash, which is fine enough and light enough to be carried with the flue gas stream exiting the boiler, or as bottom ash, which is coarser and heavier and falls to the bottom of the boiler. The fly ash/bottom ash split is about 80 percent fly ash and 20 percent bottom ash. Units 1 and 4 produced an average of about 72,700 tons of fly ash annually during the last four years (personal communication, Chris Bone, TVA SHF, 10/15/2014).

Prior to 1988, all fly ash was sluiced to ash ponds on the plant site and dredged to dredge cells. In 1988, SHF converted to dry fly ash collection. Until 2010, TVA supplied dry fly ash to a nearby cement kiln for use as raw material in cement manufacturing. This kiln used an average of 100,000 tons per year of dry fly ash. This quantity diminished in 2009 to approximately 37,000 tons and 1,900 tons in 2010.

Fly ash that is not sold or used is conditioned to approximately 18-20 percent moisture in pug mills and hauled to an onsite permitted fly ash stacking area for disposal (see Figure 1-1). Rainfall runoff from the active permitted dry fly ash stacking area is routed to the ash pond per the KPDES permit (KPDES No. KY0004219). This discharge flows through the ash pond and joins the condenser cooling water discharged by Outfall 002 into the Ohio River.

As of 2014, the existing dry fly ash stacking Phase I area has about 1.3 million cubic yards (cy) of remaining disposal capacity, out of a total capacity of 18,600,000 cy for the whole dry stack.

If no fly ash were marketed, there would be enough disposal capacity in the Phase 1 and 2 areas to last until at least FY2025 under current regulations for the disposal of CCRs (personal communication, Steven Shamblin, TVA, 10/15/2014).

All bottom ash produced at SHF is currently sluiced to the active bottom ash pond disposal area (see Figure 1-1). Bottom ash is reclaimed there for use in dike construction, roadways on the plant reservation, or for community projects like walking tracks and parking lots. Between 50,400 and 95,000 tons of bottom ash are handled in this manner annually (based on data from 2009-2013).

3.7.2 Environmental Consequences

Alternative A - No Action Alternative

Under the No Action Alternative, it is assumed that Units 1 and 4 would continue to operate until December 31, 2017, at which time they would be retired. Following the retirement of Units 1 and 2, ash production would decrease by about 22 percent; this decrease would extend the life of the current ash stacking area.

Alternative B – SHF Unit Retirement

Retirement of Units 1 and 4 could potentially alter the capacity of the dry stack. Depending on unit retirement/closure plans, the quantities of solid waste would be decreased, thus extending the life of the use of the ash stacking area under current CCR handling and disposal regulations.

Alternative C – Install and Operate SCR and FGD Systems on SHF Units 1 and 4

Construction Waste

Construction activities would generate solid waste, including concrete, metals, plastic, and wood, primarily resulting from the demolition and/or removal of existing plant components. The majority of debris generated would be considered nonhazardous wastes. These wastes would be properly disposed of at approved solid waste facilities or recycled in compliance with KDEP waste regulations. Sufficient landfill capacity exists in the vicinity of SHF to accommodate any solid wastes that are not recycled.

CCR Wastes

Under Alternative C, CCR from Units 1 and 4 would comprise a mix of dry fly ash and FGD residue (primarily calcium salts). Approximately 28,600 tons and 247,000 tons of bottom ash and fly ash, respectively, are currently generated annually by Units 1-9. The installation of the SCR and FGD systems would not change these quantities; however, an additional 114,000 tons per year of FGD residue would be generated, for a total quantity of approximately 82,000 tons to 219,000 tons (upper limit) of CCR generated per year by Units 1 and 4.

The dry CCR byproduct would be disposed of in the dry stacking area along with fly ash from the other seven units. This would require a minor modification to the current KDEP solid waste permit. TVA would continue to seek beneficial uses for the CCR to the greatest extent possible. For example, bottom ash that meets industry specifications would be marketed for ready-mix concrete, concrete-block manufacturing, or other products.

Although a significant quantity of segregated ash and residue from wet FGD systems (which has a different chemical composition from dry FGD system residue) at other TVA coal plants is beneficially reused, the current beneficial uses of comingled fly ash and dry FGD residue are very limited. TVA is currently participating with others in an ongoing Electric Power Research Institute study entitled "Development and Demonstration of High-Volume Uses for Spray Dryer Absorber Solid Products." This collaborative study is developing uses for SDA byproducts, as well as providing engineering and environmental data for SDA byproduct applications. This byproduct has essentially the same make up as the byproduct from the proposed CDS systems. The study is scheduled for completion in 2016 and will guide TVA's future efforts to recycle the mixed fly ash and FGD residue that would be produced at SHF under the proposed action.

The propose action includes comingling of the CCR from the Unit 1 and 2 FGD/SCR systems with the pure fly ash from the seven other units. These waste streams could be segregated in the future if there were a need; however, all waste in this action would be disposed of in the onsite dry stacking area, unless it can be beneficially reused. Potential impacts of "ammonia slip," or excess unreacted ammonia, as a result of the installations of SCRs on Units 1 and 4 include increased levels of ammonia being deposited on the dry fly ash. Current standards for the marketability of fly ash require that fly ash have low levels of ammonia (less than 50 ppm). Dry fly ash at SHF is currently not being marketed; however, the marketability of the comingled FGD wastes and ammoniated ash with the pure fly ash would greatly reduce the likelihood of finding a beneficial reuse.

If ammonia levels are high enough, the ammonia could be irritating to eyes and nasal passages. Ammonia odor problems have also been known to occur on fly ash disposal areas when the ash is conditioned with water for disposal or during rainfall events, especially under alkaline conditions. SHF previously had alkaline conditions due to the now retired Unit 10 materials, combustion of coal, and limestone, which were highly alkaline, exhibiting pH measurements above 10. Generally, at levels below 100 ppm, fly ash would not have any detectable odor problems. The quantity of ammoniated fly ash from Units 1 and 4, when mixed with the non-ammoniated fly ash from the other seven units, is estimated to be 99.4 mg NH_3-N/kg ash. This level is barely below the 100-ppm level for detectable odors. The ammonia odor level is therefore considered borderline. To obtain more precise information on SCR impacts, once online, fly ash samples would be collected from the baghouse hoppers and from the ash silo system to determine actual ammonia levels on the fly ash. If ammonia is detectable, TVA would address it by temporarily reducing the NOx removal rate prior to catalyst replacement.

Bottom Ash

Bottom ash is collected from the boilers upstream of the proposed FGD and SCR systems. The quantity and chemical composition of bottom ash, as well as its beneficial uses, would not change under Alternative C.

Resource-Specific Mitigation Measures/BMPs

Aside from implementation of waste reduction and minimization techniques during construction and demolition activities and having only an open stack of 10 acres at a time, no additional mitigations/BMPs have been identified for Alternative C.

3.8 Socioeconomics and Environmental Justice

3.8.1 Affected Environment

The Shawnee Plant is located about 10 miles northwest of Paducah. It is surrounded by farmland and forest on the east, south and west, and the Ohio River runs adjacent to the north side of the plant. Metropolis, Illinois is located across the Ohio River 2.5 miles from SHF. The large USEC/DOE industrial complex, now largely shut down, is located about 3 miles south-southwest of SHF. Population density within a 2-mile radius of SHF is low, about 48 per square mile (US Census Bureau 2014). Approximately seven percent of the population in this area is minority, lower than the 11 percent minority population of both McCracken County and the state of Kentucky (US Census Bureau 2013). Per capita income of residents within two miles of SHF is $23,670, comparable to the state per capita income of $23,210 and lower than the McCracken County per capita income of $25,884 (US Census Bureau 2013, 2014). 2012 poverty rates for the county and state are 16.3 percent and 18.6 percent, respectively (US Census Bureau 2014).

SHF current employs 277 people. Approximately 245 of these employees work on plant operations and the remainder work in plant support roles such as equipment support services, supply chain, human resources, finance, ash handling, and safety. The operation of Units 1 and 4 requires 15 unit operators. Based on the current 75:25 blend of PRB and Colorado coal burned at Shawnee and average mine productivity rates (USEIA 2013b), approximately 18 people are employed to produce the approximately 2133 tons/day of coal used in Units 1 and 4.

The September and October 2014 unemployment rates for the state of Kentucky were 6.7 and 6.2percent respectively, declines from the average unemployment rate of about 8.0 percent over the previous 24 months (Bureau of Labor Statistics 2014). September and October 2014 unemployment rates for McCracken County were 6.8 and 6.1 percent, and for the Paducah KY-IL Micropolitan Statistical Area 6.5 and 6.4 percent. Average unemployment rates for these two areas for the preceding 24 months were 8.2 and 8.1 percent, respectively. The overall labor force for the Paducah statistical area in October 2014 was 7,147 (Bureau of Labor Statistics 2014).

While TVA does not pay taxes, it does make tax equivalent payments to the states where it sells electricity or owns power-related assets and to 146 local governments where TVA owns power property. The tax equivalent payments are proportioned among the states according to the value of TVA's power properties and power sales revenues in each state. Fiscal year 2014 tax equivalent payments to the state of Kentucky were $40,380,262. The redistribution of these payments within the state is determined by state legislation. In recent years McCracken County has received about $1.1 million in tax equivalent payments.

3.8.2 Environmental Consequences

Alternative A – No Action Alternative

Under this alternative, Units 1 and 4 would eventually be shut down if the USEPA Agreements are not changed, potentially resulting in the loss of 15 employees at SHF. There would be little effect on area employment by business providing goods and services to SHF. Depending on whether the mines producing the coal used by Units 1 and 4 can find alternative markets for the coal, approximately 18 people employed in producing the coal could lose their jobs. Overall impacts on the area employment rate would be insignificant. No adverse effects on minority or low income populations would occur. There would be a slight decrease in TVA tax equivalent payments to the state of Kentucky and to McCracken County due to the reduced value of a seven-unit Shawnee plant.

Alternative B– SHF Unit Retirement

The impacts of this alternative would be the same as those described for Alternative A, the No Action Alternative.

Alternative C – Install and Operate SCR and FGD Systems on SHF Units 1 and 4

Construction of the proposed SCR and FGD systems would take between 18 and 24 months and require a temporary workforce of up to 200 people. A portion of these workers would likely be recruited from the local labor market while other tasks would likely be performed by workers based elsewhere and temporarily relocating to the project area. This would result in short-term, beneficial impacts on employment in the local area and from increased spending on goods and services.

The operation of the SCR and FGD systems would require an additional five assistant unit operators at SHF. Supplying and transporting the lime and other materials needed to operate the SCR and FGD systems could result in a small increase in off-site employment. The potential shift from a 75:25 blend of PRB and Colorado coal to a 50:50 blend of PRB and ILB coal would increase employment at the mines from approximately 18 to 33 due to the lower productivity of ILB mines compared to PRB and Colorado mines (EIA 2013b).

Alternative C would not result in disproportionate adverse impacts on minority or low income populations. The proportion of the population in the immediate vicinity of SHF that is minority or low income is not markedly greater than that of McCracken County or the state of Kentucky. The nature of the proposed action is also not likely to result in noticeable adverse effects on nearby residents.

Alternative C would likely result in a slight increase in TVA tax equivalent payments to the state of Kentucky and to McCracken County.

3.9 Transportation

3.9.1 Affected Environment

Shawnee Fossil Plant is located adjacent to the Ohio River about 10 miles northwest of Paducah. The plant site is served by barge, highway, and rail transportation modes. The barge facilities are designed for unloading coal. Highway access from Interstate 24 is by Route 305 to Route 358 to Route 996, a distance of 8.7 miles. 2009 - 2011 average annual daily traffic counts (the most recent available counts; Kentucky Transportation Cabinet 2011) for these roadways are 7,075 on Route 305 near I-24, 2,407 on Route 358 near its junction with Route 996, and 1,037 on Route 996 a short distance north of its junction with Route 358. These roadways are in good condition and until recently Routes 305 and 358 accommodated a much higher volume of traffic due to employee and truck traffic to and from the nearby USEC/ DOE plant that has now shut down. Most of the traffic on Route 996 is due to SHF employees and deliveries of goods to SHF. Coal is currently delivered to the plant by rail.

3.9.2 Environmental Consequences

Alternative A – No Action Alternative

Under this alternative, there would be no immediate change in the existing transportation infrastructure or barge, highway, or rail traffic associated with the operation of SHF. The eventual retirement of Units 1 and 4 would result in a small decrease in highway traffic due to the reduction in employment at SHF and fewer deliveries of goods to the site. Rail traffic would also be reduced due to the smaller quantities of coal burned at SHF.

Alternative B – SHF Unit Retirement

The impacts of this alternative would be the same as those of Alternative A.

Alternative C – Install and Operate SCR and FGD Systems on SHF Units 1 and 4

Vehicular traffic on roadways near SHF would increase during construction of the SCR and FGD systems because of construction workers and materials moving to and from the plant. Assuming most construction workers drive their own vehicles, commuter traffic would increase by up to about 200 vehicles per day over an 18-24 month period. Construction materials, including components of the SCR and FGD systems, would be delivered primarily by truck, with some larger components likely delivered by rail. Trucks delivering construction materials would further increase roadway traffic. This increase in traffic would be temporary, and the resulting total traffic on Routes 305 and 358 would likely be less than when the nearby USEC/DOE plant was operating. These roadways, along with Route 996, can accommodate the increased construction traffic without adverse effects to safety, congestion, or other roadway users.

The operation of the SCR and FGD systems would require an additional five employees; their commuting to and from SHF would have a negligible effect on traffic. The ammonia and hydrated lime required to operate the SCR and FGD systems would be delivered by truck. Depending on the blend of coal burned in Units 1 and 4, up to about 4,000 truckloads per year, or 20 trucks per day assuming weekday delivery, would travel to and from the site to deliver lime. Two U.S. Department of Transportation-approved tanker trucks per week would deliver ammonia. Although this additional truck traffic would be noticeable on the roadways connecting to SHF, their impacts on traffic would be insignificant. Until an off-site use for the additional CCRs generated by the FGD systems is available, all traffic associated with CCR handling and disposal would be on the plant site and would not affect area public roadways.

3.10 Cumulative Impacts

Air Quality Cumulative Impacts

Nationally and regionally, the trend in air quality has been very positive. Pollution levels have significantly declined and are expected to continue to do so as emissions from plants, industrial processes, and vehicles continue to decrease. TVA has reduced its system-wide SO_2 emissions by 95 percent since 1977 and system-wide NOx emissions by 88 percent since 1995. TVA's proposed actions would contribute to this positive trend and to the positive benefits to human health and environment associated with cleaner air.

Solid and Hazardous Waste Cumulative Impacts

SHF would strive to beneficially reuse the CCR waste to the greatest extent possible. Generation of solid waste over time results in a cumulative impact to landfill/dry stack facilities to which the solid wastes are transferred and stored. Based on the capacity of surrounding landfills and the expected life span of the proposed onsite dry stack, TVA's proposed actions' contributions to cumulative impacts to local landfills are expected to be minimal.

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6. APPENDIX A

PUBLIC COMMENTS RECEIVED ON DRAFT EA AND TVA'S RESPONSES TO COMMENTS

A draft of this final EA was issued for comment on November 25, 2014. Notices of availability of the draft EA were sent to state, federal, and local agencies, and to those who submitted scoping comments. Its availability was also announced by advertisements in Paducah-area media, by news releases, and by notice on the TVA website. TVA accepted comments through an electronic comment form on the project website, by mail, and by email. The comment period closed on December 9, 2014.

TVA received 589 comments on the draft EA. The majority of these comments were form letters submitted through a campaign organized by the Sierra Club of Kentucky and Tennessee. TVA carefully reviewed all of the comments and edited the text of the final EA as appropriate. Many of the comments were similar in substance. To avoid repetition, TVA grouped similar comments and produced one synthesized comment for each comment grouping.

Following is a listing of the comments and TVA's responses to the comments, grouped by subject area. It includes the names of the commenters contributing to each synthesized comment. Instead of listing the numerous individuals who submitted the Sierra Club form letter, they are collectively identified as "Sierra Club of Kentucky and Tennessee form letter" in the following section. All of the commenters are listed in the commenter index at the end of this section, along with their affiliation and the identification numbers of their comments.

Air Quality

1. A significant body of research shows impacts of coal plant emissions of air pollutants on human health, including increased respiratory and cardiac ailments. Information provided in the Shawnee Fossil Plant Health Impact Assessment shows increased rates of heart disease and asthma in Ballard and McCracken Counties. While installing the SCR and FGD systems under Alternative C would improve area air quality and reduce the harmful effects of air pollution, the two units would still be major sources of air and water pollutants, which would continue to harm the environment, including human health. (*Commenters: Deborah Payne – Kentucky Environmental Foundation, Gary Smith, Gisela M. Topolski, Jo Ann Van Horne*)

Response: Installation of the SCR and FGD systems would result in significant decreases in the emissions of air pollutants. Numerous environmental factors besides emissions from the Shawnee plant, as well as lifestyle factors, affect public health in the Shawnee area and it is difficult to quantify the specific contribution of Shawnee emissions.

Health

2. As described in the Health Impact Assessment of the Shawnee Fossil Plant prepared by the Kentucky Environmental Foundation, unemployment is an important social determinant of human health. In deciding on Shawnee Units 1 and 4, TVA should carefully consider the decision's effect on employment and associated effects on health. (*Commenter: Deborah Payne – Kentucky Environmental Foundation*)

Response: Comment noted. As described in EA Section 3.8.2, Alternative C - Install and Operate SCR and FGD Systems on SHF Units 1 and 4 would result in a sizeable short-term increase in employment during construction and a small increase in employment to operate and maintain the systems. Retiring Units 1 and 2 would result in a small decrease in employment.

NEPA Compliance/Adequacy

3. The draft EA uses different environmental baselines when comparing the environmental impacts of Alternative B - Retire SHF Units 1 and 4 and Alternative C - Install and Operate SCR and FGD Systems on SHF Units 1 and 4. Alternative A - No Action and Alternative B both state that Units 1 and 4 must be retired by December 31, 2017. The impact analyses for Alternative C compares its impacts to a baseline of continued operation of Units 1 and 4 in their present condition into perpetuity. The comparison of Alternative C with the proper retirement baseline would show the impacts of Alternative C to be significantly more harmful. (*Commenter: Mary Whittle – Earthjustice et al.*)

Response: Comment noted. The EA has been revised to better describe the differences in the impacts of installing and operating the SCF and FGD systems on Units 1 and 4 under Alternative C and the impacts of retiring these two units.

Alternatives to the Proposed Action

4. The draft EA fails to analyze all reasonable alternatives to retrofitting Units 1 and 4. Other feasible alternatives, which are likely more cost effective than the retrofit alternative, include the following:

- Replacing Units 1 and 4 with the purchase of existing under-utilized natural gas plants and/or market purchases. Recent prices paid for gas plants average about $500/kW of capacity, significantly less than the $653 to $840 per kW for retrofitting Units 1 and 4.
- Replacing Units 1 and 4 with a mix of renewable energy and energy efficiency. This would comply with the Clean Air Agreements and contribute to a balanced TVA generation portfolio, which consists primarily of coal-fired units. Unlike other recent TVA coal plant decisions, replacement of the Shawnee units with fossil fuel generation is not needed to provide voltage support, which makes the failure to consider a renewable/energy efficiency option wholly unreasonable. Several recent studies by the Department of Energy and others show an abundant renewable energy resource in the region, and the recent experience of other utilities show it is available at reasonable prices.
- Retiring one of the Shawnee units and retrofitting the other. (*Commenter: Mary Whittle – Earthjustice et al.*)

Response: See response to Comment 7. Retiring one of the two units and controlling the second roughly would split the benefits, costs, and impacts associated with retiring both or controlling both. While there may be some economies of scale associated with controlling both units, these are likely not substantial, and the cost of controlling one unit would be about half of the estimated cost of controlling two units. The benefits of continued operation of one controlled unit basically would be half those of controlling two units. Separately, both units have real value for the TVA system because of their load-following capabilities, their fuel diversity, and low operating costs. Controlling one unit and retiring the other would decrease air pollutants more, but controlling both units also would reduce emissions from their current levels. All three combinations--control two, retire two, control/retire one unit each--would contribute toward the improvement in air quality.

5. The discussion of the Alternative C operational impacts on greenhouse gases/climate change in Section 3.1.2.3 states: 'IRP analyses considered the retirement of between 2,400 MW and 7,000 MW of coal-fired generating capacity. Recent TVA decisions are moving coal unit retirements toward the upper end of this range.'

With the recent announcement of the retirement of the Allen Fossil Plant coal units, TVA has announced plans to retire 7,632 MW of coal-fired generating capacity. This is well beyond the purported limits of the IRP analyses, and much more than the 4,700 MW of coal retirements analyzed in the Final IRP and incorporated in the Recommended Planning Direction. Retirements exceeding 4,700 MW were rejected as being inconsistent with TVA's obligation to provide adequate and reliable service at the lowest system cost. (*Commenter: Karen Greenwell – Wyatt, Tarrant & Combs)*

Response: The planning direction approved by the TVA Board in the 2011 IRP was purposefully structured to be flexible to allow staff to account for future developments in TVA's decisions about specific energy resources. The IRP did identify 2,400 to 4,700 MW for idled coal-fired capacity with the qualitative direction to consider increasing the amount of idled coal capacity. The IRP also directed staff to employ more natural gas generation on the system. The energy resource decisions that TVA has made are fully consistent with the 2011 planning direction. The commenter confuses nameplate capacity with net dependable capacity, the latter being the kind of capacity that TVA used in the planning direction and 7,000 MW upper range of its analyses. Net dependable capacity is typically less than nameplate capacity. On a net dependable capacity basis, TVA has or committed to idle/retire approximately 6,319 MW in total to date across the TVA system. If the Board decides to retire Shawnee Units 1 and 4, this total would increase by approximately 268 MW to 6,587 MW, below the 7,000 MW considered in the IRP analyses.

<u>Preferences for Alternatives</u>

6. The proposed plant retrofits under Alternative C will do nothing to reduce carbon emissions that cause climate change and will result in more carbon emissions for decades. (*Commenters: Jennifer Dowdy, Sierra Club of Kentucky and Tennessee form letter, Gary Smith*)

Response: Comment noted. As discussed in the EA in Section 3.1, worldwide anthropogenic CO_2 emissions were estimated at 36 billion tons in 2013. CO_2 emissions at Shawnee in 2013 were estimated to be 7,934,617 tons, a very small amount compared to global emissions. TVA does expect CO_2 emissions to slightly increase on a tons per megawatt-hour of generation basis, as discussed in Section 3.1, because the pollution controls that TVA proposes to install to reduce SO_2 and NO_x emissions consume electricity to run (they would be parasitic loads at the plant). This potential increase could be offset if TVA switches from using western coals in the two units to a blend that includes Illinois Basin coals that have lower CO_2 emission factors. From 2005 through 2013, TVA reduced CO_2 emissions on its power system by approximately 32 percent and expects to continue to reduce CO_2 emissions.

7. While Alternative C would reduce emissions of some air pollutants, it would not reduce emissions of carbon dioxide, one of the main causes of climate change. TVA should retire Units 1 and 4 and replace them with increased energy efficiency, renewable generation, demand response, and the nuclear capacity about to come on line. Although these potential replacement sources have environmental impacts, there are more desirable because they do not emit carbon dioxide. (*Commenter: Joe Schiller*)

Response: See response to Comment 6. As discussed in Section 2.1.4, Shawnee Units 1 and 4 are not needed to maintain reliable electric service in the Paducah area. TVA can retire them without replacing them with other energy resources. These units, however, do contribute to the total energy resources and capacity on the TVA system and TVA projects a need for additional energy resources in the future. Continued operation of the two units would help address this system-wide need and this is another benefit of controlling the units. The energy resources that could be used to address this system-wide need are addressed in TVA's 2011 IRP and associated Environmental Impact Statement from which this EA tiers.

8. Converting the two units to burn biomass is preferable to Alternative C as it would eliminate the harmful environmental impacts of burning coal. It would also help the economy of the surrounding area, in keeping with TVA's mission. (*Commenters: Gayle Kaler – City of Paducah, Lavina Rogers and Reidland Elementary School students, Joe Schiller, Mary Ellen Thomason*)

Response: Comment noted. While converting the two units to burn biomass would eliminate many of the impacts associated with burning coal, TVA has determined that it is not a reasonable alternative due to it much greater cost and uncertainties over the fuel supply. See Final EA Section 2.1.4.

9. I oppose the alternative of retiring Units 1 and 4. While this would be easy to implement, it would have a negative impact on the surrounding area, as well as TVA's ability to provide the affordable power produced by the two units. (*Commenter: Mary Ellen Thomason*)

Response: Comment noted.

10. I support Alternative C - Install and Operate SCR and FGD Systems on SHF Units 1 and 4. This alternative will ensure reliable, low cost, cleaner coal generation, maintain local employment, and provide additional employment during construction. (*Commenters: Butch , Vanessa Barnett, John Crivello, Eddie Doss, Vincent Duncan, Deborah Edmonds – Paducah Area Chamber of Commerce, Ricky Futrell Sr., Gayle Kaler – City of Paducah, Darrell Massey, Lavina Rogers and Reidland Elementary School students, Thomas Selph, Carolyn Sturgis, Mary Ellen Thomason, Pat Vannerson, Joyce Walker, Tracy H. Willhite*)

Response: Comment noted.

11. Please retire the two units. If additional base load capacity is needed, construct a smaller, safer 4th generation nuclear plant. Cooperate with the Department of Energy on this to utilize some of the weapons-related nuclear material in Kentucky for fuel. Also consider the use of geothermal generation. New renewable generation can meet much of future non-base load needs. (*Commenter: Edgar Gehlert*)

Response: TVA is evaluating new nuclear plants in the development of the Integrated Resource Plan, scheduled to be completed in 2015. While feasible in some other parts of the United States, geothermal energy is not currently feasible in or near the TVA service area. TVA will evaluate the future use of geothermal energy if it is shown to be technically and economically feasible. While renewable energy, as well as energy efficiency, can meet some non-base load energy needs, it does not always provide the flexibility necessary to meet peak power needs. TVA is evaluating increased use of renewable energy and energy efficiency in the new Integrated Resource Plan.

12. Removal of the current cap on solar installations in the TVA region would stimulate the installation of solar facilities by individuals and small producers. This would provide safe, environmentally sensitive production of electricity to replace that lost by retiring Units 1 and 4. (*Commenter: Debbie Cardin*)

Response: See response to Comment 7. Renewable resources, including solar, are addressed in TVA's 2011 IRP and associated EIS. Removing the current caps on solar installations through the Renewable Standard Offer and Generation Partners programs could result in increased solar generation in the TVA region.

13. Retiring Units 1 and 4 will hasten the eventual retirement of the remaining Shawnee generating units. This will have major negative economic impacts on the Paducah area. For this reason, I prefer Alternative C. (*Commenter: Lavina Rogers and Reidland Elementary School students*)

Response: Comment noted. The economic impacts on the Paducah area of retiring the two units are described in Section 3.8.2 of the EA. The Shawnee units have both shared and separate infrastructure. Retiring the two units would affect only their separate infrastructure. Because TVA would continue to operate the remaining seven units, there would be little if any impact on shared infrastructure (*e.g*., coal delivery infrastructure, switchyard, ash handling).

14. Since the Paducah Power System left the TVA system and began getting its power from Prairie State Energy, electricity rates have greatly increased. Please implement Alternative C, which will assure Shawnee will continue to operate and help Paducah Power System return to TVA. This will result in lower future power bills. (*Commenter: Richard and Janice Yasko*)

Response: Comment noted. Whether TVA controls or retires the two Shawnee units would have little effect on TVA's future ability to provide power to Paducah Power System, should Paducah Power System decide to get its power from TVA.

15. The load-following ability of Units 1 and 4 enhances their value to the TVA system. It also helps TVA better integrated the intermittent generation provided by wind and solar generation. For this reason, I prefer Alternative C. (*Commenters: Eddie Doss, Charles R. Perry, P.E.*)

Response: Comment noted.

16. The Shawnee plant is almost 60 years old and one of the largest contributors to air and water pollution in the region. Alternative C will cost TVA customers hundreds of millions of dollars and keep the plant running for decades, despite TVA's own analysis showing the two units are not needed for reliability purposes in the area. Alternative C would result in burning coal for decades with significant environmental impact, instead of phasing out the units and investing in energy efficiency and renewable technologies. Save money and eliminate pollution by retiring the units, providing a fair transition for the plant workers impacted by the retirement, and accelerating the transition to clean energy. (*Commenters: Jo Tilley Dortch, Jeffrey Eastman, Gene Nettles, Sierra Club of Kentucky and Tennessee form letter, Gary Smith, Gisela M. Topolski, Jim Walts*)

Response: While installing additional air pollution controls on the two Shawnee units would not reduce emissions as much as retiring the two units would, controlling the units would help improve air quality in the area. The analyses done for the EA show that either alternative, control or retirement, would not result in significant environmental impacts and there would be short-term economic benefits from the control installation projects.

17. TVA has not properly maintained some of its coal plants, such as Johnsonville. This deterioration has led to them being shut down. I hope you will save some of the fossil plants. (*Commenter: Tracy H. Willhite*)

Response: Comment noted. The TVA Board's direction to staff when it approved the 2011 IRP was to continue to move TVA to a more balanced, diverse power system. That includes maintaining some of TVA's existing coal-fired generation.

18. Wind farms are detrimental to bird populations and one of the most detrimental and ugly features of the country's beautiful landscapes. A coal plant is far less ugly than thousands of windmills standing in corn or soybean fields. Wind energy cannot replace coal and the best alternative here is Alternative C. (*Commenter: John Crivello*)

Response: Comment noted.

19. TVA should fight the anti-coal movement and continue to burn coal in Units 1 and 4. (*Commenters: John Crivello, Darrell Massey, Pat Vannerson, Tracy H. Willhite*)

Response: Comment noted. The TVA Board's direction to staff when it approved the 2011 IRP to continue to move the TVA power system to a more balanced, diverse portfolio of energy resources. That includes maintaining some of that coal generation.

<u>Purpose and Need for Action</u>

20. The draft EA does not adequately justify the statement of purpose and need for action. TVA acknowledges that Units 1 and 4 are not needed for reliability purposes their retirement would not affect reliable service in the Paducah area. Nevertheless, TVA cites an unspecified 'growing demand for energy and capacity on the TVA system' as justification for the proposed action. The draft EA, citing the 2011 IRP, states that 'demand forecasts indicate that there will be a general need for more generation on the TVA system in the future.' There is no evidence in the record that supports such demand growth, and TVA has on several recent occasions acknowledged that the current demand is much less that that projected in the 2011 IRP. (*Commenter: Mary Whittle – Earthjustice et al.*)

Response: TVA expects modest load growth into the future. The 2011 IRP anticipated higher load growth than TVA's present predictions, and the 2015 budget (publically discussed and approved at the TVA Board of Directors meeting in August 2014) projects peak growth of approximately 1% per year and energy growth of approximately 0.9% per year.

<u>Cost Estimates</u>

21. The draft EA claims that the cost of the proposed retrofits is $175 to $225 million. A review of EPA data indicates that this may underestimate the cost of the retrofits by 20 to 40 percent. The EPA Integrated Planning Model projects the capital, fixed O&M, and variable O&M cost of adding these controls to plants of capacities and heat rates comparable to SHF are $1,035 to $1,176 per kWh. This translates to the significantly greater cost of $270-310 million for Alternative C. The TVA cost estimate is limited to capital costs and does not account for their impact on the dispatch of Units 1 and 4. Based on EPA Integrated Planning Model data,

operating the SCR and FGD systems on Units 1 and 4 would increase variable O&M costs by $7-8 million per year and fix O&M costs by $4.5-5 million per year. The draft EA also does not consider other reasonably foreseeable compliance costs including the Clean Power Plan, the CCR rule, and the ELG rule. These rules may further increase variable O&M costs, and in turn affect the dispatch of the units. (*Commenter: Mary Whittle – Earthjustice et al.*)

Response: The capital cost estimates for Alternative C are based on the specific configuration of the Shawnee units and the project scope outlined in this EA, not generic assumptions from the EPA Integrated Planning Model. TVA accounted for the variable cost and operational impacts of installing controls on Units 1 and 4 in an overall portfolio evaluation; however, these are not significant drivers of the decision. Given the low dispatch price of the Shawnee units, any future (and as-yet not finalized) environmental regulations affecting the variable O&M costs are not anticipated to have a significant effect on unit dispatch.

22. The analyses in the draft EA do not explain how TVA will recover the costs of installing and operating the SCR and FGD units unless they are operated far beyond their anticipated lives. Most other plants of Shawnee's vintage are retired or projected to retire by 2025. To recover the cost of the retrofits, TVA would likely have to operate the units well beyond this date. It is also unclear how operating them would be viable in the absence of the other 7 Shawnee units. (*Commenter: Mary Whittle – Earthjustice et al.*)

Response: TVA's portfolio analysis confirms that the proposed action is the least-cost solution for TVA ratepayers. The Energy Policy Act of 1992 directs TVA to take into account such things as diversity of resources, reliability and risk factors on a system-wide basis in order to provide customers "adequate and reliable electric service" at the lowest system cost. Expected unit life is factored into this analysis. As discussed in the EA, the Shawnee units are in good material condition and have an excellent performance history. This EA does not address the future plans for the other 7 units at Shawnee.

Impact Assessment

General

23. The assessment of Alternative B - Retire SHF Units 1 and 4 is inadequate in its analysis of the following topics:

- Impacts on electric rates and affordability, particularly by low-income populations and if the generating capacity is replaced by gas-fired generation
- Impacts on TVA's ability to provide an affordable and reliable power supply for manufacturers and other energy-intensive industries, particularly in the McCracken County / western Kentucky area
- Impacts on employment of those providing good and services to Shawnee
- Impacts of decommissioning and demolishing Units 1 and 4
- Impacts of constructing and operating the generation that would be necessary to replace that currently provided by Units 1 and 4 (*Commenter: Karen Greenwell – Wyatt, Tarrant & Combs)*

Response: TVA's Integrated Resource Plans are analyses that identify least-cost, system wide strategies or plans for meeting future demand on the TVA power system. These analyses consider potential impacts on all of TVA's ratepayers (the public served by TVA). TVA's proposal to install additional controls on Shawnee Units 1 and 4 are consistent with and would implement TVA's 2011 IRP. Neither Alternative B (retire the two units) or Alternative C (control the two units) are expected to have a material impact on end-use customer rates given the relatively small size of SHF Units 1 and 4 and the myriad other factors that affect customer rates. Further, since TVA sets rates on a system-wide basis, the *rate-related* impacts of either alternative would be shared across the TVA system and not localized on low-income populations or the western Kentucky area.

Section 3.8 of the Final EA has been revised to provide more information on direct and indirect employment at Shawnee. An analysis of the impacts of decommissioning and demolishing Units 1 and 4 is beyond the scope of this EA because it is very unlikely to occur for several years and possibly much longer (more than two decades in the case of the retirement of TVA's Watts Bar coal-fired power plant). The impacts of demolishing a coal plant are discussed in two recent EAs prepared by TVA for the former Watts Bar coal plant (see http://www.tva.com/environment/reports/wbf_deconstruction/index.htm) and for the former John Sevier coal plant (see http://www.tva.com/environment/reports/johnsevierdeconstruction/index.htm). The impact of the future demolition of the Shawnee plant would be generally similar to those described in these two EAs. The general impacts of constructing and operating replacement generation are described in the 2011 IRP EIS.

24. The SCR and FGD systems proposed under Alternative C would consume electricity and therefore decrease the amount of generation available to serve customers. The draft EA does not disclose the parasitic load of the SCR and FGD systems, or the heat rate penalty or derate from operating the systems. (*Commenter: Mary Whittle – Earthjustice et al.*)

Response: The parasitic loads associated with operating SCR and FGD systems on Shawnee Units 1 and 4 will result in an approximately 3% - 5% derate on each unit and correspondingly slightly degrade the net heat rates of the units.

Biological Resources

25. The draft EA does not adequately address the concerns raised by the U.S. Fish and Wildlife Service during project scoping on potential impacts to endangered and threatened species, to wildlife using the ash pond and other associated water bodies, and to fish- and wildlife-related activities. Listed species, as well as other fish and wildlife, would benefit from the retirement of the two units. (*Commenter: Mary Whittle – Earthjustice et al.*)

Response: Response: There is no evidence that the current operation of the nine SHF units is adversely impacting endangered and threatened species and other fish and wildlife resources. As described in EA Sections 3.4 and 3.5, current SHF discharges comply with applicable standards and permit limits, including toxicity levels, which have been established, in part, to protect fish and wildlife. Discharges under Alternative C would continue to comply with applicable standards and toxicity levels.

The U.S. Fish and Wildlife Service was provided an opportunity to comment on the draft EA but did not do so.

Economic Impacts

26. The full retirement of the Shawnee plant would reduce the approximately $1.1 million in TVA in-lieu-of-tax payments to McCracken County. This payment, funds that TVA has contributed to the McCracken County School budget, and the $300,000 in payroll taxes paid by Shawnee

workers to the county are important for maintaining local services, including education, police, fire-fighting, and emergency medical services. Reduction in these services would have adverse effects on the area. The retirement of Units 1 and 4 would result in a lesser reduction of these payments, but would still have the potential to adversely affect services. (*Commenter: Deborah Payne – Kentucky Environmental Foundation*)

Response: Comment noted. Socioeconomic impacts of the alternatives are described in EA Section 3.8.2.

Water Resources

27. The analysis of groundwater in Section 3.4 of the DEA does not property attribute any groundwater contamination to the disposal of coal ash, as indicated in TVA's own groundwater monitoring reports. These monitoring reports show, for example, elevated levels of boron and manganese, as well as other pollutants, attributable to leachate from the coal ash disposal units. The EA should acknowledge this and describe the impacts to groundwater that would result from the operation of the FGD systems. This analysis should incorporate the expected changes to ash chemistry and leachate that will result from the operation of dry sorbent injection systems on the other seven Shawnee units. (*Commenter: Mary Whittle – Earthjustice et al.*)

Response: The primary focus of Section 3.4 is on the potential impacts on groundwater associated with the ammonia discharges from the SCR systems. This is the only element of the proposed action that potentially could impact groundwater. Heavy metals are not expected to significantly increase in the leachate stream as a result of the proposed process and the nature of the mixed coal-combustion residuals (CCR). A limited number of groundwater MCL limits have been exceeded in a few groundwater samples at the CCR management facility. TVA thinks these likely resulted from excessive to turbidity in the collected sample and were not accurate results. Subsequent samples from the same well have all yielded results which indicated these constituents were non-detect or below the applicable MCL.

All shallow groundwater at the site discharges to the Ohio River or its tributaries, Little Bayou Creek and Bayou Creek, without traversing private property. Consequently, there is no potential for contamination of any private groundwater supplies located on properties bordering the Shawnee plant reservation. Furthermore, the plant site lies within the Department of Energy (DOE) Water Policy Boundary, which restricts use of ground and surface water. Property owners residing within the boundary have agreed to use public water supplies to preclude potential health effects of the DOE contaminant plumes associated with the former USEC plant that is adjacent to Shawnee. Additionally, the referenced EPA health advisory concentrations for boron and magnesium noted in the comments are not regulatory standards and do not denote unsafe or unregulated discharges to groundwater.

Dry sorbent injection (DSI) systems are currently being installed on the nine SHF units for MATS compliance. These DSI systems will use a calcium-based sorbent and not a sodium-based sorbent that raised concerns raised by the study referenced by commenter. A recent study of the effects of DSI sorbents on CCR (Schantz, M.D and Sewell, M., 2013, The Growth of Dry Sorbent Injection (DSI) and the impact on Coal Combustion Residue, Lhoist North America, Fort Worth, TX), found that the leachability of the majority of the evaluated metals was at levels less than the detection limit for the calcium-based sorbents. CCR mixed with the calcium-based sorbent also had a lower degree of metal solubility. This is likely because the non-spent sorbent reacted with the pozzolan in the flue gas stream to encapsulate metals. Leachability is inversely related to pH and the calcium-based sorbent will make the CCR discharges more alkaline (higher pH) and consequently reduce leaching. The use of the calcium- based DSI sorbent would reduce the leaching and mobilization of metals, resulting in reduced potential groundwater impacts.

28. The Shawnee plant generates large quantities of ash which contains varying levels of heavy metals. Environmental conditions such as acidity can affect the abilities of these metals to leach out of ash into surrounding ground and surface waters. The current installation of the Dry Sorbent Injection (DSI) systems to reduce acid gas emissions would result in increased mobilization and leaching of heavy metals if it uses a sodium-based sorbent. (*Commenter: Deborah Payne – Kentucky Environmental Foundation*)

Response: The DSI systems being installed on the nine SHF units will use a calcium-based sorbent which does not produce the acid conditions leading to increased leaching of heavy metals that can result from use of a sodium-based sorbent.

29. According to the KPDES permit for Shawnee, the plant annually discharges 42,500 pounds of aluminum and 2,000 pounds of manganese, along with hundreds of pounds of other toxic metals, into the Ohio River. The analysis of the potential impacts to this discharge under Alternative C does not address the discharges of aluminum, iron (29,000 pounds/year), or manganese. Nor does it analyze boron, a key coal ash indicator pollutant that has been measured at elevated concentrations in Little Bayou Creek adjacent to the ash disposal area. (*Commenter: Mary Whittle – Earthjustice et al.*)

Response: Surface Water effluent limitations set by Kentucky Department for Environmental Protection are determined based on analytical data from Outfall 001 at SHF, background analytical data from the Ohio River, flow data from Outfall 001 at SHF, and the flow in the Ohio River. Based on reasonable potential analysis and water quality-based effluent calculations (see pages 3A and 5-7 of the SHF KPDES permit), as well as historical KPDES toxicity and reportable metals concentrations discharged from the ash pond, Outfall 001 does not cause or contribute to aquatic toxicity. Projected metals concentrations are substantially below toxic concentrations, the implementation of the proposed action, based on, EPA and KDEP NPDES regulations and Water Quality Standards would not have adverse impacts.

30. EA Table 3-6 shows a 10% increase in selenium discharges and a 50 percent increase in chromium discharges under Alternative C. Although changes in discharges of other metals are relatively small, the net change is an increase of 126 pounds of toxic metals discharged. The resulting impacts of this increase on aquatic species are not adequately described. This analysis also does not describe the difference in discharges of toxic metals between Alternative C and Alternative B following the retirement of Units 1 and 4. (*Commenter: Mary Whittle – Earthjustice et al.*)

Response: Projected dry stack storm water concentrations are estimated calculations based on analyses conducted for the Gallatin FGD project (TVA 2013) and dry scrubber effluent from an outside operation, since TVA does not currently operate a dry scrubber. These calculations are considered to be representative, but conservative, for SHF depending on fuels. Projected increases in concentrations from the dry stack are minimal and well below the no observable effect levels (NOEL) when mixed in the receiving stream, the Ohio River. Selenium concentrations at Outfall 001 are estimated to change from 0.002 mg/L to 0.00205 mg/L with an in-stream concentration in the Ohio River of 0.0008 mg/L, well below the Water Quality Standard, while chromium concentration would change from the current 0.003 mg/L to

0.0031mg/L, the same as the concentration in the Ohio River at the intake. Therefore, based on this information no adverse impacts to surface waters are expected.

7. APPENDIX B

SHAWNEE FOSSIL PLANT UNITS 1 AND 4 NEPA REVIEW PROCESS

The National Environmental Policy Act (NEPA) requires federal agencies, including the Tennessee Valley Authority (TVA), to consider the potential environmental impacts of actions they propose to take that will impact the physical environment before making a final decision to proceed. Specifically, NEPA requires the preparation of an Environmental Impact Statement (EIS) for a major action significantly impacting the quality of the human environment. The purpose of an EIS is to assess the potential environmental impacts of the proposed action and alert the federal agency decision maker and the public to those impacts before a final decision to proceed with the action is made. Regulations or procedures guide implementation of the statute.

TVA is subject to and complies with two sets of regulations or procedures that implement NEPA. These are the regulations promulgated by the Council on Environmental Quality (CEQ) at 40 C.F.R. parts 1500-1508 and TVA's own NEPA procedures which supplement CEQ's regulations. TVA's NEPA procedures were adopted through a rulemaking process with public notice and opportunity for comment. TVA initially published its final NEPA procedures in the *Federal Register* in 1980 and later amended them after public notice and comment and republished them in the *Federal Register* in 1983. 48 Fed. Reg. 19,264 (Apr. 28, 1983). CEQ approved TVA's initial and amended procedures. Internally, TVA's "NEPA Compliance" staff currently oversees TVA's compliance with NEPA.

CEQ's regulations and TVA's NEPA procedures identify three levels of NEPA review. The most detailed and time-consuming level of review is an EIS. EISs are comprehensive, detailed documents often exceeding 300 pages exclusive of appendices and typically take 12 to 36 months or longer to complete. EIS processes provide opportunities for public comment, including a minimum mandatory 45-day comment period on draft EISs. Section 5.4 of TVA's NEPA procedures provides that certain actions "normally" require an EIS including large water resource projects, major power generating facilities, and uranium mining and milling complexes. This refers to the construction of such facilities, not their continued operation. This section also requires the preparation of an EIS for "any major action, the environmental impact of which is expected to be highly controversial." The controversy must be about the significance of environmental impacts, must have valid scientific underpinnings, and must be substantial. What is "substantial" requires consideration of the number of people raising legitimate environmental concerns in the context of the potentially affected population and whether other expert agencies have environmental concerns.

The lowest level of NEPA review applies to those actions determined to fall within one or more of the Categorical Exclusions (CEs) identified in TVA's NEPA procedures. Section 5.2 of the procedures identifies 28 categories of actions that were predetermined during the rulemaking process normally to not result in significant environmental impacts and to not require an EIS. Neither CEQ's regulations nor TVA's procedures require that CEQ applicability determinations be documented. However, it is TVA's practice to prepare a "Categorical Exclusion Checklist" to document its CE determinations for a number of its CEs. An opportunity for public comment on a CE is not required and TVA does not provide one.

The middle level of NEPA review is an Environmental Assessment (EA). EAs are more concise, less detailed documents than EISs, and can be as short as 10 to 15 pages. However, it is TVA's practice to provide substantial information in its EAs, and TVA's EAs often exceed 50 pages depending on the number of resources analyzed and the complexity of analyses. Neither CEQ's regulations nor TVA's NEPA procedures require public comment on draft EAs, but TVA normally provides a 30 day comment period. The purpose of an EA is to determine whether a proposed action that is not categorically excluded is a major action with significant impacts on the quality of the human environment. If it is, an EIS is required. If it is not, TVA concludes the EA process by issuing a Finding of No Significant Impact, allowing the TVA decision maker to decide whether to proceed with the action.

TVA prepared an EA for the emission control projects proposed at Units 1 and 4 of its Shawnee Fossil Plant. TVA provided the public three weeks, from October 20, 2014 to November 10, 2014, to comment on the scope of the EA, including the environmental resources and alternatives that should be addressed in the EA. Additionally, TVA released the draft EA to the public for comment on November 25, 2014 to December 9, 2014; providing in total approximately 5 weeks for public input into the EA process. Notice of the availability of the EA was published in local newspapers, by news releases, on TVA's agency internet site and sent directly to potentially interested agencies, organizations, and those who provided comments during the scoping period.

The EA "tiers" from the "Final Environmental Impact Statement for TVA's Integrated Resource Plan" (March 2011) (IRP EIS). Tiering is a process in CEQ's regulations and TVA's procedures that allows an agency to go from a broader NEPA review, typically an EIS, to a more site-specific NEPA review without readdressing the issues or repeating in detail the information and analyses in the broader review document. 40 C.F.R. §1508.28. TVA provided extensive opportunities for public participation during the preparation of the IRP EIS. These included public comment periods and webinars during which members of the public could ask questions about IRP analyses and make comments. TVA also assembled and regularly met with a group of interested individuals from a variety of organizations, including the Sierra Club and the Southern Alliance for Clean Energy, and provided them opportunities to review and comment on ongoing IRP analyses.

The IRP EIS contains analyses of the need for electricity from the TVA power system, different kinds of energy resources, and strategies for meeting projected future demand for electricity including continued operation or retirement of its coal-fired power plants, the addition of more renewable resources, and expanded use of energy efficiency programs. The IRP EIS summarizes TVA's analyses of the environmental impacts of alternative strategies using different combinations of energy resources including air quality and solid waste impacts.