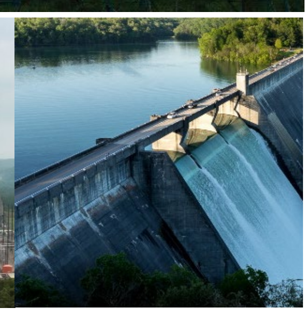
Appendix A – TVA IRP Executive Summary

2019 Integrated Resource Plan

EXECUTIVE SUMMARY



TENNESSEE VALLEY AUTHORITY

2019 Integrated Resource Plan (IRP)
Executive Summary

Introduction

PURPOSE AND NEED

The Tennessee Valley Authority's 2019 Integrated Resource Plan (IRP) is a long-term plan that provides direction on how TVA can best meet future demand for power. It shapes how TVA will provide low-cost, reliable and clean electricity; support environmental stewardship; and foster economic development in the Tennessee Valley for the next 20 years. The plan is a crucial element for TVA's success in a constantly changing business and regulatory environment, and it will better equip TVA to meet many of the challenges facing the electric utility industry in the coming years to benefit the Valley. The IRP will enhance TVA's ability to create a more flexible power-generation system that can successfully integrate increasing amounts of renewable energy sources and distributed energy resources (DER) while ensuring reliability. The IRP also will inform TVA's next Long-Range Financial Plan.

TVA POWER SYSTEM

As the nation's largest public power provider, TVA delivers safe, reliable, clean, competitively priced electricity to 154 local power companies and 58 directly served customers. TVA's power portfolio is dynamic and adaptable in the face of changing demands and regulations. TVA's portfolio has evolved over the past decade to a more diverse, reliable and cleaner mix of generation resources, which today provides 54 percent carbon-free power. In Fiscal Year (FY) 2018, TVA efficiently delivered more than 163 billion kilowatt-hours of electricity to customers from a power supply that was 39 percent nuclear, 26 percent natural gas, 21 percent coal-fired, 10 percent hydro, and 3 percent wind and solar. The remaining one percent results from TVA programmatic energy efficiency efforts.

SUMMARY OF IRP PROCESS AND GOALS

TVA used an integrated, least-cost framework that considered multiple views of the future to determine how potential power-generation resource portfolios could perform in different market and external conditions. We conducted the IRP process in a transparent, inclusive manner that provided numerous opportunities for public education and participation. Stakeholders and the public provided invaluable input that helped shape the IRP. The analysis performed in this IRP study relied on industry-standard models and incorporated best practices while using an innovative methodology to more fully evaluate the role of distributed energy resources as resources in our power supply. Resource cost and performance input data were independently validated. TVA's goal with the IRP was to identify an optimal energy resource plan that performs well under a variety of future conditions, taking into account cost, risk, environmental stewardship, operational flexibility and Valley economics. Per the National Environmental Policy Act (NEPA), TVA also prepared an Environmental Impact Statement (EIS) to analyze the 2019 IRP's potential impacts on the environment, economy and population in the Tennessee Valley.

TVA's 2019 IRP Recommendation

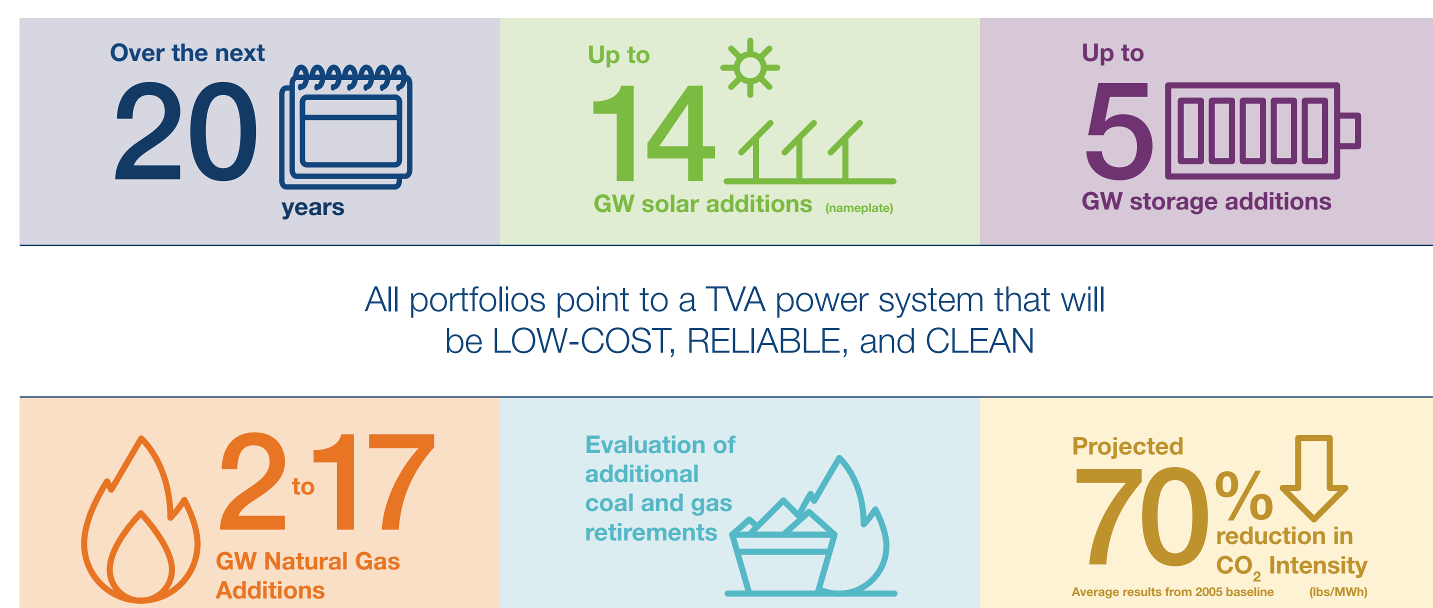
STUDY RESULTS

During the IRP process, TVA — with significant input from stakeholders and the public — considered a wide range of future scenarios, various business strategies and a diverse mix of power-generation resources to build on TVA's existing asset portfolio. IRP study results show:

- There is a need for new capacity in all scenarios to replace expiring or retiring capacity.
- Solar expansion plays a substantial role in all futures.
- Gas, storage and demand response additions provide reliability and/or flexibility.
- No baseload resources (designed to operate around the clock) are added, highlighting the need for operational flexibility in the resource portfolio.
- Additional coal retirements occur in certain futures.
- Energy efficiency (EE) levels depend on market depth and cost-competitiveness.
- Wind could play a role if it becomes cost-competitive.
- In all cases, TVA will continue to provide for economic growth in the Tennessee Valley.

OBSERVATIONS

TVA has observed that the scenario, or future environment, it finds itself operating in will have more impact on overall results than the strategy or strategies it implements. TVA also recognizes that all strategies have positive aspects but also have unique tradeoffs to consider. If TVA needs to shift its resource mix, that need will be driven by these key variables: changing market conditions, more stringent regulations and technology advancements. Recognizing that a variety of future scenarios are possible and each strategy has positive aspects, all IRP results are included in the IRP Recommendation to provide flexibility for how the future evolves.



2019 Integrated Resource Plan (IRP)
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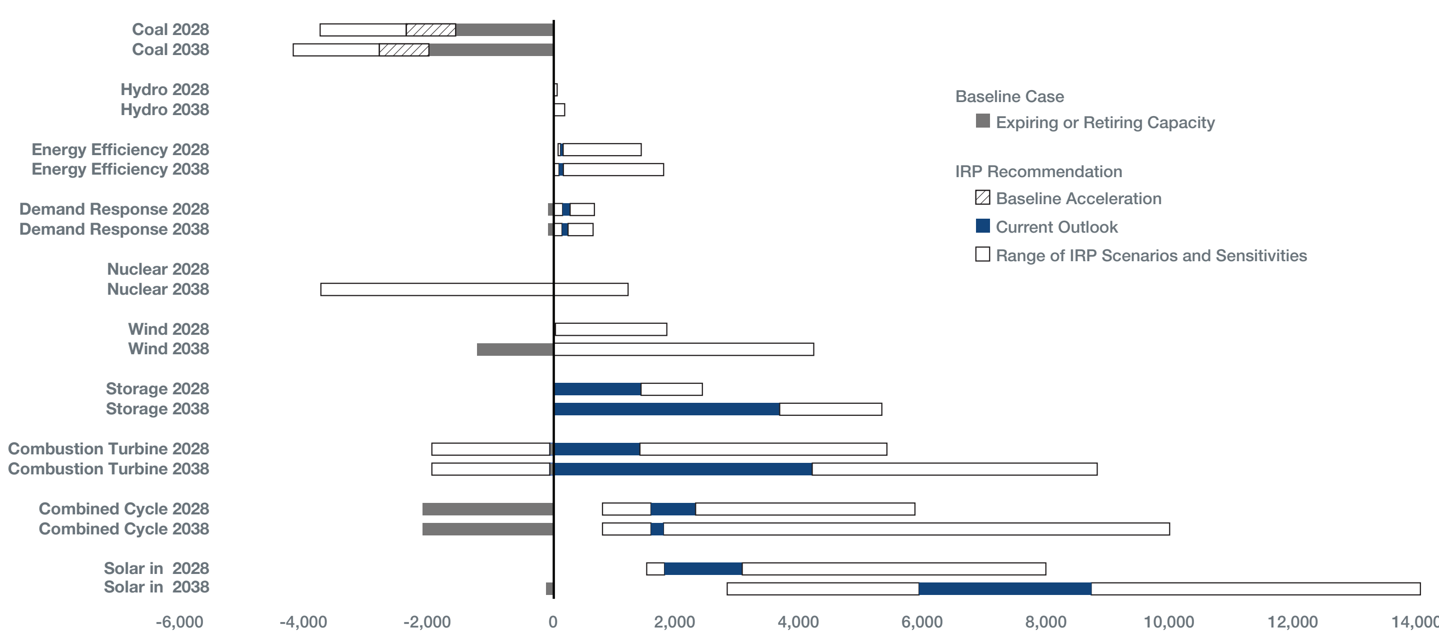
TVA's 2019 IRP Recommendation

Range of MW Additions and Subtractions by 2028 and 2038



Notes

- **MWs are incremental additions from 2019 forward. Board-approved coal retirements are excluded from the totals.**
- **Browns Ferry Nuclear Plant license is not extended in the No Nuclear Extensions Scenario (outside of TVA control).**
- **Upper bounds of potential natural gas and solar additions are driven by the Valley Load Growth Scenario.**
- **Solar and wind are shown in nameplate capacity; accelerated solar additions are reflected in the IRP Recommendation.**
- **Solar, gas, and storage ranges include utility-scale and distributed additions (where promoted in a strategy).**

TVA's 2019 IRP Recommendation

TVA's recommended planning direction affirms its commitment to a diverse and flexible resource portfolio guided by the least-cost system planning mandate. The ranges shown, stated in megawatts (MW) of capacity, provide a general guideline for resource selections. In developing a Recommendation from the study, TVA elected to establish guideline ranges for key resource types (owned or contracted) that make up the target power supply mix. This general planning direction is expressed over the 20-year study period while also including more specific direction over the first 10-year period. Meeting the Valley's future needs in accordance with the resource technologies and ranges in this Recommendation will position TVA to continue to deliver low-cost, reliable and clean power to the people of the Tennessee Valley.

Coal: Continue with announced plans to retire Paradise in 2020 and Bull Run in 2023. Evaluate retirements of up to 2,200 MW of additional coal capacity if cost-effective.

Hydro: All portfolios reflect continued investment in the hydro fleet to maintain capacity. Consider additional hydro capacity where feasible.

Energy Efficiency: Achieve savings of up to 1,800 MW by 2028 and up to 2,200 MW by 2038. Work with our local power company partners to expand programs for low-income residents and refine program designs and delivery mechanisms with the goal of lowering total cost.

Demand Response: Add up to 500 MW of demand response by 2038 depending on availability and cost of the resource.

Nuclear: Pursue option for second license renewal of Browns Ferry for an additional 20 years. Continue to evaluate emerging nuclear technologies, including small modular reactors, (SMR) as part of technology innovation efforts.

Wind: Existing wind contracts expire in the early 2030s. Consider the addition of up to 1,800 MW of wind by 2028 and up to 4,200 MW by 2038 if cost-effective.

Storage: Add up to 2,400 MW of storage by 2028 and up to 5,300 MW by 2038. Additions may be a combination of utility and distributed scale. The trajectory and timing of additions will be highly dependent on the evolution of storage technologies.

Gas Combustion Turbine: Evaluate retirements of up to 2,000 MW of existing combustion turbines if cost-effective. Add up to 5,200 MW of combustion turbines by 2028 and up to 8,600 MW by 2038 if a high level of load growth materializes. Future CT needs are driven by demand for electricity, solar penetration, and evolution of other peaking technologies.

Gas Combined Cycle: Add between 800 and 5,700 MW of combined cycle by 2028 and up to 9,800 MW by 2038 if a high level of load growth materializes. Future CC needs are driven by demand for electricity and gas prices, as well as by solar penetration that tends to drive CT instead of CC additions.

Solar: Add between 1,500 and 8,000 MW of solar by 2028 and up to 14,000 MW by 2038 if a high level of load growth materializes. Additions may be a combination of utility and distributed scale. Future solar needs are driven by pricing, customer demand, and demand for electricity.

The IRP Recommendation meets the dual objective of ensuring flexibility to respond to the future while providing guidance on how our resource portfolio should change as the future unfolds.

Implementation

CONSIDERATIONS

With the implementation of the IRP Recommendation will come certain challenges. For example, the IRP Recommendation includes significant renewables expansion, which means it will become increasingly important to know the location of renewable resources, both utility and distributed scale, and how weather impacts solar generation. Early experience with battery storage on the system would provide additional insight to how the various storage-use cases might be employed to provide economic benefit and system flexibility, especially with increasing penetration of renewables. TVA will need to partner with local power companies and other stakeholders in the region to better understand the potential for distributed resources in the Valley and their locational value to inform resource decisions. Finally, the IRP Recommendation also includes more conventional resources, primarily gas-fired, and TVA will need to consider the implementation challenges in the areas of siting and permitting, both for the units themselves and associated transmission lines and gas pipelines.

In the process of developing the IRP, stakeholders raised a number of policy-related issues that are outside the scope of the IRP itself but will need to be considered as TVA moves toward implementation of recommendations from the IRP study. These considerations include continued evolution of programs that provide flexibility for customer-owned generation, evolution of federal/state energy and environmental policies, advancements in customer expectations and requirements for clean energy, and enhancing low-income equity and energy/environmental justice.

NEAR-TERM ACTIONS

The scenarios and strategies evaluated in the IRP provide insights to how TVA's resource portfolio may need to evolve as the future becomes clearer. The results indicate there are near-term actions that would provide benefit across multiple futures. The actions include:

RENEWABLES & FLEXIBILITY

- Add solar based on economics and to meet customer demand.
- Enhance system flexibility to integrate renewables and distributed resources.
- Evaluate demonstration battery storage to gain operational experience.

EXISTING FLEET

- Pursue option for license renewal for TVA's nuclear fleet.
- Evaluate engineering end-of-life dates for aging fossil units to inform long-term planning.

ENERGY USAGE

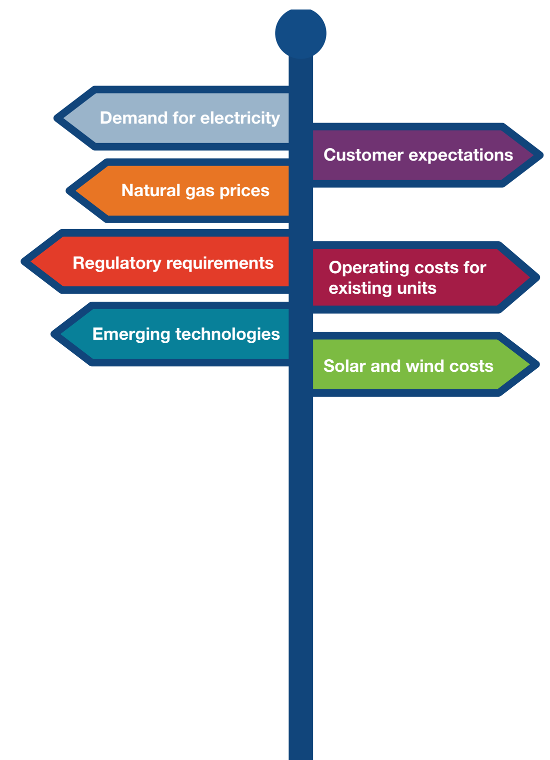
- Conduct market potential study for energy efficiency and demand response.
- Collaborate with states and local communities to address low-income energy efficiency.
- Collaboratively deploy initiatives to stimulate the local electric vehicle market.

DISTRIBUTION PLANNING

- Support development of Distribution Resource Planning for integration into TVA's planning process.

KEY SIGNPOSTS TO GUIDE DECISIONS IN THE LONGER TERM

As the future unfolds, TVA will monitor key signposts that will guide decisions in the longer term. The signposts relate to key variables that could have a significant influence on the future generation portfolio. These key signposts include:



TVA will closely monitor these key drivers related to changing market conditions, more stringent regulations, and technology advancements to inform appropriate actions within the recommended ranges and appropriate timing for initiating the next IRP.

How TVA Developed the Integrated Resource Plan: An 18-Month Process

OVERVIEW

Developing the 2019 IRP has been an approximately 18-month process that began in February 2018 and will conclude when a Record of Decision is released. The IRP process will have included the following activities:

- **Scoping,** which took place in winter/spring 2018 and identified issues important to the public and laid the foundation for developing the IRP.
- **Development of Model Input and Framework,** which occurred in spring/summer 2018 and included identifying and developing scenarios, resource options and business strategies to evaluate how a future portfolio might change under different conditions.
- **Analysis and Evaluation,** which took place in fall 2018 and included developing and evaluating the performance of the 30 resource portfolios.
- **Presentation of Initial Results,** which occurred in February 2019 with release of the draft IRP and EIS.
- **Public Comment Period,** which was held from February 15 to April 8, 2019.
- **Additional Analysis,** which was completed in response to stakeholder and public comments.
- **Completion of the Study**, which includes the IRP Recommendation, near-term actions and key signposts, and the final environmental assessment.
- **Publication of the Final IRP and EIS** on June 28, 2019, on TVA's website.
- **Expected Request for Approval** of the IRP Recommendation from the Board in August 2019.
- **Record of Decision** will be published after Board approval.

2019 Integrated Resource Plan (IRP)
Executive Summary

Developing the IRP

PLANNING APPROACH

Uncertainties and Scenarios
With input from the IRP Working Group, TVA designed scenarios that are outside of TVA's control but represent possible futures in which TVA may find itself operating. TVA created a list of uncertainties that could alter the future operating environment and affect the cost of electricity and/or mix of optimal resources. The scenarios are:

Strategies
With input from the IRP Working Group, TVA developed five strategies, which are business decisions or directions that TVA could employ in each scenario. As it relates to strategies in the IRP, the word "promote" means an incentive was modeled to make the resource more attractive for adoption or selection. The five strategies are:

	SCENARIOS
1	**CURRENT OUTLOOK** which represents TVA's current forecast for these key uncertainties and reflects modest economic growth offset by increasing efficiencies;
2	**ECONOMIC DOWNTURN** which represents a prolonged stagnation in the economy, resulting in declining loads (customers using less power) and delayed expansion of new generation;
3	**VALLEY LOAD GROWTH** which represents economic growth driven by migration into the Valley and a technology-driven boost to productivity, underscored by increased electrification of industry and transportation;
4	**DECARBONIZATION** which is driven by a strong push to curb greenhouse gas emissions due to concern over climate change, resulting in high CO_2 emission penalties and incentives for non-emitting technologies;
5	**RAPID DER ADOPTION** which is driven by growing consumer awareness and preference for energy choice, coupled with rapid advances in technologies, resulting in high penetration of distributed generation, storage and energy management;
6	**NO NUCLEAR EXTENSIONS** which is driven by a regulatory challenge to relicense existing nuclear plants and construct new, large-scale nuclear. This scenario also assumes subsidies to drive small modular reactor (SMR) technology advancements and improved economics.

	STRATEGIES
A	**BASE CASE** which represents TVA's current assumptions for resource costs and applies a planning reserve margin constraint. This constraint applies in every strategy and represents the minimum amount of capacity required to ensure reliable power;
B	**PROMOTE DISTRIBUTED ENERGY RESOURCES** which incents DER to achieve higher, long-term penetration levels. The DER options include energy efficiency, demand response, combined heat and power, distributed solar and storage;
C	**PROMOTE RESILIENCY** which incents small, agile capacity to maximize operational flexibility and the ability to respond to short-term disruptions on the power system;
D	**PROMOTE EFFICIENT LOAD SHAPE** which incents targeted electrification (by incentivizing customers to increase electricity usage in off-peak hours) and demand response (by incentivizing customers to reduce electricity usage during peak hours). This strategy promotes efficient energy usage for all customers, including those with low income;
E	**PROMOTE RENEWABLES** which incents renewables at all scales (from utility size to residential) to meet growing or existing consumer demand for renewable energy.

MODELING ASSUMPTIONS AND CANDIDATE TECHNOLOGIES

TVA uses an industry standard model to derive an optimal capacity plan, considering the focus of each strategy evaluated in each scenario. Modeling assumptions, the framework of IRP planning, are the constraints and planning guidelines that are put into the model. The reliability constraint is especially critical, as it ensures we have enough capacity at all times to provide reliable electricity to customers. For the 2019 IRP, it also is crucial to understand how the system would operate with more renewables and DER on the system – driving a greater need for operational flexibility. TVA considered a broader range of mature and emerging technologies in this IRP, including some distributed energy technologies.

STAKEHOLDER & PUBLIC INVOLVEMENT

Throughout the IRP process, TVA engaged external stakeholders to understand diverse opinions and to challenge assumptions. TVA established the IRP Working Group, whose 20 members represent diverse interests in the Valley. The IRP Working Group met approximately monthly to review input assumptions and preliminary results and to enable its members to provide their respective views to TVA. TVA also presented IRP progress updates to the Regional Energy Resource Council (RERC), a federal advisory committee that provides advice to the TVA Board of Directors on a range of energy-related matters, including the IRP.

During a 60-day scoping period from February 15 through April 16, 2018, TVA obtained public comments on the scope of the effort to develop this IRP, which helped shape the draft IRP and EIS. After the release of the draft IRP and EIS on February 15, 2019, TVA provided a public comment period through April 8, 2019. TVA held meetings across the Tennessee Valley and an online webinar, and accepted public comments via mail, email, online and in-person at the meetings. Input was critical in shaping the IRP and EIS, and many of the sensitivity analyses that were performed were informed by stakeholder and public input.

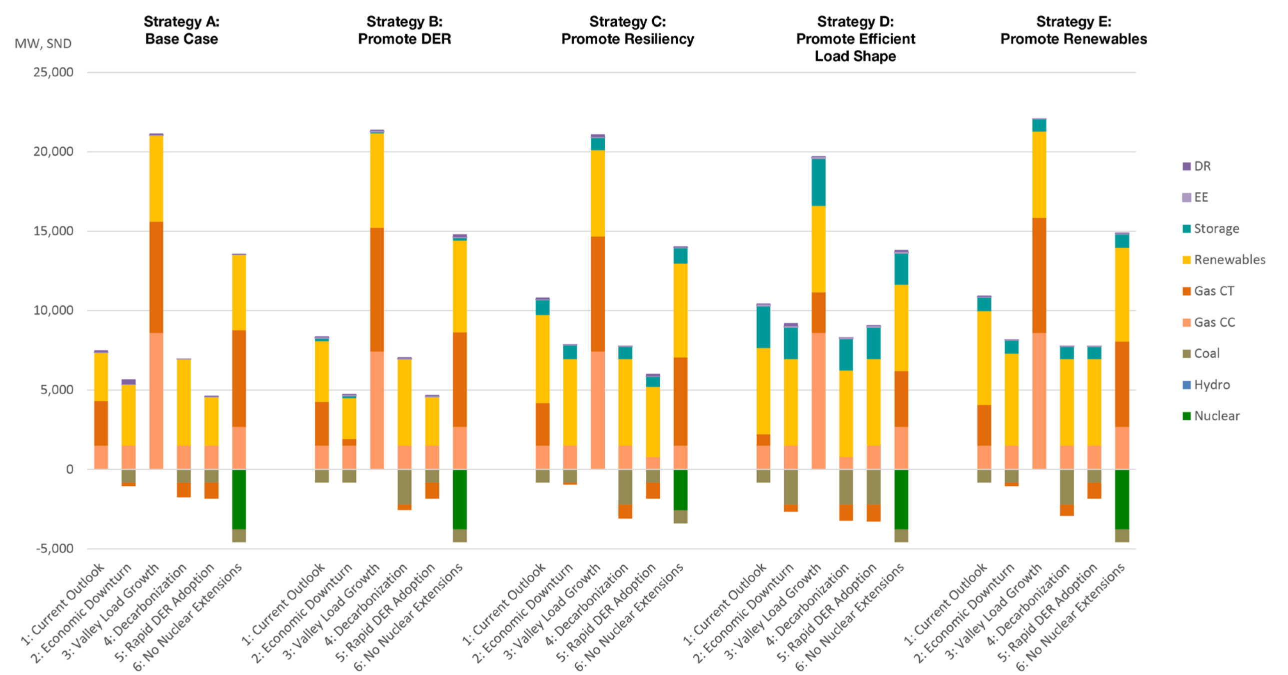
The IRP Working Group included representatives from:

- State and local governments
- Academia and research groups
- Advocacy groups
- Local power companies (LPCs)
- Economic development organizations
- Directly-served/ industrial customers

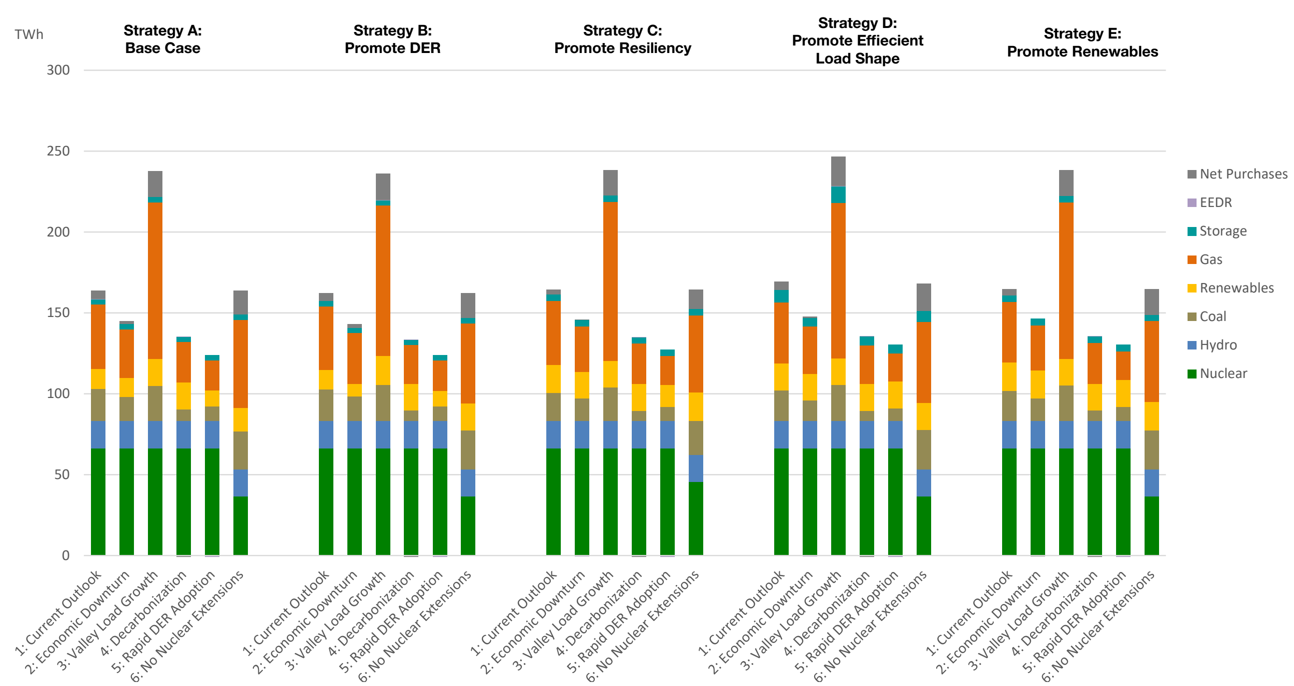
Developing the IRP

EVALUATING THE PORTFOLIOS

Incremental capacity by 2038 consists of additions of new energy resources and retirement of existing energy resources for the portfolios associated with each strategy.



Total Energy in 2038 by resource type in the portfolios associated with each strategy.



EVALUATING THE PORTFOLIOS

Each IRP case represents a combination of expectations about the future environment TVA operates in and potential strategies TVA could employ that result in unique resource portfolios. The modeling process resulted in 30 resource portfolios. The model analyzed how to achieve the lowest-cost portfolio with each strategy in each scenario, looking for the optimal solution within that particular combination. With input from the IRP Working Group and RERC, TVA identified 14 metrics that reflect desired goals and priorities in areas related to cost, risk, environmental stewardship, operational flexibility and Valley economics. The metrics were used to evaluate tradeoffs among the 30 resource portfolios.

Strategy Performance

	COST	RISK	ENVIRONMENTAL STEWARDSHIP		OPERATIONAL FLEXIBILITY	VALLEY ECONOMICS
			CO_2, Water, Waste	Land Use		
STRATEGY A: BASE CASE						All strategies have similar impacts on the Valley economy as measured by per capita income and employment
STRATEGY B: PROMOTE DER						
STRATEGY C: PROMOTE RESILIENCY						
STRATEGY D: PROMOTE EFFICIENT LOAD SHAPE						
STRATEGY E: PROMOTE RENEWABLES						

Good Better Best

Developing the IRP

SENSITIVITY ANALYSIS

When analyzing results from the draft IRP, TVA identified issues that warranted further evaluation prior to finalizing the study. In addition, TVA received helpful input from the IRP Working Group and the RERC, as well as from the public during the comment period. Many of the questions raised by TVA, stakeholders and the public focused on certain key assumptions that could influence results. To explore the impacts of changes in key assumptions and to inform the Recommendation, TVA evaluated sensitivities related to the following categories: natural gas prices; storage, wind, combined heat and power (CHP) and small modular reactor (SMR) capital costs; greater energy efficiency (EE) and demand response (DR) market depth; integration cost and flexibility benefit; pace and magnitude of solar additions; higher operating costs for coal plants; more stringent carbon constraints; and variation in climate.

Summary of 2019 IRP Sensitivities

SENSITIVITY CASE Base Case comparison is the Current Outlook unless otherwise noted	CAPACITY EXPANSION IMPACTS BY 2038 GREEN indicates increase and RED indicated decrease in resource						
	NUCLEAR	COAL	GAS	HYDRO	SOLAR	WIND	EEDR
Higher Natural Gas Prices				+55 MW	+2,050 MW		
Lower Natural Gas Prices			2,000 MW CT replaced by CC		-5,900 MW		
Lower Wind Costs			-1,100 MW		-3,100 MW	+4,200 MW	
Greater EE & DR Market Depth			-2,000 MW		-2,200 MW		+2,100 MW
Integration Cost & Flexibility Benefit			Minor timing differences		Minor timing differences		
Pace & Magnitude of Solar Additions					+1,100 MW		
Magnitude of Solar Additions (Valley Load Growth)			1,000 MW CC replaced by CT		+6,000 MW		
Higher Operating Costs for Coal Plants		-2,200 MW	+1,500 MW				
More Stringent Carbon Constraints (Decarbonization)		-2,000 MW accelerated	CC expansion accelerated	+175 MW			
Variation in Climate	Summer derates	Summer derates	CT expansion accelerated		+2,100 MW		

Note

- **Impacts shown in Summer Net Dependable MW, except for solar and wind that are shown in nameplate MW**

FORMING THE IRP RECOMMENDATION

The IRP results — including the 30 primary cases and the sensitivity cases — provide a robust set of potential resource additions and retirements. The final Recommendation is derived from this evaluation. The Recommendation takes into account customer priorities around power cost and reliability across different futures, along with environmental stewardship and Valley economics considerations. In developing a recommendation from the study, TVA elected to establish guideline ranges for key resource types (owned or contracted) that make up the target power supply mix. In order to distill the considerable number of cases evaluated through the original scenario and strategy analysis and the sensitivity cases, the Recommendation uses ranges that are centered on results obtained under the Current Outlook scenario. The other scenario and sensitivity results provide a sense of how the target power supply mix might change as the future changes. Recognizing that a variety of future scenarios are possible and each strategy has positive aspects, all IRP results are included in the Recommendation to provide flexibility for how the future evolves. Implementing the least-cost resource plan with all of these priorities in mind will help ensure TVA continues to fulfill its mission to serve the people of the Tennessee Valley.

The IRP and the Tennessee Valley Environment

PURPOSE OF THE EIS

TVA's EIS assesses the natural, cultural and socioeconomic impacts associated with the 2019 IRP. The five strategies are the basis for the alternatives discussed in the EIS. The Base Case serves as the No-Action Alternative, and the remaining four strategies are the Action Alternatives. The draft EIS analyzed and identified the relationship of the natural and human environment to each of the five alternative strategies. The final EIS includes an additional alternative, the 2019 Recommendation (Target Power Supply Mix). The portfolios associated with each of the five alternative strategies, as well as the 2019 Recommendation, are quantitatively and qualitatively evaluated to determine the environmental impact. This evaluation addresses systemwide topics, including

- Greenhouse gas emissions
- Fuel consumption
- Air quality
- Water quality and quantity
- Waste generation and disposal
- Land requirements
- Socioeconomic impacts
- Environmental justice.

Public comments on the draft EIS and draft IRP are addressed in the final EIS.

The primary study area described in the EIS includes the combined TVA service area; the Tennessee River watershed; and parts of the Cumberland, Mississippi, Green and Ohio Rivers in TVA's power service area. For some resources, such as air quality and climate change, the assessment area extends beyond the TVA region. For some socioeconomic resources, the study area consists of the 170 counties where TVA is a major provider of electric power and/or operates generating facilities.

The IRP and the Tennessee Valley Environment

ENVIRONMENTAL IMPACTS OF THE 2019 IRP

Under all the portfolios and the 2019 Recommendation, there is a need for new capacity, with a significant expansion of solar generation overall. Uncertainty around future environmental standards for carbon dioxide emissions, along with the outlook for loads and gas prices, are key considerations when evaluating potential coal retirements. Emissions of air pollutants, the intensity of greenhouse gas emissions (CO_2 intensity) and generation of coal waste decrease under all strategies. Strategies focused on resiliency, load shape and renewables have the largest amounts of solar and storage expansion and coal retirements, resulting in lower environmental impact overall but higher land use. For most environmental resources, the impacts are greatest for the No Action alternative. The exception is the land area required for new generating facilities, which is greater for the action alternatives, particularly strategies which focus on resiliency, load shape and renewables. Most of this land area would be occupied by solar facilities, which, compared to most other energy resources, have a relatively low level of impact to the land. Additional sensitivity analysis showed the potential for an extended range of resource additions and retirements, which generally resulted in reduced impacts to most environmental resources. The land area occupied by solar facilities, however, could greatly increase.

Conclusion

TVA finds considerable value in undertaking an IRP and EIS, and especially appreciates the input, review and insights of individuals on the IRP Working Group and the Regional Energy Resource Council. They spent considerable time helping TVA develop a robust plan that meets all the criteria outlined in its objectives. TVA values their involvement and the expertise they provided on behalf of their respective stakeholders in making this a better IRP.

As with any long-term plan, TVA's IRP reflects what we know today and can reasonably expect for the coming years. TVA and our employees across the Valley stand ready every day to carry out our three-part mission around energy, the environment and economic development. In an ever-changing world, TVA will do its best to continue to serve the people of the Tennessee Valley by providing low-cost, reliable and clean power in an environmentally responsible manner while promoting economic development across the Valley.

TVA

Appendix B – TVA Alternatives Evaluation

TVA Asset Strategy Overview

TVA's asset strategy incorporates the strategic direction from the 2019 Integrated Resource Plan (IRP) and continues to support affordable, reliable, resilient, and cleaner energy for the customers we serve.

Highlights from the asset strategy include:

- Maintaining the existing low-cost, carbon-free nuclear and hydro fleets
- Retiring aging coal units as they reach the end of their useful life, expected by 2035
- Adding 10,000 MW of solar by 2035 to meet customer and system needs, complemented with storage
- Using natural gas to enable coal retirements and solar expansion
- Leveraging demand-side options, in partnership with local power companies
- Partnering to develop new carbon-free technologies for deeper decarbonization

Coal Fleet End-of-life Evaluations

The 2019 IRP acknowledged the potential for coal retirements and recommended a near-term action to evaluate end-of-life dates for aging fossil units to inform planning.

Evaluations assessed the cost, reliability, and environmental implications associated with continued operation of TVA's coal fleet and concluded that it is:

- Among the oldest in the nation (Cumberland 1973, all other plants 1950s vintage)
- Experiencing material condition and performance challenges, especially Cumberland and Kingston
- Projected to have increasing performance challenges due to lack of portfolio fit
- Contributing to environmental, economic, and reliability risks

Retirement planning assumptions were developed based on relative unit condition and fit, as well as the time required to build replacement generation, subject to further evaluation in environmental reviews under the National Environmental Policy Act (NEPA).

December 2023 – Bull Run (Board-approved)

December 2026 – Cumberland 1 unit (Board-approved)

December 2027 – Kingston 9 units

December 2028 – Cumberland 1 unit

December 2031 – Gallatin 4 units

December 2033 – Shawnee 9 units

Compliance with ELG Rule requires installation of controls by December 2025 or retirement by December 2028

Compliance with ELG Rule requires installation of controls by December 2025

Kingston EIS Background and Purpose and Need

TVA's IRP acknowledged continued operational challenges for the aging coal fleet and included a recommendation to conduct end-of-life evaluations on TVA's remaining coal plants.

The decision associated with this EIS is a specific, discrete component of TVA's blended asset strategy and consistent with the recommended target power supply mix in the 2019 IRP

TVA's recent evaluations confirm:

- The aging coal fleet is among the oldest in the nation and is experiencing deterioration of material condition and performance challenges.
- TVA has developed planning assumptions for the Kingston Fossil Plant (KIF) unit retirements.
- TVA proposes to retire and decommission the KIF units by 2027, and to provide replacement generation that can supply at least 1,500 MW of firm, dispatchable power.

Need for Firm, Dispatchable Power

The 1,500 MW of replacement generation needed to replace the retirement of Kingston must be firm, dispatchable power and must be operational by 2027 so as not to leave TVA short on required generation and capacity to meet system demands and planning reserve margin targets.

Firm, dispatchable power ensures that TVA can call on the generating capacity year-round, particularly during peak load events – those periods of maximum electricity demand from customers, typically late afternoon in the summer and before or around dawn in the winter.

Firm, dispatchable power provides a backstop for solar resources that are unable to or are very limited in their ability to meet maximum demand that occurs in the pre-daylight or early-daylight hours of the winter season.

Replacement generation is needed in the East Tennessee area.

TVA would need to continue operating the coal-fired units if replacement generation is not in place by 2027.

Transmission

Kingston Fossil plant's location on the 161 kV system near Knoxville makes it integral to maintaining system reliability and stability in the area. Retirement of Kingston Fossil without replacement generation in the area or appropriate transmission upgrades would, significantly impact the ability to add additional load in the area, degrade the stability of Watts Bar and Sequoyah nuclear plants to a point where generation would need to be curtailed, and potentially violate NERC Transmission Planning (TPL-001) standard criteria.

Returning the Knoxville area to current system performance without local generation would require approximately $500M in transmission work such as a 500/161 kV intertie bank, construction of four additional 161 kV lines, multiple 161 kV line upgrades, synchronous condensers and at least three static synchronous compensators or STATCOMS. The transmission system would also need to be upgraded to integrate the replacement power in alternative locations.

Future integration of Inverter Based Resources, such as solar and batteries, will degrade area stability and require synchronous condensing or STATCOMS in all alternatives considered, even the No Action Alternative.

Project Action Alternatives

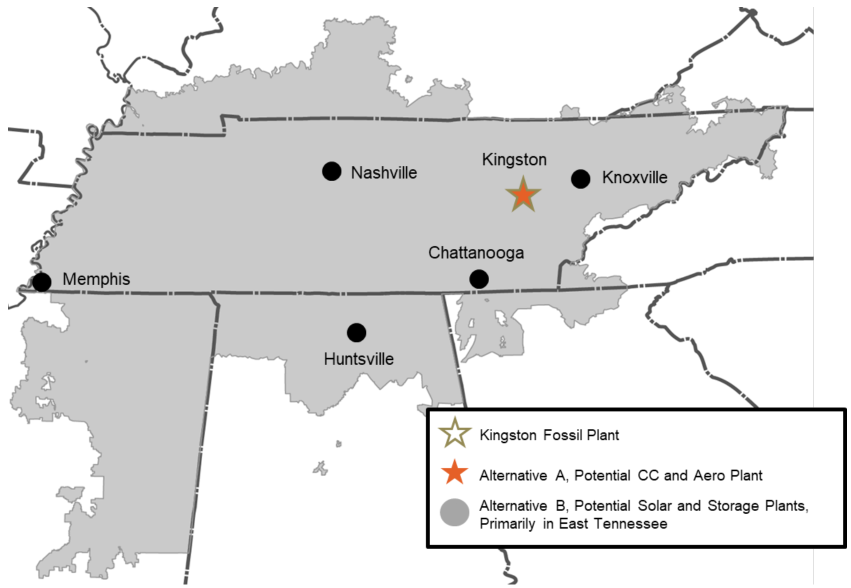
The Kingston Fossil Plant (KIF) Retirement EIS includes two action alternatives, which include the demolition of KIF, in addition to the no action alternative. To recover the generation capacity lost from retirement, TVA staff evaluated the following alternatives for replacement generation:

Alternative A

Retirement of KIF and construction and operation of a Combined Cycle Combustion Turbine (CC) Gas Plant, Aeroderivative Combustion Turbine (Aero CT), storage and solar facilities on the KIF reservation, and on-site and off-site transmission system upgrades. A related action: Enbridge's Ridgeline Expansion Project, a 122-mile-long natural gas pipeline and associated aboveground structures.

Alterative B

Retirement of KIF and construction and operation of solar and storage facilities, primarily in East TennesseeX



TENNESSEE VALLEY AUTHORITY

No Action Alternative

Under the No Action Alternative, TVA will continue to operate Kingston Fossil.

The No Action Alternative includes increased operating costs consistent with the Higher Operating Costs for Coal Plants sensitivity studied in the 2019 IRP.

The No Action Alternative also includes costs over $600M for plant modifications necessary to ensure compliance with USEPA's March 2023 Proposed ELG Rule. These upgrades may be further updated through changes to the ELG guidelines by USEPA.

This alternative would require specific actions related to wastewater treatment and the management and disposal of CCR, primary solid wastes, at KIF. Projects have been previously analyzed in NEPA documents or are future projects, which are either underway or would commence within the next five years.

Alternative A: Retire KIF and Construct CC, Aero CT, storage, and solar facilities

Retirement of KIF in 2027 with demolition to follow

Construction and operation of a CC Gas Plant, Aero CT Gas Plant, and storage and solar facilities on the KIF reservation

CC plant would be associated with an estimated 122-mile pipeline and gas compressor station.

The construction of the natural gas pipeline(s) under Alternative A would be subject to Federal Energy Regulatory Commission (FERC) jurisdiction and additional review will be taken by FERC in accordance with its own NEPA procedures.

Alternative A: CC, Aero CT, storage and solar facilities

Alternative A includes a 673 MW CC plant, 848 MW Aero CT plant, 100 MW battery, and 3-4 MW solar site to recover the dependable capacity KIF as well as account for load forecast increases

The Kingston Reservation offers several key benefits:

- Existing TVA property
- Existing transmission interconnection to the TVA system, which can largely be repurposed
- Nearby to a major interstate natural gas pipeline with adequate capacity and potential to generally locate proposed pipeline lateral along existing transmission line corridor
- Favorable air permitting prospects, since it will be replacing a higher emitting coal unit

CC	Aero CT	Solar & Storage
• Effective in baseload or intermediate operations with high fuel efficiency, relatively low construction costs, and flexible operations • Can provide grid support, follow load, and are fully dispatchable year-round	• Peaking units with the ability to start and ramp quickly, and offer flexible operations • CT plants can provide grid support and are fully dispatchable year-round • Offer synchronous condensing capability	• Carbon-free • Variable energy resource, matches up well with summer demand • Stores energy at lower loads to meet peaks and manage intermittency

Unit flexibility and dispatchability is increasingly important as TVA integrates about 10,000 MW of solar by 2035

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Alternative B: Retire KIF and Construct Solar and Storage

Retirement of KIF in 2027 with demolition to follow

Construction and operation of solar and storage facilities to replace the generation and capacity of KIF

Alternative uses generic site analysis and assumes procurement via competitive request for proposal (RFP) process with a power purchase agreement (PPA) structure and TVA constructed, subject to site-specific NEPA review

Solar and storage facilities will need to be primarily located in East Tennessee for regional grid support

Alternative B: Solar and Battery Storage Facilities

Solar resources are becoming more competitive on a cost per MWh basis; however, they are not dispatchable, and generation is intermittent in nature, varying by time of day, weather, and season.

To provide dependable peak capacity needs for the TVA system, solar generation must be paired with dispatchable resources, such as gas and/or storage.

Battery energy storage systems (BESS) typically represent one of the lowest cost storage options today, with four-hour BESS systems providing a reasonable balance of cost, output, and duration.

Alternative B includes 1,500 MW of solar and 2,200 MW of battery storage to recover the generation and dependable capacity of the Kingston retirement as well as account for load forecast increases.

TVA has determined that although solar can also be paired with battery storage to achieve similar demand following capabilities, such a pairing is constrained in that lithium-ion batteries are energy limited. The energy limited nature of battery storage makes Alternative B operationally challenged in its ability to meet required year-round generation needs, such as sustained high electric loads longer than 4 hours and with no solar generation.

Sites will require interconnection and transmission work; Evaluations conducted during the EIS indicated an expected duration of eight to nine years, failing to meet the purpose and need.

Alternative B Development

Solar evaluation

- TVA analysis began by replacing the average annual energy output of the KIF Plant with solar generation, with consideration for differences in annual capacity factors between coal generation and solar generation.
- Analysis of TVA's system and operation indicated a need for 1,500 MW of additional solar to replace the annual energy of KIF, on top of the 10,000 MW of solar already targeted in the base plan.

Storage evaluation

- The TVA system is dual-peaking, meaning that it experiences peak loads in both summer (typically late afternoon) and winter (typically early morning, just before dawn).
- Battery storage (typically lithium-ion) is currently the lowest cost option for storage capacity, which would ensure TVA's winter capacity reserves are maintained with the retirement of KIF.
- TVA staff utilized the SERVM model to determine what level of storage would maintain industry standard reliability of one Loss-of-Load-Event (LOLE) in 10 years, with risk spread equally between summer and winter. Analysis indicates that 2,200 MW of battery energy storage, paired with 1,500 MW of additional solar capacity, will maintain an annual 0.1 LOLE with balanced seasonal risk with the retirement of KIF.

Alternatives Considered, but Dismissed

Resource Option	Reasoning
Hydro Pumped Storage	Longer timelines to meet environmental requirements and for construction fail to meet 2027 timeline for the retirement of KIF. Long-duration storage technology is currently being studied by TVA for further evaluation and potential deployment in the early 2030s.
Small Modular Reactors (SMR)	Longer construction timeline and first-of-a-kind deployment risks fail to meet 2027 timeline for the retirement of KIF. Potential to serve cost-effective baseload or load following needs in the future with low fuel costs, carbon-free generation, advanced passive safety systems, and anticipated cost reductions achieved by assembling components in a factory setting.
In- and/or Out-of-Valley Wind	Not selected due to low wind speeds in Tennessee Valley and higher transmission costs for out-of-Valley wind, both of which increase relative costs. Wind can provide dependable capacity in both summer and winter, though intermittent.
Energy Efficiency (EE)	Dismissed as EE programs take time to scale and market, while also facing increasing costs for higher depth and penetration levels. EE cannot provide support in East TN. EE is well-positioned to help TVA absorb load growth resulting from increased electrification of the economy in the future.
Demand Response (DR)	Dismissed as they are limited in the number of calls available and do not provide reliable firm, dispatchable power. DR cannot provide support in East TN. DR can help TVA absorb load growth resulting from increased electrification of the economy and allow TVA to offset physical capacity needs.
Distributed Generation	Cost for distributed generation is generally higher than utility-scale generation for the same type of resource. TVA has therefore determined that the combination solution of utility-scale solar paired with utility-scale storage as presented in Alternative B provides a feasible lower-cost solution.
Alternative Fuels (Hydrogen)	Technology is not viable today but design of Alternative A is such that future implementation of hydrogen fuel blending could result in further significant GHG emissions reductions.

Capacity and Resource Planning Process

Capacity and resource planning follows least-cost principles to develop a resource strategy, aligned with TVA's strategic direction, that identifies the power resources needed to meet system demand with appropriate reserve margin.

The process requires key inputs based on TVA's experience and expertise such as electricity demand, fuel and power costs, construction costs, environmental regulations, asset operating characteristics, target planning reserve margin, and transmission considerations.

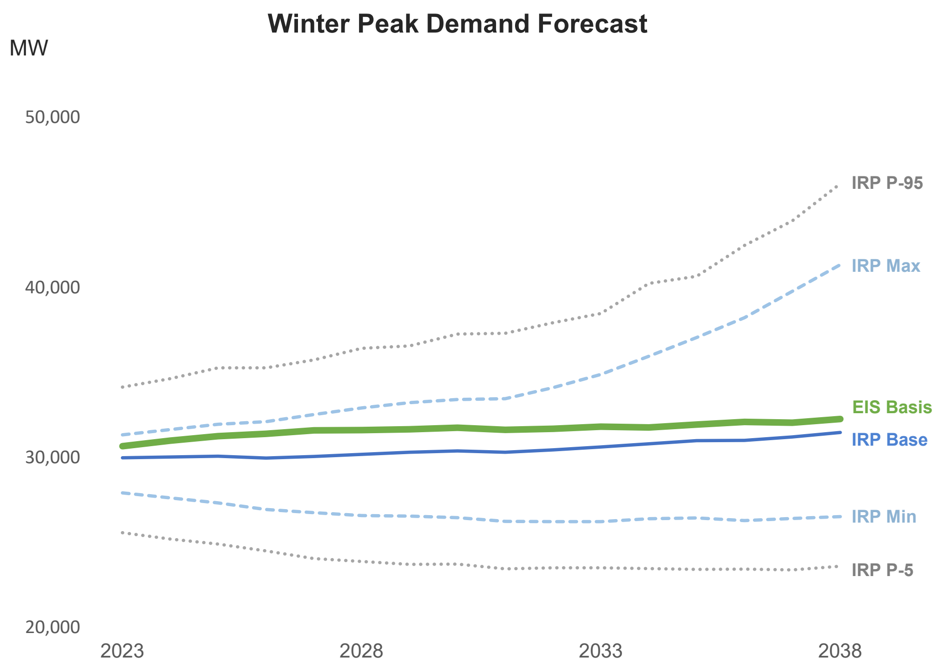
Key assumptions are validated and compared against industry benchmarks, studies, and forecasts, then modeled leveraging commercially available tools including Anchor Power Solution's EnCompass and Energy Exemplar's Aurora.

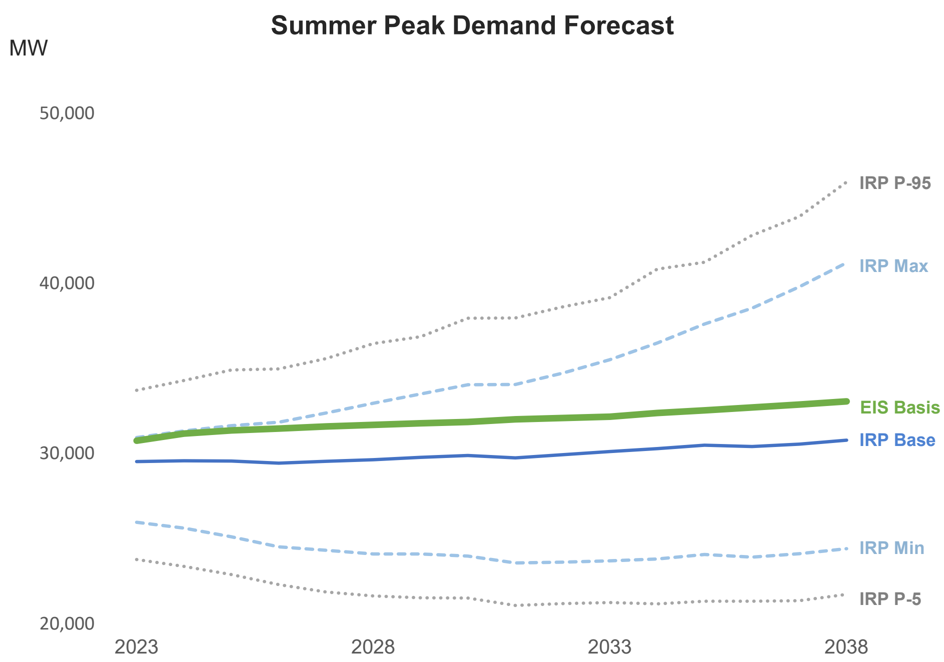
Integrated Resource Plan: Key Signposts

TVA's asset strategy incorporates the strategic direction from the 2019 IRP and inputs are regularly updated. Several assumptions are still aligned with the 2019 IRP.

Demand for electricity	Growth driven by Valley in-migration, energy intensive sectors, and Economic Development momentum
Natural gas prices	Near-term COVID-19 and supply-driven volatility, with lower fundamental prices over the long term
Stakeholder expectations	Increasing customer and stakeholder emphasis on renewable and clean energy; Preference for low-cost energy
Regulatory requirements	Biden policy on climate change, pipeline challenges, and pending updates to regulations (ex: Inflation Reduction Act (IRA), EPA Proposed GHG Rules)
Operating costs for existing units	Better understanding of fleet investments needed, helping inform portfolio direction
Renewable costs	Competitive solar offers but solar supply chain challenges persisting; Reflects the IRA.
Emerging and developmental technologies	Continued advancements in storage; DOE and utilities partnering to advance new clean technologies

Peak Load Forecast within IRP Ranges



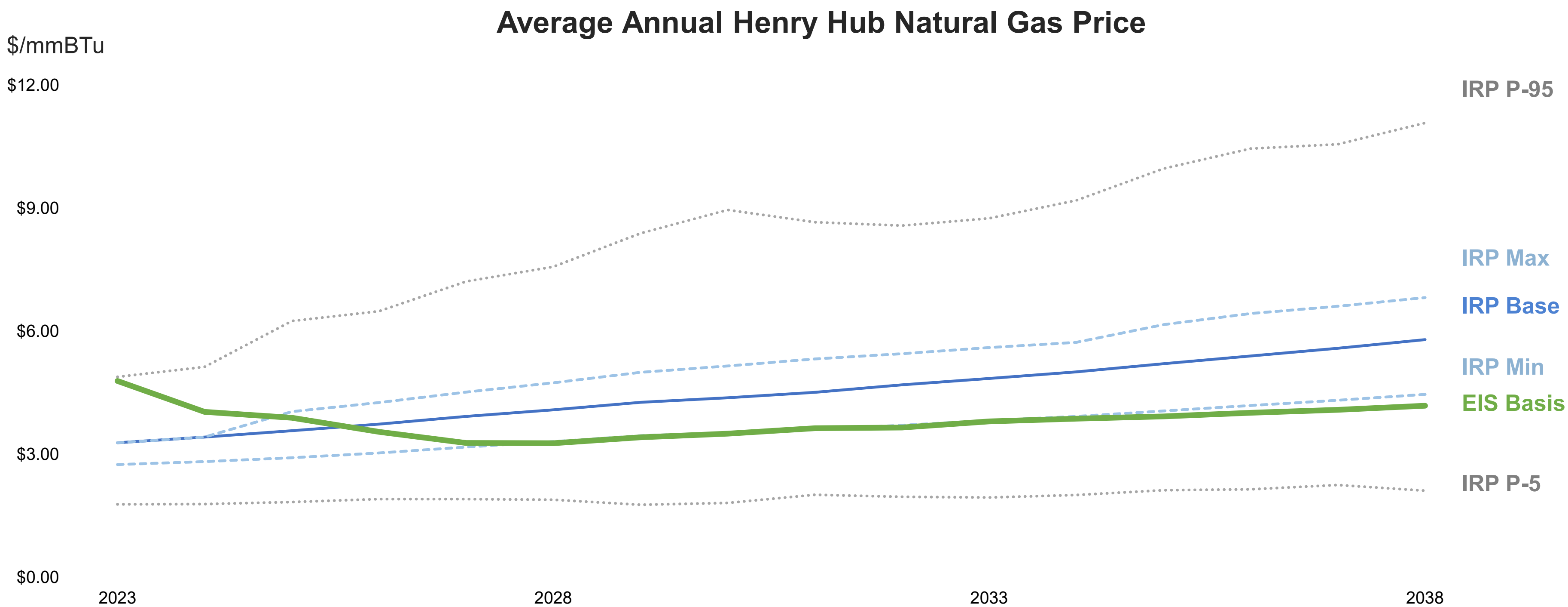


Assumptions for Key Inputs

	Natural Gas CC (1x1)	Natural Gas CT (3x)	Aeroderivative CT (10x)	Solar (50 MW Nameplate)	Storage
Summer Net Dependable Capacity (MW)	673	663	530	25	50
Winter Net Dependable Capacity (MW)	724	693	570	--	50
Capital Cost* (2023 $ / kW)	1,022	570	1,209	1,411	1,906
Life (years)	30	30	30	20	20
Capacity Factor (%)	>50	1-10	10-45	25	87 RTE**
Integration Cost ($/MWh)***	--	--	--	3	--

*Gas capital costs reflect TVA assumptions; solar and storage capital cost assumptions reflect NREL's latest Annual Technology Baseline
**RTE is the round-trip efficiency ratio of energy output relative to energy consumed to charge
***Intermittent resources require the balance of system resources to absorb sub-hourly fluctuations, driving a cost. Cost increases with greater amounts of solar. See 2019 IRP.

Natural Gas Prices within IRP Ranges



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Natural Gas Resource Costs

TVA has deep experience constructing and operating both simple cycle and combined cycle natural gas plants and cost assumptions are developed using recent project cost experience

Operating characteristics are reviewed twice per year utilizing vendor input

Pipeline costs, if applicable, are included for specific projects and modeled as a generation cost leveraging quotes and pricing from suppliers

Resource	MW	2023$/kW
Frame CT 2x	442	647
Frame CT 3x	663	570
Frame CT 4x	884	535
Aero 2x	106	1,698
Aero 4x	212	1,349
Aero 10x	530	1,209
Aero 20x	1,060	1,162
1x1 CC 7HA.03	673	1,022
2x1 CC 7HA.03	1,348	894

Solar Costs

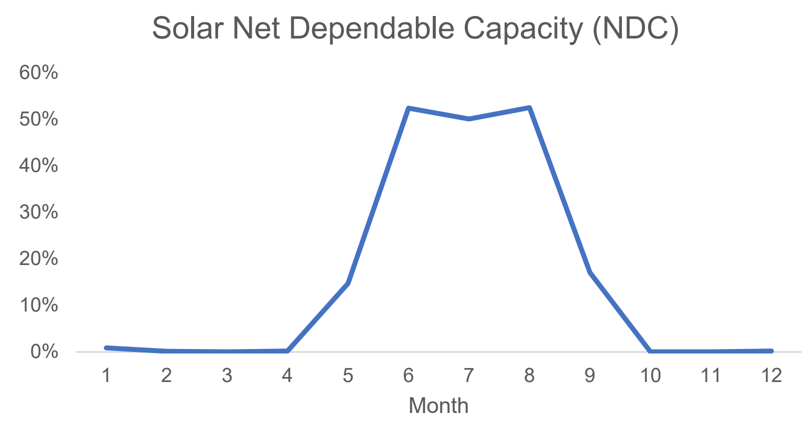
Cost assumptions developed using recent RFP pricing at the 25th percentile, then transition to the "NREL 2023 – Advanced Market" price forecast toward the end of the decade that accounts for the IRA.

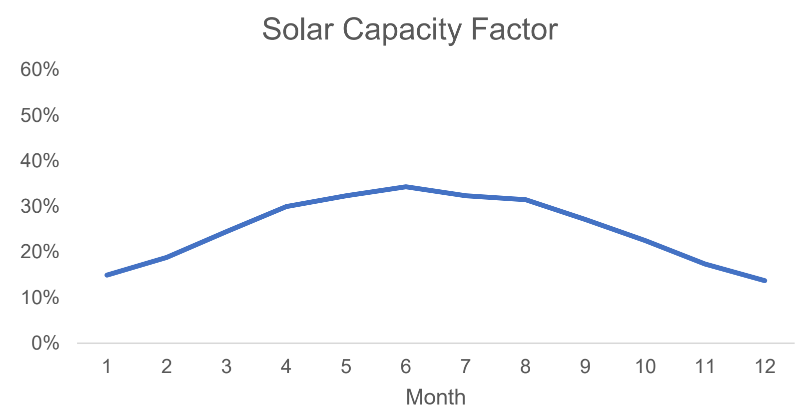
Assumptions reviewed and updated semiannually

Operating characteristics based on utility-scale, single-axis tracking solar installations in the TN Valley

Net Dependable Capacity is the percent of nameplate capacity that has a 50% confidence level of being available at the time of peak load for the month

Capacity Factor is the ratio of actual energy generation divided by the theoretical continuous maximum amount over the period





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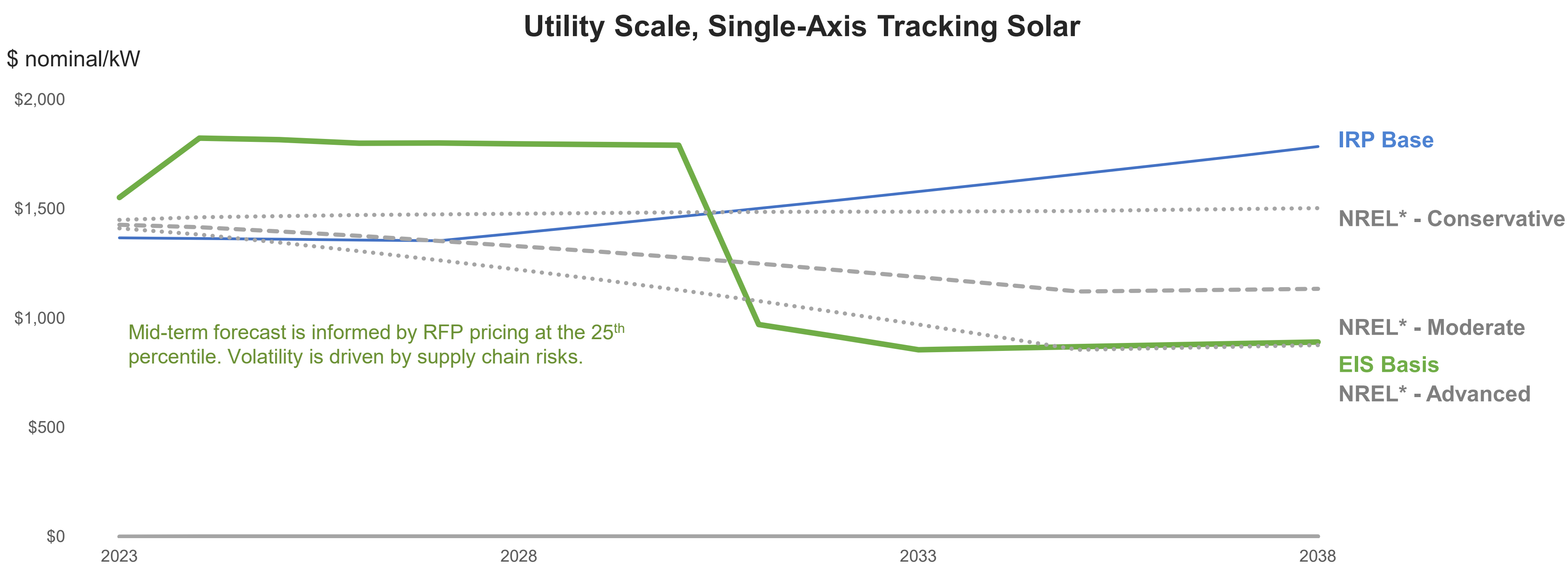
Solar Resource Costs



*National Renewable Energy Laboratory (NREL) forecasts

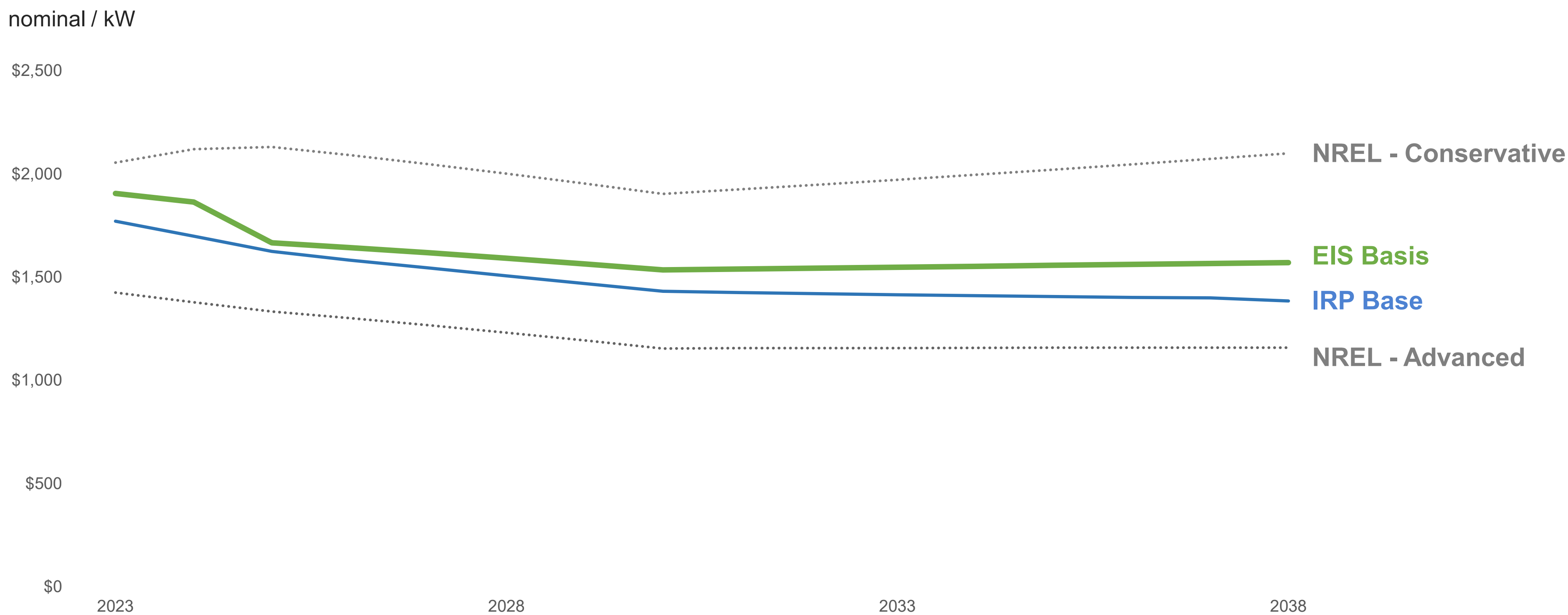
Storage Costs and Projects

Cost assumptions developed based on the "NREL 2023 – Moderate Market" case for four-hour batteries and accounts for the IRA.

Assumptions reviewed and updated semiannually.

Moving to a greater volume of inverter-based resources (solar and storage) weakens the transmission system and increases the risk of power quality issues for larger load customers without backstopping those additions with flexible, gas generation. Greater volumes of solar generation will create ramping challenges that are mitigated with flexible, dispatchable gas generation and battery storage.

Storage Resource Costs



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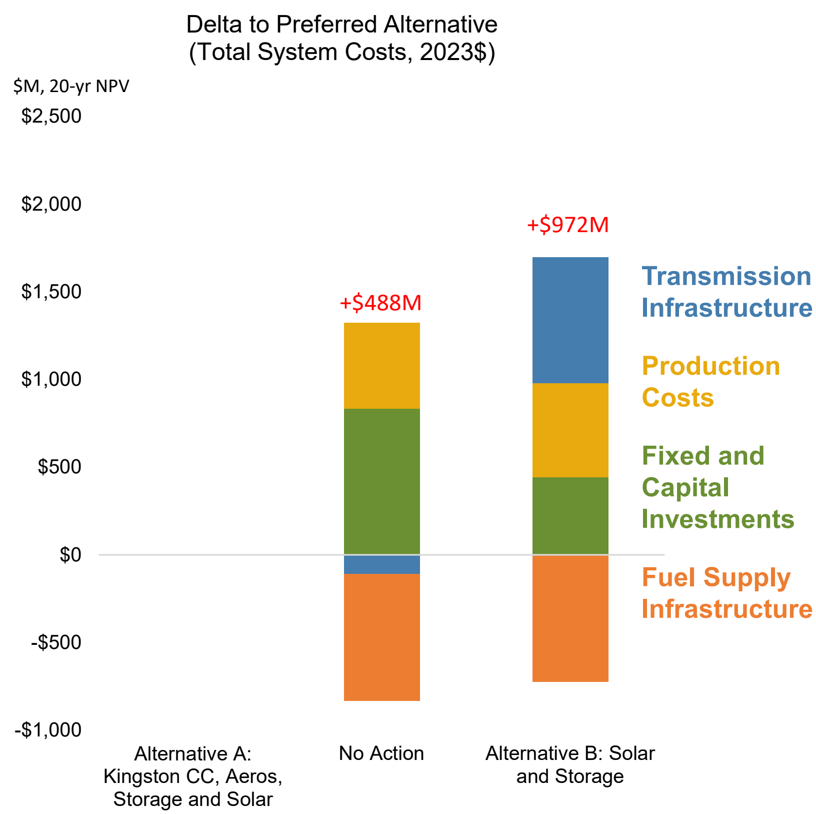
Total System Costs Comparison



Total system costs includes all capital, fixed, variable, and fuel costs associated with running the TVA system, as well as spending for requisite pipeline and transmission upgrades in each alternative

Alternative	Production Costs^	Fixed and Capital Costs	Transmission Infrastructure	Fuel Supply Infrastructure
Alternative A: Kingston CC, Aeros, storage, and solar	Included are costs associated with CC and Aero plant construction and operation, transmission upgrades, and pipeline lateral construction.			
No Action Alternative	Higher	Higher	Lower	Lower
	Substantial risks related to evolving and future regulatory requirements such as the ELG* Rule and plant material condition			
Alternative B: Solar and Storage	Higher	Higher	Higher	Lower
	Solar and storage and transmission projects fail to meet 2027 timeline and higher costs for reliability at KIF. Reflects IRA. Does not include $655M of ELG compliance cost.			

*Effluent Limitation Guidelines
^Production Costs include ongoing fuel, start, and variable O&M costs

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Key Cost Updates from Draft to Final EIS

- **Solar Prices:** Updated near-term prices to reflect TVA's recent carbon-free RFP then transitions to NREL's latest Annual Technology Baseline (ATB) from July 2023 and used their "Market" case, which reflects the IRA. Compared to the DEIS, solar prices are higher in the near-term and lower in the long-term. This manifests in a significant savings in the Production Costs.
- **Storage Prices:** Updated prices to reflect NREL's latest ATB and accounted for the IRA. Even with the tax credit, the latest NREL costs are about the same or slightly higher than the NREL costs used in the DEIS. This manifests in increased Fixed & Capital Costs.

Carbon Rate Comparison

All action alternatives significantly reduce system carbon intensity (lbs/MWh), compared to no action

The highly efficient advanced-class CC and Aero CTs in Alternative A reduce system carbon emissions by offsetting coal generation and by improving the combined fuel efficiency of the entire TVA gas fleet

Solar facilities in Alternative B reduce system carbon emissions by offsetting coal and gas generation, however this is partially offset as existing coal and gas units increase generation for battery charging or hours when solar is unavailable

Once completed, Alternative B results in the lowest system carbon rate, followed closely by Alternative A

Alternative	**FY30 Carbon Rate (lbs/MWh)***	**FY30 Rate Reduction (2005 baseline) Compared to Alternative A***
No Action Alternative	477	-3 percentage points (worse)
Alternative A: Kingston CC, Aero CT, Storage, and Solar	441	n/a
Alternative B: Solar and Storage	429	+1 percentage point (better)

*Vintage: FY23 Budget and associated alternative runs

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Planning is Grounded in Least-cost Principles

In resource planning, TVA applies fundamental least-cost planning principles*:

Low Cost	Risk Informed	Environmentally Responsible
Reliable and Resilient	Diverse	Flexible

Load varies hourly and seasonally, with weather a large driver, and highest peak loads are typically of short duration

Resources have a variety of operational and economic characteristics and constraints, with tradeoffs that contribute to the best portfolio fit overall

*In alignment with the Energy Policy Act of 1992

Least-cost Planning Evaluation

Alternative	Low Cost	Risk Informed	Environmentally Responsible	Reliable and Resilient	Diverse	Flexible
No Action Alternative	Cost risk associated with material condition and environmental compliance	Long-term fuel supply and regulatory risks	Results in highest system carbon rate, continued production of CCRs*	Challenged material condition; dependable year-round capacity	Contributes to balanced portfolio, long-term coal supply chain risks	Supports intra-day load swings, limited by start costs and minimum up/down times
Alternative A: Kingston CC, Aero, Storage, and Solar	Lowest total system cost, most effective at serving large energy needs	Robust fuel supply chain, potential use of alternative fuels or CCS*, fastest online	Substantial system carbon rate reduction, assists in integration of renewables	Dependable year-round capacity; East TN transmission support	Lateral connection to major interstate pipeline with multiple supply sources	CC supports baseload or intermediate needs; Aeros have very fast ramp speeds
Alternative B: Solar and Storage	Highest total system cost; extensive transmission work and large number of solar and storage locations	Fails to meet purpose and need timeline with transmission build-out and land and resource procurement	Substantial system carbon rate reduction, lowest system carbon rate	Dependable year-round capacity; requires upgrades for dynamic/reactive support; batteries are limited in duration (four hours)	Contributes to balanced portfolio, adds to aggressive solar build plans	Batteries support fast peaking needs and have a wide operating range

*CCS = Carbon Capture and Sequestration; CCR = Coal Combustion Residuals

Best	Good	Worse	Worst

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Additional Considerations

The decision associated with this EIS is a specific, discrete component of TVA's blended asset strategy and consistent with the recommended target power supply mix in the 2019 IRP

New gas contributes to TVA's ~80% carbon reduction by 2035 path by enabling the retirement of the remaining coal plants by 2035, while emitting about 65-70% less CO_2 than aging coal plants

Natural gas represents a highly flexible, reliable fuel source that helps enable high penetration levels of intermittent renewable resources

CC plants are positioned to further contribute to a net-zero future using alternative fuels, such as hydrogen, and/or carbon capture and sequestration (CCS) technology

TVA is exploring partnerships with federal agencies and peer utilities to advance the research and development of both alternative fuels and CCS technology, which could enable their use at existing or future TVA gas facilities

Action alternatives are in addition to TVA's target to add 10,000 MW of solar by 2035, TVA currently has over 2,500 MW of solar either operating or contracted

TVA is working to gain operational experience with battery storage technology through the deployment of a 20 MW battery storage project near Vonore, TN and nearly 180 MW of storage paired with solar under contract, all planned to be online over the next several years

TVA is also exploring pilot projects for additional short- and long-duration storage use-cases

Preferred Alternative

TVA's financial and system analysis, using the least-cost planning framework along with consideration of the environmental impacts of the two alternatives, indicates that Alternative A, retirement of KIF and replacement with CC, Aero CT, storage, and solar facilities, is the Preferred Alternative.

Key considerations include:

- Alternative A aligns with the 2019 IRP near-term actions to evaluate engineering end-of-life dates for aging fossil units to inform long-term planning and to enhance system flexibility to integrate renewables and distributed resources.
- Alternative A is the lowest-cost alternative and supports high reliability while greatly reducing carbon emissions compared to no action.
- Alternative A can be constructed on a TVA-owned brownfield site, largely leverage existing transmission infrastructure, and supports East Tennessee grid stability.
- Alternative A is a mature technology and can be built and operational sooner than other action alternatives, which reduces economic, reliability, and environmental risks, and is also designed for future implementation of alternative fuels.

EPA Proposed GHG Rules Sensitivity

The EPA is proposing new emission guidelines for GHG from existing coal units and proposing amendments to the New Source Performance Standard (NSPS) for GHG emissions from new gas units. These rules are not final; this sensitivity covers estimated impacts. Refer to the Final EIS document for more information.

No Action Alternative

Since the No Action Alternative assumes Kingston Fossil would continue to operate, the fossil plant would be retrofitted with CCS on Jan 1, 2030.

Alternative A

For new baseload gas units (Kingston CC), there are two options:

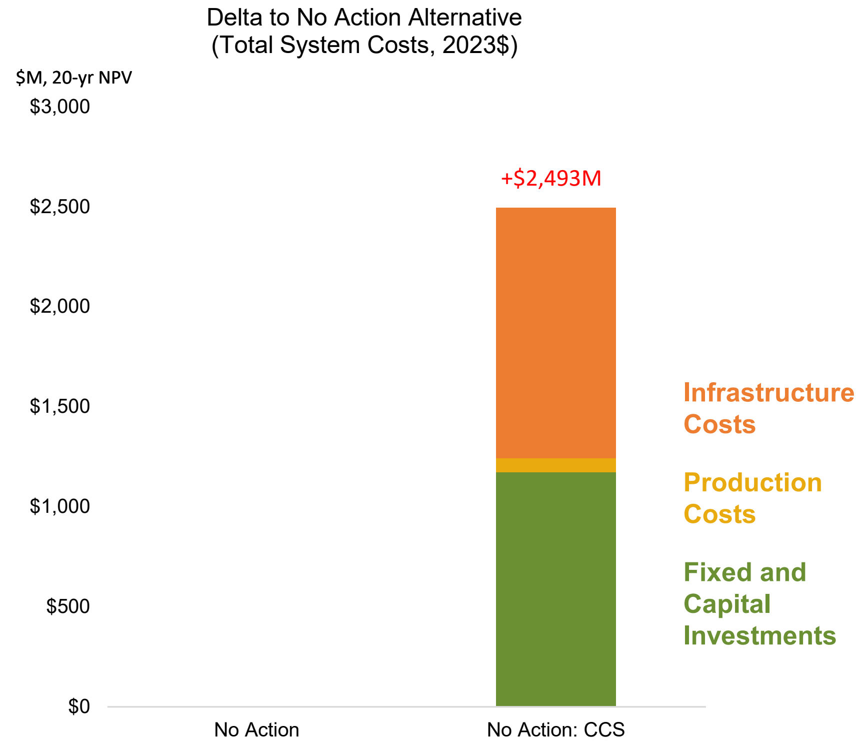
1. 30% low-GHG H2 co-firing by 2032 and 96% low-GHG H2 co-firing by 2038 or
2. 90% efficient CCS by 2035

Kingston Aero would be considered a low utilization unit and therefore would not be impacted. Alternative B is not impacted by the proposed rules.

No Action Alternative Sensitivity Analysis

Estimated CCS path for Kingston Fossil was modeled and compared to the base case No Action Alternative:

- Higher Fixed and Capital Costs and Production Costs: Reflects the CCS retrofit costs and additional capacity needed given the efficiency loss with CCS.
- Higher Infrastructure Costs: Reflects the carbon transportation and storage costs.



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Alternative A Sensitivity Analysis

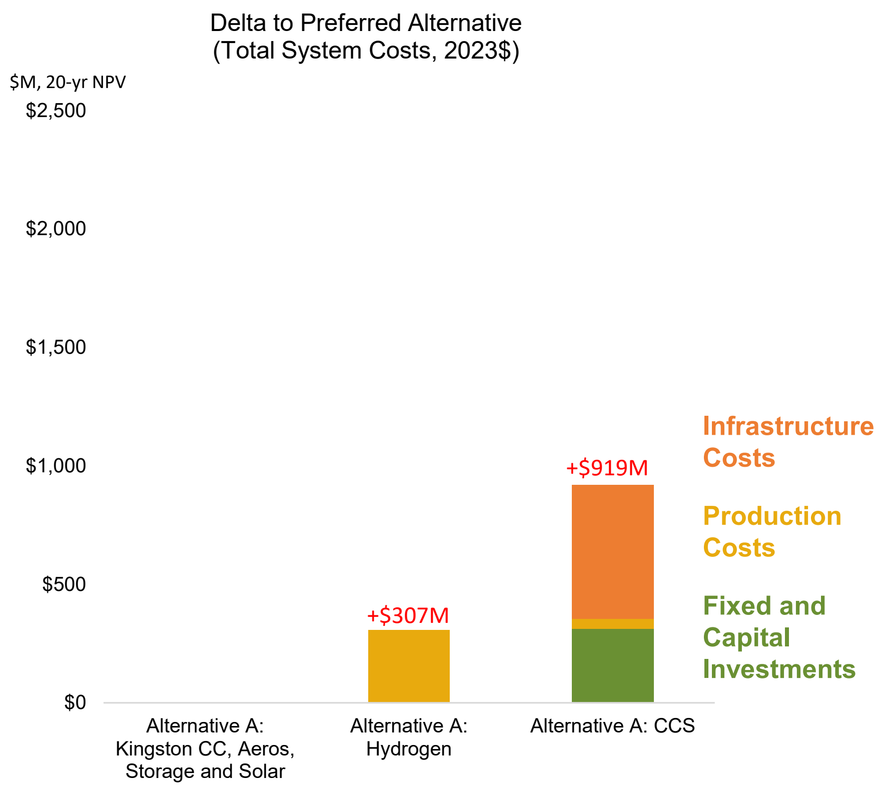
Estimated hydrogen and CCS paths were modeled and compared to the base case Alternative A:

Hydrogen

- Higher Production Costs: Reflects EPA's projected delivered cost for hydrogen.

CCS

- Higher Fixed and Capital Costs and Production Costs: Reflects the CCS retrofit costs and additional capacity needed given the efficiency loss with CCS.
- Higher Infrastructure Costs: Reflects the carbon transportation and storage costs.



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Appendix C – Winter Storm Elliot After-Action Report

TVA TENNESSEE VALLEY AUTHORITY

After Action Report / Winter Storm Elliott

Contents

Preface

Every day, businesses are confronted with challenges that test the operational abilities of an organization and the fortitude of all involved. One of the hallmarks of successful organizations is the ability to learn from these events … to adapt and improve.

At TVA, we are a learning organization … committed to continuous improvement.

Reliable and secure energy is essential for families and businesses. It's what you expect and deserve. At TVA, we take great pride in providing the 10 million people of the Tennessee Valley region with reliable energy 24/7.

We fell short of your expectations during Winter Storm Elliott. While we planned and prepared for this event, the storm's speed and intensity exceeded our efforts.

Immediately following the storm, we proactively initiated an **After-Action Technical Team** to conduct a thorough review of what happened and why. This team included subject matter experts from areas across our organization. We also asked employees to provide us with immediate recommendations based on the challenges they encountered during the storm.

Working with our 153 local power companies (LPCs) across the seven-state region we serve, we formed a **Customer Engagement Team** to provide ongoing feedback to our review process. And we engaged a **Blue Ribbon Commission** to provide independent perspectives and insights.

We took these steps – first and foremost – because it's the right thing to do. As a learning organization, we are committed to understanding and sharing lessons learned and – more importantly – implementing actions to ensure we are better prepared to manage significant events in the future.

This report highlights the findings from the events surrounding Winter Storm Elliott, recommendations for improvement, and actions associated with each recommendation.

The strength and resilience of our system was tested during Winter Storm Elliott, and we will learn, adapt, and improve.

It's a privilege to serve you.

Don Moul
Executive Vice President
Chief Operating Officer

Bob Dalrymple
Senior Vice President
Resource Management & Operations Services

TVA Background

Nine decades ago, TVA was created with a clear mission to benefit the public good. TVA was established with the innovative concept of managing the vast resources of the Tennessee Valley as an integrated system across jurisdictional boundaries and to help lift the seven-state Tennessee Valley region from the depths of the Great Depression.

Since day one, a hallmark of TVA has been innovation, as we built dams to control flooding and constructed transmission infrastructure to bring the first electric lights to rural communities and farms.

TVA's unique, longstanding mission focuses on:

- **Energy:** affordable, reliable, resilient and clean
- **Environmental Stewardship:** protecting and preserving public lands and water
- **Economic Development:** attracting investment and creating jobs

Today, TVA is the largest public power provider in the United States and is one of the nation's largest electricity generators. TVA supplies the energy that approximately 10 million people and over 750,000 businesses across the Tennessee Valley region rely on every day.

TVA is not doing this alone. The strength of partnership cannot be overstated. We are leveraging expertise and support from customer partnerships, industry partnerships, and stakeholder groups to help forge a path forward for the region that benefits all.

Companies choose to locate to the Tennessee Valley region because of the affordable, reliable, resilient, and clean energy TVA and Local Power Companies (LPCs) provide, and we want to ensure we can continue to support those economic opportunities for our region. In FY 2022 TVA helped create 26,500 new jobs and retain 40,000 jobs.

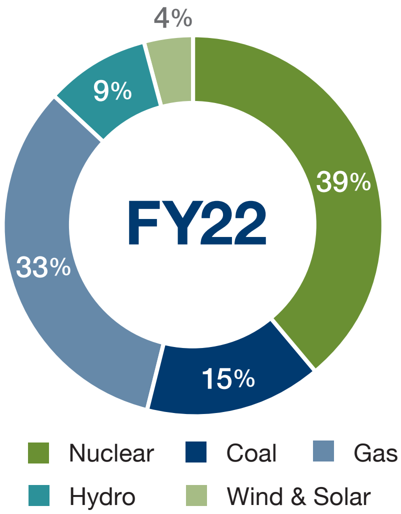
ENERGY

ENVIRONMENTAL STEWARDSHIP

ECONOMIC DEVELOPMENT

TVA Power System Background

TVA operates one of the nation's largest and most diverse energy systems, with more than half of our energy supply coming from carbon-free sources. TVA also owns the nation's third largest nuclear fleet, with a generating capacity of over 8,000 MW (or enough power for 4.5 million homes and businesses), that is the backbone of our clean generation portfolio. TVA has a total of 232 generating units, as well as power purchase agreements (PPAs) with power producers.



TVA, like all other power grid operators, must ensure that the supply of electricity matches demand for electricity at all times. Power systems and generating facilities are built and maintained in accordance with an established design basis, which incorporates criteria such as safety, functionality, reliability, environmental impact, and regulatory compliance requirements, and ensures that the system can perform as intended under normal and abnormal circumstances at a reasonable cost to consumers.

To maintain reliability, power providers must always have more generating capacity available than required to meet peak demand. This additional generation, called "reserve capacity," must be enough to cover uncertainties such as unplanned unit outages, severe weather events, unexpected changes in energy use, or undelivered power purchases. Weather and economic activity are significant drivers of demand, or load, and TVA plans its system to be able to meet the highest demands, or peaks, that occur in the summer and the winter months by three primary forecasts to predict those loads:

- **Long-Term forecast** determines electric needs up to 20 years into the future and identifies reserve margins for the summer and winter peaks that target industry best-practice levels of reliability, while minimizing the cost of reserves and reliability events to consumers. This view, provided in Integrated Resource Plans (IRPs), is used to inform the development of appropriate generation assets.

- A closer, **Mid-Term view** is developed each year in the fall for the winter and in the spring for the summer. The mid-term view primarily informs trading positions in the energy market. If TVA has excess generation, it can sell power and capacity to neighboring utilities. Conversely, if additional power and capacity are required, it can purchase its needs in the market. The mid-term forecast was developed and made available internally in November 2022 and was used to prepare for Winter Storm Elliott.

- The real-time operations staff uses the **10-Day Forecast** to determine immediate needs. This forecast influences purchases on the day-ahead market and the dispatch of generation assets.

TVA meets its customer load requirements through a mixture of TVA-owned generation as well as market purchases. TVA's current Integrated Resource Plan set planning margins at 17% above peak load requirements in the summer and 25% above requirements in the winter. TVA has more than 38,111 MW of generation capacity (owned and contracted) available. In order to balance cost and reliability, TVA's generating assets are designed to withstand a one in ten-year reliability event.

TVA's ability to reliably deliver electricity to our customers is executed by an operations function called the Balancing Authority (BA). Staffed 24/7, the BA operations desk is responsible for ensuring supply of electricity precisely matches the demand for electricity at all times. The BA has several complex systems that provide a forecast of energy consumption, a real time view of energy being used, and a real time view of power plant production. The BA has several methods for balancing electricity supply with demand in the event there is not enough TVA power – buy power from other systems; request voluntary reductions from the public; require reductions from industrial customers participating in incentivized programs; require reductions from LPCs from their industrial, commercial and residential customers; and, as a last resort, reduce consumption directly from the bulk system level.

Finally, to support bulk energy system reliability and resilience in extreme conditions, TVA, Tennessee Valley Public Power Association, and local power companies maintain emergency load curtailment procedures designed to ensure the stability of the grid even in extreme events.

Winter Storm Elliott Background

TVA's objective and that of our 153 local power company partners is to never interrupt power. That's what we plan and strive for every day. During Winter Storm Elliott, we fell short of that objective.

Winter Storm Elliott was a powerful storm that impacted most of the eastern continental United States, bringing heavy snowfall and high winds to the Midwest and Northeast and freezing rain and high winds to the South.

The December 2022 storm wreaked havoc across the nation, causing travel disruptions and power outages.

The National Weather Service referred to Winter Storm Elliott as a "once-in-a-generation storm," which brought record-breaking cold temperatures and high winds to our region and across the nation.

Winter Storm Elliott did not take TVA by surprise. TVA anticipated and prepared for this event, but the storm's speed and intensity exceeded forecasts and TVA's efforts.

Key weather facts for the Tennessee Valley region during Winter Storm Elliott:

- TVA's system average temperature was 3F at 8 a.m. CDT on Friday, Dec. 23. This was the coldest system average temperature since Feb. 5, 1996.
- On Friday, Dec. 23, the morning lows were Nashville 1F, Memphis 1F, Huntsville 3F, Knoxville 4F, and Chattanooga 7F.
- The afternoon high was 11F for the system average, falling to 8F for most of Friday night and early Saturday, Dec. 24.
- There have not been back to back mornings with system temperature lows in the single digits since February 1996.

What Happened

A month prior to the storm, TVA developed and shared the Mid-Term forecast with the Transmission, Nuclear, Power Operations, and Facilities Management teams to complete the cold weather readiness actions and winter readiness certification process. These certifications were used by generation leadership, planning and real-time operations to determine energy reserve positions and inform short-term trading needs.

In mid-December, TVA Operations employees began tracking Winter Storm Elliott, making initial observations a week before it impacted the Tennessee Valley region. Severe weather notifications were issued to internal emergency management employees regularly throughout the week leading up to the storm and multiple business units engaged in preparedness activities. TVA committed a significant amount of generation resources ahead of the event to meet predicted demand, and took additional measures such as:

- TVA's generation plants took extra steps to ensure readiness.
- TVA's External Relations team began outreach to customers and stakeholders.
- TVA Police & Emergency Management engaged with TVA business units to remind them of the possibility of agency-level emergency coordination based on storm impact.

On Wednesday, Dec. 21, 2022, the TVA Reliability Coordinator issued a Cold Weather Alert and a Conservative Operations Alert for the entire TVA system starting Thursday, Dec. 22, 2022, at 8 a.m. CDT through Monday, Dec. 26, 2022, at 5 p.m. CDT.

The high winds, heavy rain, and cold temperatures of Winter Storm Elliott arrived in the TVA service territory on December 22. These conditions increased energy demand beyond what had been forecast, resulting in the highest 24-hour electricity demand supplied in TVA history on December 23 as the speed, intensity, scale and duration of Winter Storm Elliott exceeded the design basis for some of TVA's power plants. In total, 38 of TVA's 232 generating units were negatively impacted, mostly due to instrumentation that froze.

TVA employees worked around the clock to increase generation to meet the demand, including dispatching units that had previously not been in service and executing day-ahead, real-time purchases and emergency purchases.

TVA set multiple energy demand records during Winter Storm Elliott

- **On Friday, Dec. 23, highest 24-hour electricity demand supplied in TVA history – 740 gigawatt-hours.**
- **Highest winter peak demand at 7 p.m. CDT on Friday, Dec. 23 – 33,425 megawatts (third-highest peak demand in TVA history).**
- **On Saturday, Dec. 24, at 1 a.m. CDT, highest weekend peak demand in TVA history – 31,756 megawatts**

In addition, TVA employees worked in extreme weather conditions to keep generating units online and restore units impacted during the storm. This included placing additional temporary structures, insulation, and heaters around equipment at impacted units. As a result of their efforts, 14 of the 38 generating units lost were recovered and returned to service within 48 hours.

TVA's nuclear and hydro assets were not affected by the extreme weather due to their plant design and operated without issue supporting energy demand during the event.

The storm also challenged neighboring utilities, limiting power availability, resulting in energy demand exceeding supply being generated and purchased. For the first time in TVA's 90-year history, TVA was forced to implement emergency procedures directing local power companies to reduce power demand that resulted in localized interruptions in order to keep the overall system stable.

Event Timeline

FRIDAY, DEC. 23, 2022

On Thursday, Dec. 22, the energy consumption forecast for the next day was 31,163 MW. To meet this demand, TVA would need about 90% of TVA's owned and contracted power production available.

On Friday, Dec. 23, between 1 a.m. – 6 a.m. CDT, temperatures were dropping rapidly as the BA monitored real time electricity consumption, which resulted in a significant increase in the projected demand (beyond what was forecast). To meet that demand, the BA needed about 97% of TVA's available owned and contracted power.

The rapid drop in temperature and other weather-related conditions also caused freezing issues at some power generating facilities, which resulted in the loss of approximately 20% of the available energy production. As a result, TVA needed about 17% more power than was available.

To maintain system stability and address the deficit, the BA acquired 3% market power, called on industrial customers who participate in interruptibles programs interruptibles programs to reduce demand, resulting in 5% reduction in consumption, and finally called on LPCs to reduce their load by 5%. After a little more than two hours, several affected power plants had recovered and returned to service and the BA ended the call for LPCs to reduce consumption.

SPECIFICS:

At 4:30 a.m. CDT, demand for power exceeded the forecast by nearly 1,500 MW while TVA lost generation from multiple units (coal, gas, and independent power producers).

At 4:48 a.m. CDT, TVA called on industries and interruptible contracts to reduce energy demand, resulting in a reduction of demand by 1,612 MW (approximately 5% of system demand).

By 9:00 a.m. CDT, TVA had lost 6,705 MW of generation from coal, combined cycle gas, and independent power producers.

At 9:31 a.m. CDT, TVA initiated emergency procedures, directing 153 local power companies to reduce energy demand by 5%.

At 11:43 a.m. CDT, 2 hours and 12 minutes later – emergency procedures to reduce energy demand were lifted. Energy demand had been reduced by approximately 2,900 MW.

SATURDAY, DEC. 24

Following the peak electricity demand on Friday, Dec. 23, the BA began preparing for Saturday, Dec. 24. Nineteen percent of the available TVA owned and contracted power production remained out of service due to the freezing issues, and industrial customer consumption remained reduced by 5%. The forecast of energy consumption projected a need for 100% of the available TVA owned and contracted power plus an extra 6%.

The BA acquired 20% market power to cover the forecast and provide some contingency. Early in the morning of Saturday, Dec. 24, off-system purchases were cut off by other power systems because of emergency conditions on their own systems. TVA was forced to direct local power companies to reduce power consumption by 5% and then by 10%.

Five and a half hours later, the BA ended the call for LPCs to reduce consumption.

SPECIFICS:

At 4:51 a.m. CDT, because of continuing high energy demand and generation challenges, TVA directed local power companies to reduce energy demand by 5%.

At 5:12 a.m. CDT, this was increased to 10%. TVA also instructed its industrial customers and direct serve customers to reduce demand.

At 10:30 a.m. CDT – 5 hours and 39 minutes later – emergency procedures to reduce energy demand were lifted. Energy demand had been reduced by approximately 4,800 MW.

Winter Storm Elliott was challenging, not only to TVA but to all the local power companies in the Valley region as well as utilities around the eastern United States. Because of the active participation and collaboration of many, including TVA, industrial customers, and residents, as well as decisive and deliberate actions by 153 local power companies across seven states, the grid remained stable and more serious consequences were avoided.

Figure 1 – TVA's Emergency Load Curtailment Program (ELCP)

Preventative Reductions

- **STEP 10** In-House Load Reductions by TVA and LPCs
- **STEP 20** Public Appeal for Voluntary Load Reductions
- **STEP 30** Last Action to Avoid Firm Load Curtailment

Firm Load Curtailment

- **STEP 40** Partial Curtailment of Large Firm Load
- **STEP 50** Interruption of General Firm Load
- **STEP 60** TVA Emergency Tripping of Firm Load

Immediately following Winter Storm Elliott, TVA asked employees to capture lessons learned. More than 250 actions were captured and completed by the end of January.

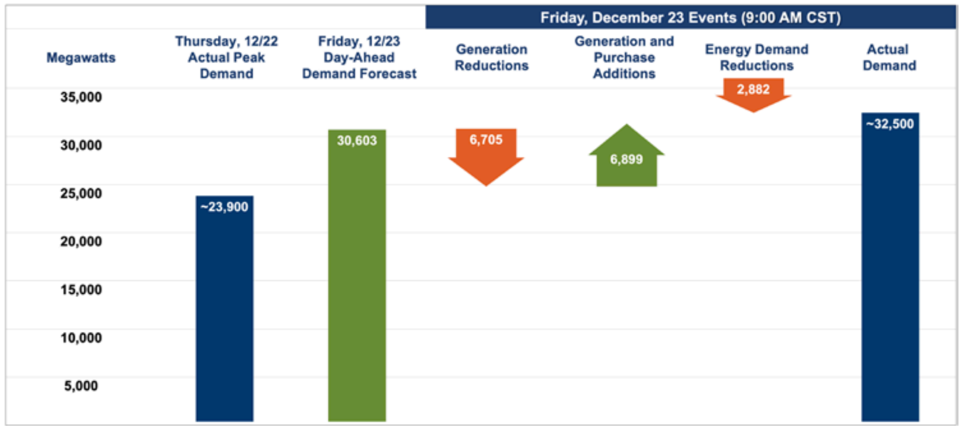
These actions included strengthening and increasing the operational resilience at TVA's generating facilities, placing more robust enclosures at generating facilities, and enhancing insulation around instrumentation.

In addition, TVA is developing design modification plans for impacted generating units – to address both winter and summer peaks.

Emergency Management Processes and Procedures have also been evaluated and updated to improve internal coordination, communication, and preparedness. These updates are designed to clarify triggering events and better define roles and responsibilities.

Finally, processes for communicating with customers and key stakeholders are being updated to ensure TVA provides clear, consistent, and actionable information to all stakeholders.

Figure 2 – Dec. 22 Plan to Dec. 23 Peak Hour 9 a.m.



Generation and losses on 12/23 are snapshots of conditions for hour ahead of calling ELCP Step 50 (9:00 AM CST)

Figure 3: Dec 23 Plan to Dec 24 Peak

Generation and losses on 12/24 are snapshots of conditions for hour ahead of calling ELCP Step 50 (5:00 AM CST)


B
GULATION
TANK

What We Learned

Following Winter Storm Elliott, TVA immediately took steps to understand what happened and why and to draw lessons from the event through initiating a formal After-Action Technical Review. As part of this effort, TVA engaged industry experts and customers for input and feedback, incorporated independent oversight and expertise, and committed to share findings and progress as part of TVA's commitment to transparency.

TVA's After-Action Reviews included:

Blue Ribbon Commission – A panel of experts charged with the comprehensive review of actions taken before and after Winter Storm Elliott to provide independent perspectives to TVA leadership.

Bob Corker, *former U.S. Senator*

Joy Ditto, *former President of American Public Power Association (APPA)*

Mike Howard, *retired CEO of the Electric Power Research Institute (EPRI)*

The After-Action Technical Team – A team of internal experts from across multiple disciplines charged with examining TVA's preparation for and response to Winter Storm Elliott.

Customer Engagement Team – A team engaging with key customer leaders to gather input and feedback related to TVA actions taken before, during and after Winter Storm Elliott. Members include:

- **Doug Peters**, Tennessee Valley Public Power Association
- **Rob Hoskins**, Tennessee Valley Industrial Committee
- **John Bowers**, Pickwick Electric Cooperative (TVPPA Operations Coordination Advisory Group Chair)
- **David Wade**, EPB of Chattanooga
- **Doug McGowen** and **Alonzo Weaver**, Memphis Light, Gas and Water
- **Alan Gates**, Pennyrile Rural Electric Cooperative
- **Marlin Williams**, North East Mississippi Electric Power Association (TVPPA Communications Advisory Group Chair)
- **Teresa Broyles-Aplin**, Nashville Electric Service
- **Keith Carnahan**, Meriwether Lewis Electric Cooperative
- **Steve Hargrove**, Sheffield City Utilities Department (TVPPA Government Relations Advisory Group Chair)
- **Dave Cross**, Plateau Electric Cooperative
- **Jason Griggs**, Milan Utilities

TVA has taken this process seriously and has been responsive to the questions and concerns of our respective Team. We believe that TVA is better prepared to address extreme weather events going forward and look forward to seeing more of these recommendations implemented to ensure we continue to get better at serving our customers together.

– Customer Engagement Team

The review looked at five main categories or activities across the agency and the response of each to the storm:

Energy Supply

- Like most utilities, TVA has a generation plan to meet customer load requirements through a mixture of TVA-owned generation as well as market purchases. In the event TVA were to experience higher-than-forecast demand, TVA could make up for that shortfall by buying energy and capacity from the energy markets.

- In addition, prior to the winter and summer seasons, each generating plant must certify that it has completed the necessary checks and preventive maintenance activities to support cold or hot weather operations. Nuclear plants have a similar process for their own certification.

Real Time Load Forecasting and Operations

- While long- and mid-term forecasting as well as real-time load forecasting are instrumental in planning for how to meet a forecasted demand at any given time, decisions may need to be made in real-time to ensure TVA can meet demand, including calling on agreements with interruptible contracts and as well as other partnerships as needed.

Emergency Protocols

- TVA, Tennessee Valley Public Power Association, and local power companies maintain emergency load curtailment procedures designed to ensure the stability of the grid even in extreme events. In addition, several TVA business units may implement Emergency Operations Centers (EOCs) to align key personnel to support a specific event. Depending on the magnitude of the event, TVA’s enterprise leadership team also may direct the activation of the Agency Coordination Center.

Customer and Stakeholder Engagement

- Communication during an emergency event is critical – both internally across the agency and externally to customers, stakeholders, and the general public. The External Relations Regional Model is designed to facilitate timely conversations with customers and stakeholders while TVA Communications is responsible for sharing information with the general public.

Transmission

- TVA manages one of the largest transmission systems in North America with 16,400 miles of line – enough to span the United States six times over – providing the critical link that connects power from our generating plants through a network of 153 local power providers. Teams maintain the transmission system as well as balance the flow of power over that system with a focus on delivering power reliably where and when it’s needed, regardless of fluctuations in demand or weather.

A team was formed for each category to conduct a deep-dive into what happened, how TVA responded, and how TVA can improve in the future. Specifically, each team determined the specific events, or drivers, that led to load reduction during Winter Storm Elliott; considered improvement opportunities to support an enhanced response to future hazards; and documented strengths, which include actions taken that had positive outcomes and should be evaluated for future events. Based on the teams' findings, they also determined recommendations for potential changes to the approach or execution of TVA's strategy.

The severity, duration and scale of Winter Storm Elliott resulted in dramatic increases in energy demand, decreased availability of TVA owned and contracted electricity supply, as well as decreases in imported electricity from neighboring markets. In order to maintain grid stability, this required TVA to curtail load to maintain grid stability.

Drivers

The teams identified two drivers that had direct ties to the reduction of load during Winter Storm Elliott:

- Rain followed by extreme cold weather and wind created an environment that was beyond design basis of TVA generating sites, causing some units to trip offline causing a generation deficiency
- Due to the regional nature of the weather event, energy market purchases were curtailed, contributing to the generation deficiency

In addition to direct drivers of the event, the teams identified improvement opportunities in each category and what TVA did well in each category.

Improvement Opportunities

TVA recognizes the importance of reviewing the actions taken during Winter Storm Elliott to identify improvement opportunities and address those areas. Several opportunities were identified across the categories:

- The importance of accurate forecasting to utilities can't be overstated, and in this instance, TVA's operational and real-time industry load forecasting tools did not accurately predict the load or the potential risks experienced during Winter Storm Elliott.
- While no gas generation units tripped offline because of gas pressure issues from the interstate pipelines, the gas fleet identified opportunities for improved communication across the fleet and TVA, to enhance coordination and visibility related to gas supply, pressure alignment and troubleshooting.
- The flow of information, both internally across the organization and externally with customers, stakeholders, and the public, was not timely or fully effective, which resulted in inconsistent messaging and lack of situational awareness and expectations, and slow internal coordinations, approvals and stakeholder responses.
- Slow internal coordination and approvals resulted in delayed information-sharing, social media updates, and responses to customers.
- There are opportunities for better coordination and implementation of emergency procedures and protocols across the agency.

Strengths

While TVA found itself for the first time in its 90-year history directing local power companies to reduce their load, with many executing rolling outages to meet the request, several areas within TVA did perform well and should be considered strengths.

- Employees at the sites stayed focused on safety, even during very challenging weather conditions, and successfully performed their duties without incident throughout the storm.
- The execution of the Emergency Load Curtailment Program (ELCP) itself worked well. TVA's Transmission and Operations center executed the ELCP as designed and local power companies responded quickly when called upon, supporting grid stability and reliability.
- Interruptible products, providing the needed load reductions, outperformed expectations.
- The Reserve Sharing Agreement with Louisville Gas & Electric/Kentucky Utilities, in which LGE/KU and TVA make energy available to each other when outside assistance is needed, worked as designed.
- TVA's Regional External Relations Model enabled strong local engagement and outreach with customers, public officials and communities to help resolve challenges.
- TVA's Transmission system performed well throughout the storm.
- TVA's principal carbon-free assets (nuclear and hydro), which were not negatively impacted by the extreme cold weather that affected other generation technologies.

Financial impact to TVA

TVA also performed an assessment using available data and assumptions to calculate an estimated financial impact of Winter Storm Elliott. Overall, the financial impact to TVA totaled approximately $170M, which included increased fuel and purchased power costs, costs of repair and hardening of assets, and lost revenue as local power companies and direct serve customers reduced their power usage during the storm. We estimate that residential customers with average energy use would have seen an increase of about $5.20 in February because of Winter Storm Elliott.

What We Are Doing

Based on TVA's review the team identified a number of near- and medium-term actions to address the drivers and improvement opportunities. While TVA teams have already started addressing some of the actions, others are being planned to ensure completion in the coming months.

ENERGY SUPPLY

Site Resiliency

Recommendation 1: Conduct assessments and inspections to develop prioritized, site-specific improvement plans to address gaps in design basis. [In Progress]

Recommendation 2: Execute maintenance or upgrades for existing assets, in-flight projects, and new construction using the revised design basis and maintenance standards. [In Progress]

Recommendation 3: Revise maintenance standards to sustain the implemented resiliency improvements. [In Progress]

Recommendation 4: Establish standardized triggers and responses (e.g., stepped-up checklists, enhanced governance, temporary event-based roles) to be implemented immediately prior to extreme weather events to improve cross-organization coordination and communication. [In Progress]

Recommendation 5: Assess existing fuel resiliency strategy to identify areas where improvements can be made to strengthen resiliency readiness model at TVA's sites and within its fuel strategies and capacities. [In Progress]

Energy Market Purchases

Recommendation 1: Establish process(es) to analyze and communicate market liquidity risks in seasonal and 10-day horizons. [In Progress]

Recommendation 2: Redesign Power Supply Update Report (PSUD) to better communicate market reliance risks (capacity position, net system position, risk based on purchases). [Nearing Completion]

REAL-TIME LOAD FORECASTING AND OPERATIONS

Load Forecasting Tools

Recommendation 1: Evaluate the prioritization and timing of necessary software updates to Itron and Tesla with TVA's Technology & Information Business Unit. [In Progress]

Recommendation 2: Evaluate options for data analytics application to better understand real-time risks and uncertainty in load forecasting during extreme events. [In Progress]

Load Forecast Processes

Recommendation 1: Develop formal process(es) to improve coordination of load forecasting between real-time operations and Enterprise Forecasting for extreme events. [In Progress]

Capacity

Recommendation 1: Establish documented attributes and guidelines for capacity related to external sources. [Nearing Completion]

Recommendation 2: Define risks associated with non-capacity products. [In Progress]

EMERGENCY PROTOCOLS

Recommendation 1: Develop and update procedures and documentation used to implement and execute Emergency Operations Centers and the Agency Coordination Center, including triggers and checklists. [In Progress]

Recommendation 2: Improve crisis management technology, content, and emergency activation drills. [In Progress]

Recommendation 3: Improve existing and develop new agency-wide emergency and crisis management training. [In Progress]

Recommendation 4: Update Emergency Load Curtailment Program (ELCP) to incorporate lessons learned and feedback from LPCs. [Nearing Completion]

CUSTOMER AND STAKEHOLDER ENGAGEMENT

Recommendation 1: Develop coordinated response plan, process, and templates. [Nearing Completion]

Recommendation 2: Ensure training, education, and maintenance of processes and information for coordination and communication. [Nearing Completion]

Recommendation 3: Ensure centralized access to information, clearly defined roles, and execution of process. [In Progress]

Strategic Considerations

TVA's After-Action Technical teams identified key strategic considerations to inform decisions over the long term, which cover potential changes to the approach or execution of TVA's strategy that could help support an improved response to future hazards. These were reviewed by TVA's Enterprise Leadership Team, the Customer Engagement Team and the Blue-Ribbon Commission. These Strategic Considerations include:

- Continue assessing risks in capacity planning.
  - Implications of extreme weather on capacity planning and operational preparation
  - Market purchase risks for long-term and short-term capacity needs to support load growth (energy security and resiliency)
  - Fuel resiliency and redundancy
  - Qualities and criteria for generation resources to be included as capacity in resource plans
  - Implications of continued economic development, electrification, and available energy efficiency opportunities on load forecasts
- Expand power demand response and distribution system control.
  - Volume of responsive load (demand response products)
  - Technology improvement for distribution system automation and control
- Engage with customers, key stakeholders, and communities to identify opportunities to invest in emergency preparedness, resilience, and communication technology improvements.

As TVA includes these considerations in decisions going forward, we will work closely with our customers, stakeholders and policy makers to explore and support options that help support the energy needs of the future.

Looking Forward

At TVA, we are committed to delivering energy that is affordable, reliable, resilient, and clean. As people's reliance on electricity continues to grow, so does the critical role it plays in people's lives.

Our region is a great place to live and work. Economic development, combined with overall population growth, is driving energy demand. After nearly a decade of flat growth, our seven-state region is growing at six times the national average – resulting in a nearly 3% increase in power demand from 2019 to 2022.

TVA is aggressively working to meet this challenge by investing in new generation and infrastructure. The region's ability to continue to thrive – to attract new jobs and investments – requires clean, sustainable energy.

By the end of the decade, TVA anticipates adding 10,000 to 14,000 megawatts of new generation to meet that demand. Today, we are building 3,800 megawatts of new generation, including solar energy, energy storage, combustion turbines, and combined-cycle natural gas. We are also investing in infrastructure, enhancing our transmission system and building a state-of-the-art System Operations Center in Meigs County, Tennessee.

Communities and businesses alike benefit from affordable, reliable, resilient, and clean energy. We are committed to delivering that energy today and tomorrow.

Here's our plan of how to help meet the region's growing capacity, with the goal of always providing the energy security people can rely on:

- Fiscal Year 2014 and 2022, TVA invested **$18 billion** in capacity expansion and base capital, including about **$1 billion** a year, to maintain existing assets.
- Between 2023 and 2027, TVA will invest **$12 billion** for capacity expansion and base capital.
- We are building about **3,800 MW** of new generation, including combustion turbines, solar projects, combined-cycle natural gas, and energy storage.
  - **750 MWs:** Simple cycle CTs at Colbert (3 – 250 MWs) – Late 2023
  - **750 MWs:** Simple cycle CTs at Paradise (3 – 250 MWs – Late 2023
  - **1,500 MWs:** Combined cycle at Cumberland – Late 2026
  - **500 MWs:** Peaking aero-derivative CTs at Johnsonville – Late 2024
  - **200 MWs:** Solar at Lawrence County – Late 2027
  - **20 MWs:** Battery at Vonore – Late 2023
  - **100 MWs:** Shawnee Solar* – Late 2028

**Pending environmental reviews*

- We are investing in our current assets to ensure they are running as effectively and efficiently as possible – that we're getting every megawatt we can.
- We are evaluating responses to the 5,000 MW carbon-free RFP and expect to make selections this summer.
- We have 1,000 MW of new supply contracts in place since Winter Storm Elliott.
- We currently have 1,600 MW of demand response and are looking to add more.

As we work to address these challenges, the strength of our partnerships cannot be overstated. Key partners include our 153 local power companies, direct serve customers, elected officials, industry partners, communities, and more. Working together, we will ensure our region continues to have energy security, which includes sustainable energy solutions, and economic opportunities for generations to come.

Appendix

After Action Findings

Finding	Type
Energy Supply	
Rain followed by extreme cold weather and wind created an environment that was beyond design basis for TVA generating sites, causing some units to trip offline creating a generation deficiency	Driver
Due to the regional nature of the weather event, energy market purchases were curtailed, contributing to the generation deficiency	Driver
Gas pipeline communication, pressure alignment, and troubleshooting could be improved to enhance TVA's resiliency to future extreme weather events	Improvement Opportunity
TVA's principal carbon-free assets (nuclear and hydro units) were not negatively impacted by the Event despite the extreme cold weather that impacted other generation technologies	Strength
Sites remained focused on employee safety during the Event and were able to successfully perform all duties without incident during the Event	Strength
Real-Time Load Forecasting and Operations	
Operational/real-time industry load forecasting tools did not accurately predict the load and potential risks experienced during Winter Storm Elliott	Improvement Opportunity
Assess risks in capacity planning	Strategic Consideration
The Reserve Sharing Agreement with Louisville Gas & Electric/Kentucky Utilities functioned as designed	Strength
Emergency Protocols	
TVA's Transmission and Operations Center executed the ELCP as designed	Strength
Across the Agency, there were opportunities for better coordination and implementation of emergency procedures and protocols	Improvement Opportunity
Local Power Companies provided the needed load reductions when called upon to support grid reliability	Strength
Interruptible products outperformed expectations	Strength
Customer and Stakeholder Engagement	
Internal and external information flow and response was not timely or fully effective, resulting in inconsistent knowledge and external messaging, lack of situational awareness and expectations, and slow internal coordination, approvals, and stakeholder responses	Improvement Opportunity
TVA's Regional External Relations Model enabled local engagement and outreach with customers, public officials, and communities to help resolve challenges	Strength
Transmission	
Transmission system performed well during Winter Storm Elliott	Strength

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2023-306 0523

Appendix D – Response to Public Comments on the Draft EIS

Table of Contents

A. Introduction

A draft of this environmental impact statement (DEIS) was released for public comment on May 19, 2023. The Environmental Protection Agency (EPA) Notice of Availability of the DEIS was posted in the Federal Register on May 19, 2023; and the comment period closed on July 7, 2023. The DEIS was transmitted to state, federal, and local agencies and federally recognized Indian tribes. It also was posted on TVA's public NEPA review website. Notice of availability of the DEIS and the request for comments was published in newspapers serving the Kingston Fossil Plant (KIF) area. Notification letters were provided with the Highland Rim Economic Corporation commodity distribution event. Coloring books that contained fact sheets and information about the project were sent home with children who attend schools local to KIF. Postcards were sent to households within a 3-mile radius of KIF. Email notifications of the availability of the DEIS were sent to people who had previously requested notifications. TVA held three public meetings during the public comment period, one virtual and two in-person. TVA accepted comments through an electronic comment form on the project website, by mail, and by email. Comments received during public meetings were also accepted.

TVA received 602 comments on the DEIS; one of which contained around 4,350 signatures; most of these comments generally support the retirement of the KIF coal-fired generating units but opposed Alternative A, and preferred Alternative B. Comments were primarily submitted through a web comment form or directly to TVA's NEPA email inbox. Several form emails generated by multiple environmental groups were also submitted, in addition to separate comments and questions, including the Sierra Club, Southern Environmental Law Center (SELC), Southern Alliance for Clean Energy (SACE), Center for Biological Diversity, and Citizens' Climate Education.

A few of the comments stated a broad support for the continued use of coal to generate electricity; these were interpreted as supporting the No Action Alternative, under which TVA would continue to generate electricity with the existing KIF coal-fired units. Comments were received from two federal agencies (U.S. Environmental Protection Agency [USEPA] and National Park Service [NPS]), two state agencies (Tennessee Department of Environment and Conservation [TDEC] and Tennessee Department of Transportation [TDOT]), the Attorney General of the State of Tennessee, Mayor of Nashville, one local agency (Roane County Environmental Review Board), one local power company or LPC (Harriman Utility Board), the Tennessee Valley Public Power Association [TVPPA], and Tennessee Valley Energy Consumers Group [TVECG], over 35 different non-governmental organizations (NGOs), and a variety of local residents, landowners, and other interested stakeholders. A list of commenters and their affiliation is provided in Part C of this appendix.

As part of the Final EIS (FEIS), TVA carefully reviewed all of the timely, substantive comments that it received. Many of the individual comments were similar in substance. To avoid repetition, TVA grouped similar comments and produced one synthesized response for each comment grouping. The commenters contributing to each synthesized comment are listed in Part B of this appendix. Because TVA worked to retain nuances among comments, a number of synthesized comments are similar and likely overlap. The result of the review and synthesis of the 602 comments is the following list of 229 substantive comments to which TVA has provided responses in this appendix. Part C provides a list of individual commentors (their affiliation if provided is listed in parentheses), commenting organizations (state, federal, non-governmental) and names of individuals signing form emails or petitions submitted through a commenting organization, and the identification numbers of the comments addressing their submitted comments. A total of 602 comments were received, 125 in support of the proposed action, 39 opposing the proposed action, 83 in mixed support of the proposed action, and 355 neutral of the proposed action.

B. Response to Comments

INTEGRATED RESOURCE PLANNING

1. TVA demonstrates forward thinking in this Draft Environmental Impact Statement (DEIS) as described in the Summary and by selecting Alternative A. This forward thinking should inform decisions made in new Integrated Resource Plans (IRP) and be used to alter adopted IRPs. Rapid changes in the electricity generation and distribution systems will occur over the next few decades. Adopting procedures to allow changes to existing IRPs will assist TVA's plans to transition to a clean energy future. (Commentor: Citizens' Climate Education)

Response: The IRP is a long-term planning document that incorporates a reasonable range of potential scenarios with ranges of potential resources identified, which is developed by accounting for various risks, as described in the IRP. Thus, the IRP provides direction on how TVA can best meet future demand for power. TVA closely monitors key drivers related to changing market conditions, more stringent regulations, and technology advancements to inform appropriate actions within the recommended ranges and appropriate timing for the next IRP. TVA is currently working on its next IRP.

2. TVECG requests that TVA delay the decision on the replacement of the Kingston coal units until after the completion of the TVA 2024 Integrated Resource Plan and then make the decision based on guidance from the 2024 IRP.

TVECG will be participating in the TVA IRP and we will be making our own power system model studies for comparison to TVA results. Our study procedures will differ from TVA procedures in the following ways:

- **The objective function of TVECG studies is reliable service at the lowest rate to consumers. Unlike the TVA management objectives, fuel cost and purchase power costs are included.**
- **The TVECG model is a full risk-based model. Among those risks are the availability and cost of natural gas and the possibility of significant future requirements to reduce or capture emissions.**
- **The TVECG model is optimizing the cost of energy to consumers. It will include non-grid connected home solar and direct appliance connected solar as well as home efficiency improvements. Optimizing consumer benefits may not always align with optimizing TVA management benefits.**

(Commentor: Tennessee Valley Energy Consumers Group [TVECG])

Response: The 2019 IRP remains valid, and TVA does not agree that it should extend the life of the coal fired units by delaying the decision on the Kingston Retirement Project until the completion of the 2024 IRP. The 2019 IRP continues to appropriately guide TVA in making future generation decisions. As concluded on page 4 of the Concentric Report, provided as Appendix N, TVA's 2019 IRP "reflects the characteristics of an IRP as a strategic and forward-looking tool and serves as a solid basis for that guides decision-making to ensure a reliable and cost-effective energy future." Like the rest of the utility industry, TVA is undergoing a transition as it seeks to lower carbon emissions, address aging infrastructure, and meet load growth driven by development and electrification. The proposed retirement and replacement of coal generation at KIF is one piece of a larger decarbonization effort that TVA is undergoing.

TVA has considered a reasonable range of alternatives as required under NEPA that satisfy the purpose and need of its proposed action to retire KIF and replace that retired generation, and the preferred alternative best aligns with TVA's statutory least-cost planning obligations. One of the near-term actions of the 2019 IRP was to evaluate engineering end-of-life dates for aging fossil units to inform long-term planning and to enhance system flexibility to integrate renewables and distributed resources. This evaluation confirmed that the aging TVA coal fleet is among the oldest in the nation and is experiencing deterioration of material condition and performance challenges. Based on this evaluation, TVA developed a phased plan to retire its coal fleet by approximately 2035. To implement the retirement plan and retire the KIF coal units in 2027, the replacement generation at Kingston must be in place and operational by the end of 2027. This retirement date, which was selected based on considerations such as KIF's high cost and deteriorating facility condition, does not allow TVA the flexibility to delay the installation of the replacement generation beyond 2027. Such delay would result in cascading delays for retirement of other coal units in TVA's fleet. The proposed retirement and replacement of the nine coal-fired KIF units is consistent with the 2019 IRP and near-term future TVA energy production goals. See the Purpose and Need section of the FEIS for more information on the timing of the retirement and replacement of KIF.

Natural gas prices are seeing near-term pandemic and supply-driven volatility but compared to the 2019 IRP, fundamental prices are lower over the long-term. See Appendix B for more information on TVA's natural gas price forecast. Following implementation of its IRPs, TVA continues to monitor key signposts that will guide decisions for the long-term.

3. TVA continues to argue that the alternatives considered, including the preferred alternative, align with the 2019 IRP. However, there have been significant statutory, regulatory, and technology changes since the development of the non-binding 2019 IRP and the choice of generation for this plant is inconsistent with these changes. The IRA and future policies significantly affect the analysis of each alternative by impacting aspects of the energy market, such as energy prices and demand and supply, as well as the underlying cost of technologies. The EPA notes that the Department of Energy has estimated the impacts of the IRA on clean energy and GHG emissions. The DEIS states that the tax incentive provisions of the IRA are likely to take more time to implement than is available to TVA, given the 2027 timeframe identified in the purpose and need, and available guidance. The EPA recommends that TVA consider the proposed regulations and guidance released by the IRS on June 14, 2023, about the Direct Pay tax credits under the IRA. TVA is an applicable entity, and the new direct pay provision will let TVA receive a payment equal to the full value of tax credits for building qualifying clean energy projects. TVA should consider updated resources such as the U.S. Treasury Department's Final Rule on Section 45Q Credit Regulations, that provide clarity on how to use the credit for qualified carbon sequestration. (Commentor: USEPA, Joe Schiller)

Response: Reliance on the 2019 IRP to address this site-specific retirement/replacement action is proper because the analysis in the 2019 IRP continues to be valid. TVA's 2019 IRP identified 2200 MW of coal retirements, but also identified a near-term action to evaluate end-of-life dates for aged coal units in TVA's fleet to inform long-term planning on whether retirements in excess of 2200 MW could be achieved. This additional evaluation is presented in TVA's Coal Fleet End of Life Study. The proposed KIF retirement is consistent with that study. Likewise, the gas additions to replace the coal generation at Kingston are consistent with the target supply mix of the 2019 IRP. The 2019 IRP envisioned the addition of 5,200 MW of CTs and between 800 and 5,700 MW of CCs by 2028, and up to 8,600-MW of CTs and 9,800-MW of CCs by 2038 in order to facilitate the retirement of coal plants and to integrate larger quantities of renewables onto the grid. Maintaining grid reliability necessitates providing firm, dispatchable power year-round to meet peak load events which can occur at times when solar is unable to fully meet the maximum demand, typically during pre-daylight or early morning hours of the winter season.

TVA has reviewed the resources referenced by the EPA and has considered and accounted for the potential impact of the tax benefits provided through the IRA on the alternatives assessed in this EIS. While the IRA would provide incentives for various forms of renewable energy and storage options in the long run, TVA's solar prices for the next few years are informed by recent market offers, which remain elevated due to supply chain risks. See Appendix B for more information on TVA's solar costs. The total system cost comparison of the alternatives provided in Appendix B takes into consideration the IRA incentives. See also Section 1.2.3.3.1 of the FEIS for information on the IRA.

TVA has been implementing renewables, including solar, onto the TVA power system with over 2,900 MW of solar capacity added (operating and contracted) to-date. TVA is experiencing delays of up to 3-years implementing current solar projects due to supply chain issues and other solar market factors, as outlined in Section 1.2.3.3.1 of the FEIS. Based on this recent direct experience, the estimated implementation rate for solar in the TVA PSA is approximately 1,000 MW per year. The solar market factors outlined in Section 1.2.3.3.1 of the FEIS are a few of the current real-world issues TVA is facing in implementing solar and would be factors that, in addition to the needed transmission updates, would prohibit solar from being implemented in a timely manner to be utilized as a replacement generation for KIF.

With respect to EPA's proposed GHG regulations, TVA has considered and discussed the availability of mitigation technologies such as CCS and hydrogen co-firing in the FEIS. See Sections 1.2.3.3.2 and 3.7.2.3.1.4 of the FEIS.

4. TVA should take a step back to evaluate this project within the larger scope of how the agency will do its part to achieve 100% carbon-free electricity with renewable and distributed sources by 2035. In that regard, TVA should incorporate Synapse Energy Economics' recently released study, TVA's Clean Energy Future: Charting a course to decarbonization in the Tennessee Valley ("TVA Clean Energy Future Study"), into all decision-making and especially in evaluating replacements for the Kingston Plant. The study outlines specific pathways for TVA to meet three vital goals: (1) increasing resilience and reliability; (2) decarbonization; and (3) affordability, which are also considerations TVA has outlined in the Kingston Draft EIS. TVA has a responsibility under NEPA and the TVA Act to evaluate these renewable and distributed energy pathways. (Commentor: Center for Biological Diversity)

Response: TVA evaluated renewable and distributed energy pathways in assessing all reasonable alternatives for replacing the generation from the retired coal units at KIF. As to decarbonization, TVA is charting a decarbonization course consistent with its statutory mandates to sell power at rates as low as feasible and to add generation consistent with "least system cost" planning principles and the 2019 IRP target power supply mix. The preferred alternative for KIF is consistent with the goals of increasing resilience and reliability, advancing decarbonization, and maintaining affordability. TVA has given due consideration to the Synapse's study, TVA Clean Energy Study (March 2023), in evaluating replacements for the Kington Plant and developing this EIS.

5. TVA's reliance on the 2019 IRP to inform a decision to build a new gas plant in 2023 is irresponsible and arbitrary because neither that document nor the modeling exercise on which it is based reflect TVA's climate commitments, coal retirement plans, major climate legislation, and significant changes in the energy market.
Among other things, the 2019 IRP does not:

- **incorporate and model TVA's own commitment to an 80 percent greenhouse gas ("GHG") emissions reduction by 2035 from 2005 levels and to achieving net-zero emissions by 2050;**
- **incorporate and model TVA's obligation to comply with federal decarbonization targets, including decarbonizing the electric grid by 2035, as set forth in a series of executive orders;**
- **anticipate or find a need for additional coal retirements (beyond Paradise 3 and Bull Run) earlier than 2032 (although the model was permitted to select earlier retirements if found to be cost effective);**
- **commit TVA to evaluate additional coal retirements beyond 2,200 MW, which it exceeded by deciding to retire the Cumberland Fossil Plant by 2026;**
- **ground-truth its modeling assumptions through an all-resources Request for Proposals;**
- **incorporate incentives from two recent groundbreaking pieces of legislation: the Infrastructure Investment and Jobs Act ("IIJA") and the Inflation Reduction Act ("IRA"), which are both expected to lower transmission, wind, solar, and storage investment costs;**
- **reflect the effect of recent price volatility, supply chain challenges, and winter reliability challenges; or**
- **consider resources that require new high voltage DC transmission (HVDC), including wind located in the Southwest Power Pool, Midcontinent Independent System Operator, and Electric Reliability Council of Texas territories.**

EPA summed up this long list of shortcomings in its own comments on this DEIS: "[T]here have been significant statutory, regulatory, and technology changes since the development of the nonbinding 2019 IRP and the choice of generation for this plant is inconsistent with these changes." (Commentors: U.S. Environmental Protection Agency; Southern Environmental Law Center and Conservation Groups, Center for Biological Diversity)

Response: See response to *Comment No. 3.*

TVA's capacity and resource planning follows least-cost principles to develop a resource strategy that identifies the power resources needed to meet system demand with appropriate reserve margin. The process requires key inputs based on TVA's experience and expertise in areas such as electricity demand, fuel and power costs, construction costs, environmental regulations, asset operating characteristics, target planning reserve margin, and transmission considerations. Key assumptions are validated and compared against industry benchmarks, studies, and forecasts, then modeled leveraging commercially available tools including Anchor Power Solution's EnCompass and Energy Exemplar's Aurora.

When analyzing results from the draft 2019 IRP, TVA identified issues that warranted further evaluation prior to finalizing the study. In addition, TVA received helpful input from the IRP Working Group and the Regional Energy Resource Council (RERC), as well as from the public during the development of the IRP. Many of the questions raised by TVA, stakeholders, and the public focused on certain key assumptions that could influence results. To explore the impacts of changes in key assumptions and to inform the IRP Recommendation, TVA evaluated sensitivities related to the following categories: natural gas prices; storage, wind, combined heat and power (CHP) and small modular reactor (SMR) capital costs; greater energy efficiency (EE) and demand response (DR) market depth; integration cost and flexibility benefit; pace and magnitude of solar additions; higher operating costs for coal plants; more stringent carbon constraints; and variation in climate. See Appendix B for more information on assumptions used in the EIS and how they compare to assumptions in the 2019 IRP. The IRP is a dynamic plan that can adapt to future market conditions, consistent with the approved target supply mix. See pages 36-39 of the Concentric Report provided as Appendix N.

Regarding site-specific decisions that tier from an IRP, such as this one, TVA considers any applicable statutory, regulatory, market, or technology changes to ensure that the decision still complies with least-cost planning principles. As noted in more detail in response to *Comment No. 24 through 31*, TVA has investigated potentially applicable statutory changes, such as the IRA, and reliability issues experienced in the TVA Service Territory during Winter Storm Elliott, in this EIS. The EIS also explains why wind generation is not a viable option at this time in the TVA Service Territory. See Section 1.2.2.4 for information on reliability, Section 1.2.3.2 for a discussion of Winter Storm Elliot, and Section 1.2.3.3.1 for information on the 2022 IRA.

The retirement and replacement of coal generation at KIF is one piece of the larger decarbonization effort that TVA is undergoing. The target power supply mix identified in the 2019 IRP is consistent with TVA's and the Administration's goals to reduce carbon emissions. As to this comment's contention that TVA may not make decisions tiered from the 2019 IRP because it did not consider the current Administration's climate-related Executive Orders, TVA endeavors to support the Administration's goal to reduce emissions to the extent these goals can be achieved consistent with TVA's own statutory requirements. The Proposed Action reduces carbon emissions consistent with decarbonization goals and TVA's least cost planning mandate. The fact that these Executive Orders were promulgated after the 2019 IRP's completion does nothing to diminish its applicability or accuracy in predicting TVA's generation needs. Indeed, this site-specific EIS that tiers from the 2019 IRP addresses the Executive Orders referenced by the commenter. See Section 3.7.1.1.8.4. All action alternatives significantly reduce system carbon intensity, compared to the No Action Alternative.

TVA is executing a plan to reduce carbon emissions 70 percent from a 2005 baseline by 2030. As articulated in TVA's May 2021 Strategic Intent and Guiding Principles document, TVA has achieved a 63 percent reduction in mass carbon emissions in energy supply from calendar year 2005 to 2020, primarily by diversifying the TVA generation portfolio, which included:

- Addition of 1,600 MW of new, carbon-free nuclear generation (Watts Bar Nuclear Plant Unit 2) and extended power uprates at all three units at Browns Ferry Nuclear Plant
- Addition of over 1,600 MW of renewable energy (over 400 MW solar and 1,200 MW wind)
- Retirement of approximately 8,600 MW of coal generation which included:
    - 800 MW John Sevier Fossil Plant retired by 2012
    - 1,600 MW Widows Creek Fossil Plant, all units retired by September 21, 2015
    - 1,300 MW Colbert Fossil Plant retired on March 23, 2016
    - 1,254 MW Johnsonville Fossil Plant retired by December 31, 2017
    - 741 MW Allen Fossil Plant retired on March 31, 2018
    - 2,558 MW Paradise Fossil Plant with Units 1 and 2 retired in April 2017, and Unit 3 in February 2020
    - 865 MW Bull Run Fossil Plant to be retired by December 2023
- Addition of approximately 5,200 MW of new flexible and efficient gas generation
- Investment of over $400 million in energy efficiency programs since 2011

From this strategy, TVA also envisions a path to 80 percent carbon reduction by 2035 and aspires to net-zero carbon emissions by 2050, while continuing to provide affordable and reliable power for customers. This site-specific EIS accounts for and is consistent with this aspiration.

The TVA generation fleet in 2005 was comprised of 57 percent coal, 26 percent nuclear, 10 percent renewables (i.e., hydropower), 7 percent natural gas, and zero solar or wind capacity. As of FY 2020, TVA's generation fleet was comprised of 42 percent nuclear, 28 percent natural gas, 15 percent coal, and 15 percent renewables (i.e., 12 percent hydropower and 3 percent wind and solar). The significant decrease in coal-based generation from 2005 to 2020 and a concomitant increase in nuclear generation, places TVA on the path to 80 percent reduction by 2035.

While this EIS is specific to the retirement and replacement of the KIF coal-fired units, which requires firm dispatchable power by 2027, this action is just one component of the target power supply mix identified in the 2019 IRP. The 2019 IRP recommends solar expansion and anticipated growth in all scenarios analyzed, with most scenarios anticipating 5,000 to 8,000 MW and one anticipating up to 14,000 MW by 2038, as well as up to 5,300 MW of storage. The IRP recommendation as well as customer demand for cleaner energy has prompted TVA to release multiple Requests for Proposal for renewable energy and carbon-free energy resources since 2019. As of April 2023, TVA currently has over 2,900 MW of solar capacity both operating and contracted.

6. Given that natural gas is also a fossil fuel with a significant environmental impact, there is little environmental harm and perhaps large benefits to delaying the construction of the natural gas facilities and, if necessary, extending the life of the coal fired units while other options are considered. (Commentor: TVECG)

Response: TVA does not agree with this comment's suggestion that it should extend the life of the coal fired units. Like the rest of the utility industry, TVA is undergoing a transition as it seeks to lower carbon emissions, address aging infrastructure, and meet load growth driven by development and electrification. The proposed retirement and replacement of coal generation at KIF is one piece of a larger decarbonization effort that TVA is undergoing. One of the near-term actions of the 2019 IRP was to evaluate engineering end-of-life dates for aging fossil units to inform long-term planning and to enhance system flexibility to integrate renewables and distributed resources. This evaluation confirmed that the aging TVA coal fleet is among the oldest in the nation and is experiencing deterioration of material condition and performance challenges. The proposed retirement and replacement of the nine coal-fired KIF units is consistent with the 2019 IRP, TVA Aging Coal Fleet Evaluation (May 2021), and near-term future TVA energy production goals. See also response to *Comment No. 5* for more explanation as to why the decision to retire KIF and replace it with gas-fired generation comports with TVA's planning assessments.

7. To conclude our comments on the DEIS, we again emphasize that this should not be a separate process at all, but a decision made as part of the larger IRP that TVA is performing in parallel to this one-off analysis. TVA should pause this particular environmental review process until after the 2024 IRP is complete and include options for when to retire Kingston's coal units and how to replace them in its 2024 IRP. (Southern Alliance for Clean Energy)

Response*:* The decision associated with this EIS is a specific, discrete component of TVA's blended asset strategy and consistent with the recommended target power supply mix in the 2019 IRP. The 2019 IRP analysis remains valid and meets the dual objective of ensuring flexibility to respond to the future while providing guidance on how our resource portfolio should change as the future unfolds. See also response to comments 2, 3, and 5 for further explanation. It is noted that the target supply mix in the 2019 IRP provides a range for each generation resource. These ranges are consistent with least cost planning principles and provide TVA the flexibility to adjust the implementation of its IRP based on scenarios and circumstances that arise during the implementation of the IRP.

PURPOSE AND NEED

8. TVA also expresses concerns regarding grid stability in the Knoxville area if all 1500MW of replacement generation is not brought online by 2027. This is odd given that Kingston has a nameplate capacity under 1400MW but has had an operating capacity well below that for years. Regardless, many grid operators have viewed battery systems as one of the most effective grid stabilization technologies available. Regardless, it is TVA that has chosen to present action alternatives comprised of almost all one technology versus another. TVA has the option of responding to the valid criticisms it received from USEPA and others in the Cumberland EIS by crafting action alternatives with a more equitable mix of technologies but refuses to do so. All energy technologies differ in their strengths and weaknesses. A blended mix of technologies offers the ability to craft an optimal alternative that balances the weakness of one technology with the strength of another. (Commentor: Joe Schiller)

Response: The proposed 1500 MW of generation would replace generation lost as a result of retiring the KIF coal units and add capacity to allow for anticipated growth in regional energy demand. This proposed action is one piece of TVA's overall asset strategy, which blends a combination of resource technologies to allow TVA to support affordable, reliable, and cleaner energy for its customers. TVA's asset strategy already contemplates the blending of resources to provide the least-cost, optimal portfolio under a variety of future conditions, including the addition of 10,000 MW of solar by 2035. A key beneficial result of TVA's asset strategy is the reduction of carbon emissions. As discussed in detail in FEIS Section 1.2.2.1, this action is a specific, discrete component of that asset strategy and is consistent with the need established by the 2019 IRP to establish new capacity in the TVA region, increase reliability and flexibility, increase energy efficiency, and meet TVA energy production goals.

In conducting an alternatives analysis, agencies must "[e]valuate reasonable alternatives to the proposed action, and for alternatives that the agency eliminated from detailed study, briefly discuss the reasons for their elimination." 40 CFR § 1502.14(a). An agency must consider a reasonable number of alternatives, which are bounded by the purpose and need for the proposed agency action. Id. at § 1502.14(f), § 1502.13; see also Coal. for the Advancement of Reg'l Transp. v. Fed. Highway Admin., 576 F. App'x 477, 4[81] (6th Cir. 2014); Citizens Against Burlington, Inc. v. Busey, 938 F.2d 190, 195 (D.C. Cir. 1991) ("[A]n alternative is reasonable only if it will bring about the ends of the federal action.").

In addition to the No Action Alternative, TVA evaluated two action alternatives in detail in the DEIS:

- Alternative A- the retirement of KIF and construction and operation of a combined cycle (CC)/Aero gas plant with solar and battery resources at the same site; and
- Alternative B- the retirement of KIF and construction and operation of solar and storage facilities, primarily at alternate locations.

Further, Section 2.1.5 has been revised to describe alternatives that were "considered but not carried forward" for more detailed analysis because they do not meet the project purpose and need. In particular, in EIS Table 2.1-7, TVA evaluated a number of other resource options for replacement generation, including: natural gas-fired CC, natural gas-fired CT, battery energy storage systems (BESS), utility-scale photovoltaic (PV) solar, hydro pumped storage, small modular reactors, wind, energy efficiency, demand response, and distributed generation. TVA also evaluated other blended alternatives, including one that combines a lower amount of natural gas with other technologies, such as solar and battery storage. See FEIS Section 2.1.5.2. See also response to *Comment No. 47* regarding blended alternatives.

After careful consideration, TVA determined that blended alternatives would not meet the project's purpose and need and therefore the EIS does not evaluate blended alternatives in more detail.

9. TVA has also arbitrarily attempted to constrain its choice of alternatives by selecting an overly narrow purpose and need. TVA states that the purpose of the proposed action is to retire the Kingston Fossil Plant "by the end of 2027" and to "implement replacement generation that can supply at least 1,500 MW of firm, dispatchable power by the time the units are retired in 2027." According to TVA, only Alternative A meets TVA's purpose and need, given the time TVA says is required to complete the transmission upgrades for Alternative B and the overall need for "firm, dispatchable generation," which "Alternative B would not provide."

In any case, TVA is incorrect in its assertion that solar and storage resources could not be online by 2027. As discussed in the Grid Strategies report accompanying these comments, "in reality, batteries and solar can be deployed more quickly than methane generators." The Grid Strategies report debunks each specious claim TVA makes, including (1) that transmission upgrades are required to meet local reliability needs; (2) that TVA must wait for Internal Revenue Service ("IRS") guidance on IRA tax credits for renewable and storage resources; and (3) that Alternative B would face severe supply chain constraints. TVA's attempt to improperly constrain the purpose and need is also arbitrary because it cannot reasonably be used to support the utility's rejection of Alternative B or other clean energy portfolio alternatives. (Commenter: Southern Environmental Law Center and Conservation Groups)

Response: TVA has not improperly constrained the purpose and need. Considering the relative material condition, cost, flexibility, and environmental impacts from its coal fleet and to facilitate TVA's clean energy transition goals in a manner consistent with least-cost planning principles, TVA developed a phased approach for the retirement and replacement of the coal fleet system-wide. Based on an evaluation of the fleet, TVA determined that retirement of its coal fleet by around 2035 is aligned with least-cost planning and reduces economic, reliability, and environmental risks. TVA's planning assumptions for coal retirement dates, as outlined in the Aging Coal Fleet Evaluation, seek to balance economics, system reliability, and portfolio needs. Under this phased retirement approach, KIF and Cumberland Fossil Plant (CUF) would be retired sooner – KIF by 2027 and CUF by 2026-28 – due to Kingston's high cost and the deteriorating condition of facilities and equipment and CUF's lack of flexibility. Performance challenges are projected to increase in the future because of advancing age and difficulty of adapting the fleets' generation to the changing generation profile. The continued long-term operation of some of TVA coal plants, including KIF, contributes to environmental, economic, and reliability risks. KIF's major plant components were assessed for replacement for operation beyond 2027 and it was found that the oil filled transformers, steam turbines, and excitation systems were all in poor condition (see Section 1.1 of the FEIS). The boilers were noted as being in marginal to fair condition. Shawnee and Gallatin would be retired later due to the relatively better condition of those operating units, which was anticipated by 2035 and 2031, respectively, in the IRP (TVA 2019a).

As provided in the Aging Coal Fleet Evaluation, and as outlined in the response to *Comment No. 5*, the KIF reaches the end of its useful life in 2027. The KIF provides firm, dispatchable power that helps preserve the integrity of the electric grid in the Eastern Tennessee area. The generation from the coal plant must be replaced with firm, dispatchable power by the time the coal plant is retired in 2027. Without this replacement generation in place, required generation and capacity to meet system demands and planning reserve margin targets would not be met. Without this replacement generation in place, TVA likely would need to continue to operate and maintain the KIF coal units, which would result in continued carbon emissions, significant reliability concerns, and additional costs. Delaying the 2027 retirement date for the Kingston coal units also likely would result in cascading delays for the later planned retirements in TVA's phased coal fleet retirement plan and could delay TVA's plans to integrate more solar assets onto the system.

The locational aspect (need for replacement in the Eastern Tennessee region) and the attributes (firm, dispatchable generation) of the replacement generation are just as important as the quantitative aspect (1500 MW). KIF's location on the 161-kV system near the Knoxville load center makes KIF an integral part of the system's power flows and stability. Retirement of KIF would create a large gap in the power system in the Knoxville area. Retirement of KIF without replacement generation in the area or appropriate transmission upgrades that would be needed to connect the replacement generation to the grid would significantly impact the ability to add needed load in the area, degrade the stability of Watts Bar and Sequoyah nuclear plants to a point where generation would need to be curtailed, and potentially violate NERC criteria. See FEIS Section 2.1.5. These replacement generation needs are fulfilled by Alternative A, which would provide 1500 MW of firm, dispatchable power in the Eastern Tennessee area.

The EIS evaluates in detail Alternative B, which involves the construction and operation of solar and storage facilities to replace the generation of the nine units at KIF plus demand load growth by the end of 2027. As discussed in FEIS Section 2.1.4.3, all new generating and storage facilities would require connections to the transmission system, either directly or through an interconnection with an LPC. The length of connecting transmission lines and the need for new substations and switching stations would depend on the location and capacity of the facilities. Alternative B (Solar and Storage Alternative) would require substantial transmission upgrades and lengthy timeframes for the transmission work such that Alternative B would not meet the need to provide replacement generation by the end of 2027 when the KIF units would be retired. Moreover, as discussed in Section 2.1.4.2 of the FEIS, Alternative B would not provide customers in the Eastern Tennessee region with a reliable and resilient supply of electricity to meet year-round generation and meet dependable peak capacity needs for the TVA system. This is primarily due to the variability of solar power at night and on inclement days and the current short duration of battery storage.

In order to incorporate renewable generation sources to replace the capacity of the KIF coal facility or any addition of new generation, either transmission upgrades or new transmission infrastructure would be required depending on the size and location of that new generation to interconnect these resources to the grid. In the case of Alternative B, all sites, approximately 15 total (solar plus battery), that would make up the 1,500 MW of solar and 2,200 MW of battery would require transmission connection to TVA's grid, requiring significant transmission upgrades and new construction. Please see details of the transmission requirements in Section 2.1.4.3 of the FEIS. The amount of solar generation that can be presently accommodated at the Kingston Reservation, based on the acreages available to install solar panels, is 3 –4 MW. There may be opportunities for additional solar development within the Kingston Reservation in the future, but these opportunities will not be available in time to meet the deadline to replace the generation provided by KIF. Potential areas for future consideration would greatly depend on the D4 schedule of the coal plant as well as future regulatory decisions in ash management and would be subject to additional NEPA review.

The assertions made by commenter based on the Grid Strategies (July 2023) report have been addressed in the response prepared by Concentric Energy Services. This response, which also addresses the report prepared by Applied Energy Clinic (June 2023), is included in Appendix N.

As summarized in Section 2.1 of the FEIS, TVA has considered the impacts of the IRA on the alternatives assessed, as provided in Appendix B. While the IRA would provide incentives for renewable and storage options in the long run, those provisions are of limited applicability with respect to the choices TVA faces at KIF since the replacement generation must be in place and operational by the end of 2027 when KIF is retired. As explained in Section 2.1.4 of the FEIS, the transmission upgrades necessary for the implementation of Alternative B (Solar and Storage) would take 8 to 9 years to complete, making the 2027 operational date unachievable. TVA's solar prices for the next few years are informed by recent market offers, which remain elevated due to supply chain risks.

Additionally, supply chain constraints have created significant challenges for installation of new solar generation. TVA has been implementing solar generation and as of April 2023, TVA has over 2,900 MW of solar capacity, both operating and contracted, and continues to work towards the goal of the addition of 10,000 MW of solar generation. The solar market factors outlined in Section 1.2.3.3.1 are current real-world issues TVA is facing in implementing solar and would be factors that, in addition to the needed transmission updates, would prohibit solar from being implemented in a timely manner to be utilized as a replacement generation for Kingston. TVA is experiencing delays of up to 3 years implementing current solar projects due to supply chain issues.

10. Despite TVA's claims that "transmission-related time constraints" justify making a decision based on an incomplete assessment riddled with unaddressed miscalculations, it is concerning that TVA is willing to allocate resources towards committing to decades of natural gas purchases without considering the potential risks and uncertainties associated with gas plants, especially in extreme weather events. Recent events have clearly demonstrated the vulnerability and instability of gas plants in such conditions. Considering the supply chain limitations that apply even more strongly to natural gas compared to solar energy, it raises questions as to what evidence TVA has in asserting that natural gas will remain affordable or readily available, especially in light of recent freezes that have highlighted its unpredictability.

Moreover, it is worth noting that numerous solar projects are proceeding and being successfully completed under similar time constraints and policy conditions. Therefore, it is unclear why TVA has not conducted a thorough investigation into the detailed project costs associated with solar energy given that the assessment and analysis conducted for Alt. B is far from comprehensive. Without such investigation, it is challenging to understand how TVA arrived at the conclusion that pursuing solar energy under the given circumstances would be excessively difficult. TVA's response appears to show a disproportionate concern for the solar panel market while neglecting to acknowledge the potential issues related to known spikes and shortages in the natural gas market.

Furthermore, TVA failed to incorporate current tax incentives into their calculations, which, if properly considered, could potentially favor Alt. B. This selective approach in the EIS seems to focus solely on economic trends and policies that could impact the sustainable option (Alt. B) while overlooking potential shortages and exploitative pricing associated with the high-pollution option (Alt. A). To ensure a fair and comprehensive evaluation of both alternatives, it is imperative that TVA considers concerns for both alternatives and includes the potential impact of gas market fluctuation and current tax incentives for solar in their project proposal calculations. (Commentor: Megan Maloney)

Response: The 2019 IRP and KIF EIS account for risks and uncertainties associated with gas pricing. TVA actively monitors changes in demand, resource costs, and commodity prices. Additionally, the IRP addresses risks and uncertainties by actively evaluating the target power supply mix, which provides ranges on resource types to consider and was formulated based on a variety of inputs such as changes in gas prices. The FEIS incorporates updated solar and storage pricing that reflects actual offers through TVA's RFP process and incorporates considerations relating to the IRA. The gas price forecast used in the FEIS and its comparison to the ranges studied in the 2019 IRP are included in Appendix B. The assumptions underlying these analyses are also identified in Appendix B.

TVA acknowledges that pandemic and supply-driven volatility are impacting near-term gas prices, but forecasts overall lower fundamental gas prices compared to the 2019 IRP. Further, the ability to utilize Ultra Low Sulphur Diesel (ULSD) as an emergency backup fuel for a limited number of hours for the Aero CTs, and as described in Section 2.1.3.2.2.3 helps provide another layer of resiliency to the overall project.

TVA, as detailed in response to *Comment No. 9* and in Section 1.2.3.3.1 of the FEIS, is experiencing supply chain issues with current solar projects and is experiencing long lead times (up to 3 years) meeting current demand. Although there is hope this will improve in the coming years, it is one factor that likely would prevent Alternative B from meeting the 2027 need for replacement generation for the retiring KIF. Please see the response to *Comment No. 9* regarding additional IRA updates to the FEIS.

11. In section 1.2.4 of the DEIS, TVA states that failure to retire all 9 KIF units by 2027 would result in "cascading delays for the later planned retirements in TVA's phased 2035 coal fleet retirement plan." In a supplemental or final EIS, TVA needs to provide details for which additional coal retirements would be delayed and why, with 4 years notice, the order of coal retirements cannot be adjusted to accommodate continued operation of some KIF units to allow for integration of renewable and storage resources. (Commentor: Southern Alliance for Clean Energy [SACE])

Response: Developing a plan to systematically replace coal plants reaching end-of-life allows for more effective and proactive management of financial, logistical, and workforce impacts. This systematic planning, which began after the completion of the 2019 IRP, resulted in the evaluation of engineering end-of-life dates for aging fossil units to inform long-term goals. Substantial performance and cost risk is carried by operating a coal fleet reaching end of its useful life. The end-of-life for KIF is estimated at 2027. TVA also needs to retire KIF in its entirety to comply with EPA's ELGs. See FEIS Section 1.2.2.1. As discussed in more detail in FEIS Section 1.2.2.2, KIF and CUF are scheduled to be retired sooner due to KIF's high cost and the deteriorating condition of its equipment and CUF's lack of flexibility, while Shawnee and Gallatin are scheduled to be retired later because they are in relatively better condition. A delay in the schedule for KIF could impact workforce and construction availability for replacement generation for TVAs' remaining coal plants, Gallatin, and Shawnee, thereby delaying the retirement dates for those facilities. Thus, delaying the KIF coal retirements would have the cascading effect of delaying the Gallatin and Shawnee retirements. Retirement of just a portion of the 9 KIF coal-fired units is not practicable. Notable major components that are in poor condition at KIF include oil filled transformers, steam turbines, excitation systems, and boilers. Major system and equipment upgrades would also be needed to meet environmental regulatory requirements from the ELG rule. Further, delaying retirement of one or more of the 9 KIF units would affect TVA's decarbonization plans and the integration of renewables onto the grid.

12. Of particular significance is TVA's justification for favoring an alternative (Alt. A) that has demonstrated failure in regions like Texas and DC, particularly under the new-normal weather conditions. This raises questions as to why TVA would disregard the option (Alt. B) that has proven effective in preventing rolling blackouts in Texas. TVA should provide a robust

justification for their preference, considering the performance and reliability of each alternative under real-world conditions. (Commentor: Megan Maloney)

Response: Alternative A is the lowest-cost alternative and supports high reliability while greatly reducing carbon emissions compared to the No Action Alternative. See Section 2.4 of the FEIS. The proposed CC/Aero CT Plant would be constructed on a TVA-owned brownfield site, largely leverage existing transmission infrastructure, and would support East Tennessee grid stability. The firm, dispatchable power provided by Alternative A is needed to ensure that TVA can call on the generating capacity year-round, particularly during peak load events (i.e., periods of maximum electricity demand from customers), to provide a reliable and resilient supply of electricity to its customers. Alternative A is a mature, proven technology and could be built and operational sooner than the other action alternatives, which reduces economic, reliability, and environmental risks, and would also be designed to accommodate future implementation of alternative fuels.

After Winter Storm Elliott, TVA completed several actions to strengthen assets and to increase the resilience of generating facilities to extreme weather conditions. The After-Action Report (Winter Storm Elliott), which has been made publicly available and is included as Appendix C, provides recommendations relating to energy supply, load forecasting and operations, energy protocols, and customer and stakeholder engagement. These actions will help increase the resilience of generation facilities, including any facilities constructed under Alternative A, to extreme weather events. Further, the dual-fired capability of the Aero-derivative CTs that are part of Alternative A would also help bolster the resiliency of the grid during extreme weather conditions.

13. The document should justify the schedule Alternative A by including the timeline for permitting, building, testing, and bringing online the gas pipeline and the associated equipment. The DEIS states that the equipment needs to be in place and operational by the Kingston retirement date of 2027. The decision favoring Alternative A assumes that the completion time is significantly lower than the 8-9-year time frame cited for permitting and constructing new utility-scale solar and associated transmission capability. The DEIS assumption that permitting, and construction for alternative A can be completed in 4 years requires a detailed timeline that stakeholders can follow. (Commentor: Citizen's Climate Education)

Response: Alternative A offers the benefit of being located at an existing TVA Reservation where a great deal of site characterization (including environmental resources) has been performed over the operational history of KIF as well as in recent years. As such, TVA has the information necessary to employ avoidance measures in preliminary site design for some environmental resources, thus alleviating or reducing the need for certain permits. The construction timeline for a Combined Cycle/Aero facility is typically scheduled within a three-year window. This timeframe is supported by both TVA's previous project experiences as well as standard durations experienced within the industry. Permitting activities requiring the longest lead times include construction stormwater and air permitting; these permitting activities must be completed prior to earth-moving and air emission equipment installation. Based on TVA's past project experiences, permitting activities are expected to be completed prior to conducting such earth-moving or equipment installation activities.

TVA's in-depth project experience coupled with Tennessee Department of Environment and Conservation's (TDEC) prescriptive regulatory timeframes inform the scheduling efforts for Alternative A. The Enbridge / East Tennessee Natural Gas proposed "Ridgeline Expansion Project" is currently in the FERC review process (CP23-516). FERC has issued a Notice of Intent to Prepare an Environmental Impact Statement indicating that its DEIS would be issued in February 2024, followed by issuance of its

FEIS on September 20, 2024, and a 90-day Federal Authorization Decision Deadline of December 19, 2024. The proposed in-service date for the project remains November 1, 2026, pending FERC authorization.

If Alternative B were selected for generation replacement, each solar site would also have to be reviewed and permitted appropriately. However, in contrast to Alternative A, Alternative B could not be made operational by the KIF retirement date of 2027 due to the need for extensive transmission requirements as detailed in Section 2.1.4.3 of the FEIS and due to supply chain issues as noted in Section 1.2.3.3.1. The solar sites under Alternative B would likely be built at various locations in East Tennessee necessitating extensive transmission upgrades to connect each of these sites to the transmission grid. Please see response to *Comment No. 9* addressing additional solar/renewable resources on the Kingston Reservation.

14. TVA has skewed the purpose and need such that it favors the gas alternative. In doing so TVA has also limited which additional alternatives it might have considered, such as distributed energy and storage and energy efficiency. (Commentors: On Behalf of 37 Climate, Justice and Community Organizations)

Response: The purpose and need identified does not inappropriately limit the alternatives considered in this EIS. The 2019 IRP, which was a comprehensive study of how TVA can best meet the future energy demand in its power service area, evaluated use of a target power supply mix comprised of: the addition of up to 500 MW of demand response and 2,200 MW of energy efficiency (demand-side options); 4,200 MW of wind; 5,300 MW of storage; 8,500 MW of combustion turbines; 9,800 MW of combined cycle; and 14,000 MW of solar by 2038. See FEIS Section 1.2.2.1. The target power supply mix in the 2019 IRP appropriately accounted for different generation resources and includes distributed energy and storage and energy efficiency.

The Kingston EIS, which tiers from the 2019 IRP EIS, considers one project under the target power supply mix—the retirement of KIF coal-fired units and replacement generation—and its purpose and need statement is appropriately specific to that project. As outlined in TVA's Aging Coal Fleet Evaluation, the KIF, in its current condition, reaches the end of its useful life in 2027. As such, the retiring coal generation from the plant must be replaced with firm, dispatchable power by the end of 2027. Firm, dispatchable replacement power is of paramount need in preserving the reliability and resiliency of the power supplied over the grid. The EIS purpose and need statement appropriately allows for consideration of multiple options for replacement generation, including a gas alternative and a solar and storage alternative, both of which are evaluated in detail in the EIS. The gas alternative provides TVA replacement power that has the same attributes – firm, flexible, and dispatchable – as the power from the coal plant that would be retired. These attributes for replacement power are necessary to be able to preserve the reliability and resiliency of the electric grid in the Eastern Tennessee area. The system in this area relies on local generation to support the load, especially under fault conditions. As TVA moves away from large coal plants towards more inverter-based generation, such as solar, firm and dispatchable generation near large load areas will help maintain system stability and reliability. The gas alternative would help TVA integrate vast amounts of solar – 10,000 MW – onto the TVA electric system. The 2019 IRP identified the need for additional CC and CT generation to meet TVA's long-term goal of integrating 10,000 MW of solar onto the grid by 2035. The 1500 MW of generation from Alternative A would replace the KIF generation with a reliable and resilient power supply and put TVA in a better position to integrate large amounts of solar onto the grid without compromising the reliability of that grid in the Eastern Tennessee region.

In contrast, among other challenges, Alternative B (Solar and Storage Alternative) would require substantial transmission upgrades and lengthy timeframes for the transmission work such that Alternative B would not meet the need to provide replacement generation by the end of 2027 when the KIF units would be retired. Moreover, Alternative B would not provide the firm, dispatchable generation needed to meet year-round reliable and resilient power supply.

Although distributed energy and storage and energy efficiency are already accounted for in the target power supply mix identified in the 2019 IRP, TVA also evaluated these resource alternatives in the EIS. See FEIS Section 2.1.5. Ultimately, these resource alternatives were not carried forward for more detailed review in the EIS because they would not meet the purpose and need for this project.

15. The DEIS states in the purpose and need for the proposed action that there is a 2027 timeframe to decommission the KIF units and have replacement generation in place. The stated reasons are the anticipated costs of operating and maintaining the KIF coal units beyond their planned retirement date, significant monetary investment to comply with the EPA's 2020 Steam Electric Effluent Limit Guidelines (ELGs), operational and reliability risk due to the deteriorating condition of the coal units, and "cascading delays" in TVA's phase coal fleet retirement plan.

The EPA recommends the DEIS fully disclose the assumptions behind the 2027 decommissioning timeframe identified in the purpose and need, including whether the assumptions underlying these timeframes are consistent with recent significant changes in the energy markets and statutory and regulatory developments, notably the IRA.
The EPA also recommends that the DEIS quantify or provide additional information related to its statement in Section 1.2.4 that delaying the KIF retirement will require additional costs and increase risk.

The EPA recommends greater disclosure given the 2027 timeframe substantively narrowed the purpose and need and thus limited the consideration of alternatives and available mitigation options in the DEIS. The DEIS states that Alternative B does not "fully meet" TVA's purpose and need for firm, dispatchable generation by the end of 2027 due to transmission-related time constraints (DEIS Section 1.2.2). If only the preferred alternative fully meets the purpose and need, that indicates that TVA may have defined the purpose and need too narrowly. Additionally, the DEIS identified the 2027 timeframe as a rationale for excluding multiple alternatives from further discussion, such as a blended alternative that includes greater renewable energy generation combined with a smaller amount of natural gas (Section 2.1.5). (Commentor: USEPA)

Response: There are a number of drivers for the 2027 timeframe identified in the purpose and need statement. As discussed in response to *Comment No. 9*, one of the key drivers is the need to retire the KIF coal units in 2027 consistent with TVA's phased 2035 retirement plans for the coal fleet, which will avoid cascading delays for retirements of other coal units within the TVA system. See response to *Comment No. 12*. Another key driver for the 2027 retirement date for the KIF coal units is the decreasing reliability of the units and continuing degradation of the KIF equipment. Notable major components in poor condition at KIF include oil filled transformers, steam turbines, excitation systems, and boilers. In addition, the ELG regulations require costly controls or retirement and are one of the main drivers for retirement of KIF in 2027.

TVA is prioritizing its compliance with these guidelines and is therefore retiring KIF before 2028. If KIF does not retire by 2028, it would have to install new technologies and systems to meet the rule's limits based on chemical precipitation + biological treatment for FGD wastewater and a high recycle rate system for bottom ash transport water (BATW).

The KIF NPDES permit has been modified to reflect KIF's participation in the retirement subcategory of the 2020 ELG rule. TVA is planning for replacement generation by the end of 2027, and TVA is aware that there is flexibility with respect to the ELG rule for running the plant to the end of 2028 with appropriate notice to the regulatory agencies. TVA is aware of the flexibilities available in the rule. The plan is to comply with the ELG regulations, and the allowed flexibilities will only be used if there are delays in retiring the plant. It is not appropriate to plan to operate the plant under some scenarios, which would include operating out of compliance with the ELG rule.

Please see response to *Comment No. 3* and *No. 9* concerning the timing of the IRA credits and the updates to incorporate these IRA credits.

16. TVA justifies its obsession with building new gas generation "to enable solar" by invoking its endlessly repeated mantra that it "requires firm, dispatchable" power. However, when TVA instituted rolling blackouts during winter storm Elliot in December 2022, it was this supposedly firm, dispatchable gas and coal technology that failed to dispatch! It is important to note that a sufficient mix of hydro, solar, wind, battery storage, and Virtual Power Plant (VPP) also constitutes a firm, dispatchable power resource. TVA acknowledges in this DEIS that solar paired with storage provides firm, dispatchable power, but cites a US Energy Information Administration's (USEIA) projection of a cost of $128.84 Levelized Cost of Storage brought on-line in 2027 as being too expensive to meet its least cost planning mandate. However, Lazard, another highly respected energy industry forecaster with a track record of more accurate energy cost projections reports a cost of a 50MW 4-hour battery paired with a 100 MW solar PV system of $110-$131 unsubsidized and $65-$91 subsidized. These costs are anticipated to fall further going forward. TVA seems to be refusing to apply the cost savings of the IRA Act to justify alternative A as its preferred alternative. (Commentor: Joe Schiller)

Response: Please note that the EIS has also been updated to reflect the details of and response to Winter Storm Elliot in Section 1.2.3.2. The high wind, heavy rain, and cold temperature conditions of Winter Storm Elliot on December 23, 2022, increased energy demand beyond what had been forecast, resulting in the highest 24-hour electricity demand supplied in TVA history. Although ahead of the event, TVA engaged in preparedness activities and committed a significant amount of generation resources to meet predicted demand, the storm's speed and intensity exceeded forecasts and TVA's efforts. Following Winter Storm Elliot, TVA immediately took steps to understand what happened and why and to draw lessons from the event. TVA quickly identified and completed 250 actions to strengthen assets for future events and launched a comprehensive after-action review to identify longer-term opportunities for improvement through initiating a formal After-Action Technical Review (AATR); TVA's After-Action Report for Winter Storm Elliot is provided in Appendix C.

TVA is a leader in clean energy, operating one of the largest, most diverse, and cleanest energy systems in the nation, with more than half its energy supply last year (2022) coming from clean energy sources. TVA's solar and storage costs are sourced from the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (https://www.nrel.gov/analysis/data-tech-baseline.html). NREL has decades of focused leadership in clean energy research, development, and deployment. No other institution has the long-standing expertise and breadth of knowledge that will form the foundation of the clean energy transition. Per NREL, the Annual Technology Baseline (ATB) incorporates current and projected detailed cost and performance data for renewable and conventional technologies, providing a consistent set of technology cost and performance data for energy analyses. Solar and storage costs have been updated in the Final EIS to reflect the impact of the 2022 IRA. See response to *Comment No. 31* through *Comment No. 35* regarding TVA's updated evaluation of the IRA benefits and credits.

17. TVA is not unique in its requirement to perform least-cost planning. In fact, most states have language similar to that in the TVA Act that requires least-cost planning as a part of integrated resource planning. TVA is also bound by the same NERC reliability requirements as other utilities.
Therefore, it is unclear how TVA is "situationally different" from the utilities EPA cites in comment #3 in Appendix P of the DEIS. In a supplemental or final EIS, TVA needs to explain how it is "situationally different" such that the alternatives presented in EPA's comment #3 are not applicable in its service territory and as a part of alternatives considered. (Southern Alliance for Clean Energy)

Response: TVA is situationally different from the other utilities in EPA's comment because TVA is constrained in its decision-making by its statutory obligations to engage in least-cost planning and the provision of reliable, affordable electricity to the 10 million people of the Tennessee Valley Service Area. Further, the situational differences from the other utilities cited in EPA's comment also arise from the purpose and need of TVA's proposal which is to retire and replace the Kington coal generation by the end of 2027. The technologies in the cited examples cannot be implemented by 2027, are not adequately demonstrated on a commercial scale, or would not provide firm, dispatchable replacement generation to preserve reliability and resiliency needs. Additionally, TVA has programs in place that promote customer implementation of rooftop solar, uses unutilized customer solar generation to supplement grid inputs, and is evaluating the implementation of virtual power plant technologies and other customer and commercial resiliency opportunities.

TVA has committed to ensuring that the design of the Alternative A CC/Aero CT plant would enable and accommodate potential future modifications for carbon capture and the combustion of hydrogen (CC units only) as a replacement or supplemental fuel for natural gas when these technologies mature to scale. The proposed CC units under Alternative A would be designed to be 5 percent hydrogen capable at commissioning by adding balance of plant equipment that includes areas for future hydrogen storage, appropriately sized piping, and a blending station during the original construction. TVA would also purchase a CC unit capable of burning at least 30 percent hydrogen, by volume, with modifications to the balance of plant once a hydrogen source is available and can be feasibly integrated. For example, TVA would only consider burning hydrogen as a part of test burns or normal operations when it is commercially available at an acceptable chemical content that would reduce carbon emissions and be price competitive in the market at that time.

It is important to note that once a viable option for future mitigation projects is identified, TVA would conduct additional analyses to determine proposed pipeline routes, costs, storage requirements, or other needs with hydrogen fuel incorporation. TVA would analyze the site- specific impacts associated with any future mitigation that is planned as additional details become available. TVA has considered the USEPA's draft whitepaper on reducing GHG emissions from CTs (USEPA 2022b) and anticipates the efficiency, effectiveness, scalability, and economics of these systems to improve in the next several years, allowing for more informed decisions in the future when adequate storage locations or pipelines are identified for both the delivery of hydrogen and the storage or use of captured CO_2. TVA is exploring partnerships with federal agencies and peer utilities to advance the research and development of both alternative fuels and CCS technology, which could enable their use at existing or future TVA facilities. In addition to the current cost and maturity challenges with CCS, the potential geological features (i.e., karst instability and tendency to develop sinkholes) of the Kingston Reservation pose further challenges to the consideration of CCS at this site.

18. The TVA Act mandates that, in managing its electric generation system, TVA protect "the economic, environmental, social, or physical well-being" of the customers it serves. 16 U.S.C. § 831a(g)(1)(K)(ii). Congress has also mandated that, in planning for new resources, TVA must "evaluate[ ] the full range of existing and incremental resources (including new power supplies, energy conservation and efficiency, and renewable energy resources)" that can be relied on to serve "electric customers of the Tennessee Valley Authority at the lowest system cost." Id. § 831m-1(b)(1)(emphasis added); see also id. § 831a(b)(5) (setting out TVA's mission to be "a national leader in technological innovation, low-cost power, and environmental stewardship").

Given the climate emergency, and the present and threatened impacts of climate change on TVA customers, the agency's plan to replace the Kingston Plant with a new fossil fuel plant and pipeline is in flat violation of the TVA Act. Indeed, under TVA's current Integrated Resource Plan ("IRP"), the agency will not achieve decarbonization until sometime after 2080. Moreover, with increased reliance on gas as a replacement for coal, TVA currently forecasts that it will generate more than 34 million tons of 10 CO_2 each year in 2038. The agency already has the second highest planned gas buildout for this decade – 4 GW by 2030. (Commentor: Center for Biological Diversity)

Response: TVA's EIS, including its identification of Alternative A as its Preferred Alternative, is consistent with the TVA Act. The proposed Kingston CC/Aero CT Plant is consistent with TVA's least cost planning mandate because it would provide reliable, affordable power to TVA's customers. The first citation in the comment outlines the duties of the TVA Board relating to hearings it may conduct on issues that could have a substantial effect on the "economic, environmental, social, or physical well-being of the people of the service area." However, the TVA Act does not mandate that TVA take any particular action related to climate change, decarbonization, nor does it mandate the types of generation TVA must build. Instead, the Act requires that TVA plan for generation resources at the least system cost, a statutory mandate that TVA satisfies through its IRP process. Both as to the 2019 IRP as well as the proposed Kingston action implementing the target supply mix adopted by the 2019 IRP, TVA provided extensive opportunities for public review and comments. As to commenter's second citation relating to the application of least cost planning principles in energy planning, TVA evaluated the full range of existing and incremental resources in coming up with the target supply mix of the 2019 IRP. The proposed TVA action at Kingston implements the 2019 IRP by adding CC and CT generation at Kingston consistent with the target supply mix in the IRP. Likewise, TVA's gas buildout is consistent with the 2019 IRP and is essential to the integration of 10,000 MW of solar by 2035.

19. The capacity expansion plan on page 7 of the Aging Coal Fleet Analysis from May of 2021 is the latest capacity expansion plan that TVA has made public. Of the solar included in this plan, 74% of all solar capacity that TVA plans to install through 2026 is for corporate customers, either for data centers or through its Green Invest program. The DEIS implies, but does not state outright, that the solar in TVA's Alternative B is in addition to planned additions that include a target of 10,000 MW by 2035. Stated another way, the 10,000 MW of solar by 2035 that includes the solar presented in the capacity expansion plan in the Aging Coal Fleet Analysis document takes precedence over the solar TVA would plan itself to replace KIF. In a supplemental or final EIS, TVA needs to be clear about how much solar is in the baseline analysis before it introduces its

alternatives, and how that baseline solar is impacting the assumption that it would take 8-9 years to perform transmission upgrades needed for the solar and storage resources proposed in Alternative B. If the corporate solar described in the Aging Coal Fleet Analysis capacity expansion plan is a part of this baseline, and is delaying TVA's implementation of Alternative B, TVA should include a clear explanation in its supplemental or final EIS of how this comports with the requirement in the TVA Act that projects, including those generation project proposals considered here, "shall be considered primarily as for the benefit of the people of the section as a whole and particularly the domestic and rural consumers to whom the power can economically be made available, and accordingly that sale to and use by industry shall be a secondary purpose." (US Code Title 16, Ch 12A, § 831j) (Southern Alliance for Clean Energy)

Response: The solar proposed in Alternative B is for the purpose of replacing the retiring Kingston coal generation. The system in the Kingston area relies on local generation to support the load, especially under fault conditions. The solar under Alternative B is in addition to the 10,000 MW of solar TVA plans to add to the system by 2035. The addition of 1,500 MW of solar and 2,200 MW of battery storage under Alternative B would require extensive transmission upgrades, as explained in Section 2.1.4.2.3 of the FEIS. Evaluations indicate the duration of that work would be eight to nine years, failing to meet the purpose and need to have the replacement generation in place by 2027.

The proposed action evaluated in this EIS is one piece of TVA's overall asset strategy, which blends a combination of resource technologies to allow TVA to support affordable, reliable, and cleaner energy for its customers. TVA's asset strategy already contemplates the blending of resources to provide the least-cost, optimal portfolio under a variety of future conditions, including the addition of 10,000 MW of solar by 2035. As discussed in detail in FEIS Section 1.2.2.1, this action is a specific, discrete component of that asset strategy and is consistent with the need established by the 2019 IRP to establish new capacity in the TVA region, increase reliability and flexibility, increase energy efficiency, and meet TVA energy production goals.

20. In December 2022, TVA experienced high winter peak demand and many outages and derates at coal and natural gas plants due to extreme winter weather, called "Winter Storm Elliott," which caused TVA to implement rolling blackouts into midday on two separate days. As climate change is likely to increase the frequency and severity of these once-rare events, and these events are likely to continue to impose fuel and equipment failures for natural gas plants in particular, TVA should include in a supplemental and final EIS an explanation of how each alternative would have fared under the circumstances experienced in December 2022. (Southern Alliance for Clean Energy)

Response: TVA's After-Action report for Winter Storm Elliott identifies several actions taken relating to TVA's generating assets that would harden these assets and better protect them against future events of this kind. The opportunities identified in the After-Action report would be implemented across all existing impacted TVA facilities, including some natural gas plants, as well as any future plants to strengthen assets from future extreme weather events. Further, the dual-fuel capability of the aeroderivative component of the proposed CC/Aero CT Plant would provide further resiliency against extreme weather events.

The EIS has also been updated to reflect the details and response to Winter Storm Elliot in Section 1.2.3.2.

NEPA PROCEDURES AND COMPLIANCE

NEPA Procedure and Regulatory Compliance

21. The DEIS fails to acknowledge the commitments TVA has already made to pursuing its preferred alternative. In August 2021, TVA executed a precedent agreement with ETNG for the methane gas supply that would fuel the new plant TVA has proposed to build under Alternative A. The agreement—to the limited extent it has been made public—does not appear to leave any option for TVA to walk away if, after finishing the NEPA process, the agency decided not to select Alternative A. The DEIS makes no mention at all of the precedent agreement.

In December 2022, TVA executed a contract with GE for turbines and other equipment needed for proceeding with Alternative A. As with the precedent agreement, key provisions about the extent of what TVA has already agreed to have not been made public. What is evident, however, is that the contract has the effect of "locking in" aspects of the deal struck between TVA and GE for equipment needed under Alternative A.

For the agency's review to actually aid in decision-making—and to therefore comply with NEPA's mandate—the review must be completed before the agency has already irreversibly committed itself to a certain outcome. Although TVA has stated that it has not made any irreversible or irretrievable commitment of resources precluding real choice at this stage, the agency has also been negotiating and executing contracts for portions of the work years before completing NEPA review. The DEIS must disclose the extent to which TVA has already predetermined the NEPA process's outcome. <u>TVA does not explain why it could not have acted sometime in the past two years to keep Alternative B as a real possibility.</u> In order to ensure that Alternative A would be able to meet the purpose and need timeline, TVA began negotiations with ETNG two years ago so that preparation and review for the pipeline project could begin. TVA signed a precedent agreement with ETNG in August 2021—only a month after TVA was accepting comments on its Notice of Intent to prepare an EIS for the Kingston Fossil Plant Retirement. For Alternative A, TVA made arrangements to keep its preferred project timeline on track even before a final decision was made. But TVA refused to take similar action for Alternative B, further underscoring TVA's precommitment to the gas plant in Alternative A and TVA's refusal to take seriously Alternative B, or any clean energy alternative. " (Commentors: SELC and Conservation Groups)

Response: Under NEPA and its implementing regulations, the agency must address in the EIS "any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented." 42 U.S.C. § 4332(C)(v); 40 C.F.R. § 1502.16(a)(4). This requirement does not prevent the agency from taking steps to prepare for an alternative if it is selected. Further, the agency is not required to take equivalent steps to implement other alternatives. TVA started the NEPA review for this proposal at the appropriate time after the completion of the 2019 IRP and the Aging Coal Fleet Evaluation, which pegged the end-of-life for KIF at the end of 2027.

The EIS appropriately discusses potential "irreversible and irretrievable commitments of resources" associated with each of the action alternatives. See FEIS Section 3.21. Neither the ENTG Precedent Agreement nor the contracts with GE constitute an irretrievable commitment of resources for the Proposed Action. The Precedent Agreement that TVA and Enbridge executed in August 2021 defined the terms and conditions under which the potential pipeline project would be developed over time. The Agreement is structured as a "stage-gate" agreement that specifies certain conditions that must be satisfied before development work on the pipeline can advance, including completion of the TVA NEPA process, TVA approval for the recommended alternative, and FERC authorization for the pipeline among others. The fact that the DEIS does not mention the precedent agreement is irrelevant, as the DEIS studies the environmental effects of the pipeline as required under NEPA. And TVA has not made an irreversible or irretrievable commitment of resources precluding real choice because construction of the pipeline cannot begin until all conditions defined in the Precedent Agreement have been satisfied. TVA will not become a firm shipper on the new facilities until the pipeline is completed and placed into service upon authorization from FERC, and TVA has made no commitment to gas supply. Likewise, no commitments were made in TVA's December 2022 contract with GE that would irreversibly and irretrievably commit TVA to the Kingston project. The equipment contract was initiated in December 2022 as it requires a long lead time, and since it could be used at a different TVA project site in the future or resold if needed, does not represent an irreversible or irretrievable commitment by TVA to the Kingston project.

22. While TVA claims that its decision in this DEIS is consistent with its 2019 Integrated Resource Plan (IRP), TVA has already begun its next IRP. Given the monumental changes the electricity industry has experienced since the assumptions for TVA's 2019 IRP were developed, and that the decision on how to replace Kingston's coal units will lock TVA into a trajectory for decades to come, SACE's primary recommendation is that the Kingston DEIS be put on pause until after TVA completes its 2024 IRP. The alternatives considered in the Kingston DEIS, as well as additional alternatives, can be included as selectable resources in the 2024 IRP. Similarly, IRP modeling tools can endogenously select optimal times to retire resources, allowing TVA to evaluate the best time(s) to retire each Kingston unit relative to other coal units in its fleet based on the costs of continued operation and the potential available resource for replacement. A systematic approach to determining when to retire and how to replace each coal unit is much more in line with TVA's least-cost planning mandate than the one-off analysis it is currently undertaking where retirement dates are set, and replacements are analyzed one at a time.

Therefore, if TVA decides it must move the Kingston decision forward as a separate EIS in parallel to its ongoing IRP process, the next EIS, whether it is a supplemental EIS or final EIS, should state clearly why TVA is not including this decision as part of its IRP and why it is diverging from least-cost planning principles to continue this process as a one-off analysis. (Commentor: SACE)

Response: The Kingston EIS tiers from the 2019 IRP EIS, which continues to be effective and valid. TVA is not required, under the TVA Act or any other applicable law, to forego relying on an in-place and still applicable IRP while a new IRP is in development. The decision associated with this EIS is a specific, discrete component of TVA's blended asset strategy and consistent with the recommended target power supply mix in the 2019 IRP, which reflects the result of the least cost planning process conducted at the system level as required by Section 113 of the Energy Policy Act of 1992. The specific purpose and need animating this EIS is the retirement of Kingston at the end of its life and the replacement of firm, dispatchable generation to replace the retired coal generation. Alternative A meets this purpose and need, prompting TVA to select this alternative as the Preferred Alternative. TVA is not diverging from least cost principles in making this selection. The addition of CC/CT generation under Alternative A is consistent with the target supply mix in the 2019 IRP, and the 2019 IRP and the assumptions undergirding that IRP continue to remain valid, and TVA will continue to implement the 2019 IRP until a new IRP is in place. As confirmed on page 4 of the Concentric Report, provided as Appendix N), TVA's 2019 IRP is a strategic and forward-looking tool and continues to serve as a solid basis for guiding decision-making to ensure a reliable and cost-effective energy future. TVA is undertaking a review of the 2019 IRP consistent with its practice to review and update the IRP analysis, as needed, every 4-5 years. There is no need to delay the Kingston project pending the completion of work on the 2024 IRP.

As noted above, delaying the retirement and replacement of the KIF coal units would result in cascading delays across the system and delay TVA's efforts to meet its decarbonization goals. See response to *Comment No. 11*.

23. TVA's alternatives analysis violates NEPA by providing incomplete or misleading information that limits decision maker and public ability to make an informed comparison of alternatives. When evaluating alternatives based on economic information, the federal agency is required to provide complete and accurate information about both costs and benefits, so that the alternatives can be fairly compared. Further, NEPA requires that agencies like TVA "study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources." (Southern Environmental Law Center/Conservation Groups)

Response: TVA's analysis of each alternative and impacts for each resource can be found in Chapter 3 **of the F**EIS. This analysis includes both an evaluation of the life cycle costs and SC of GHG, where TVA's solar and storage costs are sourced from NREL's Annual Technology Baseline. Although this comment does not specify what economic information in the DEIS is "incomplete or misleading," solar and storage costs have been updated in the FEIS to reflect impacts of the IRA and to include GHG mitigation costs and considerations, as described in Appendix B.

24. TVA continues the ridiculous practice of evaluating the alternatives against the no action alternative instead of simply comparing the relative impacts of the action alternatives to each other. This allows TVA to hype the benefits of their preferred alternative while downplaying how TVA's preferred alternative A is much worse than Action Alternative B. This flawed approach is exacerbated by TVA's failure to include the upstream impacts of Action alternative A beyond the start of the new pipeline spur. Most methane and health related emissions, water pollution, and land impacts resulting from Alternative A will occur upstream of the new gas pipeline spur. This is immoral and wrong. TVA's refusal to acknowledge these effects amounts to imposing harmful impacts on people that live upstream of the ETNG pipeline but considering it okay because they are far enough removed geographically. (Commentor: Joe Schiller)

Response: Under CEQ's regulations at 40 CR 1502.14, the alternatives section should present the environmental impacts of the proposed action and the alternatives in comparative form based on the information and analysis presented in the sections of the affected environment and the environmental consequences. CEQ's regulations require agencies to include the no action alternative in the alternatives section. The No Action Alternative provides, among other things, a benchmark, enabling decisionmakers to compare the magnitude of environmental effects of the action alternatives. Under NEPA, TVA must consider effects that are both legally caused by TVA's action and are reasonably foreseeable[1]. There must be a "reasonably close causal relationship" between TVA's action and natural gas drilling in the supply region before NEPA requires that TVA analyze the effects of that regional development[2]. Upstream natural gas production is caused by a number of factors including the price of natural gas and the cost of production, and not TVA's potential selection of a CC/Aero CT Plant alternative. Moreover, East Tennessee's Ridgeline Project would interconnect with multiple interstate pipelines that connect to

[1] See Dep't of Trans. v. Public Citizen, 541 U.S. 752, 767-70 (2004).
[2] See Metro. Edison Co. v. People Against Nuclear Energy, 460 U.S. 766, 773-74 (1983).

many upstream production areas. Because upstream production is neither caused by TVA's action nor reasonably foreseeable, TVA is not required to include upstream impacts of natural gas production in its NEPA analysis. Nonetheless, TVA's LCA analysis for climate impacts accounts for upstream GHG emissions from resource extraction, production, processing, and conversion based on methodologies from NREL publications, as provided in Appendix J.

Review for Pipeline under Alternative A

25. TVA's analysis of Alternative A must fully review the air quality impacts of the proposed gas pipeline's construction and operation, including the proposed Hartsville compressor station. The construction and operation of a new 122-mile gas pipeline and associated infrastructure, including a new electric motor driven compressor station and natural gas-fired emergency turbines, is a connected action to Alternative A. TVA notes that "[o]perational emissions are expected to occur from natural gas combustion from the emergency dual-fuel turbines (to be used only when the electric-driven motor or power to supply it are unavailable), fugitives, venting, and operation of the emergency natural gas fired engine," but adds that, "[s]ince the electric motor driven compressors would be utilized during daily operation, project-specific emissions would be limited" and "impacts to air quality would be long term but minor and periodic in nature." TVA is not taking a "hard look" at the impacts of this pipeline and compressor station or making any attempt to quantify them. For example, how often have emergency turbines been used at other locations, and what were the emissions? When the emergency turbines are active, they would emit significant amounts of air pollutants, including methane, CO_2, and human carcinogens. Furthermore, electric compressor stations are vulnerable to power outages, which are relatively common and often caused by winter storms. TVA seems to recognize that power outages are a serious problem, since ETNG developed the plan for the emergency gas turbines at TVA's request. " (Commentors: SELC and Conservation Groups)

Response: Section 3.7.2.3.6 of the FEIS evaluates air quality impacts of the proposed pipeline facilities, including the proposed compressor station. The emergency turbines will be permitted to operate during testing and maintenance activities, and emergency events where the compressor station has lost power. ETNG's application[3] conservatively states that anticipated outages may be up to 500 hours per year. During these times the emergency turbines will be fully compliant with the New Source Performance Standard (40 CFR 60 Subpart KKKK) that applies to turbines. Total emissions from the facility will still qualify it as a minor source of air emissions considering the maximum operation of the emergency turbines (which is not expected to occur), and these operations are not expected to result in significant amounts of air emissions or impacts.

26. The DEIS's analysis of the Kingston pipeline's impacts on public lands is unsupported and premature. (Commentor: SELC)

Response: The analysis of the proposed pipeline impacts on public lands has been updated in the FEIS, see Sections 3.9.1.3.6 and 3.9.2.3.6. As noted in the above FEIS sections and more specifically listed in Table 3.9-1, the public lands affected environment has been detailed and impacts evaluated for the pipeline in the EIS. The gas pipeline is integral to TVA's proposed action of construction and operation of the CC/CT plant and therefore the effects of the pipeline are considered in detail in the EIS. In addition, because the pipeline proposed by ETNG requires authorization from FERC, it is the subject of a separate

3 Available online at https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20230823-5107

EIS being prepared by that agency. ETNG's construction of the natural gas pipeline will not begin until FERC's NEPA review is complete, and FERC issues a Certificate of Public Necessity under the Natural Gas Act.

27. The DEIS cannot rely on unfinished, non-NEPA documents to evaluate impacts related to the pipeline. The problem is, first, that the Draft Resource Reports remain full of gaps and missing information, as described in detail by FERC in a letter conveying 176 comments on issues in the Draft Resource Reports identified by FERC itself, EPA, and NPS.

Moreover, many of those comments describe gaps that could not be filled with desktop reviews and are not the kind of information TVA says ETNG provided. The other agencies' comments include, for example, asking ETNG to provide the wholly-omitted "Horizontal Directional Drill Monitoring, Inadvertent Return Response, and Contingency Plan (listed as 'not included in this draft')"; to explain why "Section 3.4.1 (Ecoregions) states that no known special plant communities have been identified by resource agencies… [but] table 3.6-1 states that anticipated Project impacts and habitat assessments for federally and state-listed species is 'TBD' pending consultation"; and to add "[t]he information and analyses recommended in the EPA's scoping comments, most of which was not included in this document, including upstream and downstream GHG emissions estimates."

In no case does NEPA allow an agency to satisfy its present NEPA obligations by tiering, adopting, or otherwise deferring to a self-serving, yet-to-be completed, non-NEPA document authored by an applicant for a federal license. Without proper environmental review in the DEIS itself, members of the public are less able to fully evaluate TVA's actions and make fully informed comments. TVA's attempt to incorporate ETNG's material into the DEIS violates NEPA's "rule of reason," which asks "whether an EIS's deficiencies are significant enough to undermine informed public comment and informed decision making." A DEIS is meant provide a springboard for public comment, and "[a]n environmental analysis that occurs too early in the planning process may lack 'meaningful information' necessary for informed consideration." CEQ's NEPA regulations state that agencies must "[i]dentify environmental effects and values in adequate detail so the decision maker can appropriately consider such effects and values alongside economic and technical analyses," and that when "a draft statement is so inadequate as to preclude meaningful analysis, the agency shall prepare and publish a supplemental draft of the appropriate portion." (Commentor: SELC)

Response: The EIS evaluates the impacts of the ETNG pipeline as a related action. Notwithstanding the fact that FERC is preparing its own EIS for the pipeline and related facilities, TVA considers the impacts of the pipeline and related facilities in detail in this EIS under Alternative A. This EIS appropriately uses the information that is currently available to fully consider the environmental impacts of the plant and the pipeline. See Kentucky Coal Ass'n., Inc. v. T.V.A., 804 F.3d 799, 806 (6th Cir. 2015). TVA included an analysis of the related proposed pipeline associated with Alternative A in the DEIS, utilizing site-specific results of field surveys, and where site-specific data were not available, TVA employed a conservative desktop-based geospatial analysis or "worst-case" scenario based on a 200-foot-wide construction footprint for the proposed pipeline and other aboveground facilities. The Final EIS has been updated to incorporate updated site-specific information provided in final Resource Reports submitted to FERC. TVA independently reviewed the information provided by ETNG in this EIS.

28. TVA must evaluate whether FERC's generic procedures will effectively protect the specific streams at issue. ETNG insists that the project will be constructed in conformance with, among

other things, the 2013 FERC Wetland and Waterbody Construction and Mitigation Procedures. In its NEPA review, however, TVA must take a hard look at the environmental effects of using those procedures.

> **A 2015 journal article authored by a FWS biologist examined FERC's Wetland and Waterbody Construction and Mitigation Procedures document and concluded that its national scope and general nature does not provide sufficient detailed and specific information at a regional level to adequately protect aquatic ecosystems with numerous species in complex geographic and ecologic settings.**

While the FERC Procedures do address some predictable pipeline impacts, especially during construction, the guidance does not address the longer term stream response potential, which is highly dependent on characteristics of the stream system rather than the pipeline. Therefore, depending upon the crossing locations, stream and catchment characteristics, timing, extent of activities, and application of Best Management Practices (BMPs—construction conservation measures intended to reduce impacts to the environment), impacts to aquatic species will vary but may include simplification of habitat, loss of aquatic species passage, removal of spawning gravel, increased sediment and turbidity, loss of side channels, disconnection from the floodplain, or change in hyporheic flow patterns (Reid *et al.*, 2002b). These impacts may occur at the project site or may propagate upstream, downstream, or laterally into the floodplain.

Given the generality of the Wetland and Waterbody Construction and Mitigation Procedures, TVA must take a hard look at the characteristics of each of the specific streams at issue during its environmental review to identify additional protective measures necessary beyond those prescribed in the general procedures. (Commentor: SELC)

Response: FERC certification under the Natural Gas Act is required for the pipeline, and FERC is preparing an EIS on the pipeline to inform its decision. In addition, TVA is treating the pipeline as a related action for purposes of its review of Alternative A. In the DEIS the analysis of the pipeline was a combination of both desktop and site-specific analysis and impacts from the pipeline were detailed in Chapter 3. The desktop analysis has been updated in the FEIS as additional site-specific details have been finalized and are described in detail, providing a comprehensive analysis of the potential impacts from constructing and operating the pipeline. The FEIS includes a detailed analysis of the pipeline's potential impacts to aquatic resources, see FEIS Section 3.6.1.1.2.6, Section 3.6.2.1.2.6, and Section 3.6.3.3.2.6 as well as to aquatic life, see FEIS section 3.8.3.1.2.6, accounting for ETNG's plan to comply with FERC's Wetland and Waterbody Construction and Mitigation Procedures (FERC 2013a, 2013b).

EFFECTS OF EVOLVING REGULATORY ENVIRONMENT

2020 Effluent Limitation Guidelines (ELGs)

29. The document clearly describes that "... the aging TVA coal fleet is among the oldest in the nation . . ." resulting in the need to replace the fleet (DEIS Summary, pg. iv). Another reason shows that TVA is required to close coal-fired power plants by certain deadlines. The summary should include this regulatory requirement as another driver for decision making over the next 5 years to emphasize the importance of this timeline:

- **DEIS Pg. 81 includes the statement, ". . . and before significant water treatment investments become necessary under recent and anticipated new regulations such as the Effluent Limitation Guidelines (ELGs)."**

- **Appendix C, pg. C-3 provides information on The Coal Fleet End-of-life Evaluations. (Commentors: Citizens' Climate Education)**

Response: TVA has clarified in the Purpose and Need and in the Introduction sections of the FEIS the regulatory drivers that are a part of the decision to retire KIF in the 2027 timeframe. Additional information is presented in the FEIS for proposed ELG guidelines in Section 2.1.2.1 and for the 2022 Inflation Reduction Act in Section 1.2.3.3.1.

30. "The DEIS notes that "a significant monetary investment would be required to comply with the requirements of the 2020 ELGs Operation beyond 2027" which "would also inject operational, and therefore reliability, risk back into the TVA system due to the deteriorating condition of the coal units" and later estimates that $665 million in upgrades will be required. The Steam Electric ELGs promulgated in 2020 requires, where applicable, the permanent cessation of coal combustion to be completed by December 31, 2028, not 2027. In early 2023, the EPA proposed revised Steam Electric ELGs, 88 Fed Reg 18824. The proposed 2023 ELG rule includes implementation flexibilities where appropriate. Recognizing that some coal-fired plants were in the process of closing, the 2023 proposed rule includes flexibilities that allow the plants to continue to meet the 2020 requirements instead of the new requirements contained in the 2023 proposed rulemaking. Furthermore, a plant that is in the process of closing and has filed a Notice of Planned Participation (NOPP) to permanently cease coal combustion may be able to modify the retirement schedule in the NOPP if the facility is unable to retire a plant by December 31, 2028, due to reliability concerns.

Given that TVA has until 2028 to retire the Kingston plant in addition to the time flexibilities included with the 2023 proposed rule, TVA should explain how they estimated the costs of upgrades as well as an acknowledgment of any uncertainty because these regulations are not finalized. (Commentor: USEPA)

Response: The retirement date selected for KIF was driven by several factors including the End-of-Life Evaluation and the need to implement expensive controls for ELGs to continue to operate the Coal Plant beyond the end of 2028. Several components of the coal units would need to be refurbished and replaced at considerable cost to ensure the facility's environmental compliance for operational longevity beyond 2027. Therefore, the FEIS Section 2.1.2.1 has been updated, accordingly, to clarify required ELG upgrade expenses and timing. In alignment with these considerations, TVA filed a Notice of Planned Participation to preserve the option of participating in the 2020 ELG rule retirement subcategory for facilities ceasing coal combustion by 2028. KIF's NPDES permit has been modified to incorporate the 2020 ELG retirement subcategory compliance pathway. Additionally, several components of the coal units would need to be refurbished and replaced at considerable cost in order to prolong operation beyond 2027.

2022 Inflation Reduction Act

31. Regarding Section 1.2.2 Inflation Reduction Act of 2022, TVA KIF to be decommissioned by 2027 with TVA goal of 70% carbon reduction by 2030:

- **Add additional cost-benefit analysis to explain how Alternative A, with pipeline and construction costs as well as carbon emissions from burning natural gas, can achieve this goal in less than 3 years of operations and is worth doing.**

(Commentor: Roane County Environmental Review Board)

Response: The retirement and replacement of coal generation at Kingston is one piece of the larger decarbonization effort that TVA is undergoing. New gas generation contributes to TVA's carbon reduction goals (i.e., path to ~80% carbon reduction by 2035) by enabling the retirement of the remaining coal plants by 2035, while emitting about 65-70% less CO_2 than aging coal plants. Appendix B provides the cost comparison for Alternatives A and B as compared to the No Action alternative. The social cost of carbon is considered in the life cycle analyses of alternatives discussed in Section 3.7 and Appendix J. The FEIS includes updated cost estimates that account for IRA credits.

32. The EPA remains concerned that the analysis does not fully account for expected cost decreases of renewable energy and higher future natural gas prices. The costs of renewable energy production and battery storage will continue to fall along the timeline of this project due to subsidies from the IRA and other market factors. Similarly, the price of natural gas is projected by the Energy Information Administration to be higher than estimated in the 2019 IRP. Appendix I, for instance, conducts system-wide Life Cycle Analysis (LCA) modeling to project future GHG emissions. The DEIS notes that this "system-wide LCA reflects TVA's broader asset strategy and target power supply mix set by the 2019 IRP." However, it still does not present the full assumptions that underlie the model or report the modeled distribution of future power generation.

Furthermore, the EPA recommends a more thorough comparison of the system-wide and non-system-wide LCA results, which paint a different picture of GHGs and suggest different long-term outcomes in the mix of electricity generation between the two approaches. (Commentor: USEPA, Tennessee Interfaith Power and Light)

Response: The FEIS incorporates updated solar and storage pricing that reflects recent market offers and estimated impacts from the IRA, see Appendix B. Even after accounting for impacts of the IRA, the total system cost for Alternative B would still be higher than Alternative A. Further, while incentive provisions under the IRA may result in reduction in the costs of solar and battery storage technologies in the long run, these incentives are of limited use in the short term with respect to the generation choices TVA faces at Kingston since replacement generation must be in place and operational by the end of 2027.

The system-wide LCA reflects how TVA's entire system will operate based on the decision to retire or not retire KIF and the associated replacement generation. Each alternative has subsequent impacts for other decisions in the future that are beyond the scope of the current EIS. Given this, there would be variations in simulated dispatch, which would result in differences in emissions, driven by the dynamic nature of power system modeling.

Having a diverse portfolio of resource types – coal, nuclear, hydro, natural gas, and renewable resources – and being able to use these resources in different ways enables TVA to provide reliable, low-cost power while minimizing the risk of disproportionate reliance on any one type of resource and any fuel price volatility. See Appendix B for more information on TVA's natural gas price forecast.

33. The DEIS should consider reasonably foreseeable costs, taxes, regulations, and subsidies that have changed or are reasonably likely to change before a replacement plant is built. Every cost-effectiveness analysis needed to make a least cost decision should include updated cost parameters and assumptions. Specifically, the DEIS should still include (a) the costs of reasonably foreseeable future regulations on greenhouse gas emissions; (b) the cost reductions realized because of the IRA programs; and (c) the expected changes in the costs of renewables,

energy storage, and natural gas over time. (Commentor: USEPA, Tennessee Interfaith Power and Light)

Response: The FEIS incorporates updated solar and storage pricing that reflects recent market offers and estimated impacts from the Inflation Reduction Act. See Appendix B for more information on TVA's natural gas price forecast and Section 1.2.3.3.1 for more information on IRA and solar pricing. The FEIS discusses the GHG mitigation technologies identified in EPA's proposed GHG regulations and the emissions reductions that could possibly be realized through these nascent technologies that have not yet been adequately demonstrated. See also response to *Comment No.* 32 and *Comment No.*36. Appendix B also includes a sensitivity analysis with cost estimates based on EPA's proposed GHG regulations.

34. TVA responds to NPS comment 13 (p1572): "Additionally, the tax incentive provisions of the IRA are likely to take more time to implement than is available to TVA for purposes of choosing replacement energy for the KIF Plant." As a TN resident, and a consumer in purchasing electricity from TVA, "likely" is not a good enough reason to waste our resource on a high-polluting, dangerous, expensive, and environmentally damaging option that will tie up resources in natural gas purchases for decades, especially as TVA appears to have also "likely" underestimated the cost of solar hybrid systems, which would be much more beneficial to my community, and certainly not considered the IRA credits.

TVA also appears to wipe Alt. B out of consideration because: "The Treasury Department must issue guidance to establish certain qualifications and processes for tax incentive provisions, which could take up to a year, if not longer." This guidance appears to have been issued in May, 2023. Don't leave our money on the table. We should be getting our federal tax money back into our community by implementing Alt. B using those credits. Please recalculate the comparison to include all existing and expected solar tax benefits. (Commentor: Megan Maloney, Tennessee Interfaith Power and Light)

Response: The FEIS incorporates updated solar and storage pricing that reflects recent market offers and estimated impacts from the IRA. See response to *Comment No. 33* and Appendix B.

35. TVA was deservedly criticized for not including the cost savings to alternative C solar with storage, provided in the Inflation Reduction Act (IRA). TVA continues to refuse to apply savings from the Infrastructure and IRA legislation passed in 2022 maintaining that not all the relevant tax provisions have been finalized. However, many have, and TVA should include those!

TVA also cites the Levelized Cost of Energy in the USEIA 2022 Energy Outlook Report which had not yet incorporated the implications of the Infrastructure and IRA into its modelling. It should be noted that the USEIA has a long track record of badly predicting renewable energy prices and installation. While parts of the USEIA 2023 Energy Outlook Report are now published, the levelized cost of energy (LCOE) report is not, despite being due out in March. However, the USEIA acknowledges that it still has not incorporated all the cost implications of these Laws into its modelling. However, Lazard has modelled the subsidized cost of solar PV and battery storage as stated in the previous paragraph. (Commentor: Joe Schiller)

Response: Solar and storage costs have been updated in the FEIS to reflect the impact of the 2022 IRA. TVA's solar and storage costs are sourced from NREL's Annual Technology Baseline (https://www.nrel.gov/analysis/data-tech-baseline.html). Per NREL, the Annual Technology Baseline (ATB) incorporates current and projected detailed cost and performance data for renewable and conventional technologies, providing a consistent set of technology cost and performance data for energy analyses.

Even after accounting for impacts of the IRA, the total system cost for Alternative A will still be higher than Alternative B. Further, while incentives from the IRA are expected to provide cost savings for solar and storage in the long run, these incentives are of limited applicability with respect to the choices facing TVA in the short term at Kingston.

2023 Proposed Greenhouse Gas Rule (CWA Section 111b)

36. The DEIS also does not appear to evaluate the potential implications of reasonably foreseeable air quality and greenhouse gas regulations (2023 Proposed GHG Rule) on natural gas units. The EPA and other commentors recommend including a discussion of their expected impacts, particularly in terms of costs, on the preferred alternative." (Commentor: USEPA; Citizens' Climate Education)

Response: At the time of the public issue of the KIF Retirement DEIS, the new draft GHG regulations had not been released to the public and therefore were not reflected in the document. However, updates have been made to take into account the cost of mitigation requirements in this draft rule and the site-specific emission reductions that would possibly be realized with the implementation of mitigation.

Initial plant design under Alternative A would accommodate future modifications to incorporate CCS or hydrogen co-firing when these newly emerging or nascent technologies may become commercially available in the future. The FEIS discusses the technologies, like CCS and hydrogen co-firing, that are identified in EPA's 2023 Proposed GHG regulations. TVA believes these technologies have not been adequately demonstrated for commercial use. Nonetheless, the FEIS gives consideration to these GHG mitigation measures and incorporates a sensitivity analysis with the cost of these mitigation measures using EPA and DOE information. See Appendix B for a sensitivity analysis that examines how the alternatives compare under the EPA's proposed GHG rules and concluded that if Alternative A were selected, TVA would need to pursue hydrogen co-firing or carbon capture to comply with the proposed GHG rule (if finalized as currently written). Under the No Action Alternative, TVA would need to pursue carbon capture for continued operation of the existing coal plant. The costs associated with these paths are sourced from EPA and DOE and are presented by alternative in Appendix B.

In addition to the costs associated with these potential mitigation measures, further discussion of the 2023 proposed CAA Section 111(b) rule is provided in Section 1.2.3.3.2 and a qualitative discussion of the potential impacts of the rule are presented in Appendix B.

Executive Orders and Current Administration Goals

37. The summary should highlight compliance with the Biden Administration's CO2 emission reduction goals more clearly. The appliable paragraph (DEIS pg., 363) states:

"Alternative A from generation at the Kingston site would be approximately 55 percent below 2018 CO2 emissions and 84 percent below 2008 CO2 emissions, exceeding the Biden Administration goal of 65 percent reduction in Scope 1 GHG emissions by 2035 from a 2008 baseline (TVA 2022d)."

> **Comment: The goal as stated by the Biden administration does not mention years 2018 or 2008 but refers to a 2005 baseline. It states: "President Biden issued**

Executive Order 14082 on September 12, 2022, to implement provisions from the Inflation Reduction Act. It reiterates the goal of reducing GHG emissions 50 to 52 percent by 2030 (2005 baseline), achieving a carbon pollution-free electricity sector by 2035, and achieving net-zero emissions by 2050. The EO further states that it shall be implemented consistent with applicable law and subject to the availability of appropriations." (Commentor: Citizens' Climate Education)

Response: The use of year "2035" on page 363 of the DEIS is in error. The year referenced in the FEIS has been updated to reflect "2030." With this correction, the statement on p. 363 of the DEIS (now p. 405 of the FEIS) is consistent with EO 14057, which sets a government goal of reducing Scope 1 GHG emissions by 2030 from 2008 levels. Note that this goal of EO 14057 does not strictly apply to "non-standard" federal operations which includes generation of electric power produced and sold commercially to other parties, as is the case at the Kingston site and all of TVA's power plants, per the CEQ Implementing Instructions for EO 14057.

In the DEIS overall Summary statement, on page iii, it is stated that TVA has already met a goal of EO 14082 and reduced carbon emissions by roughly 60 percent against the 2005 benchmark. EO 14057 states the goal of reducing Scope 1 and 2 greenhouse gas emissions by 65 percent from 2008 levels by 2030. Based on the Fiscal Year 2021 Federal Sustainability Report (TVA 2022i), TVA's "standard operations" have already achieved a reduction of 84 percent in Scope 1 and 59 percent in Scope 2 emissions from a 2008 baseline. In accordance with CEQ Implementing Instructions for EO 14057, "non-standard operations" which include generation of electric power produced and sold commercially to other parties, are not included in these GHG reduction goals.

The other goals of achieving a carbon pollution-free electricity sector by 2035 and achieving net-zero emissions by 2050 are discussed in Section 3.7.1.1.8.4 (Executive Orders Addressing GHG Emissions Reductions), the FEIS overall Summary Statement on p. iii, Section 1.2.2 (Integrated Resource Planning), and Section 1.2.3.3.1 (IRA of 2022).

TVA acknowledges the current Administration's climate goals as outlined in several recent Executive Orders and endeavors to support their goal to reduce emissions "to the extent permitted by law," but TVA must do so in a manner that also allows it to comply with its own statutory requirements, including the least-cost planning provisions under the TVA Act.

TVA's own climate goals align with the intent and purpose articulated in the referenced Executive Orders implemented by the current Administration, which is to reduce emissions. TVA is executing a plan to achieve a 70 percent reduction in carbon intensity by 2030 (from 2005 levels), sees a path to ~80 percent reduction by 2035, and aspires to achieve net-zero emissions by 2050.

ALTERNATIVES AND ENERGY RESOURCES

38. In the scoping period for the Kingston coal turbine retirement TVA discussed three action alternatives. In this DEIS, TVA combined Action Alternatives A (Combined Cycle (CC) gas turbine) and B (combustion turbine, i.e., peaking (CT)) from the scoping document and added an insignificant amount of solar and storage to create a new Alternative A. This modification may be a response to criticisms and suggestions from the USEPA and other commentors regarding the deficiencies of both the Kingston scoping document, but also the Cumberland coal plant DEIS and FDEIS; however, this action alternative is insufficient to assuage the concerns expressed by those commentators.

The amount of solar and storage proposed in the reconstituted Action Alternative A is insignificant and fails to address the many valid criticisms of the alternatives put forward in the Cumberland unit 1 FDEIS and the Kingston scoping document. The USEPA and others suggested TVA look at a sufficient range of possible alternatives or alternatives that combine a range of technologies. This DEIS does not do that. Note: 3 MW of solar out of 1500 MW of gas generation (0.2% does not constitute a reasonable blend of alternatives). TVA only considered Li ion battery technology which TVA has criticized as not providing sufficient storage duration, despite other longer duration battery technologies now commercially available. Lastly, TVA did not consider wind generation, energy efficiency improvements, or a variety of commercially available distributed energy resource technologies collectively referred to as virtual power plant (VPP) in a mixed technology action alternative despite its low cost and complementarity to solar.

If TVA is serious about addressing its failure to provide a mixed resources action alternative as expressed by commentors in the first Cumberland EIS and Kingston scoping document, then it would determine an appropriate ratio of gas generation necessary to backstop solar and propose an action alternative that provides this mix. If TVA is sincere in its assertion that gas is needed to enable more solar in their generation portfolio then TVA should formulate an Action Alternative that provides that mix of gas, solar and battery storage in its portfolio. TVA insists that it is taking a whole system approach to implementing solar and storage, but the range of action alternatives presented in this DEIS contradict this claim. If natural gas enables solar, then the 1500MW of new natural gas generation TVA selected for the First Cumberland coal turbine replacement as well as other new gas turbine installations elsewhere on the TVA grid should have already enabled Action Alternative B of this DEIS. (Commentor: Joe Schiller, Center for Biological Diversity)

Response: Section 2.1 of the KIF EIS provides a thorough description of the wide range of alternatives considered and the key factors and criteria that were used in development of the alternatives evaluated in detail in the EIS, including TVA's preferred alternative. See response to *Comment No. 47* on blended alternatives and responses to *Comment No. 46* and *Comment No. 54* for additional details on the alternative evaluation and selection process.

The decision associated with this EIS is a specific, discrete component of TVA’s blended asset strategy and consistent with the recommended target power supply mix in the 2019 IRP. The 1,500 MW of replacement generation needed to replace the retirement of KIF must be firm, dispatchable power and must be operational by 2027 so as not to leave TVA short on required generation and capacity to meet system demands and planning reserve margin targets. Firm, dispatchable power ensures that TVA can call on the generating capacity year-round, particularly during peak load events – those periods of maximum electricity demand from customers, typically late afternoon in the summer and before or around dawn in the winter. Firm, dispatchable power provides a backstop for solar resources that are unable to or are very limited in their ability to meet maximum demand that occurs in the pre-daylight or early-daylight hours of the winter season, and also improves the reliability and resiliency of the electric grid. Long-duration storage technology is currently being studied by TVA for further evaluation and potential deployment in the future.

Alternative A includes gas generation and solar and storage facilities. The solar is in addition to the 10,000 MW of solar that TVA plans to add. The size of the solar and battery included as part of Alternative A were selected based partly on the current availability of land on the reservation. The solar would be utilized to serve station service needs. See *Comment No.9* that further addresses additional renewable resource on the KIF Reservation. These generating assets can be constructed at a brown-field site leveraging existing transmission to support East Tennessee grid stability.

TVA also considered other blended alternatives, including blended alternatives with a substantial renewable component or that combine a lower amount of natural gas with solar and storage. See EIS Section 2.1.5.2. Ultimately, TVA did not carry forward such blended alternatives for more detailed review in the EIS because they would not meet the project purpose and need to provide 1500 MW of firm, dispatchable power by 2027.

39. TVA's intention to replace the Kingston Plant with a Combined Cycle Combustion Turbine ("CC") fossil gas plant and 16 dual-fuel Aeroderivative combustion turbine ("CT") fossil gas plants ("CC/Aero CT Plant") – and concomitant refusal to even consider viable alternatives that would maximize energy efficiency and distributed energy – is untenable, as it fails to even address the most pressing issue today: the urgent need to rapidly transition away from all fossil fuels toward a renewable and just energy economy to avoid the worst impacts of the climate emergency and address the disproportionate harm experienced by environmental justice communities from continued reliance on fossil fuels. Given the latest climate science, and the significant climate change harms already occurring in TVA's territory, TVA must, at minimum, fully address a NEPA alternative that would offset the Kingston Plant's electricity production with distributed energy resources ("DER"), storage, energy efficiency improvements, and demand response. Moreover, the TVA Act demands that TVA move forward with this alternative. (Commentor: Center for Biological Diversity)

Response: TVA's decision to retire coal capacity and the alternatives being considered is consistent with the 2019 Integrated Resource Plan target power supply mix. The target supply mix adopted by the TVA Board in 2019 is consistent with least-cost planning obligations in 16 U.S.C. Section 831m-1, which does not, as this comment suggests, require TVA to move forward with any particular type of generation, and aligns with the requirement in Section 15d(f) of the TVA Act to sell power "at rates as low as feasible." All of these considerations have informed the alternatives in the FEIS, which are also expected to meet the intentions of TVA's Strategic Intent and Guiding Principles (May 2021) document, including a plan to reduce carbon emissions by 70 percent and a path to ~80 percent by 2030 and 2035, respectively, and to attain the aspiration of net zero by 2050. The addition of at least 1500 MW of CC/Aero CT natural gas generation provides firm dispatchable power that not only enables the retirement of the coal units but also helps integrate larger amounts of renewable energy to meet TVA's plan to install 10,000 MW of solar by 2035. While all action alternatives are consistent with TVA's aspirations to further decarbonize its resource portfolio, Alternative A best meets the stated purpose and is the lowest-cost solution.

Section 2.1.5 **of the F**EIS has been updated and provides a description of the wide range of resource alternatives considered but eliminated from further discussion and the reasoning as to each. See also response to *Comment No. 47* for further discussion of alternatives. Distributed energy resources were considered as they are included in TVA's asset strategy evaluated in the 2019 IRP. See FEIS Section 2.1.5.3.

40. TVA's EIS cites contradicting and unclear time restraints. For example, it claims in a comment response that the IRA tax credits, which would reduce the cost of Alt. B, cannot be considered because detailed guidance will not be provided in time; however, detailed guidance appears to have been released in May 2023, making this concern moot.

TVA should inform the public in more detail of the time table they're referencing and why they think it negates their own proposed Alt. B, when comparable solar projects have been installed within similar time limits (TVA points out 2027 as a potential deadline, but in other places in the

EIS mentions a need to execute the project in two years, or that waiting one year is too long).

Please also add justification as to why meeting each deadline is more important than considering the social cost of investing in fossil fuel technology at an opportunity cost of investing in cleaner technology. (Commentor: Megan Maloney)

Response: With respect to IRA tax credits, the FEIS incorporates updated solar and storage pricing that reflects recent market offers and estimated impacts from the IRA. With respect to the time constraints associated with Alternative B, as discussed in FEIS Section 2.1.4, to meet TVA's phased 2035 retirement plans for its coal fleet, at least 1500 MW of operational replacement generation is needed to replace the retiring units at KIF by the time they are retired at the end of 2027. See response to *Comment No. 2* regarding the need to retire KIF by 2027.

TVA is a summer and winter peaking power system. This means that to reliably serve load, not only does TVA have to have enough generation capacity to meet its summer load peaks but must also be able to meet winter load peaks, which can be just as large. Winter peaks tend to occur twice a day, with the largest in the morning before the sun rises. Solar generation does not produce power during this period and therefore long-duration storage is required to shift any solar generation to meet peak needs. Based on a reliability analysis, TVA determined that 1500 MW of solar and 2200 MW of batteries would be required to meet the purpose and need of KIF replacement generation. This amounts to a total of 3700 MW of inverter-based generation that would need to be interconnected to the transmission system. At an estimated 100 MW per site for BESS and estimated 100 MW per solar site, roughly 22 BESS sites and 15 solar sites (estimated combined total of 37 sites) would be required to replace the retiring capacity of KIF. These solar and battery interconnections would be in addition to the solar and batteries already planned to be interconnected as part of the broader asset portfolio.

Adding generation to the power system requires system upgrades because the power flows differently on the system and will overload transmission lines. Those system upgrades also require outages of transmission lines. Based on TVA's experience with making system upgrades, all of the necessary work associated with interconnecting approximately 37 additional sites of inverter-based resources – solar and batteries - is estimated to require 8-9 years to complete. As to the incentives provided in the IRA for renewables and storage, those incentives are of limited use with respect to the generation choices TVA faces at Kingston since replacement generation needs to be installed by the end of 2027 when KIF must be retired (see TVA's Coal Fleet End-of-Life Evaluation).

41. Additionally, please address how this timeline relates to TVA's commitment to install 10,000 MW of solar by 2035. If the TVA continues to use "time constraint" restrictions to kick the can down the road every time there's an opportunity to invest, how does TVA expect to ever meet their obligations and promises regarding provision of sustainable clean power? TVA will need to begin solar installations soon to meet their stated commitment, yet sufficient projects are not planned. Alt. B would address that commitment, but if resources are instead wasted on a natural gas plant, it doesn't seem likely TVA will meet these commitments.

Please add a more detailed justification for why missing this opportunity at increased social and environmental cost is seen by the TVA as an acceptable cost for the community. (Commentor: Megan Maloney)

Response: Please see responses to *Comment Nos. 13, 26, 38,* and *42*. TVA has already begun solar installations working towards TVA's goal of having 10,000 MW solar capacity online by 2035 and continues to do so through both power purchase agreements with solar contractors and TVA-owned solar generation. As of April 2023, TVA has 2,900 MW of solar online or under contract. The addition of gas-based replacement generation under Alternative A is consistent with the target supply mix in the 2019 IRP and facilitates the integration of 10,000 MW of solar on the grid by 2035.

42. Please also add a detailed timetable explaining how the time constraints on TVA's commitments to clean energy and solar are being met if not through this project. Please include concrete dates and project descriptions and site locations for the public describing the future solar installations (Commentor: Megan Maloney)

Response: See response to *Comment No. 40 and 41* for a discussion on the time constraints associated with Alternative B. Environmental reviews under NEPA for TVA's solar projects are available on TVA's website: https://www.tva.com/environment/environmental-stewardship/environmental-reviews.

While Alternative B does not meet the purpose and need to have firm replacement generating capacity constructed, operational, and fully dispatchable by 2027, TVA notes that the gas-based replacement generation under Alternative A would facilitate the integration onto the TVA grid of the 10,000 MW of solar TVA is targeting under the TVA Climate Plan and will thereby advance TVA's goal to transition to clean and renewable energy. The 2019 IRP envisions a critical role for gas in making the transition to clean and renewable energy.

43. Inconsistencies in the Draft EIS identified in comments include:

- **Total capacity being replaced is (1,500 MW), which is inconsistent with the statement that both Bull Run and Kingston Fossil Plants will be replaced. (DEIS, pg. 34)**
- **DEIS, Appendix I, Table I.6-5, pg. I-14 shows 1,298 MW coal being replaced—this is inconsistent with DEIS pg. 34 which states that both the Kingston and Bull Run coal plants will be replaced with this upgrade. The current installed capacity: Bull Run Fossil Plant – 889 MW + Kingston Fossil Plant – 1,398 MW = 2,287 MW**
- **Alternative A installed capacity: CC–673 MW + Aero–848 MW + solar–4 MW = 1,525 MW**
- **Alternative B installed capacity: 1,500 MW (Commentor: Citizens' Climate Education)**

Response: This EIS is only evaluating the retirement and replacement of the KIF with additional capacity for load growth. The replacement generation or retirement of Bull Run is not being considered in this NEPA evaluation. Any inconsistency with statements on page 34 of the DEIS has been corrected in the FEIS.

44. The DEIS states that the plant design proposed under the preferred alternative enables and accommodates future modifications necessary for incorporating CCS (Carbon Capture and Storage) and will obtain combustion equipment that can utilize hydrogen fuel blending (at least 30 percent hydrogen) as these technologies mature. TVA anticipates the efficiency, effectiveness, scalability, and economics of these systems will improve in the future, allowing for incorporation of one or more of these technologies when adequate storage locations, pipelines, or another technology for carbon storage are identified to implement CCS and/or the delivery of hydrogen. If TVA intends to install carbon mitigation measures in the future, these costs should be included in their analysis.

The EPA also believes functional carbon capture and hydrogen fuel blending technologies should be included in the initial plant design. Utilities similar in size to TVA's Kingston plant are displacing some portion of their natural gas generation with these technologies in a comparable timeframe. For example, the Intermountain Power new natural gas generating units, which will

begin operation in 2025, will be designed to utilize 30 percent hydrogen fuel at start-up, transitioning to 100 percent hydrogen fuel by 2045 as technology improves (see https://www.ipautah.com/ipp-renewed/). While smaller in scale, other utilities are displacing a portion of their natural gas use with hydrogen (seehttps://dailyenergyinsider.com/news/34040-florida-power-light-taps-cummins-for-its-green-hydrogen-facility/).

Additionally, Competitive Power Ventures is constructing a CC natural gas generation facility using carbon capture technology (see https://cpv.com/2022/12/12/cpv-selects-doddridge-county-for-location-of-3-billion-carbon-capture-project-in-west-virginia/). (Commentor: USEPA)

Response: Updates have been made to the FEIS to take into account the cost of mitigation requirements in EPA's proposed GHG rule and the site-specific emission reductions that would possibly be realized with the implementation of mitigation, including for CCS and hydrogen fuel blending. See Appendix B for a sensitivity analysis that examines how the alternatives compare under the EPA's proposed GHG rules. Under Alternative A, TVA would need to pursue hydrogen blending, co-firing, or carbon capture. Under the No Action Alternative, TVA would need to pursue carbon capture. The costs associated with these paths are sourced from EPA and DOE, and alternatives are summarized in Appendix B. Additionally, see response to *Comment No.* 36.

45. Despite our concerns that this should not continue as a separate EIS until after the 2024 IRP is complete, but instead incorporated into the IRP, we are providing the following recommendations for TVA to address in a supplemental or final EIS if TVA decides it must move forward as a separate EIS. In a supplemental or final EIS, TVA needs to explain how it determined that it would take 8-9 years to complete transmission upgrades required for Alternative B. (Commentor: SACE)

Response: See response to comment number 40 for a discussion of the estimated timeframe for the transmission upgrades that would be needed for Alternative B. Alternative B is expected to require 37 additional solar and battery sites and the extensive transmission upgrades necessary to connect these sites to the grid is expected to take 8-9 years.

46. The State of Tennessee agrees that Alternative A for the Kingston Fossil Plant Retirement would have notable long-term benefits that far outweigh any potential environmental impact. Ultimately, the State of Tennessee prioritizes energy reliability. Reliable electric service, as TVA provides to most Tennesseans, is essential for public health, safety, and property protection and is inextricably intertwined with other critical energy, telecommunications, and economic objectives.

Unfortunately, TVA's ability to meet service demands and maintain energy reliability has become a growing concern in Tennessee. In late December 2022, Winter Storm Elliott resulted in TVA directing targeted load curtailments due to extreme power demand for the first time in TVA's 90-year history. TVA Accepts Full Responsibility, Starts Full Review, TVA (Dec. 28, 2022), https://www.tva.com/newsroom/press-releases/tva-accepts-responsibility-starts-full-review. TVA experienced its winter record for peak power demand of 33,425 MW at 7 PM CT, after the sun had gone down. TVA, Local Power Companies Manage Record-Setting Demand, TVA (Dec. 24, 2022), https://www.tva.com/newsroom/press-releases/tva-local-power-companies-manage-record-setting-power-demand. During winter, peak energy demand usually comes at night until around 7 AM, times "when solar resources are not generating." DEIS at 54. "Battery storage is a new resource for TVA," and TVA has not yet gained sufficient operating experience to rely on solar

power during such peak demand times. Id. at 56. If TVA is moving away from coal, then firm, dispatchable power from natural-gas units is necessary to replace the lost energy generation.

Alternative A would fulfill TVA's core statutory objective to provide reliable electricity at rates as low as feasible to the people living in TVA's service area. Id. at vi. TVA needs to add at least 1,500 MW of operational replacement generation by the end of 2027. Alternative A best accomplishes that objective with the gas-fired combined cycle gas plant paired with sixteen dual-fuel Aeroderivative combustion turbines. TVA would balance that emphasis on natural gas with a 3- to 4-MW solar site and a new 100-MW battery energy storage system. The initial experience with battery storage would further inform TVA's operations as it attempts to expand battery storage in future solar operations.

In contrast, Alternative B would fail to provide the firm, dispatchable generation needed to meet year-round generation demands and would take longer to complete. EPA acknowledges as much by asking TVA to consider "a transition strategy" comprised of "peak shaving, increased generation from other production units, energy efficiency, and demand-management." DEIS App'x P. In other words, EPA wants TVA to ignore its statutory obligations under the TVA Act and instead implement targeted load curtailments during peak demand. TVA should not repeat on a regular basis the targeted load curtailments Tennesseans experienced during Winter Storm Elliott. Alternative B would also cost approximately $1.2 billion more than Alternative A in project costs. Such additional costs would be passed along to TVA consumers in the form of higher energy prices. TVA appropriately determined that Alternative A is the best option for providing Tennesseans reliable, low-cost electricity. (Commentor: Office of the Tennessee Attorney General and Reporter)

Response: TVA makes note of the State of Tennessee's preference for Alternative A as the best option for providing Tennesseans reliable, low-cost electricity. Reliability is of critical importance to TVA. TVA has and is continuing to work to ensure the reliability of the generation system and grid and agrees with the commenter that Alternative A is the option that best meets those goals. That is also why a secondary fuel source has been added as a back-up emergency alternative fuel to Alternative A for the Aero CT's. Please note that the EIS has also been updated to reflect the details and response to Winter Storm Elliot, see Section 1.2.3.2.

47. The range of alternatives considered within the DEIS is limited to only two action alternatives, the preferred alternative and an alternative consisting of 100% renewable energy generation. The EPA recommends that TVA consider a reasonable range of alternatives that reduce the size of their future carbon liabilities, among other concerns. Only considering two alternatives fails to disclose the available options between those two "endpoints" of a 1,500 MW natural gas fueled CC/Aero CT Plant and 100% renewable energy. The EPA recommends that TVA consider at least one blended alternative for formal analysis that combines a more balanced mix of renewables and natural gas, such as larger solar power systems than proposed in Alternative A in combination with smaller new natural gas capacity. TVA eliminated this alternative from consideration without discussion, only briefly noting in Section 2.1.5 that a "blended alternative that includes a substantial renewable component or combines a lower amount of natural gas with other technologies, such as solar and storage" would require transmission work over eight to nine years, like Alternative B, and thus not meet the purpose and need to have commercial operation by 2027. This alternative, which may require only four additional years to implement beyond the 2027 timeframe, even under a similar timeframe to 100% solar, warrants more complete consideration and discussion given it could result in significantly lower greenhouse gas

emissions and lock in smaller amounts of fossil fuel consumption. As part of this alternative, or as another alternative, TVA should consider a transition strategy (perhaps comprised of a combination of peak shaving, increased generation from other production units, energy efficiency, and demand-management) to meet capacity requirements until greater renewable energy generation is available.

Additionally, other companies have plans to retire coal plants in similar timeframes but do not rely on construction of new natural gas to replace the generation as they transition to renewable energy resources. Colorado Springs Utilities is decommissioning some coal plants and temporarily installing natural gas generators to bridge the gap until they transition to new wind and solar generation. Tucson Electric Power in Arizona is replacing capacity at the Springerville Power Station with wind and solar power systems. DTE Electric in Michigan is retiring coal assets and replacing the generation with a substantial proportion of renewables. (Commentor: USEPA, TVECG)

Response: In conducting an alternatives analysis, agencies must “[e]valuate reasonable alternatives to the proposed action, and for alternatives that the agency eliminated from detailed study, briefly discuss the reasons for their elimination.” 40 CFR § 1502.14(a). An agency must consider a reasonable number of alternatives that are “technically and economically feasible,” 42 U.S.C. § 4332(C), which are bounded by the purpose and need for the proposed agency action. Id. at § 1502.14(f), § 1502.13; see also Coal. for the Advancement of Reg’l Transp. v. Fed. Highway Admin., 576 F. App’x 477, 481 (6th Cir. 2014); Citizens Against Burlington, Inc. v. Busey, 938 F.2d 190, 195 (D.C. Cir. 1991) (“[A]n alternative is reasonable only if it will bring about the ends of the federal action.”).

The purpose of the proposed action is to retire and decommission all nine of the KIF coal units by the end of 2027, and to implement replacement generation that can supply at least 1,500 MW of firm, dispatchable power by the time the units are retired at the end of 2027. The need for the Proposed Action is to ensure that TVA is able to meet required year-round generation and maximum capacity system demands and planning reserve margin targets, particularly during peak load events. To this end, the replacement generation must have the capability to provide firm, dispatchable power to ensure grid stability in the East Tennessee region.

This proposed action is one piece of TVA’s overall asset strategy, which blends a combination of resource technologies to allow TVA to support affordable, reliable, and cleaner energy for its customers. TVA’s asset strategy already contemplates the blending of resources to provide the least-cost, optimal portfolio under a variety of future conditions, including the addition of 10,000 MW of solar by 2035. A key beneficial result of TVA’s asset strategy is the reduction of carbon emissions. As discussed in detail in FEIS Section 1.1, this action is a specific, discrete component of that asset strategy and is consistent with the need established by the 2019 IRP to establish new capacity in the TVA region, increase reliability and flexibility, integrate larger amounts of renewables on the grid, increase energy efficiency, and meet TVA energy production goals. EPA did not provide the load/capacity profiles for the utilities cited in the comments. If those utilities already have peak dispatchable capacity, they may be able to replace a portion of the total energy with non-dispatchable resources. In TVA’s case, however, the kind of replacements cited in this comment (temporary installation of natural gas generators for Colorado Spring Utilities, wind and solar for Tucson Electric Power, and renewables for DTE Electric) would not meet the purpose and need to have firm, dispatchable power in place by 2027 to ensure system reliability.

In addition to the No Action Alternative, TVA considered two action alternatives in the DEIS: Alternative A- the retirement of KIF and construction and operation of a combined cycle (CC)/Aero CT gas plant at the same site with solar and battery and Alternative B- the retirement of KIF and construction and operation of solar and storage facilities, primarily at alternate locations.

Further, Section 2.1.5 has been revised to further describe alternatives that were “considered but not carried forward” for more detailed analysis because they do not meet the project purpose and need. In particular, in FEIS Section 2.1.5, TVA evaluated a number of other resource options for replacement generation, including: natural gas-fired CC, natural gas-fired CT, battery energy storage systems (BESS), utility-scale photovoltaic (PV) solar, hydro pumped storage, small modular reactors, wind, energy efficiency, demand response, and distributed generation. TVA also evaluated other blended alternatives, including one that combines a lower amount of natural gas with other technologies, such as solar and battery storage. Other blended alternatives would not meet the purpose and need because they would not provide 1500 MW of firm, dispatchable power by 2027. The pipeline project is necessary to support the peaking requirements of the natural gas generation units as designed. A blended alternative with lesser amounts of natural gas does not meet the purpose and need since the non-gas component could not be installed by 2027 and would not provide firm, dispatchable power necessary to ensure grid stability in the Eastern Tennessee region. Further, as described in Resource Report 10 of ETNG’s application[4], the purpose of the Ridgeline Project is to provide 300,000 Dth/day (300,000,000 standard cubic feet per day) of natural gas transportation capacity and 95,000 Dth (95,000,000 standard cubic feet per day) of parking capability to deliver gas to TVA’s Kingston Plant site if TVA chooses to replace coal-fired generation at KIF with the CC/Aero CT Alternative at the same site. Any viable blended alternative that utilizes the Kingston Reservation would still require the evaluation and construction of ETNG’s Ridgeline Expansion Project.

48. In addition to the CC/Aero CT Plant, Alternative A includes a 3-5 MW solar site and a 100 MW battery storage site. This is a comparatively small use of solar and does not seem to reflect future forecasts of increasing use of renewables. Moreover, the description of Alternative A in the “Draft Air Quality & GHG” section does not include solar, and Appendix I does not include any solar-related calculations.

The EPA recommends considering a more substantive solar and battery component with Alternative A. The EPA recommends that the solar facility and battery storage facility be appropriately reflected in the calculations supporting Alternative A. (Commentor: USEPA)

Response: The 3-4 MW of solar that is included in Alternative A would be utilized for station service and would not be part of TVA’s goal to install 10,000 MW solar by 2035. For more information on this goal, see response to comment number 47. In its current configuration, the Kingston Reservation cannot accommodate larger capacities of solar generation due to space limitations. Additional space may become available in the future after D4 activities have been undertaken at the Reservation but the currently available acreage on the Reservation limits the solar component to 3-5MW. Additionally, Appendix J does include lifecycle GHG emissions calculations and associated social costs for the solar and battery storage component of Alternative A.

49. Additionally, the analysis should assess wind power as a viable part of the TVA system, as an alternative, or in combination with existing alternatives. Wind potential in the southeast is growing and as the costs of technology decreases, several modeling efforts find that an expansion of wind is optimal for this area. Wind energy resources:

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[4] Available online at https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20230823-5107

- **https://www.nrel.gov/gis/wind-supply-curves.html**

- **https://www.biologicaldiversity.org/programs/energy-justice/pdfs/TVAs-Clean-Energy-Future.pdf**

- **https://www.rff.org/events/rff-live/future-generation-exploring-the-new-baseline-for-electricity-in-the-presence-of-the-inflation-reduction-act/?mc_cid=fb2ba4aca8&mc_eid=73413f18e1**

If TVA believes that these wind energy models are incorrect about wind potential in the southeast, the TVA analysis should provide its support for this determination and explain why wind power is not being evaluated. (Commentor: USEPA)

Response: Section 2.1 of the KIF EIS provides a thorough description of the wide range of alternatives considered and the key factors and criteria that were used in development of TVA's preference. Wind was not carried forward due to higher transmission costs for out-of-Valley wind. Moreover, as an inverter-based resource, wind energy would not provide 1500 MW of firm dispatchable power that is necessary to ensure grid stability in the Eastern Tennessee region upon the retirement of the KIF coal units in 2027.

TVA has reviewed the sources cited by commenter. These sources do not detract from the reasons provided here and elsewhere in this EIS for not carrying the wind alternative forward in the alternatives analysis: lack of wind resources in the Valley, the higher transmission cost associated with out-of-Valley wind, and the need for firm, dispatchable replacement power at Kingston to ensure grid stability in the Eastern Tennessee region. See also Concentric Report, Appendix N.

50. The EPA is concerned that the DEIS does not adequately explain the rejection of other potential alternatives. For example, the EPA had recommended an alternative that generates the required baseload and peaking capacity needed to transition to greater renewable energy generation, and that does not require the construction of a new 122-mile pipeline. Given the capacity of the TVA system, it is unclear why this transitional and/or peaking capacity cannot be generated at TVA sites that would not require this extensive investment in long-term pipeline infrastructure. As noted above, in addition to being used as a criterion for ruling out Alternative B, the 2027 retirement date is used to rule out other blended alternatives with a smaller natural gas component and larger renewables component since it would take longer to put in place. However, a proper analysis would compare the costs and risks of maintaining the coal-fired units beyond 2027 with the long-term outcomes of a more balanced option. (Commentor: USEPA)

Response: TVA's asset strategy already contemplates the blending of resources system-wide to provide the least-cost, optimal portfolio under a variety of future conditions, including the addition of up to 1,200 MW of new solar generation per year. The decision associated with this EIS is a specific, discrete component of that blend reflected in TVA's asset strategy. See response to *Comment No.* 47 and the Purpose and Need section of the FEIS. The EIS evaluates Alternative B, which is a blended solar and battery alternative. In addition, TVA evaluated a number of other alternatives that were ultimately eliminated from further consideration. Section 2.1.5 of the FEIS explains this reasoning. Ultimately, TVA concluded that any such blended or transitional alternative would not meet the purpose and need to have 1,500 MW of firm, dispatchable power in commercial operation by 2027, and therefore, did not carry forward other blended alternatives for more detailed review. Additional natural gas generation capacity in the localized Kingston Reservation cannot be accommodated using the existing gas infrastructure, making it necessary to obtain a gas supply through the pipeline expansion facilities proposed to be built by ETNG.

51. TVA responded to public comments by assessing the potential for distributed energy resources (DER). The conclusion is that utility-scale solar, as proposed in Alternative B, is more cost-effective than DER (pg., 62 of the DEIS). This conclusion is supported by a policy brief conducted by the Howard Baker Center. However, that analysis also states that TVA is in a position to increase grid reliability by taking advantage of the opportunity for growth in DER, particularly battery storage. (Commentor: Citizens' Climate Education)

Response: See response to *Comment Nos. 4* and *14*. The proposal to retire and replace KIF is one part of TVA's overall diverse asset strategy. TVA is moving forward with detailed reviews of approximately 6,000 megawatts of solar energy and energy storage and building its own batteries at existing sites. This forward movement of evaluating solar energy would bring TVA closer to meeting the goal of 10,000 MW of solar implemented by 2035.

52. Skibo Energy proposes a decarbonizing storage solution that converts natural gas power plants into grid-scale storage battery equivalents. By capturing exhaust heat from gas turbines and boosting it with peak (excess) electricity it allows any gas plant to become a load following power generator. The storage allows for GW of renewable PV/wind to be added to the grid.

Bottom Line Up Front (BLUF)

- **TVA's decarbonization challenge is 20 GW or more of coal and gas plants**
- **Storage First decarbonizes natural gas power plants**
- **Converts existing coal and gas plants to GWh grid-scale battery**
- **Uses 'free energy' of gas turbine exhaust plus peak (excess) electricity**
- **1 GWh system delivers annual revenues plus ancillary services**
- **$26M of electricity arbitrage**
- **Enables 1-3 GW of new renewable energy from PV/wind farms**
- **Uses existing power generation technology supplies both frequency and non-frequency related ancillary services**

TVA's Decarbonization Challenge

- **Need to close 5 coal plants generating 20 GWh of electricity annually**
- **Could replace with 100 GW of renewable energy of solar and wind at a 20% capacity factor but need storage and/or additional gas plants to handle peak loads**
- **Shifting 25% of the renewable energy 4 hours would require 25 GWh of battery storage at $500 / kWh would cost $12.5B**
- **Plus 12 GW or more of gas turbines for peaking**

Storage First Value Proposition

- **Storage First enables decarbonization through large, long duration, distributed storage capabilities**
- **GW of PV/wind deployment**
- **Transition to renewable natural gas (RNG)**
- **Community scale solutions**
- **Sensitivity to power generation decarbonization risks**
- **Project valuation loosely tied to thermal efficiency**

- **Long-term valuation loosely tied to electricity arbitrage**
- **Valuation improves as deployment moves up the supply curve (Wright's Law)**
- **Enables decentralized power generation to avoid grid expansion costs and improve grid reliability**
- **Technology is available today to deliver solutions in years not decades**
- **Allows for strategic deployment of other power generation and storage solutions**
- **Run baseload plants at maximum capacity (nuclear, hydro, etc)**
- **Use li-ion for EVs and local reliability deployment**
- **Use other utility scale storage batteries to address community grid management**

Full-size Commercial Facility Economics - Comparison with Battery Storage

Li-Ion	1100 MWh-e $1100M CapEx Assume 80% efficiency $1M / MWh-e (CapEx assumption)	Annual Arbitrage - $29M Payback – 38 Years Lifetime – 15 Years Ancillary Services – Extra costs
Storage First	900 MWh-e $265M CapEx TES ($120M) + Power ($145M)	Annual Arbitrage - $26M Payback – 10 Years Lifetime – 30 Years Ancillary Services - Included

(Commentor: Skibo Energy)

Response: Thank you for your comment and the information. This information will be relayed to the proper team within TVA for considering future decarbonization and storage strategies. The proposal to retire and replace Kingston Fossil Plant is one part of TVA's overall diverse asset strategy, which includes adding storage to complement additional renewables. The target supply mix in the 2019 IRP includes 5,300 MW of storage, which will be implemented on TVA's system in the coming years.

53. Regarding the battery storage limits, why are the batteries for home systems capable of holding a full charge between 1-7 days, but the batteries available for TVA's installation only capable of a charge for 4 hours? (Commentor: Megan Maloney)

Response: Lithium Batteries can hold a charge for several days but will slowly lose charge during that period. The amount of time a battery can supply power is dependent on the amount of load placed on the battery (a single lightbulb as compared to a refrigerator), which is the main factor determining the discharge time of a battery. An at-home battery is designed to supply only the critical needs and not the full load requirements of a home for a limited time. Due to costs and design limitations, TVA batteries are designed to hold a charge for several days, but when discharged at full output will only provide full design power output for 4 hours. If the output of the battery is reduced by half, the battery output could last 8 hours.

54. As outlined above, there are many deficiencies with TVA's DEIS and its justifications for the preferred gas plant alternative. And because TVA's public participation process is lacking, the people most impacted by this and all TVA decisions will have little say in the matter. This goes against the very nature of public power. If TVA is truly committed to reliable, low-cost, clean, resilient and safe energy, they should comprehensively examine alternatives for distributed renewable energy, such as rooftop solar, storage, energy efficiency, and demand response. They should do so through robust public participation that meets people where they are at.

Distributed renewable energy and energy efficiency would help TVA achieve its decarbonization goals and commitment to improving the quality of life of TVA customers. DERs bring several benefits including grid management, demand response, and transmission benefits. These technologies, also when coupled with storage and energy efficiency, can minimize peak demand and effectively shift demand to meet variable supply rather than forcing supply to meet demand. Additionally, distributed solar generation can provide benefits to communities and ecosystems including reduced water use, improved wildlife habitat, and even reduced land use.

These are investments TVA can make today. TVA can reliably and effectively meet energy demand without coal or new gas, saving customers nearly $255 billion over the next two decades, lowering energy demand by 4 percentage points, and creating jobs. (On Behalf of 37 Climate, Justice and Community Organizations)

Response: TVA provided adequate opportunities for public participation as required by NEPA**,** first during the scoping process for this EIS and then during the public comment period for the DEIS. Section 2.1 of the KIF EIS provides a thorough description of the wide range of alternatives considered and the key factors and criteria that were used in development of TVA's preference. The 2019 IRP, which was a comprehensive study of how TVA can best meet the future energy demand in its power service area, evaluated use of a target power supply mix comprised of: the addition of up to 500 MW of demand response and 2,200 MW of energy efficiency (demand-side options); 4,200 MW of wind; 5,300 MW of storage; 8,500 MW of combustion turbines; 9,800 MW of combined cycle; and 14,000 MW of solar by 2038. See FEIS Section 1.2.2.1. As with this EIS, the development of the 2019 IRP and the associated programmatic EIS also provided extensive opportunities for public participation. The target power supply mix appropriately accounted for different generation resources and includes distributed energy and storage and energy efficiency. The Kingston EIS, which tiers from the 2019 IRP EIS, considers one project under the target power supply mix—the retirement of KIF coal-fired units and replacement generation. TVA currently has programs in place for distributed renewable energy, energy efficiency, and demand response, which all work together with the target supply mix of power generation.

55. The DEIS failed to consider clean energy alternatives. TVA fails to meaningfully consider important carbon-free resources—such as energy efficiency, demand response, wind, and market purchases—that, along with the solar and battery storage resources of Alternative B, would lower costs and increase the diversity, flexibility, and reliability of TVA's generation. Modeling results from Synapse Energy Economics in May 2022 concluded that replacing TVA's existing coal plants at Cumberland, Kingston, Gallatin, and Shawnee with a clean energy portfolio of solar, battery storage, energy efficiency, and wind would result in customer savings of approximately $9.4 billion over the next twenty years compared to a replacement portfolio focused primarily on gas resources. The clean energy portfolio described by Synapse would afford TVA immediate and steep GHG emissions reductions and achieve the same reliability as the gas portfolio. The clean energy portfolio also lowered costs even when compared against a second carbon-free portfolio comprised solely of solar and battery storage resources, and required the construction of fewer new solar resources overall.

TVA must consider a combination of low-cost clean energy resources—including, at a minimum, wind energy, energy efficiency, and demand response—with the solar and battery storage resources of Alternative B as another alternative for replacing Kingston Fossil Plant evaluated under NEPA. TVA's arguments against considering other carbon-free resources are unconvincing. For example, TVA arbitrarily rules out energy efficiency and demand response as incapable of

entirely replacing the capacity of the Kingston Fossil Plant on their own, but TVA never asks whether these energy resources could be synergistically combined with solar and batteries or other carbon-free resources to meet TVA's objectives. It is unnecessary for energy efficiency or demand response be enough, each on their own, to replace the entire capacity of the Kingston Fossil Plant, a point underscored by TVA's willingness to consider solar and battery storage in combination with one another in Alternative B. (Commentors: SELC and Conservation Groups)

Response: Section 2.1 of the KIF EIS provides a thorough description of the wide range of alternatives considered and the key factors and criteria that were used in development of TVA's preference. See response to *Comment No.* 47 on blended alternatives for additional details of the alternative evaluation and selection process. Wind was not selected due to low wind speeds and its intermittent nature in the Tennessee Valley and higher transmission costs for out-of-Valley wind, both of which increase relative costs. Section 1.2.3.3.1 and Appendix B describe and cite the market factors affecting both cost and availability of solar generation. As discussed in response to *Comment No. 54*, TVA currently has programs in place for distributed renewable energy, energy efficiency, and demand response, which all work together with the target supply mix of power generation identified in the 2019 IRP.

Further, Concentric assessed the Grid Strategies (Goggin 2023) and Applied Economics Council (SELC 2023) reports as part of this EIS. The Concentric analysis and conclusions are provided in Appendix N. The Concentric report concludes for the reports analyzed:

- The Grid Strategies report relies on selective and inconsistent assumptions such as using winter capacity ratings that are out of line with industry planning parameters, and employs assumptions about wind, energy efficiency, transmission costs, and timing that are overly optimistic and inconsistent with industry observations. Further, the Grid Strategy report fails to recognize that the near-term deployment of natural gas generation provides a solid foundation for aggressive renewable expansion.
- Contrary to Applied Energy Clinic's contention, the 2019 IRP continues to be valid for evaluating resource additions and retirements. The 2019 IRP serves as a flexible roadmap, offering a framework for informed decision-making while allowing adjustments in response to evolving factors.

The Concentric report confirms the reasonableness of TVA's identification of Alternative A as the preferred alternative. The report concludes that Alternative A is predicated on a robust planning process and consistent with the target supply mix in the 2019 IRP.

56. In a supplemental or final EIS, TVA needs to explain why it eliminated non-wires alternatives as tools to reduce the 8-9 year lead time for Alternative B. TVA should provide a list of non-wires alternatives considered, and a detailed description of how those could reduce the 8-9 year lead time and why they were not included in Alternative B. (Commenter: Southern Alliance for Clean Energy)

Response: TVA considered various resource types, including non-wire alternatives. See FEIS Section 2.1.5. As part of the purpose and need for this assessment, TVA needs firm dispatchable generation to meet its capacity needs and to provide needed reliable and resilient supply of electricity. In order to qualify as firm, the generation needs to be deliverable during all times including on system peak. Non-wire alternatives, such as dynamic line ratings, increase the capacity on lines during off-peak times when the sun angle or wind speed assumptions are too conservative. While dynamic line ratings may help reduce transmission upgrades during off-peak times, TVA would still be required to complete upgrades associated with peak power flows and upgrades associated with interconnecting the generation and therefore would not substantially change the timeframe (8-9 years) outlined in the EIS for making the upgrades.

57. TVA's response to EPA's comment recommending a reasonable range of alternatives is inadequate. Among other issues, TVA does not address why it is or isn't considering the three wind resources listed by EPA:

- **https://www.nrel.gov/gis/wind-supply-curves.html**
- **https://www.biologicaldiversity.org/programs/energy-justice/pdfs/TVAs-Clean-Energy-Future.pdf**
- **https://www.rff.org/events/rff-live/future-generation-exploring-the-new-baseline-for-electricity-in-the-presence-ofthe-inflation-reduction-act/?mc_cid=fb2ba4aca8&mc_eid=73413f18e1**

In a supplemental or final EIS, TVA needs to show how these resources impacted its analysis, or give specific reasons these resources were not considered. (Commenter: Southern Alliance for Clean Energy)

Response: Section 2.1 of the FEIS provides a thorough description of the wide range of alternatives considered and the key factors and criteria that were used in development of TVA's preference. Wind provides dependable, though intermittent, capacity in both summer and winter. Wind was not selected due to low wind speeds in Tennessee Valley and higher transmission costs for out-of-Valley wind, both of which increase relative costs. Further, and as explained in the Concentric Report provided in Appendix N, as an inverter-based resource, wind energy would not provide the firm, dispatchable power necessary to ensure grid stability in the Eastern Tennessee region upon the retirement of the KIF coal units in 2027. Please see the response to *Comment Nos.* 2 and 3 in Appendix D for additional information on the above-mentioned comment originally made by EPA and TVA's response to that comment.

58. To Whom It May Concern:
I'm writing to you as the General Manager of Harriman Utility Board (HUB), one of the 153 local power companies (LPCs) across the Valley regarding the "Draft Environmental Impact Statement" (DEIS) you have published to assess the impacts associated with the proposed retirement and demolition of the nine coal-fired units at the Kingston Fossil Plant (KIF) and the construction and operation of facilities to replace the retired generation.

HUB serves over 11,000 customers, of which about 83% are residential. Our service area includes the small town of Harriman (population ~5,950), the tiny town of Oakdale (population ~ 193), and parts of rural Roane and Morgan Counties in Tennessee. The "Kingston Fossil Plant" falls within our electric service area, though you don't need to purchase power from us because you make your own. Interestingly, the plant has a "Harriman" address, despite having "Kingston" in its name.

The folks in our community speak freely and openly to us in a way that they may not to you through this public comment period. This letter is an attempt to tell you what we believe our customers want for the future of the "Kingston Fossil Plant".

When deciding the future of the Kingston Fossil Plant, please consider power generation that is reliable and resilient first; then please also consider affordability and environmental stewardship. All your goals for the future of TV A's generation can be met, but you must drive toward that

"carbon free" vision responsibly. Natural Gas generation is not "carbon free"; however, we do believe it's the bridge needed to get us to a "carbon free" future.

It is our understanding that TVA is considering two alternatives to replace the existing Kingston units. "Alternative A" includes construction and operation of a single combined cycle (CC) combustion turbine gas plant paired with 16 dual-fuel Aeroderivative (Aero) combustion turbine (CT) units (CC/Aero CT Plant), 3- to 4-MW solar site, and a 100-MW battery storage system at the existing "KIF" site on the Kingston Reservation. "Alternative B" includes construction and operation of multiple solar generation and energy storage facilities at alternate locations, portions of which would be in East Tennessee. Of these two options proposed, HUB strongly encourages you to select Alternative A.

We believe TVA can be and should be a leading voice in Washington DC and show the country how to achieve a more sustainable future without compromising the quality of service we enjoy today. We believe a member of your executive team said it best that we all agree on a carbon free future. We just don't all agree on the timeline to achieving it.

After the recession of 2008, TVA experienced a decade of stagnant load growth. Our biggest concern was not whether we had enough power generation, it was how to increase efficiency to reduce the need to build a future generation plant? Fast forward to 2020, the Valley was impacted by the terrible COVID-19 outbreak. But what we did not expect from the pandemic was the mass migration into the TN Valley by new residents, businesses, and major industries. We are proud of the leadership at TVA and the State and Local Governments for driving such economic success, but we'd urge you to recall that a large piece of what made our area attractive to economic developers was the affordability and reliability of electric service. The people that live and work here were blissfully unaware that TV A has capacity challenges until Christmas weekend 2023.

Coming off the initial windstorm that preceded Winter Storm Elliott, our crews had been working all night to get customer power restored. Then later that morning as they were wrapping up, hoping to soon get some rest, we got a call from TV A that we must take action to shave load immediately. For us, that meant turning off the power to hundreds of customers at a time. I' 11 be honest; that was a disturbing feeling. Frankly, it was insulting to those that had worked all night to get the power back on. This letter is not to condemn TV A for what happened. In fact, your leadership team has done an incredible job emerging from this disaster. However, now that we are all enlightened, we must use that knowledge to make informed decisions moving forward.

Natural gas is the only viable option for replacing the coal units at the Kingston plant due to your time constraints. You must maintain reliable and resilient generation at the Kingston site for reliability in the East TN, particularly Knoxville and Oak Ridge areas. The Department of Energy facilities in Oak Ridge are vital to national security and innovation. They cannot rely on solar generation and storage alone to power their facilities. You already know this, as do the communities you serve.

Not once has a customer called us and asked us to reduce our carbon footprint. However, thousands and thousands of times, customers have called us to restore their power despite whatever hazards we must face (wind, storms, hail, snow, ice, extreme temperatures ...). We do this for them because we believe we are acting toward the public good.

Our customers are willing to take on a little more "carbon" for a little while longer to ensure they have power to fuel their heating/cooling systems, hot water heaters, stove tops, TVs, computers, medical beds, oxygen equipment, etc. In fact, they value reliability so much that many of them have purchased generators fueled by natural gas, diesel, or gasoline. By and large, our customer base includes economic and social conservatives. They are hard-working people, many of which are connected to the TVA plant either because they work there, used to work there, or know someone that does or did.

Please stand firm in your commitment to the Valley. Choose to carry forward with a plan to convert from coal to natural gas at the Kingston Plant. Please do not decommission a single megawatt of generation until the new generation is in place.

We all know that a solar array will not always start generating when you need it to, just as it will not always produce as much as you expect it to. It's nice when it works, but TVA must be able to call on dispatchable power generation at any time to cover the difference.

We commend your staff for developing Alternative A to include multiple layers of generation and energy storage. This kind of innovation will keep TVA relevant for many decades to come. With the anticipated distributed energy resources (DER) expected to arrive in the Valley, TVA will need the flexibility at its centralized generation plants to better respond to the ever-changing load/demand needs of the transmission and distribution systems.

Lastly, when you revamp the Kingston Fossil Plant, please consider using "Harriman" in its name. We'd love to get away from the stigma associated with the "Kingston" coal ash spill of 2008, one of the worst disasters in TVA history and move into the new era in partnership with you.

Thank you for your time in reading this letter and for your commitment to public service. You are an incredible team slated with an incredible amount of work to do. Your work does not go unnoticed by the LPCs. (Commenter: Harriman Utility Board)

Response: Comment acknowledged. We have noted the HUB recommendation to consider the need for flexibility at TVA's centralized generation plants to better respond to the ever-changing load/demand needs of the transmission and distribution systems. TVA agrees that, and as underscored by the Concentric Report (Appendix N), Alternative A is consistent with TVA's least cost planning goals, ensures reliability, provides needed capacity to support anticipated demand growth in the area, and will help support TVA's decarbonization efforts. We also note that reliability is of critical importance to TVA especially as the supply target mix changes and evolves. TVA has and is continuing to work to ensure the reliability of the generation system and grid. That is why a secondary fuel source has been added as a back-up emergency alternative fuel to Alternative A for the Aero CT's. Please note that the EIS has also been updated in Section 1.2.3.2 to reflect the details and response to Winter Storm Elliot concerns.

59. TVA must adopt a new "Agency Preferred Alterative" and end its preference for methane fueled generation. As these and other comments argued, with supporting scientific data, continuing to burn any fossil fuel contributes greenhouse gas (GHG) emissions that will drive our planet above the 1.5º centigrade tipping point at which we will have an unmanageable level of climate disruption.

I personally, being 84 years old, have seen enough climate disruption.1 I have, by choice, lived in Tennessee for 50+ years I know that July is not the kindest month. But as I write this we have

Extreme Heat warnings followed by thunderstorms accompanied by flood warnings. I will not live to see the worst effects of climate change but you, whoever reads this, will see the worst effects as will your children and grandchildren. GHG emissions if not stopped will make much of the earth a very difficult and dangerous place to live while destroying our ability to raise food and keep livestock. We are continuing to destroy the life support capabilities of our planet and the life forms that have involved under climate conditions previous to the Anthropocene.

Our species and the botanical and biological species which we rely on are being erased by extinction. The final Environmental Impact Statement must expressly recognize the impacts of climate disruption and propose the quickest possible closure of coal fired generation facilities and that some combination of several actions be taken to end TVA's contribution to GHG emissions. This means no shift to methane, of course. These actions to end TVA's contribution to GHG emissions include:

(1) Energy efficiency with activities that actually reduce energy use;2
(2) expanded renewable energy generation (wind, solar, geothermal - both produced within the TVA "fence" and imported;3
(3) Energy storage with both batteries and long term using pumped storage both run of the river and mountaintop pools;4
(4) Distributed Energy Resources (DEI)5 Expansion of the Local Power Company (LPC) "Flex" program and TVA's actions to support this element of local generation, storage and grid readiness should be addressed in the final EIS. Arbitrary limits on DER resources must be avoided. If investors, LPCs community solar proponents or others want to contribute localized resources they should be supported and encouraged by TVA and its partner LPCs.

The EIS must avoid repeating TVA's misinformation on the impacts of more renewable energy. The overstatement of impacts on farmland from solar arrays is laughable is it were not such a serious error. The DEIS drafters were either misled by a fossil fuel financed campaign designed to stir up farmers or unwisely relied on out of date information looking backward to the days when each solar panel generated much less electricity than is typical today. TVA needs to be up-to-date on the scientific facts and existing and oncoming technologies which are or will be readily available off the shelf to decarbonize our Valley generation by the time the Kingston coal fire plants ends operation.

A similar error is made in the DEIS as to the cost of solar generation by relying on prior bid information which is long out of date compared to the current market. CEO Jeff Lyash has said TVA wants as much solar as it can get. The EIS should support this claim by demonstrating a solar energy and storage construction program, followed by staff suggested and Board approved Budgets by which TVA will move from Laggard to Leader.

TVA should not increase end users energy cost burden by spending billions of dollars on gas fired generation for two reasons. EPA's proposed regulations limiting GHG emissions from fossil fueled electrical generation. These should be clearly explained and acknowledged in the EIS. While it may be some time before these regulations are in final form and tested by litigation the handwriting is on the wall. To meet these proposed limits TVA will have to either inject hydrogen into the methane fuel to reduce the carbon in the emissions or capture and geologically sequester carbon in the missions. Neither of these seems an inviting choice for TVA. There is no utility scale

hydrogen generation in prospect in the Valley notwithstanding Department of Energy happy talk about “Hydrogen Hubs”.

“In November [2022], Dominion Energy, Duke Energy, Louisville Gas & Electric Company and Kentucky Utilities Company (LG&E and KU), Southern Company and the Tennessee Valley Authority (TVA), along with Battelle and others, announced they had formed a coalition to pursue federal financial support for a Southeast Hydrogen Hub.” (https://siteselection.com/issues/2023/jan/tva-floors-the-clean-power-accelerator.cfm

This hub is to serve the entire southeastern U.S. with many existing coal and gas plants and a few planned gas fired plants including those TVA says it wants to spend billions to build. TVA and other big companies are counting on billions of federal dollars, not financing this by themselves. There is little carbon emissions free surplus electricity to make hydrogen to dilute natural gas that I have discovered. This leaves TVA with a “energy tax” the energy that must be drained from the gas plant’s generation to produce hydrogen that is then fed back into the fuel supply.

Likewise Tennessee lies over limestone karst and sandstone. These sedimentary strata are full of groundwater passages, aquifers, radium ore lens and cracks and faults. To assure that CO2 emissions are securely contained and will not leak back into the atmosphere they must be pumped into the “basement” rock (igneous or metamorphic) which may be thousands of feet below the surface.

TVA’s devotion to gas as a fuel makes no sense. There are ample examples that renewables plus storage can strengthen the grid and provide energy more reliably than fossil gas. My argument is supported by Winter Storm Elliot and TVA’s own after action report of the failure of coal and gas fired plants while solar continued to operate serving end user customers and supplied energy for the Racoon Mountain pumped storage.

The propose pipeline to be constructed by Enbridge has not been approved by the Federal Energy Regulatory Commission (FERC). I have spoken with several of the landowners along the route and they are angry and fearful. TVA’s alliance with Enbridge a.k.a. East Tennessee Natural Gas has meet persistent opposition. TVA is headed for the same reputation as a land grabbing bully that it had when it was building dams. This conflict will not be over or forgotten quickly.

The difference today is that this conflict can be avoided because TVA is the sole customer of the main 30 inch diameter pipeline and the branch lines to other proposed combustion turbine locations. If TVA does not spend billions building gas fired generation it will avoid a new generation of critics and negative media coverage.

Now is the time to back away from the much greater use of gas as a fuel and set a course widely advised by EPA and other experts as well as approved by most media coverage and polling indicating that the public supports renewable, fuel cost free, generation of electricity that leaves behind the legacy of coal ash.

P.S.TVA could reduce demand going forward if it would support legislation in each state requiring that all new construction comply with the most recent available Energy Code. TVA also should meet with Bob Southerlan who built the most energy efficient office building in the world 30 years ago. It still performs better than any building built to LEEDS standards. As every study shows a dollar spent on energy efficiency gives a greater return than anything else we can do to reduce

energy demand and the costs that come with generation and transmission. (Commenter: Brian Paddock)

Response: Comments noted. TVA currently has programs in place for distributed renewable energy, energy efficiency, and demand response, which all work together with the target supply mix of power generation. Please refer to the following referenced websites for additional details on some related TVA programs: Home - Helping people & businesses save on energy - TVA EnergyRight and Solar (tva.com).

Additionally, EPA's proposed GHG regulations and the carbon mitigation strategies identified in EPA's proposed rule are acknowledged and discussed in the FEIS. In regard to the natural gas pipeline, ETNG and its parent company Enbridge are involved in the EPA Methane Challenge Program One Future Commitment (ONE Future) under the Natural Gas STAR program. ONE Future is focused on identifying and implementing policy and technical solutions that reduce methane emissions across the natural gas value chain. In 2021, the overall methane leak rate for all Enbridge Gas Transmission assets was reported as 0.028 percent as reported in their 2022 Sustainability report. It is reasonable to assume that the leak rate from a new pipeline complying with the latest New Source Performance Standards would be even lower.

The solar costs in the EIS reflect up-to-date assumptions. In the near term they reflect recent RFP offers and the long-term forecast aligns with NREL's latest Annual Technology Baseline, see Appendix B

60. The Final EIS Would Benefit from Additional Discussion Concerning Potential Future Modifications for Transitioning to Hydrogen Fuel. The Draft EIS states that "TVA has committed to ensuring that the design of the Alternative A CC/Aero CT plant would enable and accommodate potential future modifications for carbon capture and the combustion of hydrogen (CC units only) as a replacement or supplemental fuel for natural gas when these technologies mature to scale." Draft EIS at 65. TVA adds that "once a viable option for future mitigation projects is identified, TVA would conduct additional analyses to determine proposed pipeline routes, costs, storage requirements, or other needs with hydrogen fuel incorporation." Id. at 66.

The Final EIS would benefit from incorporating additional analysis related to the viability of hydrogen as a fuel substitute, both as it relates to the gas generating facilities and to the 122-mile proposed interstate pipeline to be connected to the gas generating facilities. Regarding the future operation of the gas turbines, the Final EIS should address the potential issue of increased nitrogen oxides ("NOx") emissions. Hydrogen combustion emits NOx, therefore, reducing NOx emissions will require advances in pollution control technology and/or lower flame temperatures. U.S. Department of Energy, Pathways to Commercial Liftoff: Clean Hydrogen at 51 (March 2023), available at https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf. Although it seems likely that incremental NOx emissions associated with hydrogen combustion can be addressed by adjustments to or improvements in the current Best Available Control Technology for NOx, it seems prudent to review the efficacy of available control technologies in addressing this issue. This is particularly true where, as here, current BACT for NOx emissions (selective catalytic reduction) typically employs ammonia as a reagent.

Regarding the proposal to build a 122-mile natural gas pipeline to serve the new gas-fired facilities, the Department of Energy observes that "[s]teel makes up more than a quarter-million miles of the U.S. natural gas transmission system, but at high temperatures or high pressure, hydrogen embrittlement (permeation of H2 into steel) can crack steel pipes, leading to leakage or combustion." U.S. Department of Energy, Pathways to Commercial Liftoff: Clean Hydrogen at 50,

n.122 (March 2023), available at https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf; see also Kevin Topolski et al., National Renewable Energy Laboratory, Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology at 46 (October 2022), available at https://www.nrel.gov/docs/fy23osti/81704.pdf (explaining that "[r]esearch on the impact on pipeline steels has demonstrated that the presence of hydrogen significantly affects both fatigue crack growth and fracture resistance, with the most significant degradation in these properties occurring with small increases in hydrogen partial pressure around 1 bar"); Siemens Energy, "Hydrogen power and heat with Siemens gas turbines," at 7 (2022) ("Unchanged, pipelines today are unlikely to exceed 25 vol% hydrogen due to concerns over leakage through seals, welds, and valves or other mechanical constrains"). To the extent TVA plans to modify the gas-fired facilities in the future to accommodate hydrogen, it should evaluate and address these technical limitations in the Final EIS. (Commenter: Tennessee Valley Public Power Association, Inc.)

Response: TVPPA's comments, including those related to increased NOx emissions from hydrogen co-firing and the problem of hydrogen embrittlement affecting steel pipelines, have been duly noted. The FEIS discusses in Section 3.7.2.3.1.4 the two technologies for GHG mitigation – CCS and hydrogen co-firing – that are identified in EPA's proposed GHG regulations. TVA concluded on reviewing the EPA proposal that these nascent technologies are not yet adequately demonstrated for commercial use and the proposed GHG standards are not achievable. Nonetheless, TVA performed a sensitivity analysis of the cost of Alternative A using EPA and DOE information to inform a direct comparison of the costs between alternatives in the event that EPA's final rule requires these technologies. See Appendix B for a sensitivity analysis that examines how the alternatives compare under the EPA's proposed GHG rules. Under Alternative A, if EPA's proposed GHG rule is finalized as proposed, TVA would need to pursue hydrogen co-firing or carbon capture. The costs associated with these paths are sourced from EPA and DOE and alternatives are summarized in Appendix B. TVA does not anticipate that the 122-mile natural gas pipeline would be used to secure hydrogen supply, nor can it be estimated whether a source of hydrogen supply would be available. Hydrogen for the use of this mitigation is an evolving technology that is not readily available in the region at this time. Once a viable option for future mitigation projects is identified, TVA would conduct additional analyses to determine proposed pipeline routes, costs, storage requirements, or other needs with hydrogen fuel incorporation, and review environmental effects.

61. As an East TN energy storage company spun off from Oak Ridge National Laboratory, the best choice is to allocate the Kingston Fossil plant land for the energy storage technologies such as our Metal Hydride GLIDES energy storage.

Operation of such grid-scale storage can easily absorb a vast majority of the Kingston Fossil plant employees with a minimum amount of required training. (Commenter: Ayyoub Momen)

Response: The EIS considers battery storage in both of the action alternatives. Alternative A includes a 100-MW battery storage component. Alternative B includes battery storage as a dispatchable complement to solar.

62. Location of new CC/Aero CT Plant: From page 35 (Draft Environmental Impact Statement) based on this initial screening, TVA selected three sites on the Kingston Reservation as potential sites for the construction of a CC/Aero CT facility (Figure 2.1-4). After further site evaluations, Option A (38.78 acres) and Option B (26.32) were eliminated due to insufficient acreage. The 47.92-acre Option C was identified as the preferred location for the proposed CC/Aero CT facility on the

Kingston Reservation as the site was large enough to provide the acreage needed to accommodate the proposed CC/Aero CT Plant.

But it shows in the report that TVA owns the entire peninsula and Option A could expand later into the existing Steam Plant site after tear down or adjacent wooded area to gain the additional 9-acre difference between Option A and Option C.

You state on page 39 "CT plant would occupy approximately 30 acres, and an additional 10 to 25 acres on-site would be used for equipment lay-down. Option A has 38.78 acres already identified.

Also on page 39 you state "Larger project equipment could be delivered to the site by rail or barge, and smaller items by truck. Option A is actually closer to these existing delivery points than Option C. (Commenter: Bettria Cox)

Response: Comment acknowledged. The 47.92-acre area (Option C) was chosen as the preferred location for the CC/Aero CT facility as it was largely unencumbered by existing coal plant infrastructure that must remain in place until replacement generation is online, of sufficient size, and offers adjacent area that can be used for connected infrastructure such as substation and transmission line connections. A transportation plan would be developed to optimize delivery of supplies and equipment to the site. Option A does not present any environmental advantages over Option C.

63. Both energy efficiency and demand response alternatives for replacing Kingston generating capacity are dismissed with limited analysis (DEIS Appendix C, pg. 15). TVA should provide references to plans that will increase energy efficiency "depth and penetration levels" and demand response. Providing such references will support TVA's statement that energy efficiency and demand response are "well-positioned to help TVA absorb load growth resulting from increased electrification of the economy in the future." The public is interested in this initiative and the opportunities TVA plans to provide. (Commenter: Citizens' Climate Education)

Response: The decision associated with this EIS is a specific, discrete component of TVA's blended asset strategy and consistent with the recommended target power supply mix in the 2019 IRP, which includes energy efficiency and demand response. TVA's asset strategy includes leveraging demand-side options, in partnership with local power companies. As noted in the Concentric Report (Appendix N, Page 21), "TVA is working to offset approximately 30% [percent] of new load growth in the next 10 years through energy efficiency and demand response programs" (TVA 2023k). Consistent with the range in the Board-approved power supply mix (TVA 2019a), TVA announced $1.5 billion in funding for energy efficiency and demand management through TVA's 2028 fiscal year (TVA 2023i).

Please refer to Section 2.1.5 for alternatives considered but dismissed with respect to the discrete, specific proposal to retire and replace the KIF generation. See response to *Comment No. 47*. Moreover, and as explained in the Concentric Report (Appendix N, Page 3), "TVA considered a full range of resource options in its Draft EIS to replace the Kingston units and account for load growth with 1,500 MW of firm, dispatchable power needed to maintain system reliability. Pumped hydro, small modular nuclear, energy efficiency, wind, demand response, distributed energy resources, and hydrogen were among the options screened out as alternatives primarily based on the relative economics, availability by 2027, inability to provide firm power, and inability to meet the locational need in East Tennessee."

64. I am the chairperson of the Indigenous Peoples Coalition which is an organization of many tribal peoples including Cherokee, Muscogee Creek, Choctaw, Cheyenne and Mohave. We wish to

express our opposition to the proposed TVA pipeline. There are reportedly over 122 Indigenous sites in the project area which is in the heart of the ancient Cherokee homeland and should not be disturbed by the ravages of this ill-conceived endeavor. Further, this project would endanger the communities and natural environment of the area. Consideration should be given to a clean energy portfolio for renewable energy and storage. (Commenter: Albert Bender)

Response: TVA appreciates the comment. TVA is in the process of evaluating the potential effects of TVA's actions on Indigenous sites and other historic properties, in consultation with federally recognized Indian tribes and the Tennessee State Historic Preservation Officer. See Section 3.13 in the FEIS. TVA has found, in consultation, that the preferred alternative will result in no adverse effects on historic properties within the area of potential effects (APE) of TVA's undertaking, following the process in 36 CFR Sections 800.1-13. TVA is coordinating with the U.S. Federal Energy Regulatory Commission and ETNG regarding the NHPA Section 106 compliance efforts for the pipeline project, which is an action related to TVA's proposal to build a CC/Aero CT Plant. The potential impacts of the pipeline on historic properties are discussed in Section 3.13.3.3.6 of TVA's FEIS.

65. TVA should cite issues they have had or anticipate having with operating solar generation that support the decision to continue the use of fossil fuels. TVA advertises its experience and this should be referenceable: "TVA has over 2,500 MW of solar either operating or contracted" and "is working to gain operational experience with battery storage . . ." (DEIS Appendix C, pg. 32). (Commenter: Citizens' Climate Education)

Response: Please see Section 1.2.3.3.1 and Appendix B which describes and cites the market factors affecting both cost and availability of solar generation.

66. Rather than relying on internal experience only, TVA should draw and reference on other U.S. power generators who have documented their experience successfully installing and operating renewable energy. , The following references are sources that constantly update the efforts of other power generators success in installing renewable energy and could provide a resource for TVA to draw upon.

- **[Deep Decarbonization Pathways Project. UN Sustainable Development Solutions Network (ongoing updates)]**
- **[Publications about 100% Clean Energy by Clean Energy States Alliance (ongoing updates)]**
- **[Map and Timeline of 100% Clean Energy States by Clean Energy States Alliance (ongoing updates)]**

(Commenter: Citizens' Climate Education)

***Response*:** Your comments and references are noted. TVA works with industry partners like EPRI and other utilities to benchmark and share experiences on current and new technologies. This information informs TVA's implementation of the target power supply mix adopted in the 2019 IRP, which includes addition of extensive renewable energy to TVA's system. The proposal to retire and replace KIF is one part of TVA's overall diverse asset strategy. Although implementation of clean and renewable energy is a major goal that TVA is actively pursuing by adding approximately 1,200 MW of renewal energy per year, other TVA mandates such as least cost planning and reliability were also taken into account in this evaluation. See response to *Comment No. 47*.

67. TVA, why can't we either have nuclear or natural gas ? Both without the solar panels. I can point out several articles regarding the toxicity of solar panel production and their inability to be

recycled, same goes for the batteries. Why do you seek to punish rural Tennesseans by clear cutting our green belts and oxygen producing flora and fauna to install electric systems THAT DON'T WORK !!!!!! Why do you hate us ? Are we not cosmopolitan enough or do we not know enough movies stars to halt this stupid project ? Help me understand. Most solar panels cannot be manufactured in the USA and need to be purchased from China. Same goes with the batteries and neither can be recycled. How does that meet your "green" requirements. Either go nuclear or go natural gas but ditch these asinine, stupid , profoundly troublematic solar/battery proposal. I mean, how ignorant can you be. (Commenter: Dennis Walsh)

Response: Comment acknowledged. Section 2.1 of the KIF EIS provides a thorough description of the wide-range of alternatives considered and the key factors and criteria that were used in development of TVA's preferred alternative. Please see Section 3.8 of the KIF EIS for a description of impacts to flora and fauna as a result of the proposed action and alternatives and Section 3.14 for a description of solid and hazardous waste impacts. Note that TVA's preferred alternative is Alternative A. As part of Alternative A, a 3- to-4-MW solar facility is proposed on a 35-acre existing coal yard. TVA's preferred site for battery is located on a previously developed parcel and would require the removal of approximately 3.5 acres of trees. If Alternative A is selected, the removal of flora and fauna would not be necessary for the installation of the solar facility and a very small amount of clearing would be necessary for the battery (if battery site 1 is selected).

68. Please find attached a fix I had for TVA back in 2009, since that time Kenneth P. Whaley passed October 2018, contact on this information should be sent if any to the above information. There is most likely enough money to be made with this process to pay for Gas Solar or Both.

Prices for these metals or a lot higher that back in 2009.

Attached proposal submitted August 28, 2009 to TVA titled: Fly Ash Recycle & Disposal Facility for Bull Run & Kingston Steam Plant.

Brief info from attachment:
Our OBJECTIVE for this proposal is to turn the fly ash into a usable product such as all marketable metals. Excess carbon is to be re-cycled and returned to each respective plant.

Our PROPOSAL for this project is to acquire lands half way between the Kingston Steam Plant and Bull Run Steam Plant (Subject property is located on DOE lands approximately 15 miles away from each Plant). Whaley and Son's, Inc.(WSI) & Southern Design Group, Inc. (SDG) have been working independently on this problem since the spill in December of 2008 utilizing major efforts to locate disposal sites for fly ash disposal. Presently we intend to locate lands of DOE-CROET that would permit the construction of a Type II landfill disposal site dedicated for disposal of Bull Run and Kingston Steam Plant (Site to be permitted in accordance with Rules of Tennessee Department of Environment and Conservation Division of Solid Waste Management and An Act to amend Tennessee Code Annotated, Title 68, Chapter 211, relative to coal ash.) We would further propose to recycle all marketable metals and Carbon/Unburned Coal from the fly ash by-product upon the disposal site. Proposal is to sell the metals on the open market and the Carbon/Unburned Coal back to TVA.

The main objective would be to reach a point that most of the fly ash would be re-cycled and sold on the open market while at the same time utilizing the proposed Type II landfill site for disposal of any excess waste. We would hope to reach this goal in a period of three years. Our objective is

also to haul the waste from both plants by truck through gasket control of the tailgates and tarps to prevent any of the ash from entering the environment. We also anticipate having the ability to handle the existing fly ash from Bull Run Steam Plant and Kingston Steam Plant and continuing to recycle the projected future waste stream. (Southern Deign Group, Inc.)

Response: Thank you for your comment, which addresses issues beyond the scope of this EIS. This information has been forwarded to the appropriate group within TVA.

69. On behalf of the Metropolitan Government of Nashville-Davidson County, I would like to thank you for this opportunity to share my thoughts on the Tennessee Valley Authority's (TVA's) proposed retirement and demolition of the nine coal-fired units at the Kingston Fossil Plant (KIF) and the construction and operation of facilities to replace the retired generation.

Residents and businesses of Nashville and Davidson County have long relied on TVA for our energy needs through the Nashville Electric Service. Our office seeks to exhaust every potential avenue for advancing decarbonization in our city. In 2021, Mayor Cooper's Sustainability Advisory Committee, comprised of Nashville stakeholders from all walks of life, recommended a science-backed plan to reduce Nashville's annual greenhouse-gas emissions by 80% of their 2014 levels by 2050, and the city adopted this target in February 2022. Additionally, Metro government, through a renewable portfolio standard adopted in 2019, is required to source 100% of its energy from renewable sources by 2041. The Cooper Administration has sought to advance pragmatic solutions to achieve this goal. On the renewable energy front, we are working with TVA as part of its Green Invest program to deploy a large solar array and have installed or are exploring installation of on-site solar at over 200 Metro properties. Further, we are closely working with Nashville Electric Service on their efforts to take advantage of the 5% flexibility provision in their TVA contract to pursue in- and out of county solar installations that will help us meet both our decarbonization goals and renewable portfolio standard. Our city also embraces private sector and community stakeholder efforts to implement similar clean energy solutions.

In the DEIS, TVA explores two potential action alternatives for the KIF:
(a) retiring KIF and constructing a combined cycle gas plant paired with a dual-fuel Aero combustion turbine plant and new switchyard, a 3 to 4 megawatt (MW) solar site, a 100 MW Battery Energy Storage System (BESS), and a new transmission line infrastructure and connections to support the Kingston Reservation (Alternative A), and
(b) retiring KIF, investing in the local and regional transmission system, and the construction and operation of more than 15 solar sites and BESS facilities through PPA agreements, a portion of which would be located at alternate locations in eastern Tennessee (Alternative B).

TVA indicates that Alternative A is their preferred alternative.

Any of these proposed options would be an improvement from the status quo of coal at KIF. The DEIS shows that both proposed alternatives result in a decrease in greenhouse gas emissions on an annual basis relative to no action. However, Alternative B results in more than double the reductions in greenhouse gas emissions compared to Alternative A (Alternative A results in a yearly reduction of 1.65 million tons of CO_2 equivalent greenhouse gases; Alternative B would result in a yearly reduction of 3.4 million tons of CO_2 equivalent greenhouse gases). Unfortunately, TVA is not pursuing the more climate-forward option of Alternative B, instead expressing a preference for Alternative A.

Despite its lesser reduction in yearly emissions, TVA cites Alternative A as its preferred option by stating that it would allow for a swifter transition from coal than Alternative B, specifically that Alternative A could be built and be operational sooner than Alternative B, which would decrease economic, reliability and environmental risks.

Even if Alternative A offers benefits from an accelerated phaseout of coal, it will come at the cost of prolonged natural gas consumption. If we assume the combined cycle and combustion turbine plants will operate for 30 years, establishing new plants would commit TVA to polluting the environment with over 52.5 million tons of CO_2 equivalent gases[1]. While some natural gas consumption may be necessary in the short-run, TVA should explore solutions that don't obligate natural gas use as part of a long-term generation strategy.

The lifespan of the proposed plants undermines any cost-based argument made by the TVA. Establishing new natural gas plants effectively locks Nashville and the Tennessee Valley into fossil fuels for decades to come. If the TVA decides to retire the plants early to adopt renewables, they will have to pass the cost of the plant onto its customers, including those residing in Nashville. Leaving Nashvillians on the hook to pay for further pollution is unacceptable, whether the plants operate for years or are retired quickly. If we are to ask our city's residents to pay for a major investment in replacing the KIF, it should be in renewables and storage. In the DEIS, as part of Alternative A, TVA commits to 3 to 4 MW of solar and a 100 MW BESS, and this is impressive.

We've witnessed significant volatility in natural gas prices, which should raise concerns about the strategy of continued reliance on fossil fuels going forward. As it requires the construction of a new, 122-mile-long pipeline, TVA's preferred Alternative A would stand as a stark symbol that TVA is doubling down on the fuels that have led to our climate crisis, rather than meeting the challenge and opportunity of the moment.

TVA needs to serve as a leader in addressing the existential threat of climate change. This is possible while fulfilling TVA's responsibility to provide reliable and affordable power. While we applaud TVA's initiative in replacing the coal powered KIF and increasing renewables and BESS as part of its generation strategy, we ask TVA to maximize clean energy initiatives as part of its portfolio by pursuing Alternative B.

On behalf of the City of Nashville, I appreciate your consideration of these concerns. The Metropolitan Government of Nashville-Davidson County remains committed to decarbonization and looks forward to moving toward its climate goals in partnership with TVA. (Commenter: Office of Mayor John Cooper, Metro Nashville and Davidson County)

Response: Thank you for your comment. TVA needs to replace the proposed retirement of KIF with firm, dispatchable generation by the end of 2027 to sustain a stable grid in the Eastern Tennessee region. This proposed gas addition to replace generation from the retiring coal plant would not only reduce GHG emissions but would also enable the integration of 10,000 MW of solar that TVA anticipates adding to its generation profile by 2035. Both Alternatives A and B, compared to the No Action Alternative, would result in a net reduction in GHG emissions. While this net reduction is greater for Alternative B than Alternative A, Alternative B does not meet the time-critical need to have replacement power in commercial operation by the time the coal plants are retired in 2027.

The addition of this CC/Aero CT Plant to the target supply mix helps move TVA closer to its decarbonization aspirations and bolsters flexibility and reliability in all areas of the Tennessee Valley, but especially in the Knoxville area. See also the response to *Comment No. 47* addressing why blended alternatives using lesser quantities of natural gas would not meet the purpose and need to replace the generation of the coal plants retirements. As to volatility of natural gas prices, see response to *Comment No. 93*.

70. In the draft EIS, TVA notes that it has developed a Climate Action Adaptation and Resiliency Plan to identify risks associated with and plan for climate change effects. The EPA recommends that the final EIS disclose and consider whether and the extent to which the alternatives are consistent with TVA's Adaptation Plan.

In Section 3.7.1.1.8.2 and associated text in Table 2.2-1, Regional Climate, the analysis looks at how climate change impacts (such as increases in temperature, flooding, and drought events) may affect operations of the preferred action and alternatives. The EPA recommends that this analysis use climate projections specific to the study area rather than using national or global climate projections.

This analysis should also consider that increased heavy precipitation and flooding could potentially expand the existing 100-year floodplain, which may affect appropriate siting and elevation of Project components. Furthermore, in Section 3.7.2.3.1.5, the gas pipeline in Alternative A is described as being buried and thus not exposed to flooding. Climate change may heighten the risk of landslides due to both higher wildfire risk and flooding, the compounding effects of which may result in destabilized soil and resulting debris flows. This heightened risk of landslides should also be considered in the climate impacts analysis.

The EPA also recommends that in addition to the climate analysis on operations, TVA considers how alternatives may exacerbate climate change impacts to surrounding areas. For example, increased drought could reduce local water availability, heightening any impacts the preferred alternative has on water resources as well. For all the above, the EPA recommends that TVA consider adaptation measures to reduce impacts. (Commenter: EPA)

***Response**:* The 2019 IRP evaluated climate change (Please refer to the 2019 IRP Section 5.5.2.2) and it was noted there that the effects of climate change may mean hotter, drier summers and warmer, wetter winters. Hotter and drier summers will reduce the output of thermal and hydro resources and increase loads. On the other hand, a warmer and wetter winter will decrease loads and increase hydro generation. TVA performed a sensitivity analysis to gauge the impact of a 3°F increase in the average annual temperature across the Tennessee Valley, coupled with changes in seasonal rainfall. Analysis for this sensitivity indicates that the TVA system would become summer peaking. CT additions are accelerated to replace the impact of derated coal and nuclear capacity in the summer until about 2,100 MW nameplate of additional solar can be added to help maintain summer reserve margins. Total Resource Cost increased by about $3 billion due to the increased peaking and thermal derates in the summer, while carbon emissions improved slightly due to increased solar and hydro generation and decreased coal generation.

The most likely site-specific climate change impact would be due to flooding. The 100-year flood and TVA Flood Risk Profile elevations of the Clinch River at KIF include the influence of the operation of Norris Dam at Clinch River Mile 79.8, Melton Hill Dam at Clinch River Mile 23.1, Watts Bar Dam at Tennessee River Mile 529.9, Fort Loudoun Dam at Tennessee River Mile 602.3, and the Emory River, a significant

unregulated tributary entering the Clinch River at Clinch River Mile 4.4 (TVA 1970). As noted in Section 3.5.2.2.1, the 100-year flood and TVA Flood Risk Profile elevations of the Clinch River at KIF would be 746.8 and 748.1 feet, respectively; and the 100-year flood and TVA Flood Risk Profile elevations of the Emory River at the KIF intake channel would be 747.5 and 750.0 feet, respectively.
Flood frequency elevations are expected to change over time, if only because more years of rainfall and streamflow data have accumulated. When recomputed to account for climate change or for other reasons, flood elevations will remain unchanged, increase from current levels, or decrease from current levels. Flood elevations that stay the same or decrease would result in the same or decreased flood risk to proposed Project facilities. Flood elevations that increase would result in an expanded 100-year floodplain and increased flood risk to proposed Project facilities.

The flood-damageable project facilities have been sited outside floodplains or within floodplains on filled areas such that grade elevations are anywhere from 6.9 to more than 48 feet above the Flood Risk Profile elevation. Under any alternative, should frequency flood elevations increase, TVA would identify and implement the appropriate measures which could include installation of berms, sandbags, retaining walls, or flood walls or other measures to protect flood-damageable equipment threatened by increasing flood elevations in the short-term; and would further elevate vulnerable equipment in the long-term, if warranted. Transmission structures could be relocated outside areas of flooding, their bases could be fortified with grillage surcharge, or the structures could be retrofitted or replaced with materials and structures that better withstand flooding.

Only above-ground portions of the ETNG pipeline would be subject to increased flooding. As with facilities proposed at KIF, ETNG could install berms, sandbags, retaining walls, or flood walls or other measures to protect above-ground flood-damageable pipeline equipment in the short-term and could further elevate vulnerable equipment in the long-term. For buried infrastructure, pipelines could be buried deeper or covered by material resistant to erosion to reduce the potential for buried pipe to be exposed during flooding.

Alternatives A and B would have life cycle GHG emissions with potentially adverse effects to affected populations, and with potentially disproportionate adverse effects to qualifying EJ populations. Adverse effects could include increased flooding due to more intense precipitation events and more frequent or longer duration droughts due to warmer temperatures more quickly removing soil moisture during dry periods. However, with annual precipitation expected to increase, the impact to availability of water resources may not be as significant. Further, neither Alternative A or B would require large volumes of water withdrawal and the proposed retirement of KIF will eliminate current cooling water withdrawals.

Adoption and implementation of Alternative A or B would also result in significant and beneficial, site-specific and system-wide (cumulative) reductions in TVA’s GHG emissions, reducing the associated environmental, health, and social cost impacts. These emission reductions would be beneficial in helping to slow the rate of climate change or reduce climate change impacts from the current baseline (site-specific and system-wide) and would be consistent with TVA’s Climate Action Adaptation and Resiliency Plan (TVA 2021i), which includes watershed monitoring and modeling and sharing of data to project potential water availability issues and be able to implement adaptation practices.

Adoption of the No Action Alternative would not provide a GHG emissions reduction benefit, would not be consistent with TVA’s Climate Action Adaptation and Resiliency Plan, and would not support TVA in meeting federal GHG reductions targets or other climate goals.

ENVIRONMENTAL EFFECTS

Air Quality, GHG, and Social Cost of Carbon

71. "The DEIS fails to disclose the impacts of GHG emissions. Under NEPA, TVA must “quantify and consider” a project’s greenhouse gas emissions or explain why it cannot. “The key requirement of NEPA is that the agency consider and disclose the actual environmental effects in a manner that brings those effects to bear on decisions to take particular actions that significantly affect the environment.”

For climate change, this includes a “qualitative summary of the impacts of [greenhouse gas] emissions based on authoritative reports.” (Commentors: SELC and Conservation Groups)

Response: The DEIS conducts a comprehensive quantification of GHG emissions, including life cycle emissions for the No Action and action alternatives, and provides their social costs as a climate impact. Section 3.7.1.1.8 (Greenhouse Gases and Climate) of the DEIS provides summary information on impacts of GHG emissions from authoritative reports. Section 3.7.1.1.8 has been updated in the FEIS to supplement the qualitative discussion with additional information.

72. The DEIS fails to fully consider the Kingston alternatives' climate impacts, including lifecycle greenhouse gas emissions and relation to federal climate policy. Upstream methane leakage is an important, foreseeable, indirect impact of building and operating a new gas plant, and a direct and indirect impact of building and operating a new gas pipeline. Across the methane gas supply chain, from production through combustion, gas infrastructure leaks significant amounts of methane. As a greenhouse gas, methane is more than eighty times as powerful as carbon dioxide in its first twenty years in the atmosphere. Yet methane is shorter lived than carbon dioxide. That means “achieving significant reductions would have a rapid and significant effect on atmospheric warming potential.” Because of its potency as a greenhouse gas, methane emissions “significantly erode the potential climate benefits of natural gas use” relative to coal. Nearly a decade ago, scientists demonstrated that natural gas plants have net climate benefits relative to coal plants “as long as leakage in the natural gas system is less than 3.2% from well through delivery at a power plant.” Based on the latest report from the Intergovernmental Panel on Climate Change, that figure may be closer to 2.8 or 2.9%. In a recent, large-scale study, researchers from Stanford University estimated a system-wide methane leakage rate of 9.4%. That figure is more than six times a recent EPA estimate (1.4%) and about three times the rate at which burning methane gas has net climate benefits relative to coal. (Commentors: SELC and Conservation Groups)

Response: Methane leaks from the natural gas pipeline and further upstream from natural gas extraction and production are accounted for in the GHG life cycle analysis emissions calculations and associated social costs of methane emissions; refer to *Comment No. 74*. Section 3.7.1.1.8.3 (GHG and Climate Assessment Methodology) of the FEIS explains that ETNG is committed to reducing methane emissions under the USEPA's Methane Challenge Program and to providing transparency by reporting such emissions annually. ETNG’s parent company, Enbridge, has committed to reducing methane emissions across each individual segment of the supply chain to 1 percent or less of total produced natural gas. In 2021, the overall methane leak rate for all Enbridge Gas Transmission assets was reported as 0.028 percent as reported in their 2022 Sustainability report. It is reasonable to assume that the leak rate from a new pipeline complying with the latest New Source Performance Standards would be even lower. Enbridge also participates in an industry network that partners to implement methane emission reduction technologies and practices to further reduce methane emissions. The study cited by the commenter claiming a system-wide methane leakage rate of 9.4 percent is inaccurate because it only looked at facilities in one state, which accounted for about 2.7 percent of all oil and gas facilities; and, further, the study indicated a small number of wells and pipelines accounted for the vast majority of leaks. These are likely those facilities that are not participating in USEPA or other methane reduction programs like Enbridge and its industry network that are working to reduce methane emissions. Furthermore, a methane leakage rate of 2.8 or 2.9 percent ignores domestic studies identifying methane leakage rates as being on average at 1.6 percent. Lastly, the Methane Emissions Reduction Program, created by the IRA, provides $1.55 billion in funding, including financial and technical assistance to improve methane monitoring and reduce methane and other GHG emissions from the oil and gas sector.

73. TVA has likely underestimated the Kingston Gas Plant's greenhouse gas emissions. To calculate combustion-related emissions, TVA assumes a capacity factor of 55% for the Kingston combined cycle plant and 10% for the Kingston combustion turbine plant based on industry-wide averages. However, as EPA noted, "55% and 10% seem low given that these will be new state of the art CC and CT that TVA has indicated would displace older less efficient capacity elsewhere in the system and are needed for growth in the intermediate region." TVA has claimed that this gas plant would likely operate more efficiently than many other fossil fuel-fired plants on its system. TVA failed to address whether these plants are likely to operate at above-average rates and, therefore, emit more greenhouse gas than projected. TVA must analyze how, on its system, the new gas-fired plants would operate, and TVA should estimate greenhouse gas emissions accordingly." (Commentors: SELC and Conservation Groups)

Response: TVA has estimated the 55 percent and 10 percent capacity factors as a lifetime average based on U.S. Energy Information Administration (EIA) industry averages of actual capacity factors over the last 5 to 10 years. TVA believes these are reasonable estimates for use as part of the lifetime analysis considering there are many unknown or variable factors affecting capacity factors that will occur in the future that cannot be predicted. Refer to the individual resource LCA methodology discussion in Appendix J for the reasoning regarding the capacity factors used in this EIS.

74. TVA's analysis of air quality and emissions impacts fails to comprehensively evaluate the upstream methane impacts associated with the preferred CC/Aero CT gas plant. Additionally, TVA did not adequately take into account the harm and associated risk of leaking pipelines, nor did they analyze combustion at plants. This violates NEPA and TVA's implementation of the statute which states the utility shall "incorporate[...] environmental considerations into its decision-making processes to the fullest extent possible." (Commentors: On Behalf of 37 Climate, Justice and Community Organizations)

Response: The EIS, Draft and Final, does take into account the impact of estimated GHG emissions from each of the alternatives presented in the EIS. The analysis incorporates emissions from upstream sources, pipeline leaks, and from the ongoing combustion in the life cycle analysis, all of which include methane emissions. These emissions include the extraction of natural gas from the earth and subsequent processing/conversion and its storage/distribution/transport to the Alternative A site, i.e., pipeline emissions. The upstream emissions also include GHG emissions from Alternative A construction activities, raw materials extraction from the earth, and manufacturing of construction materials. Appendix J of the FEIS provides the methodology for the LCA, which includes upstream emissions, ongoing combustion emissions of natural gas, and ongoing non-combustion emissions, and includes a comparative assessment of the social costs of those emissions for each Action Alternative and the No Action Alternative Additionally, refer to *Comments No. 72 and 96* for additional methane leak emissions information.

75. Data in Table 3.7-10, pg. 382 compares Alternatives A and B for TVA system-wide reduction in cost of carbon. Such a comparison is not valid in the context of this EIS because the relative benefit of each option is masked by system-wide emissions. Although, evaluation of other system-wide actions (e.g., more Distributed Energy Resources) could be evaluated to assess system-wide actions, using system-wide data to support decision making on two options is not valid. (Commentor: Citizens' Climate Education)

Response: The system-wide life cycle analysis (LCA) is one important component of the analysis of GHG emissions because the implementation of each alternative has different impacts on the rest of the power generation mix. For example, Alternative A is estimated to indirectly reduce GHG emissions from other TVA coal plants as their load factors will likely decrease due to increased efficiency of the new Kingston CC/Aero CT Plant compared to the existing KIF coal plant. TVA's resource mix includes distributed energy resources, and they are factored into the system-wide analysis. The system-wide view provides critical context regarding how the specific resource retirements and replacements, underpinning the assumptions of each of the proposed Action Alternatives, integrates into the system overall. Developing a TVA system-wide life cycle analysis reflects TVA's broader asset strategy and target power supply mix set by TVA's 2019 IRP. A TVA system-wide comparison of emissions is the most effective way to accurately identify incremental emission differences between the alternatives because it illustrates how the entire TVA system is expected to operate with each alternative. The FEIS also includes an individual GHG LCA that compares each alternative.

76. Estimated Life Cycle CO_2 emissions are shown in Appendix I Table I.6-6, pg. I-15 Estimated Life Cycle CH_4 emissions are shown in Appendix I Table I.6-7, pg. I-16 with the cost of carbon emissions shown in Table I.6-11, pg. I-19.

We have substantial difficulty agreeing with the methods used to assess GHG for Alternative A and B. In general, the framework for the analysis is incorrect, as it does not accurately reflect how emissions are generated by each alternative as described in # 1 below. TVA used a mixed methods analysis for comparing the two alternatives. Items 2-3 below discuss these errors in more detail.

1) **In general, the framework for the lifecycle analysis of GHG emissions is improper. The major source of GHG emissions for Alternative B is from the initial manufacture and installation of solar and battery storage. This could be compared to a similar calculation for the production and installation of Alternative A. Both emissions figures could then be amortized over the 30-year lifetime. Then the emissions from ongoing power production over the 30-year lifetime could be added. This would require changing the units from gm/kWh to gm/installed kW for the construction and installation phase. The units for ongoing generation would be in gm/kWh. Since both installed capacity in kW and emissions from generation in gm/kWh are known, emissions per year can be easily calculated and compared.**

2) **Tables I.6-6, pg. I-15 and I.6-7, pg. I-16 clearly show and state that there are no operational GHG emissions from solar and battery storage. This is not correct. There are emissions from ongoing production and maintenance of solar with battery storage generation, but they are very small. These tables should accurately present known data and be consistent with other tables citing same throughout the EIS. Table I.6-8, pg. I-17 lists the detailed basis for calculations shown in Table I.6-7, pg. I-16. The anticipated 1% leakage of methane from the 122-mile-long pipeline should be included**

in the calculation.

3) **TVA used mixed methods in comparing GHG emissions figures between alternative A and B. This is improper analysis. The GHG emissions because of Alternative A was determined using TVA's historical record of emissions from combined cycle gas fired plants and from single cycle gas generation. GHG emissions from Alternative B were determined from a calculation using an emission figure of 64 g/kWh of anticipated generation (at least, that is what these reviewers think they did, as it is very difficult to determine exactly what the preparers of the DEIS did. There are simply too many inconsistencies between figures and tables throughout the DEIS, as noted above, to be sure. Another way of analyzing anticipated emissions would be to use emission per unit of energy generated for both alternatives. We in general are critical of this approach as noted above, but advise avoiding mixed methods analysis, which is invalid.**

A modified analysis using recent data follows. If one uses up-to-date data and input data for solar and battery lifecycle emissions, the ratio of social carbon cost of gas to solar is approximately 15.7 (see Table 1)

The total lifecycle emissions of natural gas using an emission rate for gas in national publications (an average of 573 gm CO_2/kWh) and TVA's estimates for anticipated yearly power production Table I.6.5 pg. 1-14 (line 4: 3.2 x 109 kWh/yr. + line 6: 0.74 X 109 kWh/yr.).

The total lifecycle emissions for solar/storage using more recent average estimates of solar and TVA's estimate for storage (12 gmCO_2/kWh11 and 35 gmCO2/kWh [Table 1.6.1, pg. I-11], respectively) and the anticipated yearly power production of 3.2x109 kWh/yr. (solar) and 3.2x109 kWh/yr (storage) or 6.4 X 109 kWh/yr. [NOTE: more energy is produced per year with the solar/storage option than with natural gas.]. (Commentor: Citizens' Climate Education)

Table 1. Comparison of GHG Emissions from Alternatives Emission Factors for Each Alternatives' Lifecycle Emissions (Metric tons/yr.)

Alternative	Emissions (metric tons/yr)	Total Emissions (metric tons)	Ratio of Alternative A/Alternative B
Alternative A: Combined Cycle Aero Gas + CT	573g/kWh	2,200,000	15.7
Alternative B: Solar + Battery Storage	12g/kWh (solar) 35 g/kWh (storage)	140,000	1

Response: TVA disagrees with the commentors assertion in item number (1) that the LCA of GHG emissions is improper. The LCA is based on National Renewable Energy Laboratory (NREL) publications that provide harmonized CO_2-equivalent (CO_2-e) life cycle emission factors for each of the different life cycle segments of the electricity generation technologies being considered. See Appendix J for more information.

In reference to item number (2), in the FEIS, TVA has updated the solar life cycle CO_2-e emission factors based on a 2021 NREL updated fact sheet for solar, which includes operational and maintenance emission factors. That total life cycle value is 43 g/kWh. The NREL references provide life cycle CO_2-e emission factors for the various power producing technologies in this EIS based on stringent peer reviews and harmonization of over 3,000 life cycle analyses.

TVA disagrees with the commentors assertion in item number (3). Many GHG life cycle analyses by different companies and agencies have been conducted and published with very variable results. TVA believes using the federal government generated NREL references provides the most reliable and accurate data for use in the LCA. Additionally, the estimated methane leak rate for the entire natural gas life cycle from the NREL natural gas LCA reference, i.e., 1.6%, was already included in the LCA emission calculations; refer to Appendix J.

77. "The outdated 2020 SC-GHG estimates, which do not reflect the best available science, continue to be applied in this DEIS. The interim SC-GHG estimates developed by the Interagency Working Group (IWG) represent the best available science. The Council on Environmental Quality (CEQ's) interim guidance on consideration of GHG emissions and climate change in NEPA analyses notes that agencies "should apply the best available estimates of the SC-GHG" to the GHG emissions from a proposed action and its alternatives. <u>In TVA's response comments, "presenting estimated social costs as a range of values from successive Administrations provides decision-makers and the public with better information in an area fraught with uncertainty." As detailed below, the use of the outdated SC-GHG is misleading to decision-makers and the public as it depicts an incomplete picture of the scope of environmental impacts.</u>

As stressed previously by the EPA the SC-GHG estimates developed in 2020 under Executive Order 13783 fail to reflect the full impact of GHG emissions in multiple ways. First, those estimates fail to capture many climate impacts that can affect the welfare of U.S. citizens and residents. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns.

Assessing the benefits of U.S. GHG mitigation should also incorporate how those actions may affect mitigation activities by other countries, as those international actions will benefit U.S. citizens and residents. Scientific and economic experts have emphasized reciprocity as support for considering global damages of GHG emissions. Using a global estimate of damages in U.S. analyses allows the U.S. to continue to actively encourage other nations, including emerging major economies, to take significant steps to reduce emissions. <u>CEQ's interim guidance on consideration of greenhouse gases states that: "Given NEPA's mandates to consider worldwide and long-range environmental problems, it is most appropriate for agencies to focus on SC-GHG estimates that capture global climate damages and, consistent with the best available science, reflect a timespan covering the vast majority of effects and discount future effects at rates that consider future generations."</u> (Commentor: USEPA, Tennessee Interfaith Power and Light)

Response: As to scope of impacts, the social costs of GHG from the previous Administration are based largely on domestic effects while the social costs generated by the IWG for the current Administration are based on global effects, inclusive of domestic effects. In the DEIS, TVA has used social cost metrics from both the current and previous Administrations, as described in Section 3.7. Presenting estimated social costs as a range of values from successive Administrations provides decision-makers and the public with better information in an area fraught with uncertainty. Monetizing social costs of GHG includes both quantitative and qualitative metrics. Furthermore, the IWG in a December 2023 memo (IWG 2023) states that agencies should "use their professional judgment to determine which estimates of the SC-GHG that reflect the best available evidence, are most appropriate for particular analytical contexts, and best facilitate sound decision-making." Regardless of the specific social cost of GHG rates used, the percent difference in social costs when comparing each action alternative to the no action alternative was not significantly different. Lastly, because the EIS considers the current Administration's social cost numbers, the global effects were not ignored in TVA's consideration of the social costs.

78. TVA also engages in a pointless exercise of calculating social cost of carbon (SCC) using values from the current Biden administration ($51/MT) as well as the previous Trump administration ($7/MT). We are in the Biden administration and that is the appropriate value to apply. IF TVA feels it necessary to engage in speculative exercises to illustrate plausible variation in future SCC valuations, it should calculate SCC based on the much higher SCC value (9over $180/MT) scientists calculate as most applicable.

TVA also calculates greenhouse gas emissions for the site-specific Kingston facilities and for a system wide portfolio which diminishes the estimated benefits of alternative B by assuming that much of the charging of the battery storage in this alternative would be done by natural gas and coal generation. Rather than validating TVA's assertion that it must build more gas plants to support more solar, this result could just as validly illustrate the failure of TVA to build adequate solar! This result also leads to questions as to whether TVA is including the 6000MW of new solar build it announced this year in its System-wide portfolio analysis. If TVA adds 6000 MW of new solar to its existing 2000MW of existing solar, plus the 1500 MW of alternative B then it seems this combined 9500 MW of solar should be sufficient to support system load while also charging the 2,200 MW battery system of alternative B.

It is important to note that most new solar installations are combined with battery storage systems so that all the battery storage of alternative B and then some could be accomplished in the installation of TVA's recently announced 6000MW solar initiative. However, TVA could also add solar and storage to its existing hydropower generating reservoirs to increase its whole system flexibility while minimizing costs and maximizing utilization of existing assets. TVA's "system-wide portfolio analysis" is a black-box that fails to provide sufficient information for independent evaluation of its assertions. (Note, page 373 incorrectly refers to 12,700MW of battery storage. Also, p375 refers to the operational impact of alternative B exceeding the Biden administration decarbonization goal because alternative B is 100% carbon free. While alternative B is essential to meeting the Biden administration decarbonization goals of a 100% carbon free electricity generation system by 2035, the goals cited on p.375 are the economy wide goals. Further, these goals apply to TVA's entire generation fleet, not any individual project.)

TVA's assumption that the storage component of alternative B will be primarily charged with fossil generation taints all its subsequent analysis of GHG reductions by minimizing the actual advantages a properly designed and operated solar plus storage alternative would achieve. (Commentor: Joe Schiller)

Response: See response to *Comment Nos. 77, 79,* and *145*.

79. Additionally, the DEIS claims that there are "legal and other uncertainties regarding the propriety of" SC-GHG estimates. The EPA does not agree that there is any legal uncertainty regarding SC-GHG values. To date, the government has prevailed in both the Fifth and Eight Circuits in challenges to the IWG's interim SC-GHG estimates. There is potentially greater legal

risk in using SC-GHG estimates that do not reflect the best available science. Executive Order 13990 directed the IWG to publish the interim SC-GHG estimates for agencies to use "when monetizing the value of changes in GHG emissions resulting from regulations and other relevant agency actions until final values are published." Estimates of the social cost of carbon (SC-CO2) have been published in the peer reviewed academic literature for decades, and the SC-GHG metric has been regularly incorporated into federal policy analysis since the late 2000s. While the interim estimates proposed by the IWG have been the subject of litigation, there are currently no legal constraints on the use of these estimates, which were developed under a robust and transparent process, represent the best available science and economics, and provide essential impact information to the public and decisionmakers.

The EPA recommends that TVA remove any language from the DEIS indicating that there are "legal and other uncertainties" around the SC-GHG estimates. (Commentor: USEPA)

Response: The "legal uncertainty" refers to the fact that the use of SCC by federal agencies has been the subject of litigation and inconsistent rulings and could be the subject of further litigation related to specific agency actions. Moreover, these estimates have changed from administration to administration. Nonetheless, TVA has used the SC-GHG estimates published by the IWG in its analysis, together with other SCC metrics used under previous Administrations to provide a range of potential impacts. Monetizing social costs of GHG is not an exact science and presenting the social costs as a range of values provides decision makers and the public with better information for making an informed decision.

80. TVA uses a "proxy approach" to compare emissions, on a percentage basis, to state and national values. While CEQ's interim guidance encourages agencies to contextualize greenhouse gas emissions, as noted in TVA's response to the EPA, it specifically cautions against this type of approach: "NEPA requires more than a statement that emissions from a proposed Federal action or its alternatives represent only a small fraction of global or domestic emissions. Such comparisons and fractions are not an appropriate method for characterizing the extent of a proposed action's and its alternatives' contributions to climate change." CEQ further stresses "such comparisons and fractions also are not an appropriate method for characterizing the extent of a proposed action's and its alternatives' contributions to climate change because this approach does not reveal anything beyond the nature of the climate change challenge itself—the fact that diverse individual sources of emissions each make a relatively small addition to global atmospheric GHG concentrations that collectively have a large effect." Rather, CEQ recommends providing context for GHG emissions and climate impacts by "monetizing climate damages using the estimates of the SC-GHG, placing emissions in the context of relevant climate action goals and commitments, and providing common equivalents." (Commentor: USEPA)

Response: CEQ's interim guidance on assessing GHG emissions encourages agencies to conduct an emissions analysis for each alternative and to contextualize those emission increases or decreases against climate goals and emission inventories. The proxy emissions analysis that, among other things, expresses emission reductions from alternatives as a percentage of state or national GHG emissions helps provide this context. The DEIS provides additional context by explaining how the reductions from the alternatives help advance climate goals.

The EIS however, does more than merely calculate emissions as a fraction of domestic and global emissions. Consistent with CEQ guidance, the EIS quantifies the reasonably foreseeable direct and indirect emissions of GHG from the No Action and Action Alternatives; provides context for GHG emissions and climate impacts associated with the alternatives by using estimates of the SC-GHG; places emissions in the context of climate goals; compares GHG emissions of the action alternative to the baseline of retiring the coal plant; and discusses mitigation technologies identified by EPA in its proposed GHG regulations.

The FEIS will be updated to include common GHG equivalent emissions per the CEQ guidance. See footnote 38 in Section 3.7.2.3.1.3 and footnote 43 in Section 3.7.2.4.1.3

81. Although the description of the LCA models has improved, the EPA recommends providing additional background documentation used to estimate life cycle GHG emission for each alternative, especially on the system-wide basis.

The EPA continues to recommend against presenting the SC-GHG as a point estimate at one discount rate, i.e., in Tables 3.7-6 and 3.7-8, the SC-CO_2, SC-CH4 and SC-N_2O are only presented at the 3% discount rate. This has not changed since the previous version of the document. As emphasized in the IWG Technical Support Document, the discount rate is an important parameter in estimating the SC-GHG and to reflect uncertainty in that parameter, a range of discount rates should be considered. For transparency and to help the public understand the impacts, the EPA recommends that the climate damages be presented for each GHG from 2028-2050 at discount rates of 2.5%, 3.0%, and 5.0%. The EPA is willing to help with calculating the climate damages using the appropriate SC-GHG estimates.

The current annual SC-GHG values are in 2020 dollars. The values reported in the 2021 IWG Technical Support Documentation (TSD) are identical to those reported in the 2016 TSD adjusted for inflation to 2020 dollars using the annual Gross Domestic Product (GDP) Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) National Income and Product Accounts. The GDP Deflator should be used to adjust SC-GHG to 2021or 2022 dollars. The values should not be adjusted for inflation to create a nominal value as has been done in the DEIS (adjusted for 2% annual inflation). The EPA is willing to help with adjusting the SC-GHG correctly. The EPA continues to emphasize that a 2% annual inflation adjustment is the incorrect approach.

For transparency and replicability of results, the EPA recommends TVA provide more details on the system-wide modeling and lifecycle modeling. In particular, the results of the system-wide LCA modeling are not fully presented. While more information and tables have been added about the other LCA, there is not a similar level of detail about the system-wide model. Only the emission-related outputs are presented. The EPA recommends also presenting the distribution of electricity generation in the system-wide model outputs. It is still not clear if the LCA system-wide model outputs satisfy TVA's commitments towards achieving Net Zero GHG emissions, as well as other policy goals. What do the modeled renewables look like in this model? What assumptions are made about the rest of the system? This would help serve as a check on the results. The EPA recommends presenting the full details about the assumptions of the model and the outputs across the TVA system.

Given that there are substantial differences in the monetized costs of CO_2 emissions across the alternatives, the EPA recommends TVA address and justify its conclusion that "the SC-GHG results for TVA system-wide effects essentially show that both action alternatives are relatively close regarding their overall potential GHG effects." (Section 3.7.1.1.8.3). For example, in Section 3.7.2.3.1.4, TVA calculates that Alternative A has substantially higher estimated greenhouse gas emissions and social costs of approximately $7 billion compared with $1.05 billion for Alternative B. (Commentor: USEPA)

Response: Please see responses to *Comment Nos. 76, 78,* and *87*.

Capital costs and characteristics for potential new resources come from NREL ATB with consideration for any regional differences. For example, TVA uses a typical 8,760 hourly annual pattern representative of solar performance in its region. Consistent with industry practice, TVA also considers the Effective Load Carrying Capability (ELCC) of a new resource to contribute to meeting peak loads and maintaining system reliability. For renewable resources, ELCC reflects the percentage of generation coincident with TVA's net peak loads in summer and in winter (dual-peaking system).

TVA uses an industry-standard model (EnCompass) for power system resource planning, incorporating inputs such as overnight capital costs, fuel rates, variable and fixed operations and maintenance costs, escalation rates, etc. When evaluating alternative resource options to fulfill system needs, the model simulates future resource requirements and operations. The assumptions for electric load and inputs related to existing and future resources throughout the planning horizon are consistent between the alternatives evaluated. Existing resources (as identified in TVA's November 2023 10-K filing (TVA 2023c) are modeled based on key inputs (based on TVA's experience and expertise) such as electricity demand, fuel and power costs, construction costs, environmental regulations, asset operating characteristics, target planning reserve margin, and transmission considerations. Key assumptions are validated and compared against industry benchmarks, studies, and forecasts, then modeled leveraging commercially available tools including Anchor Power Solution's EnCompass and Energy Exemplar's Aurora. Inputs for proposed technologies evaluated under the Action Alternatives in this FEIS come from NREL ATB with consideration for regional differences. Using all these inputs, the model simulates the least-cost capacity expansion path considering how the whole system would operate under each of the Alternatives. Each alternative has subsequent impacts for other decisions in the future. Given this, there would be variations in simulated dispatch, which would result in differences in emissions, driven by the dynamic nature of power system modeling.

The balance of system resources in the alternative cases will operate differently on an hourly basis throughout the year due to the operating characteristics and costs of the new resources and how they influence economic dispatch of the system overall. The balance of system resources remain largely the same between the two alternative cases. Results reflect the themes from TVA's 2019 IRP and recent planning efforts, as summarized in Section 1.2.2.1. The relevant assumptions and data necessary for the evaluation of the system-wide LCA analysis and the assessment of climate impacts is provided in the EIS in Section 3.7.2.5 and Appendix J.

A system-wide view provides critical context into how the specific resource retirements and replacements, underpinning the assumptions of each proposed action alternative, integrate to the system overall, and completes the overall characterization of the cumulative impact of the combined system and its performance. A TVA system-wide comparison of emissions is the most effective way to accurately identify incremental emission differences between the alternatives because it illustrates how the entire TVA system is expected to operate with each alternative.

The $7 billion SC-GHG for Alternative A comparison to the $1.05 billion SC-GHG for Alternative B in the DEIS is only for the individual resource LCA, which does not take into account how the rest of the TVA power generation system would operate under those alternatives. In addition, the $7 billion and $1.05 billion are absolute nominal values and have been updated in the FEIS to $7.7 billion and $672 million, respectively. These nominal values correspond to $2.07 billion and $347 million, respectively, in Net Present Value (NPV, 2023 $). To accurately reflect SC-GHG of the alternatives, a total system comparison is needed to capture not only the SC-GHG stemming directly from the assets recommended in the alternatives but also the SC-GHG from the generation of the balance of the system, which varies with economic dispatch of the total resource portfolio modeled in each of the alternatives. These differences in generation required to meet system needs drive the resulting difference in system-wide SC-GHG between the alternatives. The system wide LCA analysis results in a narrower divergence between the SC-GHG savings for Alternative A ($1.85 billion NPV 2023 $) and Alternative B ($2.26 billion NPV 2023$) compared to the No Action Alternative (NAA), which is a difference of approximately $417 million NPV 2023 $.

TVA acknowledges that there are three discount rates (2.5 percent, 3.0 percent, and 5.0 percent) and selected the 3 percent central case set by the Interagency Working Group as a representative estimate, acknowledging that this rate could be higher or lower. The IWG does not require agencies to prioritize or select one discount rate over another. In fact, a recent memo from the IWG (December 22, 2023: https://www.whitehouse.gov/wp-content/uploads/2023/12/IWG-Memo-12.22.23.pdf) states that agencies should "use their professional judgment to determine which estimates of the SC-GHG that reflect the best available evidence, are most appropriate for particular analytical contexts, and best facilitate sound decision-making." Another consideration is that no matter what social cost of GHG rates are used, the percent difference in social costs when comparing each action alternative to the no action alternative is effectively the same.

82. The DEIS acknowledges the national net-zero emissions goals laid out by the Administration and notes the U.S. national reduction targets in the Paris Agreement. However, there is limited differentiation from a policy standpoint between the alternatives, and local plans are not addressed. The EPA believes it is essential for TVA to improve the proposed action and EIS because of the urgency of the climate crisis. TVA's DEIS overlooked options to take meaningful, cost-effective action to reduce GHG emissions and help conform TVA's action to science-driven policy goals. The most recent scientific reports by the Intergovernmental Panel on Climate Change reinforce the urgent need to take climate action. TVA's proposal provides an important opportunity to do so.

CEQ's interim guidance on GHG emissions and climate change notes that "[w]here helpful to provide context, such as for proposed actions with relatively large GHG emissions or reductions or that will expand or perpetuate reliance on GHG-emitting energy sources, agencies should explain how the proposed action and alternatives would help meet or detract from achieving relevant climate action goals and commitments, including Federal goals, international agreements, state or regional goals, Tribal goals, agency-specific goals, or others as appropriate." According to Table 3.7-3 of the DEIS, the preferred alternative would result in an estimated 1,750,705.5 tons of CO_2e per year of operation over a projected 30-year lifetime (more than 50 million tons), while Alternative B would release no direct annual emissions. The EPA recommends that the FEIS include a discussion of whether and to what extent the estimated GHG emissions from the proposed alternatives are consistent with TVA taking action to help achieve science based national GHG reduction targets.

The FEIS should also discuss alignment with agency GHG reduction goals and policies,67 including TVA's 2021 Strategic Intent and Guiding Principles document. It is not clear from the DEIS that the preferred alternative is consistent with achieving TVA's aspiration of net-zero carbon emissions by 2050. Additionally, per 40 CFR 1506.2(d), and consistent with CEQ's guidance, the FEIS should disclose and discuss any inconsistency of the proposed action with State, Tribal, or local plans or laws, including local GHG emissions reduction goals. (Commentor: USEPA)

Response: See response to *Comment No. 79*.

TVA remains committed to achieving the climate goals espoused under recent Executive Orders to the extent these goals can be achieved consistent with other statutory mandates applicable to TVA under the TVA Act and the Energy Policy Act of 1992, such as the requirements to provide power at rates as low as feasible and TVA's least-cost planning requirements. GHG mitigation measures and their impacts are further discussed in the Environmental Consequences section of this EIS.

As described in the TVA Strategic Intent and Guiding Principles document (TVA 2021h), TVA has a plan for 70 percent TVA system-wide carbon reductions by 2030 (referenced to 2005 baseline), a path to approximately 80 percent carbon reductions by 2035, and aspires to net zero carbon emissions by 2050. The entire TVA system has achieved 63 percent mass carbon emission reductions from 2005 to 2020. Both alternatives in the FEIS would advance the agency's carbon reduction goals for 2030, 2035 and 2050, although the reductions under Alternative B would be greater than reductions under Alternative A as compared to the No Action alternative. While TVA's climate plans do not precisely mirror the current Administration's or the United States' reduction targets in the Paris Agreement, they do align with their broader goal to reduce emissions. The State of Tennessee does not have any climate goals and there are not any local climate goals in the city or county in which the KIF is located.

83. The State of Tennessee does object to TVA considering the supposed "social cost" of carbon dioxide and other greenhouse gases. (DEIS at 348-53.) The State acknowledges that EPA has attempted to force this methodology on TVA and appreciates TVA's honesty about many of the shortcomings of using purported social costs of greenhouse gases. DEIS App'x P.

For starters, minimizing the global social cost of greenhouse gases is not a statutory purpose of the TVA. The agency's statutory obligations under the TVA Act include maintaining and operating federal property for national-defense purposes, promoting agricultural and industrial development, improving navigation in the Tennessee River, and controlling floods in the Tennessee River and Mississippi River Basins. 16 U.S.C. § 831. Congress has expressly directed TVA to advance the "physical, social and economic development of the area in which it conducts its operations" by "assur[ing] an ample supply of electric power." Id. § 831n-4(h) (emphasis added); see also id. § 831i (authorizing TVA to make determinations for "the application of electric power to the fuller and better balanced development of the resources of the region" (emphasis added)). Congress has authorized TVA to act in the best interest of the Tennessee Valley, not in the supposed best interest of the world at large. Executive orders and interim guidance about the social cost of greenhouse gases cannot override TVA's statutory obligations to its service area. TVA fails to justify using a "global environment" for greenhouse gas emissions when the relevant study area for all other environmental impact is "the counties where the proposed alternatives are located." DEIS at 349.

TVA correctly acknowledges, despite EPA's criticism, that TVA's emissions of carbon dioxide account for only a small fraction (less than 1% in 2019) of net carbon dioxide emissions for the entire United States. Id. at 348. Those emissions are an even smaller fraction of carbon dioxide emissions worldwide. TVA unilaterally reducing its emissions of greenhouse gases is no guarantee that foreign nations, such as China, will not correspondingly increase their emissions. In any case, TVA will further reduce its emission of greenhouse gases and hazardous air pollutants by adopting Alternative A and switching from coal to natural gas. Id. at 344. Alternative B will take longer to implement, risking more years of higher emissions from the coal-fired units.

Even if TVA considers the global impact of its emissions, estimates of the social cost of greenhouse gases are unreliable on numerous fronts. TVA correctly acknowledges that “temperatures in the southeast over the last century have not increased as much as the climate model projections anticipated.” Id. at 349. From 1895 to 2015, there was only a slight increase of 0.24 degrees Fahrenheit in the TVA region. Id. The annual average summer temperature actually decreased 0.09 degrees Fahrenheit per 100 years. Id. Even assuming mankind’s greenhouse gas emissions will increase global temperatures somewhat, the State of Tennessee just experienced two consecutive winters with severe winter storms. See, e.g., Tennessee Ice Storm Recognized as Federal Disaster, Tenn. Emergency Mgmt. Agency (Mar. 11, 2022), https://www.tn.gov/tema/news/2022/3/11/tennessee-ice-storm-recognized-as-federal-disaster.html; December Winter Weather Receives Federal Disaster Recognition, Tenn. Emergency Mgmt. Agency (Mar. 13, 2023), https://www.tn.gov/tema/news/2023/3/13/december-winter-weather-receives-federal-disaster-recognition.html.

During Winter Storm Elliott, Tennessee experienced subzero temperatures that resulted in burst pipes, boil water advisories, and over 306,000 TVA customers without power. Id. Social cost estimates improperly elevate speculative global costs over actual costs suffered by the Tennessee Valley’s residents.

TVA is right to acknowledge that the social cost benefits of Alternative B are overstated. (DEIS at 376.) Because, at this time, the United States “has little competitive onshore solar manufacturing capability,” id. at 6, Alternative B would rely on solar panel production in countries such as China. As the TVA and the Uyghur Forced Labor Prevention Act acknowledge, China has reportedly used forced labor to mine solar panel and battery materials. DEIS App’x P. Social cost calculations struggle to attach a dollar figure to such misbehavior. Further, there are negative national security ramifications for TVA making its power generation capability reliant on solar production in foreign countries that often act contrary to our nation’s interest. Congress has repeatedly legislated to “move the United States toward greater energy independence and security.” Americans for Clean Energy v. EPA, 864 F.3d 691, 697 (D.C. Cir. 2017). Alternative B would move the Tennessee Valley in the opposite direction by making TVA reliant on countries such as China as TVA moves to retire the coal-fired units in a timely manner.

Finally, even EPA acknowledges that the use of different discount rates helps “reflect uncertainty” in social cost estimates. DEIS App’x P. Because social cost estimates attempt to project decades’ worth of costs at present value, discount rate selection plays a major role in calculating the ultimate social cost. The 3% discount rate TVA selected will overestimate long-term costs compared to the 7% discount rate normally used for approximating the opportunity cost of capital, such as generation sources. DEIS at 351. A 7% discount rate is a more appropriate discount rate for analyzing social costs of greenhouse gases if TVA believes such speculative analysis is necessary for determining how to retire the coal-fired Kingston Fossil Plant. (Commentor: Office of the Tennessee Attorney General and Reporter)

Response: Comment noted. TVA remains committed to achieving decarbonization goals consistent with other statutory mandates applicable to TVA under the TVA Act and the Energy Policy Act of 1992, such as the requirements to provide power at rates as low as feasible and least-cost planning. The EIS uses the SCC methodology for evaluating climate impacts consistent with Executive Order 13,990 and the CEQ GHG Interim Guidance. However, in light of the uncertainties inherent in the use of this methodology, TVA also conducted a quantitative, proxy emissions analysis that contextualizes the emissions of the alternatives by comparing those emissions with local, state, national, and international

GHG emissions, and against other measures such as those in TVA's Strategic Intent and Guidelines document (2021).

84. TVA must apply the Social Cost of Carbon in compliance with Executive Order 13,990 and guidance from the Interagency Working Group on Greenhouse Gases. When used appropriately, the Social Cost of Carbon can help agencies fulfill President Biden's directive: to "capture the full costs of greenhouse gas emissions as accurately as possible, including by taking global damages into account." Developed in 2010 and updated in 2016, the Social Cost of Carbon is a scientifically derived metric to "provide a consistent approach for agencies to quantify [climate change] damage in dollars." The Social Cost of Carbon translates a one-ton increase in CO_2 emissions into changes in atmospheric greenhouse gas concentrations, consequent changes in temperature, and resulting economic damages. Those harms include "changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services." The current values, which adjust the 2016 values for inflation, estimate that every additional ton of CO_2 released from anywhere on Earth will cause approximately $51 in climate damages. (Commentors: SELC and Conservation Groups)

Response: See response to *Comment No. 79*. Consistent with Executive Order 13,990, the EIS utilizes SCC methodology to evaluate the alternatives. See FEIS section 3.7.1.1.8.3.

85. The Interagency Working Group has also published values for the Social Cost of Methane and the Social Cost of Nitrous Oxide, both consistent with the methodology underlying the Social Cost of Carbon. The Social Cost of Methane is $1,500 per ton—nearly 30 times greater than the cost of carbon, accounting for methane's increased potency as a greenhouse gas. Not only will the Social Costs of Greenhouse Gases convey the harms of new gas pipelines and plants, but they will also allow TVA to incorporate the social benefits of reducing greenhouse gas emissions for evaluating carbon-free alternatives. Executive Order 13990 instructs federal agencies to use the Social Cost of Carbon, which has been widely endorsed by economists and scientists, as well as the Social Costs of Methane and Nitrous Oxide, which are based on the same methodology. The Social Costs of Carbon, Methane, and Nitrous Oxide are useful and appropriate here to meaningfully convey the impacts of building new gas plants and pipelines—thereby adding decades of greenhouse gas emissions—in comparison to zero-carbon alternatives like energy efficiency, demand response, renewable energy, or battery storage. CEQ instructs agencies to apply the Social Cost of Greenhouse Gases. EPA and NPS have specifically requested that TVA do so here.

While TVA applies the Social Cost of Greenhouse Gases in its GHG analysis, it refuses to include those costs in its analysis of the alternatives' "total system costs," despite the TVA Act's mandate to account for all quantifiable environmental compliance costs. TVA must include the Social Cost of Greenhouse Gases in its calculation of total system costs. (Commentors: SELC and Conservation Groups)

Response: TVA has applied the Social Cost of Greenhouse Gases in its analysis of climate impacts using the social cost of three GHGs (carbon dioxide, nitrous oxide, and methane) from the current and previous Administrations to provide the decision-maker the full range of values of these social costs. The analysis of "least system cost" is conducted by TVA through its IRP process and the target supply mix adopted in the 2019 IRP reflects the range for different generation sources consistent with least system cost. In conducting the least system cost analysis for the 2019 IRP, TVA included all appropriate costs under applicable statutory mandates. For the proposed CC/Aero CT Plant construction at Kingston, the CC and CT capacities are within the target supply mix of the 2019 IRP.

86. The DEIS suggests there is widespread debate over the economic discount rate and whether global effects, as opposed to only domestic, should be included. As discussed below, there is broad consensus on a discount rate of 3% or less and that global effects must be included. TVA also objects that the Social Cost of Carbon "does not measure the actual incremental environmental effects of [an individual project]." Those excuses are meritless. (Commentors: SELC and Conservation Groups)

Response: TVA acknowledges there are three discount rates (2.5%, 3.0%, and 5.0%) recommended by the Interagency Working Group (IWG) and further notes that the IWG does not mandate that agencies select one rate over the other. TVA selected the 3% rate as a representative estimate, acknowledging that this rate could be higher or lower. TVA maintains that one of the drawbacks in the use of SC-GHGs analysis for assessing project impacts is that any such analysis is not capable of measuring the incremental environmental effects of individual projects. Furthermore, TVA conducted the SC-GHG analysis using estimates from the Biden Administration, which include global climate damages.

87. By refusing to apply the Social Cost of Greenhouse Gases in accordance with the Interagency Working Group's guidance, TVA has violated Executive Order 13,990. As discussed, President Biden re-established the Interagency Working Group on the Social Cost of Greenhouse Gases, instructed them to publish interim Social Costs of Carbon, Methane, and Nitrous Oxide, "which agencies shall use when monetizing the value of changes in greenhouse gas emissions." In February 2021, the Interagency Working Group published interim figures, with a range of four different values for each greenhouse gas. Those include three different discount rates: 2.5%, 3%, and 5%.

The Interagency Working Group included a fourth value—a 3% discount rate with more expensive damages—to represent "higher-than-expected economic impacts from climate change." The IWG explained why agencies should apply all four values: For the purpose of capturing the uncertainties involved in analyses, the [Interagency Working Group] emphasized and emphasizes in this [Technical Support Document] the importance and value of including all four SC-GHG values. In particular, values based on lower discount rates are consistent with the latest scientific and economic understanding of discounting approaches relevant for intergenerational analysis …

The way to address uncertainties is not to apply unsupported "prior Administration" numbers. Instead, as the Interagency Working Group explained, it is to apply the three specified discount rates, plus a fourth high-damages value. Despite this clear directive, TVA applied only a 3% discount rate. Against EPA's objection, TVA did not apply the 2.5% discount rate, the 5% discount rate, or the high-damages fourth value. TVA's refusal to apply Social Cost of Greenhouse Gas values in compliance with the Interagency Working Group's Technical Support Document violates Executive Order 13990." (Commentors: SELC and Conservation Groups)

Response: See response to *Comment Nos. 82* and *85.*

88. TVA also provides what it calls "system-wide" estimates of the Social Cost of Greenhouse Gases from the different alternatives. Without providing key assumptions, TVA made the substantial differences between alternatives largely disappear. Instead of a $6 billion difference between A and B in the Social Cost of Greenhouse Gases, TVA found a $646 million difference.

For CO_2 emissions, instead of a difference of 50 million tons, TVA found a system-wide difference of less than 9 million tons. TVA claims that Alternative B would lead to a substantial increase in operations from its gas-fired combustion turbine plants. TVA also claims that Alternative A would "indirectly reduce GHG emissions from other TVA coal plants as their load factors will likely decrease due to increased efficiency of the new Kingston CC/Aero CT Plant compared to the existing KF coal plant.

First, TVA has not disclosed any modeling details to support these assertions. As EPA objected, TVA "does not present the assumptions that underlie the model or the modeled distribution of future power generation." TVA does not give the public essential information to evaluate how TVA reached this important conclusion. With low operating costs and maximum flexibility, the 2,200 MW of storage proposed in Alternative B would likely be a more flexible, cost-effective way to address peak demand than increased use of TVA's gas-fired combustion turbine units. TVA must disclose details from its modeling to allow the public to assess the systemwide greenhouse gas impacts of Alternatives A and B.

Second, even if it's true that the Kingston Gas Plant would reduce emissions from other TVA coal plants, this effect would likely be greater for Alternative B because solar and storage have substantially lower operating costs and storage has far greater flexibility than a combined cycle gas plant. Yet TVA does not appear to credit Alternative B with significant additional GHG reductions from reduced operations at other coal plants." (Commentors: SELC and Conservation Groups)

Response: A system-wide view provides critical context into how the specific resource retirements and replacements, underpinning the assumptions of each proposed action alternative, integrates to the system overall, and represents a characterization of the potential cumulative emissions impacts from the TVA system under each action alternative. A TVA system-wide comparison of emissions is the most effective way to accurately identify incremental emission differences between the alternatives because it illustrates how the entire TVA system is expected to operate with each alternative. TVA provided modeling details to support its assertions in the alternatives analysis presented in Appendix B

Each alternative has subsequent impacts for other decisions in the future. Given this, there would be variations in simulated dispatch, which would result in differences in emissions, driven by the dynamic nature of power system modeling. All necessary generation data germane to the evaluation of the System-wide LCA analysis and the assessment of climate impacts is provided in the FEIS Section 3.7.2.5 and Appendix J.

Please also refer to response to *Comment No. 81* explaining that the social cost difference in the individual resource LCA is an absolute difference but the social cost difference in the TVA system wide LCA is a relative difference as compared to the No Action Alternative, which is the baseline.

89. The DEIS does not adequately address the air quality impacts of Alternative A. Rather than provide misleading estimates of net emissions, TVA must discuss the proposed methane gas plant's greenhouse impacts in a meaningful context. TVA finds that building new gas plants would "provide a moderate, permanent, beneficial impact regarding GHG direct and indirect emissions in comparison to the No Action Alternative." TVA reaches this conclusion by pointing to the net rate of emissions, emphasizing that the change as a percentage of national and state inventories. EPA recommends that "TVA avoid expressing project-level GHG emissions as a percentage of national

or state GHG emissions." EPA has objected that "[t]his approach trivializes substantial project-scale GHG emissions" and is "misleading given the nature of the climate policy challenge to reduce GHG emissions from a multitude of sources, each making relatively small individual contributions to overall GHG emissions." CEQ's interim guidance likewise makes clear that "[s]uch comparisons and fractions are not an appropriate method of characterizing the extent of a proposed action's and its alternatives' contributions to climate change … because this approach does not reveal anything beyond the nature of climate change itself—the fact that diverse individual sources of emissions each make a relatively small addition to global atmospheric GHG concentrations that collectively have a large effect." EPA advises that "NEPA documents [should] instead discuss the conflict between GHG emissions and national, state, and local GHG reduction policies and goals, and—equally important—ways to avoid or address the policy conflict, that increases over time, created by projects that otherwise expand and lock-in fossil fuel consumption." EPA emphasizes that "net GHG emissions should not be calculated solely against a 'business as usual' baseline, but also against decarbonization pathways that are necessary to meet science-based targets for GHG reductions." As a cooperating agency, EPA has repeated those requests here. In addition, local governments within the TVA service territory have established their own climate goals. For example, the cities of Knoxville and Nashville aim to reduce greenhouse gas emissions community-wide by 80%. And Nashville Electric Service—one of TVA's largest customers—unanimously passed a resolution against exclusive reliance on TVA's preferred alternative, the proposed Kingston Gas Plant, partly because it is out of step with the city's climate policy. TVA acknowledges federal climate goals yet refuses to say what Alternatives A and B mean for TVA's, the nation's, and local governments' abilities to meet them. As EPA notes, TVA provides "limited differentiation from a policy standpoint between the alternatives, and local plans are not addressed." EPA further objects that "[i]t is not clear from the DEIS that the preferred alternative is consistent with achieving TVA's aspiration of net-zero carbon emissions by 2050." (Commentors: SELC and Conservation Groups)

Response: See the responses to *Comment No. 78, 79 and 81.*

90. TVA must fully consider the localized air quality impacts associated with operating the proposed Kingston Gas Plant. In the DEIS, TVA's discussion of the air quality impacts of operating the proposed gas plant is largely limited to noting, several times, that impacts of the various air pollutants "would be addressed during the air permitting process for the new CC/Aero CT Plant to ensure ambient air quality standards and allowable incremental increases in pollutant concentrations would not be exceeded beyond the KIF property boundary." But compliance with Clean Air Act permitting requirements does not necessarily imply that the impacts are not significant. TVA errs in not evaluating the health and environmental impacts of the gas plant's air pollution on its own terms.

For example, over 400 tons a year of NOx may, potentially, be permitted under the CAA's regulatory scheme (though, as noted above, those regulations might change). However, it is still an enormous amount of a very dangerous pollutant. For NOx, as well as the other air pollutants emitted by the proposed gas plant, TVA must not only quantify the emissions and pledge compliance with the correct permits; it must also describe and analyze the actual impacts of the pollutants that would be emitted by each alternative, including cumulative impacts from other sources of NOx and other pollutants. This should an include an analysis of projected actual emissions resulting from frequent starting/stopping of units, projected actual emissions from the use of bypass stacks (with an informed prediction of how often bypass stacks will be used), and more detail about the expected efficiency of their proposed emissions reduction systems. TVA

must also evaluate the potential for disproportionate impacts on environmental justice communities caused by local air pollution, and not just aver that impacts would all be "minimized through permitting and monitoring." For some fuel sources and pollutants, TVA provides almost no information at all. The only specific mention of formaldehyde in the DEIS is contained in the brief section on Hazardous Air Pollutants (HAPs). TVA notes that EPA rules regulate HAP emissions, such as "emissions limitations for formaldehyde," apply to stationary combustion turbines which "are major sources of HAPs, defined as sources having the potential to emit 10 tons/year of any individual HAP or 25 tons/year or more of any combination of HAPs." TVA concludes by stating that "[a]applicability of this rule will be determined during the air permitting process when more specific information on HAP emissions from the turbine manufacturer will be available." In TVA's table describing the operational air emissions from the alternatives, it leaves out formaldehyde, noting that "[a]dditional hazardous air pollutants are emitted from fossil fuel combustion but in negligible quantities."

Whether emissions are "negligible" depends a great deal on just how toxic those emissions are. TVA must provide more detail about potential HAP emissions from the proposed gas plant, including formaldehyde, which is a known human carcinogen. Combustion turbines are known to be a significant source of emissions for formaldehyde and other HAPs. Without analyzing the amount and likely dispersal area for HAPs, TVA cannot make a fully informed decision between alternatives. TVA also does not provide adequate information in the DEIS to allow for meaningful public comment on how "new manufacturer's data" related to CC/CT emissions may affect the environmental impacts or regulatory regime for Alternative A. TVA states, in a brief "preparer's note," that this data "allows a conservative emission calculation for the CC duct burners to be revised," resulting in "lower criteria pollutant emissions so that all criteria pollutants will not be subject to Prevention of Significant Deterioration (PSD) permitting for Alternative A," but that "this new information was not provided in time to incorporate into this draft EIS," though "it will be incorporated into the FEIS." In a later section, TVA states that "[t]he new CC/Aero CT Plant is potentially a HAP major source; however, that designation will ultimately depend on the emissions guarantees provided by the manufacturer during the air permitting process, when more specific information on HAP emissions from the turbine manufacturer will be available." This is not acceptable. New data that affects the permitting regime for harmful air pollutants should be available to the public to evaluate before TVA makes its final decision—not after. TVA yet again makes the mistake of confusing a commitment to comply with CAA permit requirements with an actual analysis of the environmental impacts of the proposed alternative. TVA must comply with permit requirements and take a "hard look" at impacts in the DEIS, explaining the reasoning behind its decision for public review. TVA concludes by stating that "[a]pplicability of this rule will be determined during the air permitting process when more specific information on HAP emissions from the turbine manufacturer will be available." In TVA's table describing the operational air emissions from the alternatives, it leaves out formaldehyde, noting that "[a]dditional hazardous air pollutants are emitted from fossil fuel combustion but in negligible quantities." (Commentors: SELC and Conservation Groups)

Response: The significance of air emissions under NEPA is typically determined based on existing CAA and state environmental agency air quality rules that were implemented to protect human health and the environment*.* This includes meeting ambient air quality standards, air permit requirements, and existing equipment design standards and emissions control requirements. TVA is committed to working with TDEC and EPA to install emissions equipment that meets these requirements through the air permit process and permit conditions. That permitting process assesses local impacts from emissions sources, including protection of significant deterioration of air quality due to the impacts of proposed new sources and/or modification of existing emissions sources. Another term for a portion of this permitting assessment process is determining if the action is subject to Prevention of Significant Deterioration (PSD) permitting. The new CC/CT manufacturer's performance data indicates that PSD permit review would not be applicable as the proposed CC/CT plant would not be significant under PSD rules. The overwhelming majority of regulated pollutants would decrease in comparison to the current KIF operations, many in a significant amount, dispensing with the need for air dispersion modeling.

Although HAP emissions performance data for the proposed CC/CT plant is not available from the manufacturer at this time, TVA has conducted a conservative estimation of annual HAP emissions and formaldehyde emissions using EPA AP-42 emission factors and the 40 CFR 63, Subpart YYYY combustion turbine formaldehyde limit of 91 parts per billion by volume, dry (ppbvd). These emissions indicate total potential HAP emissions would be below the 25 tons per year (tpy) total HAP major source threshold, i.e., approximately 20 tpy, and below the 10 tpy major source threshold for any one individual HAP, i.e., approximately 8 tpy for formaldehyde. Formaldehyde actual emissions were estimated at approximately 4 tpy. Formaldehyde is the most significant HAP from natural gas combustion turbines. TDEC does not have any state-specific toxic pollutant or HAP rules that would apply to Alternative A. Additionally, considering the proposed plant would not be a major source of HAPs under federal law or state law, it would meet all HAP requirements. Additional formaldehyde specific impact information is provided in the paragraph below and will be included in the FEIS for Alternative A along with its estimated emissions.

According to the National Cancer Institute (NCI), when formaldehyde is present in the air at levels exceeding 0.1 ppm, some individuals may experience adverse effects such as watery eyes; burning sensations in the eyes, nose, and throat; coughing; wheezing; nausea[5]; and skin irritation. According to OSHA, the permissible exposure limit (PEL) for formaldehyde in the workplace is 0.75 ppm as an 8-hour time-weighted average. Additionally, research at the University of North Carolina that was completed in 2019 indicated that doses of formaldehyde inhalation exposure to rats at or below 300 ppb, which is equivalent to 0.3 ppm, did not increase cancer risk and would likely not increase cancer risk in humans (Univestiry of North Carolina 2019). The conservative estimate of the formaldehyde concentration exiting the proposed combustion turbine stacks under Alternative A would be less than 0.091 ppm (at 15% oxygen) which is less than the 0.1 ppm referenced above and over 8 times less than the OSHA PEL. (See Section 3.7.2.3.1.2 in the FEIS.) In addition, by the time the stack exhaust is dispersed in the ambient air and carried downwind to ground level receptors, the formaldehyde concentration would be expected to be reduced to levels further below 0.091 ppm.

TVA does not anticipate using bypass stacks for Alternative A in a way that would generate meaningful additional emissions. Additionally, the DEIS already included CT start/stop emissions in the analysis; refer to spreadsheets with emissions calculations provided in Appendix I. The predicted additional start/stop emissions from the CC portion of the plant, as presented in the recent air permit application submitted for the proposed CC/Aero CT Plant on Kingston Reservation, was based on eight starts/shutdowns for bypass operations and 25 starts/shutdowns for HRSG operations (equating to 40 total hours per year) resulting in minimal emissions (e.g., approximately 6 tons/year of NOx as calculated in the Alternative A

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https://www.cancer.gov/Common/PopUps/popDefinition.aspx?id=CDR0000390302&version=Patient&language=English

air permit application[6]) compared to its normal operational emission. This is because the CC portion would be for sustained base load operations with far fewer startups and shutdowns than associated with peaking CT operations. Lastly, control system efficiencies are imbedded in the manufacturer provided emissions guarantees for pollutants that are controlled, which are included in the emissions calculations provided in Appendix I.

91. TVA also does not provide adequate information in the DEIS to allow for meaningful public comment on how "new manufacturer's data" related to CC/CT emissions may affect the environmental impacts or regulatory regime for Alternative A. TVA states, in a brief "preparer's note," that this data "allows a conservative emission calculation for the CC duct burners to be revised," resulting in "lower criteria pollutant emissions so that all criteria pollutants will not be subject to Prevention of Significant Deterioration (PSD) permitting for Alternative A," but that "this new information was not provided in time to incorporate into this draft EIS," though "it will be incorporated into the FEIS." In a later section, TVA states that "[t]he new CC/Aero CT Plant is potentially a HAP major source; however, that designation will ultimately depend on the emissions guarantees provided by the manufacturer during the air permitting process, when more specific information on HAP emissions from the turbine manufacturer will be available." This is not acceptable. New data that affects the permitting regime for harmful air pollutants should be available to the public to evaluate before TVA makes its final decision—not after. TVA yet again makes the mistake of confusing a commitment to comply with CAA permit requirements with an actual analysis of the environmental impacts of the proposed alternative. TVA must comply with permit requirements and take a "hard look" at impacts in the DEIS, explaining the reasoning behind its decision for public review. (Commentors: SELC and Conservation Groups)

Response: The new CC/CT manufacturer's emissions performance data has been received and incorporated into the FEIS. See Section 3.7. This new data indicates emissions would be less than the emissions indicated in the DEIS; therefore, it would have a beneficial impact compared to the emissions previously provided. Refer to response to *Comment No. 90* regarding HAPs.

92. TVA must properly account for the impacts of the proposed gas plant on regional haze and visibility. In 1999, EPA promulgated the Regional Haze Rule to improve visibility in Class I protected areas. Visibility is reduced when particulate matter and gases spread in the atmosphere. The Great Smoky Mountains National Park, a federal Class I protected area, is located only 36 miles from Roane County, where the proposed gas facility would be located. Roane County is also in a nonattainment area for PM2.5. The proposed gas plant would emit significant quantities of pollutants that affect visibility, such as particulate matter, NOx, and VOCs.

TVA must fully consider how construction and operation of Alternative A would affect haze and visibility in the Smokies and other protected areas. However, in analyzing the potential impacts of a new natural gas facility on regional haze and visibility, TVA simply states that because "Alternative A is expected to result in a large overall reduction in combined emissions of the four Regional Haze/Visibility regulated pollutants: NOx, PM_{10}, SO_2, and sulfuric acid," the "change is a beneficial impact to nearby Class I protected areas" and regional haze requirements would not apply in permitting for constructing the new CC plant. Again, TVA confuses its NEPA obligation to

[6] "Startup and shutdown emissions are based on eight (8) starts/shutdowns for bypass operations and 25 starts/shutdowns for HRSG operations." This equates to 40 total hours per year and corroborates using the term "minimal."

analyze and disclose potential impacts before selecting an alternative and its CAA obligation to ensure compliance with air quality laws and regulations. More generally, TVA may not avoid fully considering and disclosing the potential impacts of its preferred alternative by pointing to how much better it is than the No Action Alternative. Meaningful comparison between the impacts of Alternative A and Alternative B requires the alternatives to be evaluated on their own terms, not just in reference to a nearly 70-year-old coal plant. (Commentors: SELC and Conservation Groups)

Response: As discussed in the EIS, Alternative A would result in an overall reduction in the emissions of the regional haze pollutants relative to the existing coal plant. General regional haze studies are required at the direction of the governing regulator. The proposed project is not significant under 40 CFR 52.21 and does not require a Prevention of Significant Deterioration (PSD) analysis. Significance, as defined in this federal regulation, is not transient but applicable for the life of the permitted source. According to the Federal Land Managers' Air Quality Related Values Work Group (FLAG, Natural Resource Report NPS/NRPC/NRR—2010/232), a visibility study is not performed if a PSD analysis is not required. Since both Alternatives A and B involve replacement of the generation provided by the higher-emitting coal plant, both alternatives would result in overall reductions in the emissions of regional haze pollutants although the reductions would be greater for Alternative B than Alternative A. (See Table 3.7-3 in FEIS that provides net emissions from Alternatives A and B.) See also response to Comment 94.

93. The natural gas prices projected in the [D]EIS (p842) appear optimistic and do not seem to reflect the price spikes seen in the past or the EIA predictions that natural gas prices are expected to go up due to increasing competition. https://www.eia.gov/todayinenergy/detail.php?id=56501

I question TVA's decision to set up a system that is dependent on the fluctuation of the natural gas prices. As we increase our demand for natural gas, we become part of the problem driving up the demand and increasing the cost. How is that factor evaluated in the current project proposal? What is the worst case evaluation on the costs of natural gas?

Please add to the proposal a more detailed estimation of natural gas costs for the future, including the expected increased scarcity and the additional pressure that this plant will add.

Additionally, please assess the cost risks of the price spikes and gas shortages and the associated health risks that will occur if natural gas becomes unavailable or too costly, leading to power shortages. (Commentor: Megan Maloney)

Response: See response to *Comments No. 2 and 3.* TVA regularly updates natural gas prices to capture near-term volatility. TVA's capacity and resource planning follow least-cost principles to develop a resource strategy, aligned with TVA's strategic direction, that identifies the power resources needed to meet system demand with appropriate reserve margin. The process requires key inputs based on TVA's experience and expertise such as electricity demand, fuel and power costs, construction costs, environmental regulations, asset operating characteristics, target planning reserve margin, and transmission considerations. The inclusion of natural-gas fired CTs and CCs in the Target power supply mix outlined in the 2019 IRP accounts for potential fluctuations in natural gas prices. Key assumptions in subsequent site-specific studies can then be validated and compared against industry benchmarks, studies, and forecasts, then modeled using commercially available tools including Anchor Power Solution's EnCompass and Energy Exemplar's Aurora.

94. Comparing the proposed gas plant's emissions to the existing coal plant's is misleading. The new gas plant would not displace a coal plant, which TVA acknowledges it must retire.

Instead, the gas plant would displace zero-emission alternatives, like solar and storage in Alternative B, which would operate along a similar timeline as the gas plant in Alternative A. In its recent climate guidance, CEQ has emphasized the need to analyze energy substitution:

Some proposed actions, such as those increasing the supply of certain energy resources like oil, natural gas, or renewable energy generation, may result in changes to the resulting energy mix as energy resources substitute for one another on the domestic or global energy market. Different energy resources emit different amounts of GHGs and other air pollutants. For proposed actions involving such resource substitution considerations, where relevant, CEQ encourages agencies to conduct substitution analysis to provide more information on how a proposed action and its alternatives are projected to affect the resulting resource or energy mix, including resulting GHG emissions.

To demonstrate the true climate impacts of its proposal, TVA must acknowledge and analyze the harmful effects of displacing emission-free alternatives. TVA's focus on the net rate of CO_2 emissions relative to the coal plant ignores important climate impacts of investing in new fossil fuel infrastructure. Fossil fuel plants are decades-long investments. Completed in 1955, Kingston is nearly 70 years old. If the proposed Kingston Gas Plant goes online in winter 2027, as TVA expects, the new gas plant would result in greenhouse gas emissions through at least 2058. In a letter to TVA about the Cumberland gas-fired plant, EPA stressed the lock-in effect of investing in new fossil fuel infrastructure:

[A] new natural gas-fired generating station could replace electricity generation from an existing coal-fired station in the near term, but lock in fossil fuel consumption for decades, forcing future trade-offs between now existing natural gas generation and future renewable energy generation.

With "high confidence," the Intergovernmental Panel on Climate Change has warned of this same "lock-in" effect:

Reducing GHG emissions across the full energy sector requires major transitions, including a substantial reduction in overall fossil fuel use, the deployment of low emission energy sources, switching to alternative energy carriers, and energy efficiency and conservation. The continued installation of unabated fossil fuel infrastructure will 'lock-in' GHG emissions." (Commentors: SELC and Conservation Groups)

Response: Alternative comparisons discuss changes relative to the current baseline, which in this study is existing coal operations. Consistent with NEPA's requirement to identify and compare alternatives to a No Action Alternative, the EIS appropriately compares the CC/Aero CT Plant's emissions with those of the existing coal plant. Alternatives A and B involve TVA making a conscious decision to retire the coal plant and to replace the retired generation. Accordingly, the focus on net rate of CO_2 emissions relative to the coal plant is appropriate. If TVA did not compare the CC/Aero CT Plant's emissions with those of the existing coal plant, its analysis would not capture the net effect of the action alternatives and thereby not be consistent with NEPA. See response to *Comment No. 47*, which explains why Alternative A is the only alternative that would meet the project purpose and need. As to the comment about making major transitions across the full energy sector to reduce GHG emissions, TVA notes that the decision associated with this EIS is a specific, discrete component of TVA's blended asset strategy and consistent with the recommended target power supply mix in the 2019 IRP. TVA is implementing this target power supply mix from the 2019 IRP to affect a major transition across the energy sector to reduce GHG emissions.

95. The DEIS states, "While power plant air emissions disperse across county and state lines and contribute to effects in areas downwind, these long-distance effects from any one facility or set of facilities, such as those assessed in this document, are expected to be minimal because the largest impact of individual facility emissions typically occurs in the near field, i.e., at or just beyond a fence line, and lessens with increasing distance from the facility. This is especially the case for natural gas combustion plants vs. coal and oil-fired power plants as coal and oil generates much more particulate emissions…" This statement is confusing. How is the pollution "minimal" because it's worse closer to the source (which would in this case be surrounded be residential areas)? Please clarify and add to this section that Alt. B, solar, would have vastly preferable lower emissions than either natural gas, coal, or oil-fired plants. (Commentor: Megan Maloney)

Response: The word "minimal" referred to long-distance effects from any one facility or set of facilities. The first few sentences of this paragraph are being revised to clarify the language. Additionally, the air permitting of Alternative A would require submitting information to the Tennessee Department of Environment and Conservation to satisfy expected compliance with USEPA and TN air quality standards beyond the TVA plant fence line.

96. How are these numbers highlighted below in Table 1.6-6, Table 1.6-7, and Table 1.6-11 calculated? A citation is not referenced and the model used to estimate these numbers is not transparent. Please add further detail on this model and how these results were generated so that the public can make an informed decision. (Commentor: Megan Maloney)

Response: Methane leaks from the natural gas pipeline and further upstream from natural gas extraction and production are accounted for in the GHG life cycle analysis emissions calculations and associated social costs of methane emissions. Section 3.7.1.1.8.3(GHG and Climate Assessment Methodology) of the DEIS states that the company that would operate the pipeline (Enbridge) has committed to reducing methane emissions under the USEPA's Methane Challenge Program and provide transparency by reporting such emissions annually. Enbridge has committed to reducing methane emissions across each individual segment of the supply chain to 1percent or less of total produced natural gas. In 2020, the overall methane leak rate for all members in the ONE Future Coalition under the Methane Challenge Program was less than 0.5 percent of total natural gas flow for its entire life cycle. Enbridge also participates in an industry network that partners to implement methane emission reduction technologies and practices to further reduce methane emissions.

The methodology for calculating Alt. B (solar/battery storage) life cycle CO_2, CH_4, and N_2O emissions is provided in Appendix J. The emission factors are presented in Tables J.6-1 through J.6-4 with references cited in footnotes.

97. Based on Table 1.6-17, it appears that there is a much greater social cost expected from Alternative A (Alt. A) than in Alternative B (Alt. B).

It is understood that CH4 is a far more potent greenhouse gas than CO_2. The environmental risk of CH_4 generated in Alt. A is quite high, so the TVA's least cost approach does not adequately address this risk in a meaningful manner and lacks an explicitly stated rationale, evaluation and analysis to address risks and implement risk control.

The evaluation of alternatives should encompass a wide range of risks and hazards associated with the proposed project. This includes assessing the potential for power dropouts, weather impacts (such as severe storms or extreme heat), climate change implications, methane gas leakage, fire hazards, explosion hazards, and socio-economic hazards. What strategy and rationale was employed by TVA in analyzing the integrity of the entire system, including the rising number of substation attacks, as this can have significant consequences for grid stability and reliability? Please address this in your project proposal.

To ensure a comprehensive evaluation, TVA must not only identify potential risks but also present effective risk control measures for each identified hazard. Merely stating the installation of detectors on the pipeline, for example, is not adequate to evaluate the likelihood of hazardous situations that give rise to environmental harm such as methane leak, climate damage, or direct harm to nearby communities from a related explosion, fire or release of pollutant. As each of these risks and harm carries severe penalties to the community and economy, how does the TVA's least cost approach reconcile the gap of latent opportunity cost presented above? How does the TVA assess the efficacy of the proposed mitigation strategies, such as robust leak detection systems, operational and proposed preventive maintenance, and emergency response plans, to minimize the environmental, health, and safety risks associated with both alternatives? This must be done before committing to this alternative and should be included in the proposal.

Similarly, for the solar power plant, how does the TVA evaluate the potential harm associated with the transportation, installation, and maintenance of solar panels? This assessment should include an analysis of the environmental impacts and potential risks posed by the material sourcing, production processes, chemical usage, waste management, and especially the recycling plan of the solar panel components at decommission.

How does the TVA evaluate the worst-case situations for each alternative in potential hazards, harm, economical impact and costs? The current proposal presents unsubstantiated assumptions for risk, and superficial plans for mitigation are unrealistic and inadequate to inform or protect the affected communities. (Commentor: Megan Maloney)

Response: The LCA social costs of GHGs in Table I.6-17 are only part of the whole story regarding GHG emissions and social costs from this proposed action. In this table, the action alternatives are only including the replacement resources at KIF (Alternative A) and KIF coal plant replacement resources using solar/battery storage (Alternative B). In essence, this LCA is providing a picture of GHG social costs in isolation. The bigger picture and more accurate overall GHG picture is presented in the TVA system-wide LCA. That LCA presents the savings in social costs of GHG under Alternatives A and B, as compared to the no action alternative, considering the entire TVA system. That difference is much less than the difference in social costs between Alternative A and B in Table I.6.17. Please review the response to comment 81 for a more detailed explanation of the difference in absolute SC-GHG values from the individual resource LCA compared to the narrower divergence under the TVA system wide LCA.

As described in Resource Report 11 of ETNG's application[7], the Ridgeline Project will be constructed and operated in accordance with applicable DOT/PHMSA requirements. Also as described throughout ETNG's application, construction and operation of the Project is not anticipated to have a significant

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[7] Available online at https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20230823-5107

environmental impact on affected communities with adoption of its proposed avoidance, minimization, and mitigation measures.

The potential impacts associated with the transportation, installation, and maintenance of solar panels is included in the GHG lifecycle emissions and social cost calculations for Alternative B. The entire lifecycle, including upstream, operational and maintenance, and downstream GHG emissions and social costs, were calculated and compared for each alternative. These emissions/social costs account for all risks identified in this *Comment No. 96*; and the text at the beginning of Appendix J details the methodology for the LCA.

98. Data in Appendix C are not consistent with data in Appendix I.

Appendix C, pg. C-29, includes emissions from "existing coal and gas units increase generation for battery charging or hours when solar is unavailable." This is inconsistent with Appendix I which explicitly states that there are "no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations" (Appendix I pg. I-12, footnote NA2 = Not Applicable). TVA should eliminate the inconsistencies between Appendix C and the calculations in Appendix I, where there are life-cycle carbon emissions from Alternative A, but there are no operational emissions from Alternative B included in those lifecycle operations, as reflected in DEIS Table 3.7-3, pg. 361 (Commentor: Citizen's Climate Education).

Response: The sentence referenced by the commentor in Appendix B is referring to the TVA system as a whole, which would be considered indirect emissions. The sentence referenced by the commentor in Appendix I to the DEIS (now Appendix J) is only applicable to direct operational emissions from solar/battery facilities that would be constructed to replace the KIF coal plant. This is not an "apples-to-apples" comparison and there is no inconsistency. Note that life cycle operational GHG emissions have been added to Alternative B to account for maintenance activities at the solar/battery sites.

99. The reviewer cannot verify data shown in DEIS Appendix C, pg. C-29. The reference is stated as "TVA's Vintage: FY23 Budget". A publicly available reference should be used for the carbon rate and cited. (Commentor: Citizen's Climate Education)

Response: Appendix B shows TVA's system carbon intensity under each alternative. The reference listed reflects the vintage of inputs and assumptions used in this analysis, which can be found earlier in Appendix B.

100. Appendix C, pg. 29, lists the carbon rate for Alternative A at 433 lbs./MWh while Alternative B is 420 lbs./MWh. TVA explains the rational for the carbon rates being so similar; however, the explanation does not make sense. These values are so close it appears that 'existing coal and gas units' would be used almost constantly to 'for battery charging or hours when solar is unavailable. (Commentor: Citizen's Climate Education)

Response: Appendix C (Appendix B) shows TVA's system carbon intensity based on the least-cost dispatch of each alternative. The system-wide view provides critical context into how the specific resource retirements and replacements, underpinning the assumptions of each of the Proposed Action Alternatives, integrate into the system overall. Given current costs, dispatching efficient gas is often the most economic option compared to other resources. A substantial part of dispatch merit order is the cost of fuel and ensures the least cost dispatch.

101. Carbon emissions from solar in Appendix I (i.e., Table I.6-2 pg. I-12 uses a value of 63.99 CO_2eq g/kW-hr), which is based on the reference cited for 64 g CO /kWh in the Cumberland FEIS, which dates from a reference from 2012 and when older Mono-Silicon type technology was in production. This reference should be updated to reflect accepted GHG intensity of wind, solar, and nuclear and hydro which might be in the range of 8-12 gCO_2 per kWh.

The value of 64 gCO_2/kWh is not supported by other older literature. The NREL 2012 fact sheet cites a world average of approximately 40 g CO_2/kWh.8 A newer review incorporating many older sources cites a similar figure. Current literature values suggest that GHG emissions could range from 5- 12 g CO_2/kWh for solar generation using today's technologies. The value of 64 gmCO_2/kWh is least 40% higher than that supported by current data and could be 5 times higher that newer lifecycle analysis suggests. (Commentor: Citizen's Climate Education)

Response: The FEIS includes updates to the LCA for the solar technology based on the 2021 revised NREL LCA emission factors. The result is a change in the overall CO_2-e emission factor from 64 g/kWh to 43 g/kWh for photovoltaic technology. See Section 3.7 and Appendix J.

102. As solar technology continues to improve, the lifecycle CO_2 emissions from installing and running the replacement solar array in 20 years will likely be lower than the current values. Although this is difficult to predict, some adjustment in the lifecycle analysis of Alternative B should be included to reflect lower lifecycle greenhouse emissions for future solar generation. (Commentor: Citizens' Climate Education)

Response: The EIS provides estimates based on the best available information. TVA cannot predict with any reasonable certainty what the lifecycle CO_2 emissions would be from installing and running the replacement solar/battery array over 20 years from now. There are likely other future changes that could affect the operation, maintenance, and decommissioning of both alternatives but there is no valid way to accurately predict what those would be and how the lifecycle CO_2 emissions would be affected at that future time.

103. Data in Table 3.7-10, pg. 382 compares Alternatives A and B for TVA system-wide reduction in cost of carbon. Such a comparison is not valid in the context of this EIS because the relative benefit of each option is masked by system-wide emissions. Although, evaluation of other system-wide actions (e.g., more Distributed Energy Resources) could be evaluated to assess system-wide actions, using system-wide data to support decision making on two options is not valid. (Commenter: Citizens' Climate Education)

Response: The EIS discusses estimated social costs of GHG emissions on both an individual and system-wide basis, see Chapter 3.7. A system-wide analysis is more thorough and presents a clearer measure of the change in overall GHG emissions reductions as compared to only presenting analysis with respect to a single plant or the replacement power for a single plant. Refer to response to *Comment Nos.* 81 and 88 for additional information on this topic.

104. TVA's Social Cost of Greenhouse Gases analysis violates Executive Order 13,990. By refusing to apply the Social Cost of Greenhouse Gases in accordance with the Interagency Working Group's guidance, TVA has violated Executive Order 13,990. As discussed, President Biden re-established the Interagency Working Group on the Social Cost of Greenhouse Gases, instructed them to publish interim Social Costs of Carbon, Methane, and Nitrous Oxide, "which agencies shall use when monetizing the value of changes in greenhouse gas emissions." In

February 2021, the Interagency Working Group published interim figures, with a range of four different values for each greenhouse gas. Those include three different discount rates: 2.5%, 3%, and 5%. The Interagency Working Group included a fourth value—a 3% discount rate with more expensive damages—to represent "higher-than-expected economic impacts from climate change." The IWG explained why agencies should apply all four values:

For the purpose of capturing the uncertainties involved in analyses, the [Interagency Working Group] emphasized and emphasizes in this [Technical Support Document] the importance and value of including all four SC-GHG values. In particular, values based on lower discount rates are consistent with the latest scientific and economic understanding of discounting approaches relevant for intergenerational analysis.

The way to address uncertainties is not to apply unsupported "prior Administration" numbers. Instead, as the Interagency Working Group explained, it is to apply the three specified discount rates, plus a fourth high-damages value. Despite this clear directive, TVA applied only a 3% discount rate. Against EPA's objection, TVA did not apply the 2.5% discount rate, the 5% discount rate, or the high-damages fourth value. TVA's refusal to apply Social Cost of Greenhouse Gas values in compliance with the Interagency Working Group's Technical Support Document violates Executive Order 13,990. (Commenter: Southern Environmental Law Center/Conservation Groups)

Response: See response to *Comment No. 77*, *79, and 81.*

105. The DEIS states that the plant design proposed under the preferred alternative "enables and accommodates future modifications necessary for incorporating CCS (Carbon Capture and Storage) and will obtain combustion equipment that can utilize hydrogen fuel blending (at least 30 percent hydrogen) as these technologies mature. TVA anticipates the efficiency, effectiveness, scalability, and economics of these systems will improve in the future, allowing for incorporation of one or more of these technologies when adequate storage locations, pipelines, or another technology for carbon storage are identified to implement CCS and/or the delivery of hydrogen."

If TVA intends to install carbon mitigation measures in the future, these costs should be included in their analysis.

The EPA also believes functional carbon capture and hydrogen fuel blending technologies should be included in the initial plant design. Utilities similar in size to TVA's Kingston plant are displacing some portion of their natural gas generation with these technologies in a comparable timeframe. For example, the Intermountain Power new natural gas generating units, which will begin operation in 2025, will be designed to utilize 30 percent hydrogen fuel at start-up, transitioning to 100 percent hydrogen fuel by 2045 as technology improves (see https://www.ipautah.com/ipp-renewed/). While smaller in scale, other utilities are displacing a portion of their natural gas use with hydrogen (see https://dailyenergyinsider.com/news/34040-florida-power-light-taps-cummins-for-its-green-hydrogen-facility/). Additionally, Competitive Power Ventures is constructing a CC natural gas generation facility using carbon capture technology (see https://cpv.com/2022/12/12/cpv-selects-doddridge-county-for-location-of-3-billion-carbon-capture-project-in-west-virginia/). (Commentor: USEPA)

Response: Initial plant design under Alternative A would accommodate future modifications to incorporate CCS or hydrogen co-firing when these technologies become commercially available. The

FEIS discusses these nascent technologies – CCS and hydrogen co-firing – that are identified in EPA's 2023 Proposed GHG regulations. TVA believes these technologies have not yet been adequately demonstrated for commercial use. However, Appendix B includes a sensitivity analysis that addresses EPA's Proposed GHG regulations.

While TVA has considered the examples provided by EPA, it notes that those facilities are distinguishable from the KIF. The Intermountain Power Agency (IPA) project is situated on 4,614-acre site in Utah, with substantial existing infrastructure and abundant space to build the additional facilities that would be required for additional hydrogen components. However, as stated at the referenced link, "Currently, renewable energy, such as wind and solar power, is not dispatchable. The transition to a clean energy grid will require generating resources that are dispatchable and energy storage resources with long-term, even seasonal, capabilities, such as hydrogen. The IPA project's proximity to the only major geologic salt dome formation in the west makes it the ideal location for siting and scaling up these emerging clean energy technologies" (Intermountain Power Agency 2023). The Kingston Reservation, by contrast, is approximately a quarter of the size of the IPA project and does not have the benefit of proximity to a salt dome formation. Despite those challenges, under Action Alternative A, the proposed CC/Aero CT Plant would be designed to be capable of utilizing 30 percent hydrogen fuel at start-up, with a plan to transition to up to 60 percent hydrogen when technology improves, subject to the availability of an adequate and reliable hydrogen supply.

Competitive Power Ventures (CPV) project consists of 1,800 MW of generation through combination of natural gas and carbon sequestration (Competitive Power Ventures 2023). However, unlike the CPV project, the Kingston project is not located in an area that is conducive to carbon capture and sequestration (see Section 2.1.5.3 of the FEIS) due to extensive karst geology (see Section 3.5.1.1.1.3 of the FEIS).

The Florida Power and Light (FPL) Cavendish NextGen Hydrogen Hub project will generate hydrogen onsite for blending with natural gas to power an existing combustion turbine (Kovaleski 2023). Hydrogen production to-date is an inefficient process requiring more energy than it produces. Due to these inefficiencies, hydrogen would need to be made and stored on the Kingston Reservation to have dispatchable energy available to support the energy demand of the Knoxville region. Otherwise, the site would be a negative energy sink during hydrogen production. The Kingston Reservation lacks sufficient space to construct a hydrogen production facility onsite and does not have underground salt caverns or other means of hydrogen storage to support the combined cycle facility proposed under Alternative A. As such, onsite hydrogen production and storage are infeasible on the Kingston Reservation.

106. The lifecycle of Sulfur Hexafluoride (SF_6), starting from manufacturing, produces significant SF_6 emissions. The EPA has partnered with utilities to reduce and phase out the use of this pollutant, as have other countries. In addition, SF_6 free switchgears are reported to have lower operation and maintenance costs and higher reliability. The EPA recommends that TVA monitor the evolving technology and commercial availability of SF_6-free switchgears and, where equipment availability and project requirements allow, use SF_6-free switchgear in new construction and replacement installations. For SF_6-containing switchgear, the EPA recommends that TVA implement a program of best maintenance practices, inspection, leak detection and repair. (Commentor: USEPA)

***Response*:** The switchgear units that would be utilized for this project are manufactured to meet industry standards. As stated in Section 3.7.2.3.5 of the FEIS, some older existing electrical equipment may contain the GHG sulfur hexafluoride (SF_6) gas (e.g., electrical switchgear, circuit breakers), which could have minor leaks, mostly associated with maintenance or long-term equipment degradation. Additionally, where newer equipment has been installed or is proposed, along with more efficient operation and maintenance techniques, and leak detection, these features would minimize sulfur hexafluoride emissions. The only other market-available switchgear option (vacuum) does not provide interruption to support NERC Protection and TVA reliability standards to provide safe reliable power for the Tennessee Valley. A system-wide review of SF_6 switchgear conversion would be outside the scope of this analysis; however, TVA actively monitors evolving technology for future consideration.

107. The U.S. Department of the Interior (Department) appreciates the opportunity to review the Tennessee Valley Authority (TVA) Kingston Fossil Plant (KIF) Retirement, Draft Environmental Impact Statement (DEIS). The Department supports the proposed retirement of the existing KIF coal-fired electric generating units (EGUs) and encourages TVA to increase the renewable component of their generation fleet mix to the maximum extent feasible when selecting power generation replacement options for KIF and throughout the TVA system.

TVA prepared the DEIS to evaluate the retirement, demolition, and replacement of nine coal-fired EGUs at the KIF facility, located in Roane County, Tennessee. TVA is proposing to construct and operate at least 1,500 megawatts (MW) of replacement generation with either new natural gas-fired combustion turbines (Alternative A, preferred alternative) or utility-scale solar facilities (Alternative B).

The NPS is participating as a cooperating agency in the preparation of the DEIS and provided staff-level cooperating agency comments on the KIF administrative DEIS in March 2023. We appreciate the responses and DEIS revisions that TVA provided addressing NPS input, including clarification of the equipment that will be constructed under Alternative A, and 1 Alternative A, the preferred alternative, includes the construction and operation of a combined cycle gas plant paired with sixteen dual-fuel aeroderivative combustion turbine units, a 3- to 4-MW solar site, and a 100-MW battery energy storage system (BESS) on the Kingston Reservation along with a 122-mile natural gas pipeline and gas compressor station to supply natural gas to the new plant. Alternative B includes the construction and operation of multiple solar generation and energy storage facilities at alternate locations throughout the region. TVAs full responses to NPS comments were included in Appendix P to the DEIS. This letter addresses outstanding recommendations and new information provided in the DEIS. Specifically, the Department:

(1) Continues to support the retirement of coal-fired EGUs and recommends more detailed consideration of renewable energy alternatives for replacement generation in the KIF proposal. This recommendation supports goals established in Executive Order 14057 to achieve a carbon pollution-free electricity sector by 2035.
(2) Recommends that TVA require nitrogen oxide emissions limits equivalent to those achieved with selective catalytic reduction for the combined cycle plant and the sixteen simple cycle aeroderivative combustion turbines proposed under Alternative A. Reducing these emissions will improve visibility and minimize pollutant deposition in Great Smoky Mountains National Park, located approximately 60 km southeast of KIF.

Retirement of the KIF units will reduce reliance on coal-based energy, benefiting air resources in nearby units of the NPS system, and cut climate-warming carbon dioxide emissions. For decades, the TVA coal-fired units have contributed to substantial visibility impairment, ozone formation, and pollutant deposition in NPS units across the region, including in three parks designated as Class I areas under the Clean Air Act: Great Smoky Mountains National Park in North Carolina and

Tennessee, Mammoth Cave National Park in Kentucky, and Shenandoah National Park in Virginia. Virtually all NPS units are vulnerable to the risks associated with climate change. As such, the Department has a significant interest in replacement generation that will positively affect air quality and ecosystems in these protected areas for the benefit of future generations.

As the nation's largest government-owned utility, TVA is in a unique position among federal entities to lead by example and dramatically shift the environmental and climate burden of energy production in the United States. While cleaner than coal, natural gas-fired generation still emits criteria air pollutants and just over half the amount of greenhouse gases on a pound-per-megawatt basis as coal. The KIF proposal is one of eight natural gas-fired power generation replacement projects that TVA has implemented or proposed recently.

TVA constructed two combined cycle plants totaling 2,200 MW of replacement capacity in 2017 and 2018 and has approved or proposed another 5,921 MW of natural gas-fired capacity since 2021. This new fossil fuel-fired generation will be in place for decades to come, potentially resulting in tens of millions of tons of greenhouse gas emissions annually. Further, these new-generation assets may be subject to future retrofit requirements. From a cost perspective, future retrofits with carbon capture and storage may be more costly than investing in renewable energy and storage options from the onset. Therefore, the Department encourages TVA to move to carbon-free energy sources to the maximum extent possible and employ all available mitigation options to reduce GHG emissions now and in the future.

The Department appreciates the opportunity to comment on the KIF Retirement DEIS, and we commend TVA for evaluating the retirement of coal-fired EGUs throughout its system. (Commenter: National Parks Service)

Response: Comments noted. Alternative A does include SCR technology to reduce NOx emissions; refer to Appendix I, which shows the incorporation of SCR technology for both the CC and CTs in the emissions calculations. Alternative A would provide firm, dispatchable power that is critical to preserve reliability and resiliency upon the retirement of the coal plant. TVA also notes that the proposed CC/Aero CT Plant is one component of TVA's larger decarbonization efforts and that the added CC and CT capability will facilitate the integration of 10,000 MW of solar onto the grid. Additionally, Appendix B includes a worst-case sensitivity analysis that accounts for the cost of CCS and hydrogen blending.

108. In the EPA's comment #6 it recommends "presenting the full details about the assumptions of the model and the outputs across the TVA system" from TVA's system-wide LCA analysis. TVA states in its response to EPA's comment that "All necessary generation data germane to the evaluation of the System-wide LCA analysis and the assessment of climate impacts is provided in the DEIS." However, many key pieces of information about the assumptions and outputs are missing. In a supplemental or final EIA, TVA should include at least the following in clearly marked numerical tables or spreadsheets (not charts or unlabeled tables):

- **Assumptions:**
    - **Annual total load, winter peak demand, and summer peak demand assumptions for duration of analysis.**
    - **Annual capital costs of all potential resource additions, including incentives.**
    - **Annual costs for energy efficiency and demand response resources.**
- **Outputs:**

- **Annual capacity factors for each new and existing resource for each alternative, throughout the analysis period**

In a supplemental or final EIS, TVA should clarify that it used the same assumptions in its cost analysis as in its system-wide GHG LCA analysis. The charts of assumptions presented in Appendix C, while not detailed enough for public review because no tables or values are provided, may or may not be what TVA used in its system-wide GHG LCA analysis. (Southern Alliance for Clean Energy)

Response: The relevant assumptions and data necessary for the evaluation of the System-wide LCA analysis and the assessment of climate impacts is provided in the EIS in Section 3.7.2.5 and Appendix J.

Appendix B details the pertinent assumptions TVA used in its comparison of the project costs of the different alternatives. The alternatives are compared because the differences between each alternative are specific to the decision to retire or not retire KIF and the associated replacement generation outlined in each alternative. Appendix J provides a comparison of the system-wide GHG LCA costs for the alternatives. The assumptions and conditions used in the system-wide GHG LCA are included in Appendix J.

109. On page 28 of Appendix C of the DEIS, TVA presents system-wide costs relative to Alternative A, but nowhere in the DEIS does TVA present actual system-wide costs. This is inadequate for public review because we cannot determine whether the cost differences are minor or major compared to the overall cost of each alternative. In a supplemental or final EIS, TVA needs to provide values for the absolute cost of each alternative for each of the categories presented in Appendix C: Transmission Infrastructure, Production Costs, Fixed and Capital Investments, and Fuel Supply Infrastructure. (Southern Alliance for Clean Energy)

Response: Page 29 of Appendix B provides the total system costs for the No Action alternative and Alternative B relative to the costs of Alternative A. Normalizing the total system costs in relation to the preferred alternative (Alternative A) provides a means to easily compare the costs of the No Action and action alternatives. See also response to *Comment No. 108*.

110. It is standard practice in least-cost planning and production cost analysis to perform sensitivity analysis for various assumptions and forecasts to accommodate uncertainties, particularly forecasts of fuel prices, annual energy needs, peak loads, and environmental regulatory costs and requirements. In a supplemental or final EIS, TVA needs to describe the sensitivity analyses performed to evaluate the appropriateness of future cost risk mitigation of each alternative, and publish in the supplemental or final EIS the values of adjusted assumptions used in the same manner as described in SACE comment #8 above. In addition, in the supplemental or final EIS, TVA needs to present the absolute costs of each alternative under each sensitivity as described in SACE comment #10 above.

In a supplemental or final EIS, TVA should include at least one sensitivity that complies with the EPA's proposed GHG regulations for new and existing coal and natural gas power plants. For instance, the modification of Alternative A gas resources to include carbon capture and sequestration or high levels of hydrogen blending and the projected cost of that hydrogen fuel to replace natural gas. Cost analysis that only considers up to 5% of hydrogen blending exposes TVA ratepayers to a potentially significant increase in future costs as TVA complies with the EPA's proposed GHG regulation. It is not enough to say that the final EPA GHG regulation is

uncertain and has the potential for litigation. By assuming no regulation in the next 30 years, the lifetime of the gas resources proposed in Alternative A, TVA is making an extreme and dangerous assumption that exposes TVA ratepayers to cost increase risks that were foreseeable at the time these resource decisions are being made. (Southern Alliance for Clean Energy)

Response: See response to comments 108 and 109. Appendix B includes a sensitivity analysis that addresses EPA's Proposed GHG Rules.

111. In a supplemental or final EIS, TVA needs to provide the capacity factors for the new gas plants proposed in Alternative A as part of the system-wide LCA, since it was based on least-cost dispatch rather than historical averages. (Southern Alliance for Clean Energy)

Response: See response to *Comment No. 73* for capacity factor details used for Alternative A.

Climate Change and Climate Impacts

112. Addressing climate change is a federal policy priority. TVA "may not simply disregard an Executive Order. To the contrary, as an agency under the direction of the executive branch, it must implement the President's policy directives to the extent permitted by law." The Administration has emphasized that a "100% carbon pollution free electricity sector" is "an important foundation" for the United States' strategy to reach net zero carbon emissions by 2050. The Executive Orders do not set a goal of merely "reducing emissions." The goal is a "carbon-pollution free electricity sector by 2035." The new gas plant would begin operation in winter 2027. Because the Kingston Gas Plant would emit greenhouse gases for decades beyond the decarbonization deadlines ordered by President Biden, Alternative A conflicts with our national climate goals. TVA fails to reconcile or even acknowledge that conflict with federal law. Instead, TVA points to an illusory conflict between its statutory mandates and federal climate policy. No such conflict exists. The TVA Act and Energy Policy Act require TVA to "provide adequate and reliable service to electric customers of the Tennessee Valley Authority at the lowest system cost." "[S]ystem cost" means "all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, transportation, utilization, waste management, [and] environmental compliance." [L]owest system cost" includes "harms that a decision might do to human health or the environment." Without disclosing key assumptions, TVA estimates that Alternative B will cost $1.2 billion more than Alternative A. TVA will have to apply expensive mitigation technologies to the proposed gas plant, yet TVA refuses to acknowledge those costs. Meanwhile, TVA estimates that the Social Cost of GHG emissions for Alternative A will be $6 billion greater than for Alternative B. A clean energy portfolio, including solar and storage, can provide adequate and reliable service at the lowest system cost. Replacing the Kingston Fossil Plant with a clean energy portfolio, including solar plus storage, would satisfy TVA's statutory obligations as well as federal climate policy. (Commentors: SELC and Conservation Groups, Center for Biological Diversity)

Response: TVA is a wholly-owned corporate agency and instrumentality of the United States. However, federal executive orders create binding legal obligations for TVA only to the extent that Congress or the Constitution gives the President authority to bind it in the relevant policy area. The current Administration's recently promulgated climate-related Executive Orders do not cite any specific statutory or constitutional authority addressing climate policy. These Executive Orders recognize that they "shall be implemented consistent with applicable law and subject to the availability of appropriations" and that they do not "impair or otherwise affect the authority granted by law to an executive agency or the head thereof." TVA has not received any appropriations to implement a broad climate policy of achieving zero carbon emissions by 2035. Given that these Executive Orders do not cite any specific statutory or constitutional authority and given that Congress has not appropriated funding to TVA to support their implementation, TVA must consider them within the context of specific statutory requirements imposed on TVA by Congress to carry out its mission. For instance, Congress specifically delegated authority to the TVA Board to, among other things, "establish the broad goals, objectives, and policies of [TVA] that are appropriate to carry out [the TVA] Act" and "develop long-range plans to guide the Corporation in achieving those goals, objectives, and policies." In doing so, the TVA Board must keep in mind a "primary objective" of the TVA Act--to keep rates as low as are feasible. Further, the TVA Act, as amended by the Energy Policy Act of 1992, imposes on TVA an obligation to employ a least-cost planning and selection process for energy resources, "evaluating the full range and cost of existing and incremental resources…in order to provide adequate and reliable service to electric customers…at the lowest system cost." The decision at Kingston aligns with the target power supply mix outlined in the 2019 IRP, which implements the requirements of the Energy Policy Act of 1992 and is therefore the least-cost option that also allows TVA to significantly reduce emissions.

TVA's own climate goals align with the intent and purpose articulated in the referenced Executive Orders implemented by the Biden Administration, which is to reduce emissions. TVA is executing a plan to achieve a 70% reduction in carbon intensity by 2030 (from 2005 levels), sees a path to ~80% reduction by 2035, and aspires to achieve net-zero emissions by 2050. Alternative A is consistent with TVA’s target power supply mix and systemwide decarbonization efforts.

See also response to *Comment No. 37*. Regarding the comparison of social costs of GHG between the alternatives and the difference between the individual resource LCA and TVA system wide LCA, see response to *Comment No.* 81.

113. Climate science has made it abundantly clear that to preserve a livable planet, and limit warming to 1.5 degrees Celsius, global economies must immediately transition off fossil fuels. Earlier this year, the Intergovernmental Panel on Climate Change (“IPCC”) warned that without drastic steps to curb emissions we are likely to surpass 1.5 degrees of warming by early 2030. This future would bring unimaginable harm to communities across the world, with the most severe and catastrophic consequences felt by communities of color and low-wealth.

In TVA’s footprint, the realities of a rapidly changing climate with more intense disasters are all too familiar. Communities have and will continue to face more frequent and extreme winter storms, destructive flooding, record-breaking tornadoes, and heat waves without drastic and immediate action from the country’s biggest polluters to cut emissions and transition to clean, renewable and resilient energy. As the country’s largest public power provider, TVA should be leading the way when it comes to tackling the climate crisis. In fact, TVA’s environmental policy dictates that “TVA improves the quality of life and the environment by providing [...] increasingly clean energy”. A new gas plant would do the exact opposite and instead fuel the flames of the climate crisis, thereby threatening people’s quality of life.

TVA acknowledges that the solar and storage alternative would result in more beneficial climate impacts and emissions reductions, compared to both the No Action Alternative and Alternative A. However, TVA then goes on to justify that it still believes the gas plant is the best option because it meets the utility’s purpose of providing 1,500 MW of “firm, dispatchable power”. Draft EIS at xiv. (Commentors: On Behalf of 37 Climate, Justice and Community Organizations, Center for Biological Diversity , SELC)

Response: TVA appropriately determined the purpose and need that animates the alternatives considered in this EIS. As outlined in TVA's Aging Coal Fleet Evaluation, KIF in its current condition, reaches the end of its useful life in 2027. As such, the retiring coal generation from the coal plant must be replaced with firm, dispatchable power by the end of 2027. The gas alternative provides TVA replacement power that has the same attributes – firm, flexible, and dispatchable – as the power from the coal plant that would be retired. These attributes for replacement power are necessary to be able to preserve the reliability of the electric grid in the Eastern Tennessee area. Further, the gas alternative also meets the need of integrating vast amounts of solar – 10,000 MW – onto the TVA electric system. The 2019 IRP identified a need for additional CC and CT generation to meet TVA's long-term goal of integrating 10,000 MW of solar onto the grid by 2035. The 1500 MW of generation from Alternative A would replace the KIF generation and put TVA in a better position to integrate large amounts of solar onto the grid without compromising the reliability of that grid in the Eastern Tennessee region.

In contrast, Alternative B (Solar and Storage Alternative) would require substantial transmission upgrades and lengthy timeframes for the transmission work such that Alternative B would not meet the need to provide replacement generation by the end of 2027 when the KIF units would be retired. Moreover, Alternative B would not provide the firm, dispatchable generation needed to meet year-round generation and provide a reliable and resilient power supply to customers. Under CEQ's regulations at 40 CR 1502.14, the alternatives section should present the environmental impacts of the proposed action and the alternatives in comparative form based on the information and analysis presented in the sections of the affected environment and the environmental consequences. CEQ's regulations require agencies to include the no action alternative in the alternatives section. The No Action Alternative provides, among other things, a benchmark, enabling decisionmakers to compare the magnitude of environmental effects of the action alternatives. Therefore, it is appropriate to compare both alternatives (Alternatives A and B) with the No Action Alternative since both action alternatives are being evaluated as replacement power for the retiring coal plant. Both alternatives, compared to the No Action Alternative, would result in a net reduction in GHG emissions. While this net reduction is greater for Alternative B than Alternative A, Alternative B does not meet the time-critical need to have replacement power in commercial operation by the time the coal plants are retired in 2027.

114. Recent public communications by UN chief Antonio Guterres emphasized the urgent actions needed to avoid climate disaster and that further fossil fuel development is "incompatible with human survival." He went on to state "Current policies are taking the world to a 2.8 degree temperature rise by the end of the century. That spells catastrophe, yet the collective response remains pitiful. We are hurtling towards disaster, eyes wide open — with far too many willing to bet it all on wishful thinking, unproven technologies and silver bullet solutions." TVA continues to ignore this message. TVA seems to think it can set the timeline for when it will transition to a carbon free energy system, but it is tragically mistaken in that belief—the earth's climate system is what determines that timeline.

Adding another major carbon emissions source given the current understanding of the precarious state of our planet's climate system is reckless and unconscionable. The most recent report of the International Panel on Climate Change (IPCC) has stated unequivocally that no additional fossil fuel infrastructure should be built if we are to avoid unmanageable climate disaster. (1)

TVA continually claims it is building the "energy system of the future," but seems to be mired in the past. This DEIS cites the TVA "strategic plan document" (2) which states emphatically that TVA is committed to applying the best science and technology to formulating its power planning, yet it ignores the international scientific consensus that inspired secretary general Antonio

Guterres statements quoted above. The urgency of addressing climate change is now considered accepted scientific consensus and renewable generation technologies such as solar, wind, geothermal are considered the affordable and practical technologies necessary to replace fossil generation. (1)

TVA cites 42 U.S.C. §7545(o)(1)(G) in its discussion of air pollution: "Greenhouse gases (GHG) in the atmosphere17, primarily CO2, N2O, methane (CH4), and other fluorine-containing compounds, absorb heat that is radiated from the Earth's surface. Anthropogenic increases in atmospheric concentrations of GHGs are considered the main driver for warming of the Earth's atmosphere since the beginning of the industrial era by trapping more heat, resulting in what is referred to as global warming, which is one aspect of climate change." However, TVA continues to ignore not only the greenhouse gas emissions but all the other increased air and water pollutants emitted upstream of the gas pipeline of alternative A. (Commentor: Joe Schiller)

Response: See response to comment numbers 82 and 113. TVA is not ignoring GHG or other emissions from Alternative A nor the upstream air and water impacts from the gas pipeline. The FEIS assesses these impacts in detail. As to GHG emissions, Alternative A would result in a reduction in GHG emissions although this reduction would be smaller than the reduction achievable through Alternative B. A full GHG analysis is provided in Sections 3.7.2.3.1.3, 3.7.2.3.1.4, and 3.7.2.3.7 of the FEIS regarding Alternative A, and Sections 3.7.2.4.1.3, 3.7.2.4.1.4, and 3.7.2.4.3 of the FEIS regarding Alternative B, and Section 3.7.2.5 of the FEIS regarding the TVA system wide GHG cumulative impact for each Alternative. However, Alternative B does not meet the purpose and need of having firm dispatchable power in place by 2027 when the KIF must retire at the end of its useful life. In addition to Alternative A achieving reductions in GHG emissions, this alternative also facilitates GHG reductions in the long run by enabling the integration of large amounts of renewables onto the grid.

115. TVA has yet to put forward a plan for how it will achieve federally mandated clean energy targets. Upon taking office, President Biden issued an Executive Order to transform the entire U.S. electricity sector to be carbon-free by 2035. The President emphasized the Administration's policy "to organize and deploy the full capacity of its agencies to combat the climate crisis." The Kingston Draft EIS does the exact opposite. As a federal agency and the country's largest public power provider, TVA must advance carbon-free electricity on a timeline consistent with climate science, the President's goal, and TVA's conservation mandates. The Kingston Plant Draft EIS must therefore fully and fairly consider alternatives providing for the rapid retirement of the Plant and its replacement with clean, renewable energy sources.

Last year TVA proposed a non-binding plan to decarbonize TVA by 2050. This empty promise is meaningless on its own, but also only further demonstrates that, at bare minimum, it makes no sense to build new fossil fuel resources in the middle of the climate emergency. Accordingly, to address the climate crisis and comply with the TVA Act, it is critical that TVA rapidly transition away from fossil fuels, including both its remaining coal plants as well as its fossil gas resources, and that the agency not build any new fossil energy generation to replace the retirements of existing fossil resources. (Commentor: Center for Biological Diversity)

Response: See Response to Comments 5 and 112. TVA is decarbonizing its generation fleet as evidenced by the significant decrease in coal-based generation from 2005 to 2020 and a concomitant increase in nuclear generation. Along these lines, TVA expects to retire its coal fleet by 2035. The trajectory of these GHG emissions reductions places TVA on the path to an 80 percent reduction by 2035. TVA must achieve these reductions in a manner consistent with its statutory obligations to sell power at rates as low as feasible and to add generation consonant with least cost planning principles.

Environmental Justice & Socioeconomics

116. This gas project will have disproportionate impacts on communities who have already been exposed to coal plant pollution for generations. TVA found that all of the low-income census block groups in Roane County near the plant site scored higher than the majority of Tennessee for their proximity to superfund sites, exposure to respiratory hazards and cancer risk caused by air toxins. Yet, TVAs environmental justice analysis still fails to meaningfully consider the impact that nearly 70 years of coal plant pollution has had on these communities.

For instance, TVA makes hardly any mention of the 2008 Kingston coal ash spill in its analysis. This spill was the largest industrial disaster in U.S. history, when more than a billion gallons of coal ash dumped into the Clinch and Emory rivers and the surrounding community. In the aftermath, TVA tore down 100 affected homes and turned their neighborhood into a park. During the five-year clean up of the spill, workers were denied protective equipment and now are suffering from serious illnesses due to their exposure. It's hard to imagine that a federal utility could plan to pollute these same neighborhoods for another 30 years without taking this significant history into account. (Commenter: Appalachian Voices, SELC, Center for Biological Diversity)

Response: This EIS evaluates the retirement of the KIF coal units and replacement generation and considers environmental impacts associated with that action, including potential impacts to environmental justice communities. The CC/Aero CT Plant under Alternative A would eliminate air pollution from burning coal. In addition, there would be an annual reduction in emissions of regulated criteria pollutants and greenhouse gases with significant reductions in SO_2, NOx, sulfuric acid, greenhouse gases, and particulates. Further, in the EIS (Chapter 3.7), TVA explains, with the retirement of the coal plant and the amelioration of the impacts of the Kingston ash spill (as detailed in Section 2.1.1), legacy impacts of the KIF on local communities, including EJ communities in proximity to the Kingston Reservation such as the low-income census blocks in Roane County, would be reduced with the implementation of either Action Alternative A or B. The EIS (Section 3.4.3.3) does acknowledge that Alternative A may have disproportionate impacts to EJ communities on its own or in combination with the effects of past, present, and reasonably foreseeable actions.

Short term, regional and minor effects are anticipated from GHG emissions on climate change. Since these effects would be short-term, regional, or minor, they would be less than significant, but they may be disproportionate for EJ populations due to their history of health vulnerabilities. EIS (Section 3.4.3.3) does acknowledge that Alternative A may have disproportionate impacts to EJ communities on its own or in combination with the effects of past, present, and reasonably foreseeable actions.

117. This approach to decarbonization is completely unacceptable and will only further harm communities of color and low wealth who have borne the brunt of TVA's reliance on fossil fuels. TVA's planned energy investment, as exemplified by the full swath of proposed gas projects including Cumberland, Cheatham County, and now Kingston, contradicts the agency's mission to improve the quality of life of its customers. Rather, as TVA invests in new gas and slow-walks the transition away from existing fossil fuel resources to renewables, the agency is fueling the climate crisis and energy injustice which threaten people's quality of life.

Like coal, fossil gas disproportionately harms low-income communities and people of color. In addition to driving the climate crisis via especially potent methane emissions, gas generation produces over 60 hazardous air pollutants – including volatile organic compounds, carcinogens, and endocrine disrupting chemicals. And gas generation exposes communities within closer

proximity to gas facilities to elevated ozone levels which, among other harms, can exacerbate asthma and other diseases.

Furthermore, given the Kingston Plant's legacy as the site of the country's largest industrial spill, it is especially important that TVA not repeat past mistakes by moving forward an equally risky project that could jeopardize the health and safety of communities surrounding the proposed gas plant and pipeline. Furthermore, the agency should make every effort to ensure immediate remediation and adequate clean-up of the Kingston site. Retiring the Kingston Plant cannot be divorced from comprehensive action to address the harm already done to communities in the Tennessee Valley–especially the Kingston coal ash workers–and the environment as a result of the spill. (Commentor: Center for Biological Diversity)

Response: See response to comment numbers 115 and 116. The implementation of the gas projects identified by the commenter would be consistent with the target supply mix in the 2019 IRP, which was designed to facilitate the decarbonization of TVA's generation fleet - including the accelerated retirement of the coal fleet - and the integration of 10,000 MW of solar onto the grid by 2035.

118. TVA does not fully evaluate the environmental justice implications of the alternatives. It seems that Alternative A will potentially affect a greater number of EJ populations, but in order to directly compare the alternatives, mean values should be calculated for Alternative A. (Lindsey Stevens of Roane County Environmental Review Board, SELC and Conservation Groups, Center for Biological Diversity)

Response: Methods used for analysis in Section 3.4.2 Affected Environment were based on standard practices and guidance documents, which have been developed and utilized by agencies in NEPA reviews over time. The goal of the analysis in this section was to identify EJ populations and assess the potential for disproportionate effects relative to a specific alternative rather than to compare numbers of EJ populations by alternative. Once populations were identified, effects to EJ populations were analyzed in Section 3.4.3 Environmental Consequences by resource area to provide a qualitative assessment of beneficial and/or disproportionate adverse effects associated with each alternative.

119. Just transition for workers TVA must truly consider the impact this project will have on local economies and workers. Plant closures mean workers will be impacted no matter what the replacement alternative is. In evaluating the economic impact of the proposed project, jobs must be considered for both workers at the old plant, and any potential new jobs from the replacement alternative. Workers at the Kingston plant should be given relevant notice and job training in time to transition to new jobs, either with TVA or with outside employment opportunities.

A report from Appalachian Voices that examined the job prospects at the Cumberland plant showed potential for significantly more jobs if TVA chose investments in energy efficiency and solar plus storage rather than a gas plant and pipeline. A similar analysis should be considered at Kingston to evaluate how additional renewable alternatives, like distributed energy, storage, and energy efficiency improvements, could result in more jobs in the region compared to building a new fossil gas plant and pipeline. (37 Climate, Justice, and Community Orgs.)

Response: TVA annually reviews its long-term integrated workforce plan that evaluates employee impacts as a result of potential plant closures and additions. In addition, TVA evaluates the skills of potentially impacted employees and the skills needed for proposed new plants to understand any gaps and opportunities for employees. TVA has and would continue to communicate with employees on the long-term asset decisions to provide adequate notice of plant decisions so that any impacted employees would have sufficient time to make decisions for internal or external employment opportunities.

The benchmarking that TVA has performed for new renewable sites, i.e., solar, battery energy storage sites (BESS), etc. have not shown a need for more jobs compared with other plant types. Typically, renewable sites do not have any employees working onsite to support day-to-day operation or maintenance. Rather, renewable sites are operated, monitored, and diagnosed from remote locations to eliminate the need for any employees to be stationed onsite. Regional or roving maintenance crews are established to support large geographical areas and are dispatched as needed to perform planned or unplanned maintenance when the need arises.

As such, the EIS finds that the Construction of the CC/Aero CT Plant and the pipeline associated with Alternative A would temporarily increase employment in the labor market area and have a minor beneficial effect to area EJ populations, as some employment is expected to occur from within the area. Likewise, the EIS finds that construction of the solar facilities associated with Alternative B would temporarily increase employment within portions of East Tennessee and that these socioeconomic effects could potentially have a minor beneficial effect to EJ populations in the areas selected for the solar facilities. See EIS Table 3.4-20. As to employment during operation, the Kingston CC/Aero CT Plant is expected to temporarily increase employment by approximately 2,500 directly and approximately 500 indirectly employed over the period of construction. By contrast, the solar/battery sites under Alternative B would likely not have any employees stationed onsite and would be managed by a regional crew that managed a localize area. Please see Section 3.4 in the FEIS for employment assumptions and details.

120. Section 3.4.2 Affected Environment, Table 3.4-1: the ETNG EJ study area is noted as too large or complex an area to run in the EJScreen tool.

> **Comment: This area should be broken into smaller sections, possibly by county, to run in EJScreen, especially to identify those areas with a higher percentage of low-income populations. (Lyndsey Stevens of the Roane County Environmental Review Board)**

Response: The purpose of Table 3.4-1 is to provide an introductory, high level summary assessment of the EJScreen tool data. This table is not intended to identify small areas (e.g., block groups) of low-income populations. Low-income populations for the ETNG EJ study area are identified in Section 3.4.2.2.6.2 using geospatial analyses of US census data. EJScreen relies on US census data for its identification of low-income populations.

121. Under discussions for Alternative A, minority, poverty, and LEP populations are given separately for each component (e.g., poverty ratio for the reservation, transmission, and pipeline study areas range from 33.5 to 42.9). However for Alternative B, overall values are given (e.g., Table 3.4-18 gives a poverty ratio of 36 for the study area), as well as a breakout by county. Comment: It seems that Alternative A will potentially affect a greater number of EJ populations, but in order to directly compare the alternatives, mean values should be calculated for Alternative A. (Lyndsey Stevens of the Roane County Environmental Review Board)

Response: The FEIS has been updated to include a summary table in Section 3.4 that provides a side by-side comparison of the EJ findings (minority, poverty, and LEP) of the No Action and Action Alternatives (Alternative A and Alternative B).

122. The DEIS notes that TVA "did not identify any disproportionate impacts" on environmental justice communities. The EPA recommends that the discussion of climate change and GHGs acknowledge the disproportionate impact, both in exposure and vulnerability, that GHG emissions have on already overburdened and vulnerable communities. This would be consistent with Executive Order 14096, Revitalizing Our Nation's Commitment to Environmental Justice for All, which affirms the national policy to advance environmental justice for all and defines environmental justice as "the just treatment and meaningful involvement of all people, regardless of income, race, color, national origin, Tribal affiliation, or disability, in agency decision-making and other Federal activities that affect human health and the environment so that people are fully protected from disproportionate and adverse human health and environmental effects (including risks) and hazards including those related to climate change, the cumulative impacts of environmental and other burdens, and the legacy of racism or other structural or systemic barriers." (Section 2(b)(i)). (Commenter: EPA)

Response: TVA has provided information and results of additional EJ assessments in the FEIS to further support the evaluation of the potential for disproportionate impacts. TVA has made updates to the impacts on EJ communities where necessary based on these additional assessments. These updates are provided in Section 3.4 and the Environmental Justice Considerations subsection of Environmental Consequences for each resource area and alternative evaluated in the FEIS.

123. The DEIS does not appear to identify disproportionate impacts from noise, However, Section 3.17.2.3.8 states "[n]oise-related effects, including vehicular traffic, in the ETNG Construction ROW would generally be experienced by EJ populations more than other populations. Further, some of the loudest activities and components are located in EJ population areas. While these effects would be mitigated by ETNG, to the extent practical, it is TVA's current assessment that noise effects are likely to be amplified for EJ populations." Section 3.17 identifies potential noise and vibration effects from both pipeline construction and operation (including the associated compressor station), but notes noise modeling has not yet occurred.

Additionally, Section 3.4.3.3.6 states "196 residences are located within 50 feet of [the natural gas pipeline] construction activities, and of those, approximately two-thirds are within 25 feet." The EPA recommends the FEIS further analyze construction and operation noise impacts, and practicable mitigation, from the proposed pipeline and compressor station to EJ populations. If disproportionate noise impacts are not identified in the FEIS, please provide a clear rationale for the basis of this determination. (Commenter: EPA)

Response: TVA has provided information and results of additional EJ assessments in the FEIS to further support the evaluation of the potential for disproportionate impacts. TVA has made updates to the impacts on EJ communities where necessary based on these additional assessments. The updated information indicates that unmitigated noise from HDD activities would exceed the Ldn 55 dBA FERC sound level threshold at noise sensitive areas (NSAs). ETNG would implement the following noise mitigation measures for specific locations where those exceedances are likely to occur:

- Institute work practices such as reduced idling, fitting equipment with residential mufflers.
- Install sound barrier walls between entry pit and NSAs – Barrier height minimum of 20 ft. with the exception of Norfolk Southern Railway, 30 ft. barrier height recommended.
- Install sound barrier walls between exit pits and NSAs - Barrier height minimum of 20 ft. with the exception of Norfolk Southern Railway, 30 ft. barrier height recommended.

The estimated mitigated noise impact at NSAs with the implementation of noise mitigation measures listed above (where applicable) would be at or below the Ldn 55 dBA FERC sound level requirement. Because of the temporary nature of the construction noise during normal installation of the pipeline along the pipeline route and the use of mitigation measures, no disproportionate adverse or long-term noise effects are anticipated (ETNG 2023j).

Cost Analyses of Alternatives in the Kingston DEIS

124. The EIS repeatedly makes dated statements that solar is "becoming" cost competitive or "will in the future" a cost competitive option. Please remove these dated descriptions. Solar is already a cost competitive option and has been for years. This is particularly true considering natural gas plant failures in extreme weather. (Commentor: Megan Maloney)

Response: The FEIS incorporates updated solar and storage pricing that reflects actual offers through TVA's RFP process and accounts for the IRA.

125. TVA should provide a reference for the cost residential vs. utility-scale distributed generation which is stated as the basis for choosing Alternative B over residential-scale distributed generation (DEIS Appendix C, pg. C-15). (Citizens' Climate Education)

Response: Please see Appendix A of the 2019 TVA IRP, which is incorporated in the Kingston EIS by reference.

126. The Least-cost Planning Evaluation (DEIS Appendix C, pg. C-31) describes risks for each alternative.

- **The risk associated with Alternative B relates solely to "timeline associated with transmission build-out and land and resource procurement." Elsewhere in the document additional risks are described regarding grid stability and operational experience.**
- **The risk associated with Alternative A should include an analysis of risks described in Section 3.4. Environmental Justice and Section 3.6, Construction and Operations of Natural Gas Pipeline.**
    - **Risks to Environmental Justice**
        - **(EJ) risks should be quantified so they can be considered along with project risks in terms of costs or contingency (e.g., lawsuits).**
        - **EJ populations should be quantified in terms of economic costs and included both in DEIS, Appendix C and Table 3.4-20. Risks have been identified in the analysis but excluded from these summaries (e.g., job opportunities vs. housing available to non-local labor, 195 houses with 50 ft. of pipeline with two-thirds within 25 ft.).**
        - **Risks to EJ communities are exactly the type of risk that detailed analysis is supposed to identify and avert, "Emissions are expected to be minor and widely distributed, though the effects may be amplified for EJ populations**

already experiencing cumulative air quality effects." (DEIS pg. 171-172). The analysis should quantify these risks for both Alternative A and B. The risk should not be compared to the no action scenario.

- **Risks for Construction and Operations of Natural Gas Pipeline**
  - **TVA should quantify risks associated with project planning and approval (i.e., FERC's EIS preparation and approval) and installation time-line risk of the 122-mile-long pipeline.**
  - **The commitment of Enbridge (owner of ETNG) to participant in the USEPA Methane Challenge Program as a ONE Future Coalition commitment partner and reduce methane leakage to 1% by 2025 is commendable (DEIS, pg. 350); however, the risks of methane leakage from the pipeline and compressor should be described since recent legislation imposes a fee on methane leakage. The fee could substantially increase the costs of Alternative A, especially if more current estimates showing higher leakage rates for natural gas pipelines are used in assessing fees. "**

(Commentor: Citizens' Climate Education)

Response: Although few of the potential risks were identified in the Alternatives Analysis provided in Appendix B, all risks were mentioned and considered in the FEIS for each alternative. Regarding the risks of pipeline construction and operation, as described in ETNG's Resource Report 11, the Ridgeline Expansion Project will be constructed and operated in accordance with applicable DOT/PHMSA requirements. Also as described throughout its application, construction and operation of the Ridgeline Expansion Project is not anticipated to have a significant environmental impact to affected communities with adoption of its proposed avoidance, minimization, and mitigation measures. ETNG has prepared site specific residential construction plans for the residences within 25 feet of the construction workspace, see Section 8.3.3 of Resource Report 8 (ETNG 2023h). Environmental justice communities, construction workforce and available housing are discussed in Resource Report 5 (ETNG 2023f). See also response to *Comment Nos.* 72 and 96.

127. The document describes two (2) alternatives but is a justification [of] Alternative A. Costs are not included for the preferred option (see DEIS Appendix C, pg. 28). Cost data per kW are provided for assets (see DEIS Appendix C, pgs. C- 21 and 22); however, the reviewers cannot construct the cost of Alternative A because "pipeline costs, if applicable, are included for specific projects and modeled as a generation cost leveraging quotes and pricing from suppliers." It is not clear whether this cost is included in the $/kW figure. The document should clearly state the baseline cost for Alternative A. (Commentor: Citizens' Climate Education)

Response: See response to *Comments Nos. 108 and 109*.

128. No capital cost or life-cycle cost estimate is provided for Alternative A; however, each alternative is compared to the 'cost' of Alternative A. Since there is no baseline cost estimate, reviewers cannot comment on the cost basis for Option A or reasonably compare the costs of Alternative B to the cost of Alternative A. (Commentor: Citizens' Climate Education)

Response: See response to *Comments Nos. 108 and 109*.

Capital cost assumptions, along with other assumptions, are included in Appendix B for all alternatives. The life cycle assumptions can also be found in Appendix B. See response to *Comments Nos. 108 and 109*.

129. Despite All TVA's efforts to minimize the environmental advantages of alternative B over alternative A, these advantages are still quite large. They are considerably larger than the TVA analysis reveals because of numerous biased assumptions that cannot be independently evaluated because TVA does not provide information about its "system wide modelling" approach and omissions such as IRA Act cost savings. When evaluating the financial and environmental costs TVA uses backward looking analysis that provides a veneer of rigor and expertise and is guaranteed to produce biased assessment of renewable energy projects. Renewable energy technologies are rapidly increasing in technological capability and efficiency while decreasing in cost. A retrospective analysis is simply invalid when applied to such rapidly improving technologies such as solar and storage. It is not possible to address all the implications of this flawed TVA methodology in the time available for me to digest an almost 1600-page DEIS document, not counting appendices, but I will provide a couple of examples for illustration purposes.

In terms of costs, TVA bases the number of acres of land required to host solar based on capacity factors of past PV plants. PV efficiency, installation, and operation have all advanced considerably over this retrospective study period. Increased PV efficiency over this period of TVA's retrospective analysis mean land requirements and associated costs have declined. This effect is compounded by the fact that renewable energy technology and cost are continuing to decline, recent Covid induced supply chain disruptions notwithstanding. Recent market trends in the solar supply chain are easing. Acceleration of these trends can be expected as domestic solar manufacturing capacity ramps up in response to the IRA incentives. However, TVA continues to erroneously cite supply chain disruptions as cause to avoid solar generation.

The exaggeration of land requirements inherent in TVA's retrospective analyses exaggerates estimates of adverse water and land impacts, but also ignores changes in solar developer installation procedures that have evolved to decrease land disturbance during construction and to maintain plant cover under solar arrays. This reduces potential water runoff issues and increases generating efficiency of the solar array. These evolving practices have also demonstrated that PV can keep agricultural land in agricultural production and even enhance the value proposition for both the farmer and the PV facility.

Another example of exaggerating financial and environmental cost of solar is TVA's refusal to acknowledge that a significant portion of the needed solar can be located on, or in proximity to, TVA's existing facilities such as retiring power plants and power generating dams to utilize existing transmission and other infrastructure assets with available transmission capacity. This is especially egregious given TVA has credited these benefits to other alternatives it favors. (Commentor: Joe Schiller)

Response: Section 2.1 of the FEIS provides a thorough description of the wide range of alternatives considered and the key factors and criteria that were used in development of TVA's Preferred Alternative. Please also note that IRA tax credits have been evaluated and included in Appendix B in the cost analysis for all alternatives. See response to *Comment No.* 47 regarding the alternatives considered and not carried forward.

Based on current system analysis, firm and dispatchable generation will need to be in place by 2027 to support the retirement of the nine KIF units, system load growth, and the integration and operation of planned intermittent resources (e.g., solar). TVA performed a reliability analysis to determine an appropriate combination of solar and storage resources to maintain year-round system reliability in Alternative B. See Section 2.1.4.2 of the FEIS for additional information.

Alternative B includes substantial solar and storage facility construction as well as extensive regional transmission upgrades. Batteries can offset some bulk system upgrades, and this has been included in the analysis. The Final Kingston Alternatives Analysis (Appendix B) includes transmission estimates for Alternative B and demonstrates it is significantly more expensive in comparison to Alternative A. Further, operational benefits are reflected in the production cost estimates. Based on TVA's own experience in bringing solar projects to completion, other challenges to adoption of Alternative B include the size and number of solar and storage projects required to replace generation capacity from the retiring KIF, and their lengthy implementation timelines which would fail to meet the required 2027 timeline for the retirement of KIF.

The EIS adequately considers potential siting of solar facilities at existing TVA sites. Specifically, the EIS explains that in its current configuration, the Kingston Reservation cannot accommodate larger capacities of solar generation due to space limitations. Additional space may become available in the future after D4 activities have been undertaken at the Reservation but the currently available acreage on the Reservation limits the solar component of an alternative to 3-5 MW on the Kingston Reservation. Retrofitting existing TVA facilities at other sites in the TVA service area would still require significant regional transmission upgrades to connect potential new solar and battery storage sites to the existing transmission system and would still require lengthy implementation timelines detailed above. To sustain low costs and high reliability, TVA anticipates that a portion of these new facilities would be located in Eastern TN, where they can help support regional transmission grid stability following the retirement of KIF (see Section 2.1.4.2 for additional details).

To account for uncertainties and risk, including the volatility of gas prices, the 2019 IRP included scenarios that are outside of TVA's control but represent possible futures in which TVA may find itself operating. While some key modeling assumptions have evolved in comparison to the Current Outlook in the 2019 IRP, all forecasts of major uncertainties, including electric load, natural gas price forecast, and cost of battery storage, are still within the bounds studied in the 2019 IRP.

Under the TVA Act, the TVA Board must adhere to the "primary" objective that "power be sold at rates as low as feasible." See 16 U.S.C. § 831n-4(f). Likewise, under the Energy Policy Act of 1992, TVA has an obligation to conduct least-cost planning, "evaluating the full range and cost of existing and incremental resources including new power supplies, energy conservation and efficiency, and renewable energy resources in order to provide adequate and reliable service to electric customers of the Tennessee Valley Authority at the lowest system cost." See 16 U.S.C. § 831m-1. TVA performs this least-cost planning process through its Integrated Resource Plan, last completed and approved by the TVA Board in 2019. TVA's consideration of various generation alternatives in the FEIS is consistent with its least-cost planning requirements.

TVA is complying with these express statutory requirements as it replaces generation from the proposed retirement of the KIF consistent with the target supply mix approved by the TVA Board in the 2019 IRP. Further, within its existing statutory requirements, TVA has announced an ambitious plan for a 70% carbon reduction by 2030, sees a path to approximately 80% carbon reduction by 2035, and aspires to achieve net-zero carbon emissions by 2050, all while planning to retire its aging coal fleet by 2035. Please see response to *Comment No*. 9 for further explanation as to why more solar cannot at this time be assessed to be located at the KIF site.

130. TVA continues to hide behind ruses such as its "system wide analysis" that allow it to make assertions that cannot be independently evaluated by outside experts. This allows them to make assumptions such as the battery storage of alternative B being charged by gas and coal generation without allowing independent evaluation of the validity of this assertion. In summary, TVA takes every opportunity to inject biased assumptions and constraints, and numerous omissions of salient facts to justify its selection of alternative A as its preferred alternative. Despite this, even by TVA's own flawed analysis, alternative B is clearly a superior financial and environmental choice over alternative A and a more objective analysis would increase its advantages. The analysis in this DEIS should be subjected to outside expert review along with all assumptions and constraints TVA applied to its system-wide modelling before proceeding with the FEIS. (Commentor: Joe Schiller)

Response: Section 2.1 of the KIF DEIS provides a thorough description of the wide range of alternatives considered and the key factors and criteria that were used in development of TVA's preference. Please also note that IRA tax credits have been evaluated and included in cost analysis for all alternatives. The identification of Alternative A as the preferred alternative is based on its ability to meet the purpose and need of the proposed action to retire and replace the KIF generation, including the need to have firm, dispatchable replacement generation in place by 2027. See response to *Comment No.* 47 regarding the alternatives considered and carried forward. As to TVA's development of a system-wide life-cycle analysis, an analysis of this kind reflects TVA's broader asset strategy and Target Power Supply Mix set by TVA's 2019 IRP. A TVA system-wide comparison of emissions is the most effective way to accurately identify incremental emission differences between the alternatives because it illustrates how the entire TVA system is expected to operate with each alternative. The FEIS also includes an individual GHG LCA that compares each alternative.

131. Fuel costs are passed through directly to consumer monthly bills and, as seen in 2022, natural gas prices can be very volatile. Fuel costs are excluded from TVA management objectives and bonus calculations leading to a mismatch between consumer costs and management objectives which can lead management to make decisions which are not in the consumers' best interest. (Commentor: TVECG)

Response: Natural gas prices are seeing near-term pandemic and supply-driven volatility but compared to prices during development of the 2019 IRP, TVA's current natural gas price forecast is lower, as indicated in Appendix B. Having a diverse portfolio of resource types – coal, nuclear, hydro, natural gas, and renewable resources – and being able to use these resources in different ways enables TVA to provide reliable, low-cost power while minimizing the risk of disproportionate reliance on any one type of resource and any fuel price volatility. See Appendix B for more information on TVA's natural gas price forecast.

TVA monitors key signposts that are used to guide decisions for the long-term, which include demand for electricity, natural gas prices, regulatory requirements, and emerging technologies.

132. Please clarify when and how retrofitting the natural gas plant with carbon capture is being included in calculations of social costs, greenhouse gas emissions, and infrastructure cost. The report references the potential for carbon capture in several places, including the least cost table, as a social and environmental benefit; however, it is not part of the alternative and so the benefits listed in the table would not be actualized. For this reason and because carbon capture may be mandated in the future, it should be included in the cost for consistency. (Commentor: Megan Maloney)

Response: The FEIS has been updated with a discussion of GHG mitigation measures in Section 2.3.1.10 and Appendix C to the DEIS has been revised to include the sensitivity with these mitigation costs and is now Appendix B. See also response to *Comment No.* 105.

133. TVA has been made aware through multiple National Parks Service comments that their calculations regarding cost estimations were found to be incorrect. For instance, in comment 13 (p1572): “This suggests that the LCOE of a solar hybrid system may be lower than cited by TVA and significantly lower than the LCOE of constructing both a CC plant and CT peaking units.”

And later: “The annual variable operating costs are likely much less for renewable energy options. Again, this information suggests that TVA may have underestimated the cost of a CC plus peaking CT unit and overestimated the costs of a PV system with battery backup (see comments on alternative A description). The renewable options considered under Alternative B may be more financially attractive than characterized in the DEIS and IRP, particularly if carbon capture is required in the future.”

And in comment 17 (p1577): “TVA’s capital cost estimates for utility scale PV systems of $1,203/kW to $1,293/kW are well above the range reported by Lazard of $800-$950/kW. TVA’s estimated capital costs for battery storage of $2,824/kW are six to sixteen times higher than the capital cost estimates provided by Lazard, which range from $169 to $460/kW. EIA estimated capital costs for a PV system with battery backup at $1,748/kW, significantly lower than TVA’s combined capital cost estimate for PV system plus battery back-up (approximately $4,000/kW)”

In response to these concerns, TVA directed commenters to Appendix B (by the title, they appear to mean Appendix C) for detailed information to explain the calculations. However, it has been noted that this appendix does not provide the comprehensive information needed to clarify the mistaken calculations.

Given the significance of these calculations in TVA's commitment to selecting the ""lowest cost"" alternative, regardless of potential community and environmental health impacts, it is crucial that TVA addresses and corrects these inaccuracies.

Please rectify the identified calculation errors and provide a detailed explanation of the corrections made. It is imperative that TVA demonstrate its commitment to transparency and accurate analysis in order to uphold its responsibility to choose the most cost-effective alternative while considering the well-being of the community and the environment." (Commentor: Megan Maloney)

Response: TVA’s solar and storage costs are sourced from NREL’s Annual Technology Baseline (https://www.nrel.gov/analysis/data-tech-baseline.html). Per NREL, the Annual Technology Baseline (ATB) incorporates current and projected detailed cost and performance data for renewable and conventional technologies, providing a consistent set of technology cost and performance data for energy analyses. Solar and storage costs have been updated in the FEIS to reflect the impact of the 2022 Inflation Reduction Act.

134. TVA asserts that this proposal is part of a broader investment plan and claims to have already planned for 10,000 MW of solar power. However, it appears that their current plans primarily revolve around nuclear energy, which raises concerns regarding the fulfillment of their commitment to clean and sustainable power that safeguards human health, clean water and air,

and the climate for future generations. Our objective is to prioritize options that mitigate risk and promote a cleaner future.

It is crucial for TVA to deliver their promise of 10,000 MW of solar power by 2035. The necessary grid improvements for solar energy will need to be implemented eventually, regardless of the chosen alternative. By initiating these improvements sooner rather than later, the community can begin reaping the benefits of clean and reliable power while simultaneously reducing climate change emissions.

TVA should fulfill its commitment to clean energy and prioritize the development of renewable resources that align with the goals of protecting our environment, ensuring a sustainable future, and safeguarding the well-being of our children.

Therefore, it will be beneficial for the public's understanding that TVA addresses, rationalizes and corrects the EIS calculations according to the EPA reviews and comments, include the current tax incentives, accurately consider the observed natural gas plant instability and fuel pricing instability, and support TVA's stated commitments to community health. (Commentor: Megan Maloney)

Response: TVA has already begun solar installations toward TVA's goal of having 10,000 MW solar capacity online by 2035 and continues to do so through both its power purchase agreements with solar contractors and TVA-owned solar generations. As of April 2023, TVA has 2,900 MW of solar online or under contract. The solar evaluated in this document as components of Alternatives A and B would be in addition to the 10,000 MW TVA goal and does not contribute to that goal. Please see Section 1.2.2 and Appendix B, Page 23 and 24, which describes and cites the market factors affecting both cost and availability of solar generation. While assessed in TVA's 2019 IRP, nuclear generation was not included in the action alternatives for this project and was dismissed from detailed consideration as discussed in Kingston FEIS Section 2.1.5. The IRA tax credits have been evaluated and included in the revised cost analyses for applicable alternatives presented in Appendix B.

135. The TVA's EIS does not consider the current tax credits for Alt. B, not past or current natural gas plant failures in extreme weather conditions, yet TVA thought it appropriate to include apprehensions that market shortages related to Alt. B would not resolve in years. TVA appears to repeatedly refuse NEPA review comments urging them to redo their calculations to save money. How does TVA decide which considerations are valid and which aren't?

The current mismatch of assumptions in the report presents an unrealistically optimistic scenario for the natural gas pipeline against an unrealistically pessimistic scenario for solar. This results in an apples to oranges emissions comparison, and a frankly bizarre argument that burning fossil fuel at increasing scarcity and during increasing extreme weather events over the lifetime of the plant will somehow have similar emissions to solar installations with zero emissions or hazards after installation.

The EIA overestimates the stability, cost, and safety of the natural gas pipeline while underestimating the pipeline's financial cost after considering permitting and repairs and safety mitigation, as well as CO2 emissions and carbon capture. The calculations overestimate risk to the solar installations, insisting on high storage to compensate for production decreases but also including extra supplementary fossil fuel costs that having high storage would avoid. The calculations underestimate the environmental, human, and economic risks of the pipeline despite

frequent and well documented failures of similar pipelines. Please correct the report to accurately present costs and risks to the public. (Commentor: Megan Maloney)

Response: TVA disagrees with the commenter's characterization of the assumptions underlying the cost estimates used in the EIS. TVA's solar and storage costs are sourced from NREL's Annual Technology Baseline (see response to *Comment No. 133*). Solar and storage costs have been updated in the FEIS to reflect the benefits of the 2022 IRA. See Appendix B. While incentives under the IRA may be helpful in the long run, they are of limited applicability with respect to the generation choices facing Kingston in the short term, see Section 1.2.3.3.1 of the FEIS.

See also response to *Comment No. 3*. The FEIS addresses the issue of risk to generation resources in extreme weather conditions such as Winter Storm Elliott (Section 1.2.3.2). Further, the FEIS adequately covers issues related to pipeline stability, cost and safety. See Sections 2.1.3.6.1 for stability, Appendix B for cost, and Section 3.15.2.2.6 for safety.

136. The least cost planning table (p852) appears inaccurate. First, under the "Low Cost" column: TVA was repeatedly told by the EPA that they were miscalculating costs for both systems, and refused to make the suggested corrections, instead directing the public and reviewers to an appendix that does not contain detailed enough calculations to address the concerns. TVA additionally declined to include the significant tax credits for Alt B, has not corrected the costs to reflect this or the fact that detailed guidance has been issued. Therefore the coding of Alt. B as "Worst" is not accurate. The table additionally mentions "extensive transmission work" for Alt. B but not the extensive pipeline required for Alt. A. It claims Alt. A would be "most effective" despite known failures during extreme weather emergencies of the modern natural gas systems. The cost does not include supplemental power costs for Alt. A's likely failures either, which would likely lower the coding from "Best" to something more reflective of natural gas's documented instability. Coding for both alternatives should be changed. (Commentor: Megan Maloney)

Response: The decision associated with this EIS is a specific, discrete component of TVA's blended asset strategy and consistent with the recommended target power supply mix in the 2019 IRP. Each alternative has subsequent impacts for other decisions in the future. Given this, there would be similarities in dispatch, driven by economic production cost modeling. Solar and storage costs have been updated in the FEIS to reflect NREL's Annual Technology Baseline (NREL 2023) with projected impacts of the 2022 IRA. See response to *Comment No. 133*. Even with accounting for the Inflation Reduction Act, Alternative A is still the lowest cost alternative. Alternative A includes pipeline costs.

137. Referencing least cost planning table on p852, , under "Risk informed": Alt A is again inexplicably coded "Best" despite planning on being attached to a pipeline that's already exploded in the last five years and which is being fed out of a state known for aggressively refusing to weatherize their pipeline infrastructure; being attached to this risk would take TN down with any event occurring there. The table text cites potential use of CCS but these aren't included in the cost but which would then presumably affect the "Low Cost" ranking; the EIS should not selectively choose to include or exclude the CCS depending on whether it's flattering to Alt A. Additionally, Alt B is inexplicably labeled "Fails to meet purpose" despite solar's success in extreme weather conditions where natural gas has been failing for the last two years. Coding for both alternatives should be changed. (Commentor: Megan Maloney)

Response: East Tennessee Natural Gas [ETNG] experienced a rare mainline pipe rupture in December 2018. There were no injuries or fire from the release of natural gas, and the pipeline was able to coordinate with its customers to minimize service disruptions during the incident and the ensuing capacity restrictions while investigations were being conducted. ETNG responded in an organized and coordinated fashion to remediate the incident, working side by side with local first responders to ensure public safety. The pipeline was restored to almost 80% of its capacity within 2 weeks of the incident.

TVA has not experienced failure or instability using firm transportation service during extreme weather emergencies. In fact, during Winter Storm Elliott in December 2022, TVA did not experience a forced outage to any natural gas-fired generation units due to natural gas supply, transportation, or storage.

Additionally, TVA has updated and included the cost of CCS by performing a sensitivity analysis that took into account both CCS/hydrogen co-firing for Alternative A. Also, Alternative B has been evaluated and determined to not meet the purpose and need for the following reasons: (i) it cannot be completed by 2027; and (ii) as an inverter-based resource, Alternative B does not provide firm, dispatchable power.

138. Referencing least cost planning table on p852, under "Environmentally responsible": natural gas is labeled as a substantial carbon reduction; this is only a possible claim comparing to coal, and we're not considering a new coal plant. Alt A should clearly be labeled the worst option here, as a highly polluting fossil fuel with only hypothetical potential carbon capture suggested. It also cannot possibly be considered good considering the pipelines risk to the natural areas it crosses and potential wildfire. During the virtual meeting, a TVA employee repeatedly made the absolutely bizarre statement that his analysis showed Alt A and B to have similar emissions; frankly, that statement sounded wildly miscalculated then, and the lack of reasonable comparative analysis in the EIS only further undermines that idea. (Commentor: Megan Maloney)

Response: As required by NEPA, Action Alternatives A and B are compared directly to the No Action Alternative which would involve continuing to operate the KIF, thus resulting in continued combustion of coal for electricity generation, resulting in continued emissions at the facility. Those are the three alternatives evaluated and considered in TVA's decision for retiring KIF and selecting the Preferred Alternative, Action Alternative A. While both Alternatives A and B result in a net reduction in GHG emissions, the reductions from Alternative B would be higher than the reductions from Alternative A. Also, see response to *Comment No. 113.*

139. Referencing least cost planning table on p852, the "Reliable and Resilient" column in Alt. A should be coded "Worst" and reference that even modern plants have had an extremely and unexpectedly high failure rate during extreme cold and heat events in the past two years, resulting in widespread blackouts… (Commentor: Megan Maloney)

Response: See response to *Comment No.* 137. Alternative A has a favorable rating for being reliable and resilient as it provides dependable year-round capacity. KIF's condition is challenged (No Action Alternative) and solar is not available during TVA's winter peak (Alternative B). While outages can occur, the expected year-round reliability of Alternative A is the most favorable.

140. Table 1.6-17 in Appendix I demonstrates the social cost for Alt. A is substantially higher than Alt. B during the operation of the power plant. However, the current estimation of the one-time upstream and downstream costs almost completely offset the entire benefit of renewable energy. How are those numbers evaluated? What drives the costs for both alternatives?

Additionally, Alt. B clearly has less planning in the project proposal. Where are the panels going to go? Where are the batteries going to go? Just presenting the average land required and no other details shows that TVA did not commit the same effort in evaluating alternatives. As a result, how representative and accurate are those numbers being presented? (Commentor: Megan Maloney)

Response: TVA disagrees with the commentors statement that the one-time upstream and downstream costs of Alt. B completely offset the benefit of Alt. B. While the one-time upstream and downstream GHG social costs of Alternative B are higher than those corresponding costs for Alt. A, the much larger ongoing combustion and non-combustion GHG social costs for Alt. A more than make up the difference in upstream/downstream social costs. This can be seen by reviewing the social costs in Tables 1.6-11 (CO_2), 1.6-13 (CH_4), and 1.6-15 (N_2O) [actual Tables are now J.6-11, J.6-13, and J.6-15 in FEIS]. TVA has determined the regions where solar panels and battery storage would be placed - primarily in East Tennessee with potentially some parts of Middle Tennessee. There would be a multitude of locations over the 10,000+ acres needed for the solar/battery alternative. Due to property access, use, and acquisition issues, the exact locations for solar and battery storage cannot be determined at this time, but this does not have an effect on the GHG life cycle emissions calculations and associated social costs developed for this LCA. The methodology is not and cannot be that granular for this type of LCA. The same level of rigor was applied for the assessment of both action alternatives in this EIS.

141. The EPA comments at the end of the document also challenge these numbers as inaccurate and the analysis as insufficient, and the TVA appears to respond with a refusal to address the numbers to complete the required cost/benefit analysis for this required proposal to accurately present a lowest cost comparison for public comment. Please provide the rationale and detailed analysis with corrected numbers, fully addressing the concerns raised in the National Parks Service comments, and more detailed site reviews and information on Alt. B. The statutory obligation to conduct least-cost planning requires an accurate and detailed cost analysis for both alternatives, which does not appear complete in the EIS. (Commentor: Megan Maloney)

Response: Appendix B provides the total system cost comparison among the No Action and action alternatives and provides adequate and pertinent information to the public and the decisionmaker regarding the relative costs of the alternatives. Note that TVA satisfies its statutory obligation to conduct least cost planning through development of Integrated Resource Plans. The target supply mix in the 2019 IRP represents the application of least cost planning. The Kingston proposal to add CC generation and CT Aero-derivatives tiers from the 2019 IRP and is within the MW ranges for CC and CT generation in the target supply mix of that IRP.

142. National Parks Service comment 4 (p1572) summarizes the main problem with long term economic costs if the TVA continues to invest in obsolete high-emissions infrastructure with high failure rates such as Alt. A. In response to this comment, TVA simply restated that Alt. A is the lowest-cost option. However, as TVA admits that their calculations are incorrect and fail to account for current significant tax subsidies, there is no way to know if this is correct and reason to assume it may not be.

As a result, these calculations do not provide reliable assessment, and the data is not substantiated by objective evidence nor they are utilizing the most up-to-date information. Despite TVA's least cost statutory obligation, the calculation of cost is misinformed and does not align

with reality. Therefore, this calculation does not assure the public that Alt. A is in fact the least cost option.

It is essential that TVA demonstrates its commitment to thorough due diligence by performing a comprehensive analysis using the most up-to-date data available, including all applicable tax subsidies, as well as accounting for the cost of supplemental power during likely failures of Alt. A in extreme weather events. It is crucial that these revised calculations be transparently presented to the public before making any final decisions. This would allow the public to be fully informed and engaged in the decision-making process. (Commentor: Megan Maloney)

Response: TVA's solar and storage costs are sourced from NREL's Annual Technology Baseline. Solar and storage costs have been updated in the FEIS to reflect the impact of the Inflation Reduction Act.

143. Alt. A will likely incur additional costs than Alt. B, such as Aquatic Resource Alteration Permits (ARAP) through the TN Department of Environment and Conservation. What is the cost analysis for environmental impact for Alt. A vs. Alt. B? (Commentor: Megan Maloney)

Response: The Kingston EIS does provide an overview of the permits and mitigation that would likely be required for each alternative. The permitting and compliance costs are covered in the project costs for the alternatives identified in Appendix B. Analysis of environmental impacts for each alternative are discussed throughout the FEIS. The Climate analysis in Section 3.7 of the FEIS includes an assessment of the social cost of GHG for each alternative.

144. TVA's economic analysis of the proposed alternatives is arbitrary. TVA must consider cost in evaluating the alternatives. As TVA notes in the DEIS, TVA must "evaluate the full range of existing and incremental resources (including new power supplies, energy conservation and efficiency, and renewable energy resources) in order to provide adequate and reliable service to electric customers of [TVA] at the lowest system cost." Under Section 15d(f) of the TVA Act, TVA must also sell power "at rates as low as feasible." TVA must evaluate alternatives that meet the purpose and need of the project, and part of the purpose and need of the proposed Kingston Plant retirement is to meet its least-cost planning obligations as required by statute. TVA states that its preferred alternative, Alternative A, is the lowest cost alternative, costing "approximately $1.2 billion" less than Alternative B. However, TVA provides essentially no breakdown of the costs involved, making it impossible to determine if TVA's judgment is reasonable. TVA simply asserts that Alternative A is "lowest" in comparison to Alternative B and the No Action Alternative for production costs, fixed and capital costs, transmission infrastructure, and fuel supply infrastructure. The DEIS is, with appendices, over 1,500 pages long. There is no reason that TVA cannot provide more detail about the system cost breakdown of the various alternatives. And since TVA justifies the selection of Alternative A as its preferred alternative in large part on the basis of it having the lowest system cost, despite having greater environmental impacts than Alternative B, TVA must provide that detail.

TVA's analysis of the alternatives is completely inadequate and arbitrary. In addition to lacking any detailed cost breakdown, several important factors that would lead to a higher cost for Alternative A, or a reduced cost for Alternative B, are minimized and brushed aside. TVA fails to employ like-for-like comparisons, looking at Alternative A's costs in a piecemeal fashion but using broad averages that have the result of artificially inflating the cost of Alternative B. TVA must engage in a more reasoned evaluation of the alternatives under consideration. (Commenter: Southern Environmental Law Center/Conservation Groups)

Response: The FEIS, when read in its entirety, provides a thorough, robust, and reasoned evaluation of the alternatives under consideration. As to costs, Appendix B provides the total system costs for the No Action alternative and Alternative B relative to the costs of Alternative A. Normalizing the total system costs in relation to the preferred alternative (Alternative A) provides a reasonable means to easily compare the costs of the No Action and action alternatives.

The least-cost planning requirements of Section 113 work in tandem with the TVA Act's requirements to sell power at rates as low as feasible. TVA complies with least-cost planning requirements through the development of IRPs. The target supply mix in the 2019 IRP represents the application of least cost planning. This specific generation decision is consistent with least-cost planning and, therefore, also advances the goal of Section 15d(f) to keep rates as low as feasible. The target supply mix in the 2019 IRP represents the application of least cost planning. The Kingston proposal to add CC generation and CT Aero-derivatives tiers from the 2019 IRP and is within the MW ranges for CC and CT generation in the target supply mix of that IRP. This specific generation decision is consistent with least-cost planning and, therefore, also advances the goal of Section 15d(f) to keep rates as low as feasible.

145. TVA's "system-wide portfolio analysis" is a black-box that fails to provide sufficient information for independent evaluation of its assertions. (Note, page 373 incorrectly refers to 12,700MW of battery storage. Also, p375 refers to the operational impact of alternative B exceeding the Biden administration decarbonization goal because alternative B is 100% carbon free. While alternative B is essential to meeting the Biden administration decarbonization goals of a 100% carbon free electricity generation system by 2035, the goals cited on p.375 are the economy wide goals. Further, these goals apply to TVA's entire generation fleet, not any individual project.) (4) (Commentor: Joe Schiller)

Response: TVA's system-wide analysis, which was for the entire TVA-wide power system, was performed using industry standard capacity planning and production cost models, Anchor Power Solution's EnCompass (Anchor Power Solutions 2023) and Energy Exemplar's Aurora (Energy Exemplar 2023). The capacity planning model develops a least-cost portfolio to meet demand and reserve margin while the production cost model simulates economic dispatch of the plan. The output includes an estimate of anticipated future emissions across the entire TVA system for each year.

146. TVA's assumption that the storage component of alternative B will be primarily charged with fossil generation taints all its subsequent analysis of GHG reductions by minimizing the actual advantages a properly designed and operated solar plus storage alternative would achieve. (Commentor: Joe Schiller)

Response: While the batteries in Alternative B are assumed to charge from the grid, TVA's system is evolving. Solar and battery storage proposed under Alternatives A and B would be new solar in addition to the 10,000 MW of solar that TVA plans to bring onto the system by 2035.

Geological Resources

147. I am entering into the record my opposition to the Ridgeline expansion project. I am a property owner who will be directly adversely affected by this pipeline and its construction/maintenance. In your DEIS, I see no mention of the Flynn Creek Impact Crater, a

unique geological, historical and ecological area located in Jackson County, Tennessee. The project's new easement through the center of the site threatens to have a permanent destructive impact on this important resource.

Please consider the following:

1) **Flynn Creek Impact Crater (FCIC) is the best-preserved example on earth of a rare class of ancient impact structures.**
2) **Much important scientific study has been conducted at the site, and much more remains to be learned. The site was an integral part of NASA and USGS research conducted in preparation for the Apollo Moon Landing missions of the 1960's. Discoveries made during this research resulted in a paradigm shift in geologists' understanding of cratering morphology and formation. The new easement threatens to permanently obliterate drill core sites which provide evidence in support of these new theories.**
3) **The proposed easement passes directly over the central uplift formation of FCIC. Within this uplift lies a unique, important feature- Hawkins Impact Cave (HIC). This cave is the only cave on earth known to occur in the central uplift of any crater, ancient or otherwise. Furthermore, the cave is in pristine, undamaged condition. It has been given the title of "the birthplace of impact speleology" by researchers who have studied it. In fact, the crater area is unique as well for the high number of caves located within the area of original disturbance. Construction activities such as chemical spills, blasting, and subsoil disturbance threaten to pollute/degrade/alter the watershed/sinkholes which overlie HIC, as well as other karst features in the area.**
4) **The economic potential of the area's water resources are gravely threatened by the activities listed in 3) above. The present landowner is currently developing a marketing plan to sell water collected from this 380-million-year old crater to end users such as bottled water, brewery, and distillery concerns. In addition, the sole water source for his residence is a spring fed by the threatened watershed.**
5) **The proposed and existing easements cross Flynn Creek a minimum of eight times within the crater. This will be a major disruption to the ecology of the creek and associated ten cave systems.**
6) **Several animal and plant species which are in decline, threatened or endemic to the area (e.g., yellowwood tree, dwarf and American ginseng, cerulean warbler, several bat species) will be adversely affected by habitat destruction.**
7) **Erosion potential is great where the easement traverses several steep slopes. I am confused and dismayed that FCIC, HIC, and associated features are not addressed at all in TVA's DEIS regarding the Kingston plant retirement. These important geological, historical, ecological and economic resources should be protected by TVA, which prides itself in its mission of conscientious preservation of the valuable natural resources within its purview. (Commentor: Michael Hawkins)**

Response: Additional details on the potential effects to the Flynn Creek Impact Crater from the ETNG natural gas pipeline project are provided in the FEIS in Section 3.5.1.2.2.6. Per ETNG Final Resource Report 6 (ETNG 2023g):

> …minor effects to geology could occur. The 122 miles of the proposed natural gas pipeline would be buried through a combination of trenching, boring, and directional drilling. The in-depth research of the Flynn Creek Impact Structure and Hawkins Cave conducted by USGS, NASA, and other universities occurred after the 1949 installation of the 3100 Line [pipeline]. The presence of the pipeline has not impeded the research and

installation of the [pipeline] Project and [would] not prohibit future investigations of the Flynn Creek Impact Structure or Hawkins Cave. Because of the vertical and horizontal distances and the intervening bedrock formations between the Hawkins Cave and the proposed [pipeline] Project centerline to the south of the cave, no impacts to Hawkins Cave are expected as a result of construction or operation of the [pipeline] Project. There would be no anticipated adverse cumulative effects, either direct or indirect, to geology or paleontology during or after pipeline installation.

Water Resources

148. Regarding the following statements from the DEIS:

Section 3.6.1.1.1 Kingston Reservation (No Action and 04 Activities), 4th paragraph, page 258: It is stated that in 2000, 41.2 MGD of groundwater from the Cambrian-Ordovician aquifer was used for public water supply systems.

Section 3.6.1.1.1 Kingston Reservation (No Action and D4 Activities}, 5th paragraph, page 258: It is stated that in 2000, about 3.7 MGD of water is withdrawn from the Ordovician aquifer for public use.

Section 3.6.1.1.1 Kingston Reservation (No Action and D4 Activities), 8th paragraph, page 260: TDEC indicates 23 water wells are located within a 1-mile radius from the KIF reservation (Figure 3.6-2):

> **Comment: More recent and trend data should be presented here and include what cities and utilities use this groundwater for public water supply. State where this groundwater is drawn from (location). (Lindsey Stevens of Roane County Environmental Review Board)**

Response: TVA conducted a water use survey as part of the TDEC Order Environmental Investigation to identify usable private water supply wells and surface water sources potentially being used for domestic purposes within 0.5-mile of the boundary of the KIF TDEC Order coal combustion residuals units. The scope of work for the water use survey did not include an evaluation of groundwater withdrawal rates and locations by public water supply systems. It is TVA’s understanding that the USGS (2000) reference provides the most recent data regarding groundwater withdrawal rates by regional aquifer systems. However, the referenced section(s) have been updated to provide trend data for public water withdrawals from groundwater and overall groundwater trends from 1995 through 2020, with forecasted estimates in 2045 based on observed trends, as presented in “Water Use in the Tennessee Valley for 2020 and Projected Use in 2045”, Tennessee Valley Authority, River and Resources Stewardship (Sharkey and Springston 2022).

Additionally, although portions of the regional aquifer systems are potentially suitable for drinking water supply, the public drinking water for Roane County is supplied by surface water sources. Groundwater sources in Roane County were closed to public uses prior to December 2008, except for one, and it is located approximately 10 miles east of the project area. Additional discussion of public water supply is provided in Section 3.14 Utilities (TVA 2015).

Considering the geologic and hydrogeologic conditions present at and in the vicinity of the KIF, one parcel has the potential of being impacted by coal combustion residuals management operations. This parcel is owned by Tennessee Valley Authority and occupied by the KIF coal combustion residuals (CCR) management units. Private water supply wells are not located on this parcel. No activities related to the KIF Retirement Project are planned or anticipated to occur on the CCR management units.

149. Section 3.6.1.1.1 Kingston Reservation (No Action and D4 Activities), 8th paragraph, page 260: TDEC indicates 23 water wells are located within a 1-mile radius from the KIF reservation (Figure 3.6-2):

> **Comment: This section needs to describe what efforts are being made to monitor these wells for CCR-related contaminants and if contaminated, what is being done to remediate these water sources used for agricultural and residential uses. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: The Emory and Clinch Rivers bound groundwater flow from the CCR units to the east and south. The water wells shown on Figure 3.6-2, Section 3.6.1.1.1 are either located upgradient of the CCR units or across the Emory and Clinch Rivers. Both spatial features act as natural boundaries between the CCR units and the wells. In addition, TVA has a robust groundwater monitoring network onsite and continues to comply with all TDEC/EPA requirements as it pertains to CCR monitoring and the TDEC Order. Section 3.6.1.1.1 has been updated to provide further details on TVA's ongoing CCR-monitoring activities.

150. Section 3.6.1.2.2 Retirement, Decommissioning, Decontamination, Deconstruction, and Demolition of KIF Plant, page 266:

> **Comment: This section needs to include the paragraph "TVA would implement supplemental mitigation measures required by TDEC's Administrative Order issued in August 2015, as well as the CCR pond closure plan approved by TDEC, which could include additional monitoring, assessment, corrective action programs, or other actions deemed appropriate as specified in the Environmental Investigation Plan (TVA 2018a)." This verbiage was included in Section 3.6.1.2.1 The No Action Alternative and would still apply to KIF retirement. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: Section 3.6.1.2.2 of the FEIS has been updated with the suggested revision.

151. Section 3.6.1.2.2 Retirement, Decommissioning, Decontamination, Deconstruction, and Demolition of KIF Plant, and Section 3.6.1.2.2.1 Environmental Justice Considerations: page 266:

> **Comment: From Section 3.6.1.1.1, This section needs to include that there are 23 water wells located within a 1-mile radius from the KIF reservation (Figure 3.6-2). Comment: This section needs to describe what efforts are being made to monitor these wells for CCR-related contaminants and if contaminated, what is being done to remediate these water sources used for agricultural and residential uses. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: See response to *Comment Nos.* 148 and 149.

152. Figure 3.6-4 Alternative A Footprint on the Kingston Reservation, page 281:

> **Comment: Suggest labeling Battery Sites 1, 2 and 3 for reference purposes and for relating to the text descriptions contained in this chapter. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: Figure 3.6-4 has been revised in the FEIS as recommended.

153. Table 3.6-8, page 285:

> **Comment: DOM (Domestic Water Supply) needs to be added to the list of Symbols, Acronyms, and Abbreviations at the front of this document. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: This term was added to the acronyms list in the FEIS.

154. Section 3.6.2.2.1 The No Action Alternative, page 314:

> **Comment: This section needs to include that "TVA would implement supplemental mitigation measures required by TDEC's Administrative Order issued in August 2015, as well as the CCR pond closure plan approved by TDEC, which could include additional monitoring, assessment, corrective action programs, or other actions deemed appropriate as specified in the Environmental Investigation Plan (TVA 2018a)." This verbiage was included in Section 3.6.1.2.1 The No Action Alternative and would still apply to KIF retirement. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: The recommended text has been added to Section 3.6.2.2.1 of the FEIS.

155. Section 3.6.2.2.2 Retirement, Decommissioning, Deactivation, Decontamination, and Deconstruction of KIF Plant. page 314:

> **Comment: This section needs to include that "TVA would implement supplemental mitigation measures required by TDEC's Administrative Order issued in August 2015, as well as the CCR pond closure plan approved by TDEC, which could include additional monitoring, assessment, corrective action programs, or other actions deemed appropriate as specified in the Environmental Investigation Plan (TVA 2018a)." This verbiage was included in Section 3.6.1.2.1 The No Action Alternative and would still apply to KIF retirement. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: The recommended text has been added to Section 3.6.2.2.2 of the FEIS.

156. Section 3.6.2.2.2 Retirement, Decommissioning, Deactivation, Decontamination, and Deconstruction of KIF Plant, 7lli paragraph page 315: This section indicates the barge unloading area would undergo demolition. However, Section 3.6.2.2.3.1 Construction and Operation of a CC/Aero CT Plant and Switchyard on the Kingston Reservation, 3rd paragraph, page 316, indicates that during buildout, facility deliveries may be made by barge, and minor modifications to the current barge unloading facilities would consist of grading and creation of dirt/rock ramping would occur. (Lindsey Stevens of Roane County Environmental Review Board)

> **Comment: Section 3.6.2.2.2 and other sections discussing the demolition of the barge unloading area should be revised to reflect that this area would remain or if demolished, redesigned and rebuilt. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: Section 3.6.2.2.2 has been updated to clarify that the demolition and deconstruction activities for the project, including the barge unloading area, would not begin until the CC/Aero CT plant is constructed and operational. TVA may continue to use the barge unloading area until the D4 process is initiated. As stated in Section 3.6.2.2.3.1, TVA would complete any necessary modifications to the barge unloading area that are needed for the construction phase of the project, while implementing required avoidance and minimization measures that may be required from any required permits.

157. Section 3.6.2.2.3.4 On-site Transmission Upgrades, last paragraph, page 318:

> **Comment: This sentence needs to be rewritten to indicate what impacts are expected to WWCs or surface waters. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: The referenced text has been updated to improve clarity, as follows:
Overall, with BMPs in place, impacts to WWCs or surface waters and water quality for the battery connects or upgrades to the existing on-site transmission line corridor are expected to be minor.

158. Section 3.6.2.2.3.6 Construction and Operation of a Natural Gas Pipeline, 4lli paragraph, page 320:

> **Comment: Why would ETNG follow Kingston's SPCC Plan to prevent, contain, and clean up fuel or hazardous material spills? ETNG should be required to follow federal/state regulations and have its own procedures for spill prevention and clean up, which should be reviewed and approved for use by TDEC and TVA. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: The referenced text in Section 3.6.1.2.3.6 has been updated for clarity, as follows: "[ETNG} would follow detailed measures for oil and hazardous materials storage and spill protection outlined in ETNG's E&SCP, the FERC Plan, and the FERC Procedures. These spill prevention practices include proper storage, handling and inspection of containers and tanks, minimizing refueling in recharge areas, following the appropriate emergency response procedures, and adherence to all spill prevention and control measures detailed in ETNG's E&SCP and [Spill Prevention, Control, and Countermeasures] (SPCC) Plan."

159. Section 3.6.2.2.3.6 Construction and Operation of a Natural Gas Pipeline, 9lli paragraph, page 321: ETNG would use an approved blasting plan for rock excavation.

> **Comment: Indicate who approves this plan (e.g., TDEC, TVA?). (Lindsey Stevens of Roane County Environmental Review Board)**

Response: TVA has independently reviewed ETNG's Blasting Plan and has incorporated relevant information into the FEIS. Further details regarding blasting are provided in ETNG's Blasting Plan included in Resource Report 6 (ETNG 2023g). ETNG has submitted the Blasting Plan with its application for Certificate of Public Necessity for the proposed Ridgeline Expansion Project to the FERC. The Blasting Plan is currently under review by FERC staff along with all application material, and if requirements are met, FERC will issue the Certificate of Public Necessity to ETNG.

160. TDEC (Water Resources) notes that there are several activities described in the Draft EIS that are associated with performing a hydrologic determination at the proposed site; however, it is unclear whether TVA utilized a certified hydrologic professional to perform these determinations. The site may require an Aquatic Resource Alteration Permit (ARAP) and, depending on the timeframe of work, a second round of hydrologic determination to determine whether the ARAP is needed. The disturbance at the site will be more than 50 acres, and therefore will require an individual construction stormwater permit (CGP) and a project-specific Surface Water Pollution Prevention Plan. Additionally, TVA will need to modify the Tennessee Multi-Sector Permit (TMSP).

TDEC notes that the NPDES discharge permits may no longer be necessary. (Commenter: Tennessee Department of Environment and Conservation)

***Response**:* Page 307 in the FEIS, "Field surveys were performed by Tennessee Qualified Hydrologic Professionals during the summer of 2019. A portion of the site was re-evaluated in spring of 2022 due to permitted disturbances in the area since 2019." TDEC provided Hydrologic Determination Concurrence for mapped aquatic features on site on August 26, 2022. For any proposed impacts to regulated aquatic features, TVA would apply for ARAP permitting, in compliance with TDEC Division of Water Resources regulations. TVA would seek coverage under Tennessee's Construction General Permit for stormwater discharge during construction activities, as needed. As noted, existing NPDES permits may no longer be necessary due to cessation of coal combustion activities and termination of associated waste streams. However, if additional process water waste streams are necessary for replacement generation, TVA would apply for the appropriate NPDES permitting to ensure proposed discharges meet water quality requirements. Tennessee Multi Sector Permit coverage would be modified or obtained, as necessary, for industrial stormwater discharge.

161. Section 3.6.1.1.1 Kingston Reservation (No Action and D4 Activities), 8th paragraph, page 260: TDEC indicates 23 water wells are located within a 1-mile radius from the KIF reservation (Figure 3.6-2): Comment: This section needs to describe what efforts are being made to monitor these wells for CCR-related contaminants and if contaminated, what is being done to remediate these water sources used for agricultural and residential uses. (Commenter: Roane County Environmental Review Board)

Response: The Emory and Clinch Rivers bound groundwater flow from the CCR units to the east and south. The water wells shown on Figure 3.6-2, Section 3.6.1.1.1 are either located upgradient of the CCR units or across the Emory and Clinch Rivers. Both spatial features act as natural boundaries between the CCR units and the wells. In addition, TVA have a robust groundwater monitoring network onsite and continue to comply with all TDEC/EPA requirements as it pertains to CCR monitoring and the TDEC Order.

Biological Resources

162. TVA's analysis of potential impacts to listed species is incomplete and inadequate. TVA fails to take a "hard look" at the potential impacts its preferred alternative will have on species and habitat in the project area. The problems which arise from conducting two distinct NEPA reviews on differing components of one inextricably connected project are apparent in TVA's analysis of the proposed project's impacts to wildlife. TVA repeatedly relies on FERC's as-yet-to-be-published NEPA analysis regarding projected impacts to wildlife from construction and operation of the 122-mile-long methane gas pipeline meant to serve the proposed Kingston CC/Aero CT Plant. So too does the agency rely on forthcoming decisions from a not-yet-completed consultation between ETNG and FWS to assert minimal impacts to wildlife and their habitat.

References to such future information and mitigation measures does nothing to fulfill TVA's immediate obligations concerning NEPA's "twin aims"—that the agency consider every significant environmental impact from their proposed action and disclose that analysis to the public. Rather, TVA punts large sections of this process to another agency, for another time. The analysis that TVA does undertake is insufficient and outdated. Such tactics impede the public's ability to analyze and comment upon TVA's preferred alternative. TVA's DEIS must therefore be supplemented. (Commentors: SELC and Conservation Groups)

Response: Comment noted. TVA is ensuring compliance with the National Environmental Policy Act and Section 7 of the Endangered Species Act in its analyses of potential impacts to listed species.
At the time of scoping the EIS, TVA determined, in consultation with FERC, that the agencies would undertake their respective NEPA reviews for the different agency actions. The considerations that went into this determination included: (1) Project schedules for the two federal actions--TVA's action to replace generation at KIF and FERC's action to issue a certificate for the pipeline did not align timewise, as it would not make sense for FERC to complete its review of the pipeline prior to TVA's decision regarding replacement generation (the basis of FERC's Purpose and Need); and (2) TVA's status as the "shipper" for the pipeline project, which could be perceived as a conflict of interest. For these reasons, FERC is preparing its own EIS for the pipeline, which can incorporate and rely on aspects of the KIF EIS, as appropriate.

Notwithstanding the fact that FERC is preparing its own EIS for the pipeline, TVA has considered the impact of the replacement generation and the pipeline (for Alternative A) in detail in this EIS, consistent with 40 CFR Section 1501.9(e). This EIS appropriately uses the information that is currently available to fully consider the environmental impacts of the plant and the pipeline. See Kentucky Coal Ass'n., Inc. v. T.V.A., 804 F.3d 799, 806 (6th Cir. 2015).

TVA included an analysis of the related proposed pipeline associated with Alternative A in the DEIS. The DEIS incorporated the results of a GIS-based environmental analysis of ETNG's construction right-of-way for the proposed pipeline, compressor station, M/R stations, and temporary access, laydown, or parking areas or construction areas. Since the publication of the DEIS, ETNG has conducted additional field-based surveys and assessments of the various environmental resources potentially affected by the pipeline. The FEIS has been updated to incorporate this more detailed information which is drawn from ETNG's application (ETNG 2023a) and Final Resource Reports filed with FERC on July 18, 2023 (ETNG 2023b -2023l) and has been independently evaluated by TVA. TVA disagrees that it has "punted" the assessment of impacts to "another agency, at another time." Rather, TVA's EIS includes the assessment of impacts of TVA's replacement CC/Aero CT Plant and of ETNG's pipeline and discloses those impacts to the public through the publication of the DEIS and FEIS.

Consultation with the relevant agencies regarding the pipeline (USFWS, US Forest Service, TWRA, TDEC, and USACE) was initiated by ETNG; the status of those consultations was communicated in a filing with FERC on October 5, 2023 (ETNG 2023m). The additional information provided in ETNG's October filing has been reviewed and incorporated in the updated analyses presented in the FEIS, where relevant. Based on Table 1.11-1 provided in the October filing, required consultations have been initiated with over half of the identified line segments completed and all but one of the remaining segments targeting completion by end of 2023. The remaining segment, a 0.3-mile section located in Morgan County, is scheduled for completion by fall of 2024.

163. TVA's DEIS asserts that its preferred alternative will not significantly affect federally listed bat species. It does so in part by relying on a programmatic consultation it undertook with FWS in 2018 regarding effects of its routine actions on listed bat species. Since that time, northern long-eared bat populations have continued to decline precipitously, and the species was recently reclassified from threatened to endangered. Due to the species' changed federal classification, TVA recently reinitiated its programmatic consultation with FWS to update its analysis of its routine activity impacts to the species. Based on these changed circumstances and TVA's reinitiated consultation, TVA must update its analysis of Alternative A's potential to impact northern long-eared bats.

The DEIS notes that bat roosting and foraging habitat exists at the Kingston site as well as along the associated transmission and pipeline routes. Gray bats, Indiana bats, and northern long-eared bats have all been recorded within counties impacted by TVA's proposed alternative and ETNG's connected pipeline, and these bat species have been documented both inside and outside of caves. Northern long-eared bats in particular have been documented within 5-miles of the Kingston site and within a 3-mile radius of the pipeline construction ROW. Moreover, the species has been seen in the area within the last 10 years, which suggests that individuals may exist in the area even after the introduction of white nose syndrome to local populations.

TVA must also include an updated bat strategy form in or appended to its environmental analysis so that the public may review the agency's proposed mitigation measures. (Commentor: SELC)

Response: As noted by the commentor, TVA's Programmatic Consultation for routine actions and their impacts to federally listed bats was updated in May 2023 to address the uplisting of northern long-eared bat from Threatened to Endangered status. The updated NEPA analysis and Bat Form are included in the FEIS to address potential impacts along TVA's transmission line upgrades, see Appendix F. While many of the proposed actions on the Kingston Reservation are also covered under this programmatic consultation, some are not (e.g. solar panel installation). Therefore, TVA is consulting with USFWS in an additional Section 7 ESA consultation to ensure all of TVA's proposed activities would not jeopardize federally endangered bats. To support TVA impact determinations for federally listed bats, TVA performed Phase 2 Presence/Absence surveys across the KIF site in May 2023 in accordance with the 2023 USFWS Guidelines for Indiana Bat and Northern Long-eared Bat Surveys, which also provide suitable levels of efforts to determine potential presence of tricolored bat. No Threatened or Endangered Bats were captured at the KIF Site during these surveys. The results of this survey are reported in a Bat Survey Report. TVA will also endeavor to constrain tree removal activities on the KIF site to winter months to avoid or minimize impacts to more common species of tree-roosting bats. No or minimal tree removal would occur along existing TVA transmission line upgrade activities off the KIF Reservation. Similar survey efforts were also performed along the pipeline route by ENTG and no northern long-eared bats were captured. Tree removal associated with the pipeline would also be performed in winter to minimize impacts to tree roosting bats. As mentioned in *Comment No.* 150, ENTG will also be consulting with USFWS regarding potential impacts to federally listed bats. See the response to *Comment No.* 162.

164. Table 3.8-21 Threatened, Endangered, and Other Protected Species Evaluated for Potential Impacts under the Individual Components of Alternative A Proposed on the Kingston Reservation: Comment: Under Birds, page 449, Osprey: Code SR under State Rank and Listing Status is not defined in the footnotes.

> **Comments: Under Mollusks and between plant listing, page 451: Shaded row needs header with "Plants" added. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: Added definition "SR = State-listed as rare" to table footnotes and verified this is included in other tables where appropriate. Formatting for row headers (i.e., for plants) were checked and updated as needed.

165. TVA's analysis of the impact ETNG's pipeline will have on listed bat species under Alternative A is insufficient and incomplete. The proposed ETNG pipeline traverses territory which may be used by at-risk bat species for foraging, roosting, and hibernating. The DEIS notes that the

gray bat, Indiana bat, northern long-eared bat, tricolored bat, and little brown bat have all "been documented within a 3-mile radius of the ETNG Construction ROW" and that several caves are located within this area. The DEIS further notes that that ETNG has conducted "targeted fall and summer mist net surveys" to determine whether listed bat species are present along the pipeline ROW, and ETNG's Draft Resource Report 3 indicates that surveying will continue into 2023. However, TVA fails to provide the public with access to those surveys and merely states that consultation with FWS for impacts to these species is "ongoing." (Commentor: SELC)

Response: See the response to *Comment No. 162*. The information that TVA has relied on in drawing conclusions in the DEIS was provided in the text of the DEIS itself, incorporated by reference in the DEIS, or otherwise already available to the public (ETNG's Draft Resource Reports are available online through the FERC website e-library). The same is true for the FEIS, in that the document and analyses have been updated to reflect additional data provided in ETNG's Final Resource Reports. This data has been independently reviewed by TVA. See response to *Comment No. 10* regarding the EIS's evaluation of the pipeline's impacts.

Updates to Section 3.5.1.1 of ETNG's Resource Report 3 (ETNG 2023d) include impact assessments for listed bat species and their habitats. No caves will be impacted by the pipeline and ETNG will implement BMPs to minimize potential impacts to water quality. It is ETNG's opinion that the Project *May Affect but is Not Likely to Adversely Affect* the gray bat. Additionally, the pipeline may impact potential habitat for Indiana bat, little brown bat, northern long-eared bat, and tricolored bat. Surveys and consultation for these bat species are ongoing and ENTG plans to submit a final biological assessment with effects determinations for bats by February 2024. The draft biological assessment is currently included as Appendix 3C of Resource Report 3 and provides additional information regarding bat survey methodology and results.

166. The DEIS's failure to analyze habitat impacts ETNG's pipeline could have on listed and proposed-listed bat species cannot be rectified by eventually publishing these details in a final EIS, because the public will then lack the opportunity to provide comment on that document. TVA's failure to include these details in the DEIS abrogates the agency's responsibilities to the public under NEPA. TVA should therefore supplement this document and provide additional opportunity for the public to review and comment upon completed information and analysis. (Commentor: SELC)

Response: See the response to *Comment Nos. 162,163, and 165*. Additionally, FERC has jurisdiction over the approval of, and the related NEPA study for, the ETNG pipeline, and the public has additional opportunities to participate in FERC's separate process. The evaluation of potential pipeline project impacts to listed or proposed-listed bat species is provided in ETNG's Resource Report 3 (ETNG 2023d). The information in ETNG's Resource Reports was independently reviewed and evaluated by TVA and incorporated in TVA's DEIS for the Kingston project. The public had the opportunity to file comments on TVA's DEIS. Revisions made by ETNG to its Resource Reports to update those reports were submitted by ETNG to FERC on July 18, 2023, and the revisions were incorporated by TVA in the FEIS.

167. TVA's current review of Alternative A's potential to affect listed mussel species is inadequate, as it fails to explain why reliance on an 18-year-old survey is appropriate to assume that no listed mussels occupy waterways adjacent to the Kingston Reservation. TVA must undertake a current and comprehensive survey of mussel habitat for listed inhabitants which could be affected by the proposed action. If found, TVA must then analyze the effect this proposed action could have on these species, and further action, including consultation with the FWS, may be warranted. (Commentor: SELC)

Response: See the response to *Comment No. 162*.

No federally or state-listed mollusks were found during the 2005 survey of the Clinch River/Watts Bar Reservoir in the vicinity of the KIF Reservation (Yokley 2005). River substrates were noted as degraded ("sub-optimal") and clay as the dominant substrates, overlain by varying thicknesses of mud. The FEIS has been updated to incorporate mussel information from surveys completed between 2005 and 2017 (TVA 2019d). No federally or state-listed mollusks were found during these subsequent surveys, although several specimens of common species were identified.

Green blossom pearlymussel and turgid blossom pearlymussel were delisted due to extinction in Tennessee. TVA has determined that the proposed actions on the KIF reservation would have *No Effect* on the following federally listed species: Alabama lampmussel, birdwing pearlymussel, cracking pearlymussel, Cumberland bean, dromedary pearlymussel, fanshell, finerayed pigtoe, green blossom pearlymussel, orangefoot pimpleback, pink mucket, purple bean, ring pink, rough pigtoe, rough rabbitsfoot, sheepnose mussel, shiny pigtoe, spectaclecase, tan riffleshell, Tennessee bean, turgid blossom pearlymussel, white wartyback, Anthony's riversnail, Laurel dace, sickle darter, slender chub, spotfin chub, and yellowfin madtom.

Updates to Section 3.5.1.3 of ETNG's Resource Report 3 (ETNG 2023d) includes information from a recent mussel survey conducted by Stantec; the survey effort commenced in summer 2022 and concluded in 2023. Through coordination with the USFWS and TWRA, ETNG proposed to use a three-step approach to determine which waterbody crossings were likely to contain native freshwater mussels, as follows: Step 1 – Desktop Review and Site Reconnaissance, Step 2 – eDNA Sampling and Analysis, and Step 3 – Visual and Tactile Surveys. Four small streams and three of the embayment crossings assumed to have mussels were further evaluated for freshwater mussels with Visual and Tactile Surveys (Step 3).

Results determined that overall abundance and richness were low regardless of the survey technique, eDNA or visual and tactile. Although eDNA detected the potential presence of the federally endangered Alabama lampmussel (Lampsilis virescens) at one of the small stream crossings (Site 165 – Emory River), no protected species listed under either the ESA or TCA were identified during the Visual and Tactile Survey. The survey methodology, results of the 2022 surveys and 2022 survey reports are included as Appendix C of the draft biological assessment, and a summary of the current survey status can be found in Table 3.5-2 in Appendix 3A of ETNG's Resource Report 3.

During surveys for federally listed fish species (sickle darter [*Percina williamsi*] and spotfin chub [*Erimonax monachus*]) that were completed in October 2023, five Alabama lampmussel were documented near Site 165. No listed fish were identified during these surveys. East Tennessee coordinated with the USFWS to incorporate these results into its Biological Assessment issued in January 2024 (ETNG 2024).

168. In the DEIS, TVA must analyze the impact that climate change will have on local ecosystems and species. Take, for instance, local migratory bird populations. Migratory bird population declines from climate change-driven threats are of particular concern. Research has indicated that birds will be significantly affected by the changing climate. Scientists have found that approximately 64 percent of North American bird species are moderately or highly vulnerable to climate change. And the Southeast is expected to lose communities of breeding bird populations due to warming temperatures. The DEIS should analyze the impact that the proposed

project will have not only on the nesting, feeding, and migration practices of these birds within the Kingston Reservation, but also the impacts which climate change will have upon the species' ability to survive and flourish writ large within their traditional habitat systems. (Commentor: SELC)

Response: The DEIS included an assessment of climate impacts; the FEIS has been updated to provide additional evaluation and discussion of each alternative's potential to contribute to climate impacts and their potential effects on species. The operation of the proposed CC/Aero CT Plant would contribute to climate change impacts. Climate change impacts on bird species typically include expansion and/or shifting of ranges, reductions in habitat due to more frequent fire regimes, and potentially higher rates of nest failure related to spring heat waves or droughts. The current range of the Bachman's sparrow is primarily in the southeastern U.S.; increasing warming scenarios project this species' range to expand north due to some portions of its range being lost in southern portions of its range. The early successional habitat and fragmented forests found on the Kingston Reservation may provide habitat to support the Bachman's sparrow; however, there have been no historical or recent observations of Bachman's sparrow on the Kingston Reservation. The range of the Swainson's warbler is located mostly along the southeastern coast of the U. S. with scattered range throughout the Appalachian Mountains. Climate change projections show this species' range to become more restricted along the coastline with greater warming and range gained in northern latitudes. While the forested habitats adjacent to the Clinch and Emory rivers may provide suitable habitat for Swainson's warbler, no individuals were documented on the Kingston Reservation during recent or historical field surveys. Based on the lack of occurrences of Bachman's sparrow and Swainson's warbler within the Project Area, the effects of climate change are not expected to adversely impact these species within the Project area.

Impacts to reptiles from climate change include changes in range, narrowing of reproduction windows, and impacts to habitat due to changes in fire regime, drought, and rainfall. Changes in range are particularly problematic for reptile species due to their limited mobility across the landscape; shifting of suitable habitat and range may occur faster than these species can feasibly move. Understanding the impact of climate change, including impacts within the Project area, on the eastern slender glass lizard is exceptionally challenging due to the secretive nature of this species.

Impacts to bats from climate change include loss of habitat due to increased frequency of fire, food reduction, and decreased survival due to drought and increased temperatures. Even within secluded caves or other hibernacula, bats may be susceptible to isolated weather-related events if they are trapped due to intense rainfall, prolonged freezing temperatures, or if cave entrances become blocked with snow drifts and ice. These impacts are adequately evaluated in the FEIS.

169. The DEIS does not include a detailed analysis of forest fragmentation impacts which would occur under Alternative A. Rather, it acknowledges that construction of ETNG's pipeline will require clearing approximately 755 forested acres but foregoes detailed analysis by asserting that detailed review of resulting effects to listed species will be forthcoming in ETNG's future FERC filings. Conservation Groups note that it is not enough for the DEIS to merely point to other, non-NEPA documents and processes to assert that sufficient environmental impact analysis is being undertaken. As discussed above, forest fragmentation may lead to myriad negative effects for listed bat species, among other wildlife. The DEIS itself must include an analysis of the impact forest fragmentation will have on listed species, and because it currently lacks any such meaningful analysis, the DEIS is incomplete. (Commentor: SELC)

Response: See the response to *Comment No. 162*.

To the extent practicable, feasible, and legally permissible, *ETNG* has routed the pipeline to follow an existing ETNG pipeline ROW and easement, following existing forest edges, thereby minimizing the acreage of forested land crossed and the relatively greater impacts that could be associated with clearing an entirely new ROW through a contiguously forested area. Construction of the natural gas pipeline and associated aboveground facilities would require temporary or permanent impacts to a variety of habitat types, including terrestrial areas such as forested and herbaceous habitats, and aquatic environments such as streams and wetlands (see Sections 3.6.2, 3.6.3, and 3.8 of the FEIS). Section 3.8.1.1.2.6 of the FEIS has been revised with results of updated analyses of the proposed natural gas pipeline. TVA has independently reviewed this information and adopts ETNG's conclusions. Sections 3.8.1 and 3.8.4 of the FEIS were updated to include greater detail and evaluation-regarding potential for forest fragmentation and its potential effects on species from the proposed natural gas pipeline under Alternative A.

170. ETNG's proposed action—whatever it may be—will need to be fully analyzed, not only in consultation with FWS to determine if the action may jeopardize the species and/or destroy or adversely modify its critical habitat, but also as part of TVA's NEPA analysis.

Moreover, and as mentioned above, it is not enough for TVA's final EIS to contain this information without providing the public an opportunity to provide public comment. NEPA requires agencies to provide proof—not platitudes—that environmental analysis has been done. NEPA also requires that the public be able to provide feedback on the sufficiency and contents of this analysis, something it is unable to do given the lack of information in the current DEIS.

The DEIS notes that ETNG is still actively surveying the pipeline ROW to ascertain threatened and endangered species which may be present, and the company has yet to confirm how much suitable habitat it may affect for various animals. In fact, ETNG has yet to finalize the pipeline route itself. Despite this, TVA assumes that any eventually decided-upon conservation measures will ensure that the proposed action will result in no significant effects to listed species. This stance is more wishful than factual and fails to acknowledge the multiple contingencies which could change ETNG's impacts to listed species. It also glosses over the indisputably large impact ETNG will have on hundreds of acres of landscape regardless of the pipeline's final path. ETNG's proposed pipeline is a connected action relevant to TVA's environmental review of its Kingston project. TVA's NEPA analysis must incorporate information and discussion of both facets of this gas buildout. The DEIS provides insufficient detail and analysis of ETNG's proposed pipeline impacts, and thus fails to provide adequate public notice and review at this stage. (Commentor: SELC)

Response: The public has had the opportunity to comment on the proposed pipeline as part of this NEPA process. See the response to *Comment Nos. 25 through 27*, and *Comment No. 162*.

Further, the public continues to be provided multiple opportunities to provide comment on the TVA component of the project and for ETNG's proposed East Tennessee Ridgeline Expansion Project, through participation in the public scoping and public information meetings, and through opportunities for providing comments via TVA's DEIS and FERC's DEIS processes.

This EIS appropriately uses the information that is currently available to fully consider the environmental impacts of the plant and the pipeline. *See Kentucky Coal Ass'n., Inc. v. T.V.A.,* 804 F.3d 799, 806 (6th Cir. 2015). The FEIS has been updated with additional data and updated analyses of environmental consequences of the actions proposed by the TVA and ETNG for their respective project components.

See Chapter 3. This update includes the information from the Final Resource Reports submitted by ETNG to FERC in July 2023 as part of its pipeline certification process under Section 7 of the NGA.

171. The DEIS notes that the Eastern Transmission Corridor for TVA's proposed action crosses a state Wildlife Management Area ("WMA"), the Manhattan Project National Historic Park, the North Ridge Trail, and the Obed River. In addition, the proposed Kingston pipeline is expected to transect two WMAs, a state forest, a state park, waterbodies on the Nationwide Rivers Inventory List, and tributaries to the Obed Wild and Scenic River. The DEIS fails to adequately account for the short- and long-term impacts its proposed alternative and associated pipeline will have on these myriad public lands and protected waterways. TVA's analysis must be supplemented in order to adequately account for these impacts. (Commentor: SELC)

Response: Specific impacts to natural areas within the Eastern Transmission Corridor are addressed in Section 3.9.2.3.5. The Eastern Transmission Corridor does not cross the Obed River.

Section 3.9.2.3.6 of the FEIS has been updated to reflect additional information provided in ETNG's Final Resource Reports filed with FERC in July 2023. TVA has independently reviewed and, adopts as its own, the information and conclusions contained with those filings.

172. The DEIS notes that ETNG's proposed pipeline ROW is currently routed to cross several waterbodies on the Nationwide Rivers Inventory ("NRI") list, including: Crooked Fork Creek, Emory River, White Creek, Spring Creek, Blackburn Fork of the Roaring River, Flynn Creek, and Goose Creek. The DEIS states that HDD techniques will be used "to the extent possible" on sensitive waterbody crossings, and TVA asserts that any impacts to these waterbodies due to the construction of ETNG's pipeline would be "temporary" and "minor." TVA's conclusions are both unsupported and premature.

First, TVA's belief that ENTG's installation process to place its pipeline under numerous NRI-listed waterbodies through directional drilling would cause only "minor" impacts ignores the risk that HDD poses to waterways. As outlined above, HDD requires the use of large quantities of drilling muds and can cause inadvertent returns which can have severe impacts on water quality and aquatic life. Further, TVA's finding is premature because—as acknowledged in the DEIS— ETNG has not committed to utilizing HDD to cross all of these waterbodies. It also does not appear that FERC has finished consulting with National Parks Service, as required, about the effect these crossings could have on these NRI-listed waterbodies. Once FERC has finished with that process, TVA has an obligation to independently review FERC's findings.

When a permitting agency reviews projects affecting NRI waterbodies, they must "take care to avoid or mitigate adverse effects" to those waters. As part of that process, the permitting agency must determine whether a proposed action could have an adverse effect on the natural, cultural, or recreational values of an NRI waterway such that it would foreclose the option of classifying these areas as wild, scenic, or recreational rivers in the future. ETNG's proposed pipeline could jeopardize the potential future listing of Crooked Fork Creek, Emory River, White Creek, Spring Creek, Blackburn Fork of the Roaring River, Flynn Creek, and Goose Creek as Wild and Scenic Rivers due to environmental and aesthetic degradation of the areas. Also, as FERC undertakes its NRI analysis and consultation, it may require mitigation or avoidance measures from ETNG that would change the proposed pipeline's route or impact on these waterbodies. Because ETNG plans to cross these waterbodies may substantially change, it is premature for TVA to analyze these

impacts or assert that ETNG's actions would only cause minor effects to NRI- listed waterways. TVA's DEIS is therefore incurably premature, and TVA must submit a supplemental DEIS to public comment after FERC's consultation process is completed. (Commentor: SELC)

Response: See response to *Comment Nos. 25 through 27.*

Relevant sections of the FEIS have been updated based on the revised project details from ETNG's Final Resource Reports and application filed with FERC in July 2023 (ETNG 2023 a-l). TVA has also independently reviewed, and adopts as its own, updated information on the affected environment and potential environmental effects of ETNG's proposed natural gas pipeline. TVA's conclusions on pipeline impacts are not premature and are supported by the findings in the Resource Reports which TVA has reviewed and adopted in its EIS. See also response to Comments 162, 163, 165, and 166.

As stated in ETNG's Resource Report 8 (ETNG 2023i):

> The NPS has identified tributaries to the Obed River that will be crossed by the Project. The Obed River is designated as a Wild and Scenic River; the Project does not cross the designated reach of the Obed River. The Obed Wild & Scenic River is discussed in Section 2.3.5 of Resource Report 2. Nationwide River Inventory (NRI) river segments are potential candidates for inclusion in the National Wild and Scenic River System. The Project crosses seven NRI river segments, as discussed in Section 2.3.5 of Resource Report 2. NPS will be evaluating impacts on the Outstanding Remarkable Values for the tributaries to the Wild and Scenic River crossed by the Project under Section 7 of the Wild and Scenic Rivers Act. East Tennessee is coordinating with NPS regarding the crossing of the Obed Wild & Scenic River tributaries and NRI river segments. East Tennessee has discussed waterbody crossing methodologies as well as typical erosion control techniques and post construction bank stabilization with the NPS. In addition, East Tennessee is evaluating crossing timing to determine if construction across the waterbodies used by paddlers at a time in the season when the areas are not being utilized is feasible. If construction were to happen during seasons when recreational uses are expected, East Tennessee is evaluating methods that would have the least effect on recreational use. A summary of the NPS coordination meetings is provided in Appendix 1F of Resource Report 1. East Tennessee will continue to coordinate with NPS to address concerns and minimize impacts to the tributaries of the Obed National Wild & Scenic River.

The proposed pipeline, a component of Alternative A, is anticipated to temporarily disturb approximately 34.4 acres of natural and recreational resources during construction, 8.5 acres of which would be within the previously disturbed existing 3100 Line permanent ROW.

For the resources proposed to be crossed by ETNG's proposed project, ETNG would coordinate planning and construction with landowners to ensure continued recreational use during construction (to the extent practicable) and operation of the pipeline. ETNG is consulting with the TWRA, NPS, USACE, and USFS regarding potential impacts to the properties described above in order to identify minimization and mitigation measures. East Tennessee may use signage, flaggers, or other means to ensure recreational users can safely traverse work areas.

According to ETNG's Resource Report 8 (ETNG 2023i), effects on natural and recreational resources from construction of the pipeline would be:

> […] temporary and may include trail closures or re-routes around active construction. Temporary effects on recreational users may also include noise and visual disturbance from construction equipment and construction activities.
> […] Mitigation measures during construction may include flagging of work zones, signage, re-routes, and/or closure notifications. There would be no long-term effects to use of the lands during operation of the [pipeline].

Section 2.3.5.1 of ETNG's Resource Report 2 (ETNG 2023c) describes its ongoing consultations with the NPS. ETNG's discussions with the NPS include evaluation of crossing techniques proposed, recommendations for erosion and sediment control measures to minimize and/or prevent water quality degradation, and review of the project's plans including the Horizontal Directional Drill Monitoring, Inadvertent Return Response, and Contingency Plan (provided as part of Appendix 1C-Project Plans of Resource Report 1 [ETNG 2023b]). ETNG will continue to engage NPS to avoid and minimize potential impacts to NRI waterbodies and will implement the Project Erosion and Sediment Control Plan, Horizontal Directional Drill Monitoring, Inadvertent Return Response, and Continency Plan, the FERC's Upland Erosion Control, Revegetation, & Maintenance Plan and Wetland and Waterbody Construction and Mitigation Procedures, other applicable project plans and abide by permit conditions set forth by the USACE and TDEC. ETNG will share outcomes of consultations with the NPS related to NRI waterbody crossings with FERC as they become available.

TVA has independently reviewed and concurs with the natural areas, parks, and recreation-related findings in ETNG's Resource Report 8 (ETNG 2023i).

173. The DEIS states that ETNG's proposed pipeline appears to cross the Justin P. Wilson Cumberland Trail State Park in Morgan County, Tennessee. The Cumberland Trail, as it is commonly referred, is a state scenic trail located on the Cumberland Plateau which traverses a "line of pristine high ridges and deep gorges" through an 11-county corridor. ETNG asserts, and TVA concurs, that impacts to the Cumberland Trail would be "temporary and may include trail closures or re-routes around active construction." The DEIS also acknowledges the noise and visual disturbances which could impact recreational users. Tennessee State Parks and natural areas belong to the people of the State and are for the recreational use of the public and require protection and preservation." By constructing a privately-owned gas pipeline across the Cumberland Trail, ETNG acknowledges that it will impair Tennesseans recreational use of this area, albeit temporarily. However, the proposed pipeline will also likely have long term visual impacts including a permanently cleared ROW adjacent to the trail utilized by the public. (Commentor: SELC)

Response: See response to *Comment Nos. 25 through 27, and 172*.

Section 8.4.2.2 of ETNG's Resource Report 8 (ETNG 2023i) describes the proposed crossing of the Cumberland Trail. The current trail consists of discontinuous segments that will once completed extend over 300 miles from the Cumberland Gap to Lookout Mountain. The current maps of the trail system show the Cumberland Trail ending in the town of Wartburg, while publicly available GIS data from TDEC indicates that ETNG's Ridgeline Project would cross the Cumberland Trail.[8] ETNG's crossing is in an area that may be proposed for future expansion of the trail system, but the State has not yet secured and

[8] Available online at Cumberland Trail State Scenic Trail (arcgis.com)

officially incorporated this portion into the Cumberland Trail State Park. As stated in its application, ETNG continues to coordinate with the TDEC and NPS regarding the crossing of the Cumberland Trail and to date, no site-specific crossing recommendations have been provided by the agencies.

174. Moreover, any pipeline leak or rupture could be devastating to this portion of the state park and lead to even more dramatic impairments of the public's recreational use of the area. TVA should supplement its analysis to incorporate discussion of these impacts and provide further analysis regarding the public's competing recreational and aesthetic interests in leaving this state park undeveloped and protected against the interests of a private fossil fuel developer. (Commentor: SELC)

Response: As described in ETNG's Resource Report 11 (ETNG 2023l), the Ridgeline Expansion Project consists of new pipeline to be constructed and operated in accordance with current applicable Department of Transportation and Pipeline and Hazardous Material Safety Administration requirements. As described in Resource Report 6 (ETNG 2023g), ETNG administers a robust pipeline integrity management program that actively monitors and repairs its assets during operation of the Project.

175. Tennessee state forests "belong to the people of the State of Tennessee and are for use of the public." These areas are meant to offer the public "hunting, hiking, bird watching and tranquility." Despite Tennessee's emphasis these areas are for the use and enjoyment of the public, TVA's DEIS notes that ETNG's proposed pipeline route would cross the Lone Mountain State Forest *within approximately 100 yards* of the nearest trail. The pipeline's proximity to a public access point will not only likely have short and long-term negative visual impacts for Tennesseans attempting to enjoy the forest, but could also pose a safety risk if the pipeline were ever to leak or rupture. Despite this, ETNG asserts, and TVA agrees, that all effects would be temporary and short-term.

The damage, cutting, removal, or destruction of natural resources in state forests is prohibited except with the written authorization or under the direct supervision of the district forester. ETNG anticipates land disturbance to construct its pipeline, yet in the DEIS, TVA does not state that ETNG is coordinating with the Tennessee Department of Agriculture or the district forester for these activities. ETNG must do so, and TVA's environmental analysis should be updated to reflect the results of that coordination and discuss the aesthetic and safety impacts which the proposed pipeline may have on public visitors to Lone Mountain State Forest. The public must then have an opportunity to comment on this updated analysis. (Commentor: SELC)

Response: Based on ETNG's Final Resource Report 8 (ETNG 2023i), submitted to FERC in July 2023:

> [ETNG] is currently consulting with representatives of the TWRA, NPS, and USACE regarding potential Project-related effects to the properties described above. Consultation with each managing agency is ongoing and will identify specific minimization and mitigation measures that will help the Project comply with the management objectives and regulations for the affected properties. Notes from coordination meetings with these agencies are provided in Appendix 1F of ETNG's Resource Report 1.
>
> …
>
> For the identified public and recreation lands crossed by the Project, [ETNG] will coordinate planning and construction with the applicable landowner or management agency/organization to help ensure continued recreational use during construction (to the extent practicable) and operation of the pipeline.

…
In general, effects on the public and recreation lands from construction of the Project will be temporary and may include temporary trail closures or re-routes around active construction. Temporary effects on recreational users may also include noise and visual disturbance from construction equipment and construction activities.
…
Mitigation measures during construction may include flagging of work zones, signage, re-routes, and/or closure notifications. There would be no long-term effects to use of the lands during operation of the Project. [ETNG] will continue to coordinate with USACE, TDEC, and NPS to address concerns and minimize impacts to the recreational lands crossed by the pipeline.

Aesthetic resources include visual or scenic resources, and ambient noise levels. Potential adverse effects to visual resources would occur from noticeable, unwelcome change to the visual quality of a landscape setting. Construction of the Project would temporarily alter visual quality in the immediate Project area by removing existing vegetation and disturbing soils. Construction activities will be visible from public roads, private residences, and businesses. In many cases, the activities will be blocked from residences and public viewing by trees and topography. construction would also generate dust and noise, which could impact users of nearby recreational areas. Visual and noise effects from construction activities occur only for the duration of construction activities; there would be no long-term adverse effect to aesthetic resources from the construction of the Project.

Long-term effects to visual resources from the operation of the pipeline and aboveground facilities would include the long-term or permanent removal of vegetation in operating ROWs and aboveground facility operating footprints; as well as the addition of new structures into the landscape as seen from sensitive viewpoints, which include residences and public use areas (parks, open space, state forests, etc.).
…
Visual impacts associated with the pipeline would be greatest during active construction as a result of construction equipment, personnel, and disturbed soil. Permanent visual changes associated with pipeline installation typically include the cleared permanent ROW in wooded areas and the installation of pipeline markers. Most of the pipeline will be collocated with the existing 3100 Line ROW for 111 miles of the 122 total miles.
…
The Project crosses federal public lands owned by the USACE and TVA and state lands managed by Tennessee Department of Agriculture, Division of Forestry. [ETNG] is in the process of consulting with these agencies regarding the proposed crossing of the pipeline facilities through federally and state-owned and managed parcels and the associated applications for ROW or land use approvals that may be required. [ETNG] intends to apply for real estate outgrants or easements from these agencies in the fourth quarter of 2023. [ETNG] is also coordinating with Tennessee Department of Transportation and the county road departments to obtain permits for facilities within road ROWs.

176. Wildlife Management Areas are protected areas in Tennessee which have been "set aside for the conservation of wildlife and for recreational activities involving wildlife…" The Tennessee Wildlife Resources Agency manages WMAs with a "focus[] on conservation, and where appropriate, the restoration of fish, wildlife, plant resources, and habitats for the benefit of all Tennesseans for generations to come." Despite the stated purpose and priorities of WMAs, TVA's proposed action and the related pipeline will cause or contribute to climate, land, and water

disturbances to several of these protected areas. These impacts have the potential to cause both short- and long-term effects to wildlife which inhabit the WMAs and impede the use and enjoyment by Tennesseans who recreate in these areas. Yet in its DEIS, TVA asserts that overall affects to WMAs will be temporary. This conclusion ignores the risks that activities such as HDD have on waterways and their inhabitants and glosses over long-term climate impacts which may affect these protected areas. (Commentor: SELC)

Response: TVA has evaluated and performed an independent review of ETNG's Final Resource Report 8 filed in July 2023 (ETNG 2023i), which is incorporated by reference. As stated in ETNG's Resource Report 8, the Ridgeline Expansion Project would cross multiple segments of multiple WMAs, with major portions of the crossing being located adjacent to the existing 3100 Line ROW. Crossing methods were determined through consultation with relevant agencies and federal services to minimize the total impacts to WMAs from the project. This information has been incorporated into the FEIS. In addition to modifying stream or resource crossing methods, ETNG would minimize impacts through implementation of the Project E&SCP Plan, FERC Procedures, and strict adherence to post-construction site restoration required by the USACE and TDEC. Mitigation was discussed during a March 20, 2023, meeting with the USACE and TDEC (Appendix 1F of Resource Report 1). Compensatory mitigation for the unavoidable loss of functions and riparian impacts will be mitigated through the purchase of compensatory mitigation credits (if available), in-lieu credit fee (if available) and/or an offsite Permittee Responsible Mitigation project(s). Compensatory mitigation details will be evaluated and approved by the USACE and TDEC during the Joint Permit Application review process. The final compensatory mitigation plan will be developed as part of the USACE permit process and TDEC ARAP permit process. The final compensatory mitigation plan will be provided to FERC when available, anticipated to be spring of 2024.

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177. Table 3.8-10 Invasive Plants Identified within the ETNG Construction ROW by County, page 395:

> **Comment: Roane County data need to be added to this table. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: Table 3.8-10 has been updated to include a column for Roane County. However, since no invasive plants were listed in Table 3.4-2 of ETNG's Resource Report 3, a footnote was added to Table 3.8-10 of the FEIS to provide clarification.

178. Section 3.8.1.2.3.7 Summary of Alternative A, TVA Actions, 1 paragraph, 4!!! line from bottom, page 403: Overall, effects to forested areas would be "minor moderate."

> **Comment: Clarify as either minor or moderate, expecting this to be moderate due to permanent conversion of forested areas. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: Text in Section 3.8.1.2.3.7 has been updated to clarify effects would be moderate.

179. Section 3.8.1.2.4.1 Construction of Operation of Solar and Storage Facilities, 2nd paragraph. page 406:

> **Comment: Consider goat grazing also. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: Text in Section 3.8.1.2.4.1 of the FEIS has been updated to state “sheep and goat grazing” to clarify both animals were considered.

180. Section 3.8.2 Wildlife general:

> **Comment: There is not much mention of opossums, woodchucks, and moles. Since these are plentiful, it would be believed these also exist. Red foxes are also present near the Kingston Reservation area. Some of the reference material appears dated (1993). (Lindsey Stevens of Roane County Environmental Review Board)**

Response: Text in Section 3.8.2.1.1 of the FEIS has been updated with a statement (placed above the general wildlife summary in Table 3.8-13) that other species including opossum, woodchuck, moles, and red fox have been anecdotally observed near Kingston. Minor changes to the community structure of the Ecoregions of Tennessee, including vegetation and wildlife, may have occurred since the time of publication of Martin et al. (1993) due to factors such as introduction of invasive species and climate change. However, this reference generally remains the most accurate and comprehensive description of these communities to date.

181. Section 3.8.2.2.3.7 Summary of Alternative A. ETNG Actions-Natural Gas Pipeline and Associated Structures, page 426 and Table 3.8-17 Summary of Alternative A Impacts to Wildlife Habitat, page 427:

> **Comment: The impacted numbers of acres of habitat (30 acres of habitat removal and 268 acres of impacted wildlife habitat) appear to conflict with the impacted numbers included in Section 3.8.2.2.3.6 Construction and Operation of Natural Gas Pipeline, which states about 723 acres of vegetation would be permanently impacted (primarily habitat conversion) with operation of a natural gas pipeline. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: Total impact acreages within the ETNG construction ROW have been updated and verified in the FEIS.

182. Section 3.8.2.2.3.8 Environmental Justice Considerations, ETNG Actions-Natural Gas Pipeline and Associated Structures. 1 sentence, page 428: This sentence states effects to wildlife would be minor. However, Section 3.8.2.2.3.7 Summary of Alternative A, ETNG Actions- Natural Gas Pipeline and Associated Structures, last sentence, page 426, indicates impacts to wildlife would be moderate.

> **Comment: These two sentences appear to be in conflict. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: Changed the impact from moderate to minor in the last sentence of Section 3.8.2.2.3.7 Summary of Alternative A, under the ETNG Actions.

183. Section 3.8.3 Aquatic Life:

> **Comment: There is no discussion regarding non-native invasive plants. Thermal discharges from KIF create warmer waters into the Clinch and subsequently, the Tennessee Rivers. Discussion throughout this section needs to address the effects of the alternatives and actions presented in this EIS on the growth of non-native invasive plant species. Eurasian Milfoil, Spiny-Leaf Naiad, and Hydrilla are**

known to exist in the Tennessee River system, both upstream and downstream of the Kingston Reservation. Hydrilla is particularly worrisome as it is prolific and can harbor harmful cyanobacteria. This issue needs to be addressed. (Lindsey Stevens of Roane County Environmental Review Board)

Response: A new paragraph has been added to Section 3.8.3.1.1.2 of the FEIS describing nuisance aquatic species identified near KIF.

184. Section 3.8.3.1.1.2 Aquatic Life in Surface Waters Near Kingston Reservation, top paragraph, page 434: The mussel survey was conducted during 2005.

Comment: More recent data need to be presented indicative of the Clinch River after the 2008 Kingston Ash Spill. Many fish and biota surveys were performed in conjunction with the ash spill cleanup post-2008. (Lindsey Stevens of Roane County Environmental Review Board)

Response: None of the federally listed aquatic species are considered to have suitable habitat on the KIF Reservation. No federally or state-listed mollusks were found during the 2005 survey of the Clinch River/Watts Bar Reservoir in the vicinity of the KIF Reservation (Yokley 2005) or subsequent monitoring activities completed between 2005 and 2017, as reported in (TVA 2019d). River substrates were noted as degraded ("sub-optimal") and clay as the dominant substrates, overlain by varying thicknesses of mud. Based on Yokley (2005) and conclusions of other post-ash spill monitoring activities, USEPA identified "monitored natural attenuation" as the targeted remediation approach.

As indicated in response to *Comment No.* 167, five Alabama lampmussel were documented near Site 165. East Tennessee coordinated with the USFWS to incorporate these results into its Biological Assessment issued in January 2024 (ETNG 2024).

185. Section 3.8.4.1.2.1 Construction and Operation of a CC/Aero CT Plant and Switchyard on the Kingston Reservation. 2 paragraph, last sentence, page 462: This sentence says "No nesting habitat is present for either of these species..."

Comment: This appears to contradict the previous sentence that says "Osprey nests exist on existing transmission line structures, lighting structures, platforms, and tree within and adjacent to Kingston Reservation. (Lindsey Stevens of Roane County Environmental Review Board)

Response: Changed sentence to state: "Nesting habitat for both bald eagle and osprey is limited in the vicinity of the proposed CC/Aero CT Plant and switchyard, although an osprey nest is nearby on Kingston Reservation".

186. Section 3.8.4.1.2.6 Construction of a Natural Gas Pipeline, 1 paragraph, page 487: This paragraph indicates ETNG is conducting habitat assessments and field surveys for federal and state-listed species in late 2022 and 2023.

Comment: It is unclear if the results of these surveys are reflected in the draft EIS or will be included in the final EIS. It is suggested where these results are or will be reflected be clarified. (Lindsey Stevens of Roane County Environmental Review Board)

***Response**:* This text has been removed since this paragraph discussed preliminary studies that have now been replaced by field surveys.

187. Section 3.8.4.1.2.56.1 Birds, 2nd paragraph, page 497: This paragraph discusses that migratory bird species of concern are the same as those listed for the Kingston Reservation in Section 3.6.4.1.1.1. Other species of concern are discussed in Section 3.6.4.1.1.1, such as ospreys and bald eagles, which nest and forage near the Kingston Reservation.

> **Comment: Section 3.8.4.1.2.6.1 also needs to address these other bird species as presented in Section 3.6.4.1.1.1. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: The referenced section has been updated to clarify that although osprey and bald eagle were not identified on the state and federal resources as occurring on the ETNG Construction ROW, suitable habitat exists for nesting (osprey) and foraging (eagles); referred back to 3.8.4.1.1.1 for habitat descriptions. In regard to the second comment, based on the ETNG resource reports, agency consultations are still ongoing.

188. Section 3.8.4.1.2.6.2 Mammals. Section 3.8.4.1.2.6.3 Reptiles. Section 3.8.4.1.2.6.4 Amphibians, Section 3.8.4.1.2.6.5 Plants, Section 3.8.4.1.2.6.6 Aquatic Species, and Section 3.8.4.1.2.6.7 Insects, pages 499-501: All these sections indicated that consultation with the agencies is ongoing and potential for presence of protected species within the ETNG Construction ROW and associated aboveground facilities will be refined through 2023.

> **Comment: The results of these consultations should be reflected in the final EIS. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: The referenced sections of the FEIS have been updated with available information on the current status of consultations associated with the proposed Project. A concise summary of consultation status was provided in ETNG's October 5, 2023 filing.

Cultural Resources

189. TDEC, Archaeological Resources, notes that Alternatives A and B as described in the Draft EIS could potentially disturb significant cultural resources. As planned, the project will sufficiently address adverse effects to cultural resources. TVA should continue consultation with the State Historic Preservation Officer regarding archaeological survey and testing of proposed transmission lines and solar facilities. Additionally, the site 40RE44 is a single site without subdivisions; site numbers and boundary revisions should be assigned in coordination with the Tennessee Division of Archeology.

TDEC notes that cemeteries in the project area are to be avoided. However, if human remains are encountered or accidentally uncovered by earthmoving activities, excavation within the immediate area must cease. The county coroner or medical examiner, a local law enforcement agency, and the state archaeologist's office should be notified immediately.1 A court order from Chancery Court must be obtained prior to the removal of any human graves. This is a state-level review response only and cannot be substituted for a federal agency review. (Commenter: Tennessee Department of Environment and Conservation)

Response: Comments noted. In a letter to the Tennessee State Historic Preservation Officer (SHPO), dated June 15, 2023, TVA noted that site 40RE44 is a single site without subdivisions and TVA would ensure that this is correctly noted in all future correspondence regarding the undertaking. TVA would follow steps consistent with state law regarding human remains, and any local or county ordinances regarding the treatment of any human remains identified during implementation of the project. TVA is also planning to continue consulting with the SHPO and federally recognized Indian tribes regarding archaeological survey in connection with transmission line work connected with the project. Further, any future project changes that require modifications to the Area of Potential Effect for TVA's undertaking, TVA would reconsult with the Tennessee SHPO under Section 106.

Health and Safety

190. New gas development will have a harmful impact on communities, especially frontline communities who have been disproportionately burdened by TVA's reliance on fossil fuels. Like coal, fossil gas disproportionately harms communities of color and low-wealth. Gas generation produces especially potent methane emissions, on top of over 60 hazardous air pollutants – including volatile organic compounds, carcinogens, and endocrine disrupting chemicals.

Fossil gas generation produces nitrogen oxides, or NOx, which cause respiratory problems, as well as toxic particulate matter and ozone, which can exacerbate asthma and other diseases. Fossil gas power plants also do not move – they just sit there and emit NOx when they are operating. Those NOx emissions may linger in nearby communities, leading to serious health problems for the people living near plants. And since many fossil gas power plants are concentrated in some of the most socioeconomically and environmentally disadvantaged communities, these emissions harm communities that are already overburdened with pollution. Additionally, gas compressor stations emit toxic and carcinogenic chemicals such as benzene, 1,3-butadiene, and formaldehyde. Gas combustion generates oxides of nitrogen that increase asthma risk and aggravate chronic obstructive pulmonary disease.

This problem may only get worse. A recent study by the Union of Concerned Scientists found that fossil gas plants in California will start and stop much more frequently in the future, and this increase in fossil gas plant start-ups may increase NOx emissions, emitting as much as three to seven times as much NOx during start-up than during one hour of full-load operation.

Expansion of gas imports into the TVA service area will affect emissions elsewhere as well; namely, in the regions where the gas is extracted and compressed into pipelines. Gas is associated with health and environmental hazards and reduced social welfare at every stage of its life cycle. Fracking is linked to contamination of ground and surface water, air pollution, noise and light pollution, radiation releases, ecosystem damage, and earthquakes.

Transmission and storage of gas result in fires and explosions, as well. The pipeline network is aging, inadequately maintained, and infrequently inspected. One or more pipeline explosions occur every year in the United States putting many lives at risk. This should be of significant concern to TVA given the fragile karst terrain through which the proposed pipeline. (Commenters: On Behalf of 37 Climate, Justice and Community Organizations)

Response: TVA has evaluated the potential for adverse effects associated with the proposed project, and additional information and supporting documentation, where relevant, have been incorporated and referenced in the FEIS. Additional discussion of the potential effects of the proposed CC/Aero CT plant on Kingston Reservation and any identified EJ communities is provided in Section 3.4.

The analyses and discussion of potential air emissions associated with the proposed project are detailed in Section 3.7 and associated appendices, as well as in the cumulative effects discussion.

The analysis of potential effects for air quality, GHG, and social cost of carbon emissions has been updated in the FEIS and the LCA for each alternative and includes both upstream and downstream emissions associated with natural gas production and transport and associated social cost of carbon estimates for those estimated emissions, provided in Section 3.7. As shown in this section, there would be significant reductions in operational emissions of most all pollutants under Alternative A compared to the No Action Alternative that is a benefit to the surrounding community. NOx emissions would be reduced by 860 tons/year. Additionally, based on the new level of emissions of criteria pollutants, Alternative A would not be subject to federal Prevention of Significant Deterioration (PSD) requirements and would be able to comply with all expected air permit conditions issued by TDEC for permit approval. The air permitting process would ensure that that ambient air quality standards would be met beyond the KIF property boundary. The federal National Emissions Standard for Hazardous Air Pollutants (NESHAP) for Combustion Turbines would not apply as Alternative A's emissions are estimated to be below major hazardous air pollutant (HAP) source thresholds. Further, combustion turbine vendor data indicates Alternative A would still emit at or below the HAP concentration limit in this rule, i.e., for formaldehyde. There are no TDEC HAP or air toxic pollutant requirements that would apply to Alternative A. Lastly, turbine start and stop emissions estimates from the simple-cycle combustion turbines under Alternative A were calculated and included in the analysis; refer to Appendix H which contains the emissions calculations.

A discussion of pipeline safety concerns and identified avoidance, minimization, and mitigation measures that would be implemented for the project are provided in relevant resource sections and are summarized in Section 2.3 discussion of BMPs and Mitigation Measures.

A karst features plan was developed and would be used to guide activities when constructing pipeline in karst-dominated portions of the proposed ETNG construction ROW.

Cumulative Effects

191. The DEIS does not include enough information on the significant cumulative impacts of its massive gas buildout, including the proposed Kingston Project. The DEIS fails to place TVA's preferred alternative in the full context of the 5,900 MW of new gas capacity the agency has proposed since February 2021. Collectively, this massive buildout of new gas-fired generation facilities across TVA's service area is one of the biggest proposed methane gas buildouts in the nation. This DEIS is the latest addition to a flurry of separate NEPA processes that address individual components of a broader project to meet TVA's future generation needs. TVA recently issued decisions to build new gas burning power plants at Johnsonville, Paradise, Colbert, and Cumberland City, two of which are already subject to legal challenge. Right now, in addition to this project, TVA is separately conducting its NEPA review for new methane-gas powered generation facilities in Cheatham County, TN. TVA's failure to acknowledge the cumulative impacts of these facilities obscures the full impact of this project.

At the same time, the gas companies with whom TVA partners are advancing the program through their applications to the Federal Energy Regulatory Commission ("FERC") for this project and for

the closely related Cumberland Pipeline, which would fuel TVA's new fossil fuel plant at Cumberland. All of these projects raise similar, sometimes identical, questions about the climate impacts of TVA's choices, the way federal policy is being followed (or not), and the consequences of those choices for TVA's ratepayers. TVA has ignored the cumulative impacts of its proposed gas buildout as fueled by, in addition to this project, comparable ones at Cumberland, Johnsonville, and soon Cheatham County. NEPA requires agencies to consider a project's cumulative impacts, which are "the effects on the environment that result from the incremental effects of the action when added to the effects of other past, present, and reasonably foreseeable actions." Cumulative effects "can result from individually minor but collectively significant actions taking place over a period of time." Considering these effects is essential to agencies' statutory obligation to assess the environmental impact of the proposed action and its alternatives, as well as "the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity." TVA has not adequately disclosed the cumulative effects of this project. The DEIS section identifying related environmental reviews identifies none of the six other new gas plants that TVA has proposed in the past two years. But the actions are clearly related. Together, these proposals include about 5,900 MW of new gas plants. Further confirming the close interrelation between all these projects, in November 2021 TVA's Board delegated authority to the CEO to "evaluate, decide upon, and complete, if necessary, the retirements of [both] the Cumberland and Kingston plants and replacement generation projects." Later, TVA CEO Jeff Lyash reported having already signed an agreement purchasing equipment of the Cumberland Gas Plant and locking in pricing for Kingston.

TVA has not looked at the cumulative effects of adding decades of new greenhouse gas emissions through this massive, contemporaneous gas buildout. "In evaluating a proposed action's cumulative climate change effects, an agency should consider the proposed action in the context of the emissions from past, present, and reasonably foreseeable actions." The "large-scale nature of environmental issues like climate change show why cumulative analysis proves vital to the overall NEPA analysis. The cumulative impacts analysis was designed precisely to determine whether 'a small amount here, a small amount there, and still more at another point could add up to something with a much greater impact." TVA must evaluate the cumulative climate and environmental impacts of its proposals to build new gas plants and their attendant infrastructure, including methane gas pipelines. Failure to consider these additional methane gas proposals in its cumulative impacts analysis renders each of TVA's fourteen categories of environmental impact analysis presented in Section 3 of the DEIS deficient." (Commentors: SELC and Conservation Groups)

Response: TVA conducted NEPA reviews for the four gas projects referenced by the commenter(s): Johnsonville Combustion Turbines EA, Paradise and Colbert Combustion Turbines EA, and CUF Retirement EIS. Each of these project specific NEPA reviews is consistent with and tiers from the 2019 IRP EIS, which evaluated system-wide impacts. In addition, each of these project-specific NEPA reviews includes its own cumulative impacts analysis. Likewise, the Kingston Retirement EIS includes its own cumulative impacts analysis for various resources covered in the review and is consistent with the 2019 IRP EIS. The 2019 IRP EIS evaluated system-wide impacts for the Target Supply Power Mix identified in the 2019 IRP. For example, the IRP EIS estimated average TVA system-wide emissions under the Target Power Supply Mix out to 2038. IRP EIS at 5-27. The 2019 IRP EIS covers a range of additional gas generation (both CTs and CCs) as part of the target supply mix and addresses the cumulative impacts of additional gas generation in section 5.2.1. Consistent with NEPA requirements, the project-specific Kingston Retirement EIS cumulative effects analysis evaluates "effects on the environment that result from incremental effects of the action when added to the effects of other past, present, and reasonably foreseeable future actions." 40 C.F.R. § 1508.1(g)(3) (2022); see FEIS Section 3.1.2. Additionally, the cumulative impacts discussion of the Kingston Retirement EIS has been updated to include reasonably foreseeable gas generation additions such as the Cheatham Gas Project for which TVA issued a Notice of Intent to Prepare an EIS in May 2023. The Kingston Retirement EIS also includes a TVA system-wide GHG life cycle analysis (LCA) that compares each action alternative's life cycle GHG emissions to the No Action Alternative. This system-wide GHG LCA includes all of the reasonably foreseeable projects mentioned above as well as the Kingston Fossil Plant Retirement and the proposed Cheatham Gas Plant; therefore, it includes all of the new proposed gas power generation listed in the bullets in *Comment No.* 192 below.

192. TVA has ignored the cumulative effects of its gas buildout. NEPA requires agencies to analyze and disclose the direct, indirect, and cumulative effects of their proposed actions and alternatives to those proposed actions. Cumulative effects are "effects on the environment that result from the incremental effects of the action when added to the effects of other past, present, and reasonably foreseeable actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative effects can result from individually minor but collectively significant actions taking place over a period of time." Since February 2021, TVA has proposed 5,900 megawatts of new gas generation across its fleet:

- **Paradise, KY and Colbert, AL combustion turbine plants: 1,500 MW;222**
- **Johnsonville, TN combustion turbine plant: 550 MW;223**
- **Cumberland combined cycle plant: 1,450 MW;224**
- **Kingston combined cycle and combustion turbine plants: 1,500 MW;**
- **Cheatham County combined cycle plant: 900 MW.225**

All six of these projects have been proposed over a brief period of time, and all six involve new gas plants. Because greenhouse gas emissions have global impacts, the greenhouse gas emissions TVA has locked in with these projects have significant cumulative impacts. The six projects have largely overlapped in the last several years. Not only are the Cumberland and Kingston projects nearly identical—replacing decades-old coal plants with new gas plants—but TVA has handled them jointly. In a single action in November 2021, TVA's Board delegated authority to Mr. Lyash, to "evaluate, decide upon, and complete, if necessary, the retirements of the Cumberland and Kingston plants and replacement generation projects." As discussed above, TVA also negotiated a contract with GE for pricing for gas turbines for both Cumberland Unit 1 and Kingston together. TVA published the draft EIS for Kingston the same day it published the scoping notice for the Cheatham County gas plant. Yet TVA has only looked at the greenhouse gas emissions of each plant in isolation. In its EIS, TVA must disclose and analyze the cumulative impacts of its 5,900 MW gas buildout." (Commentors: SELC and Conservation Groups)

Response: See response to *Comment Number No. 191*.

AVOIDANCE, MINIMIZATION, MITIGATION

Air Quality

193. TVA fails to adequately consider greenhouse gas mitigation. TVA must consider mitigating GHG emissions from its proposed methane gas plant. "Implicit in NEPA's demand that an agency prepare a detailed statement on 'any adverse environmental effects which cannot be avoided should the proposal be implemented' is an understanding that the EIS will discuss the extent to

which adverse effects can be avoided." Moreover, NEPA regulations command that the discussion of environmental consequences "shall include . . . [m]eans to mitigate adverse environmental impacts." NEPA requires "that mitigation be discussed in sufficient detail to ensure that environmental consequences have been fairly evaluated." Executive Order 14,008 calls for a "government-wide approach," as the "Federal Government must drive assessment, disclosure, and mitigation of climate pollution and climate related risks in every sector of our economy, marshaling the creativity, courage, and capital necessary to make our Nation resilient in the face of this threat." For methane gas infrastructure, EPA recently encouraged FERC to "routinely adopt all practicable GHG mitigation measures . . . given the reasonableness of such measures from a public interest and necessity standpoint."

EPA has published guidance on greenhouse gas mitigation from gas plants and has provided TVA with a list of on ongoing GHG mitigation projects. TVA must include an emissions mitigation plan in the Final EIS. Mitigation may include:

(1) Avoiding the impact altogether by not taking a certain action or parts of an action.
(2) Minimizing impacts by limiting the degree or magnitude of the action and its implementation
(3) Rectifying the impact by repairing, rehabilitating, or restoring the affected environment.
(4) Reducing or eliminating the impact over time by preservation and maintenance operations during the life of the action.
(5) Compensating for the impact by replacing or providing substitute resources or environments.

While TVA must consider mitigation through clean-energy alternatives to new methane gas plants, it must also consider ways to mitigate the greenhouse gas impacts of any proposed plants. To comply with NEPA, TVA must consider its options to mitigate the decades of greenhouse gas emissions it proposes. Here, TVA violates NEPA by excluding the costs of required greenhouse gas mitigation.

As EPA wrote, "If TVA intends to install carbon mitigation measures in the future, these costs should be included in their analysis." Not only does TVA have an obligation under NEPA and Executive Order 14,008 to mitigate greenhouse gas emissions, but EPA has now published a draft rule proposing to require extensive greenhouse gas mitigation for gas plants based on hydrogen blending and carbon capture technologies. Further, in its recently published scoping notice for pumped hydropower storage, TVA justifies the need for additional long-duration storage by claiming it is needed to support carbon capture and sequestration. Thus, the federal utility appears to be planning to retrofit the Kingston Gas Plant and others with carbon capture and sequestration. TVA states that "the combined cycle plant under Alternative A would be designed to accommodate future modifications necessary for incorporating [carbon capture and sequestration] and for utilizing hydrogen fuel blending if and when these technologies mature to fruition." If TVA builds gas plants, it must mitigate the plants' emissions. Those mitigation technologies are likely to add substantial costs to Alternative A relative to Alternative B. TVA cannot hide those costs from the public until the gas plants are built. Instead, TVA must disclose and analyze the costs in its EIS. (Commentors: USEPA, SELC and Conservation Groups)

Response: Initial plant design under Alternative A would accommodate future modifications to incorporate CCS or hydrogen co-firing when these technologies become commercially available. The FEIS discusses these nascent technologies – CCS and hydrogen co-firing – that are identified in EPA's

2023 Proposed GHG regulations. TVA believes these technologies have not been adequately demonstrated for commercial use. Nonetheless, the FEIS gives consideration to these GHG mitigation measures by adding a sensitivity analysis using the cost of these mitigation measures based on EPA and DOE information. See Appendix B for a sensitivity analysis that examines how the alternatives compare under the EPA's proposed GHG rules. Under Alternative A, if EPA's 2023 GHG regulations are finalized as proposed, TVA would need to pursue hydrogen co-firing or carbon capture. Under the No Action Alternative, TVA would need to pursue carbon capture. The costs associated with these paths are sourced from EPA and DOE and alternatives are summarized in Appendix B. The sensitivity analysis included in Appendix B also covers the potential financial incentives affecting the cost of Alternative B, recognizing that any such potential would not be realized in the short-term during which the KIF retired generation must be replaced with firm, dispatchable power to ensure grid stability in Eastern Tennessee.

Consistent with CEQ regulations implementing NEPA, appropriate measures for mitigating adverse environmental impacts are identified in Section 2.3 of the FEIS.

194. TDEC (Air Pollution Control) suggests that TVA consider local air quality conditions through AirNow and limit or modify demolition and construction activities during poor air quality conditions. Additionally, TDEC notes that truck traffic and other mobile equipment associated with construction projects generate emissions of PM, CO, NO_2, SO_2, VOC, and CO_2. TDEC recommends that TVA utilize on-road and non-road mobile sources with up-to-date emission control technologies and proper maintenance to minimize vehicle and equipment emissions. TDEC also suggests that TVA adopt best practices to minimize vehicle idling, which will also reduce the impact of mobile source emissions on ambient air quality.

TDEC requests that these suggestions be reflected in the Final EIS. (Commentor: Tennessee Department of Environmental and Conservation [TDEC])

Response: The temporary emissions mitigation measures for construction/demolition vehicles and equipment mentioned by the commentor are included in Section 3.7.2.2 of the DEIS with the exception of idling which has been added to Section 3.7.2.2. of the FEIS. Additionally, TVA would include the use of AirNow to monitor local air quality conditions during construction/demolition activities and to inform decisions to reduce or change the timing of construction/demolition activities.

195. TVA staff's preferred choice for replacing the Kingston plant, Alternative A, involves the construction of a combined cycle gas facility, 16 combustion turbine gas units and a 122-mile gas pipeline. This construction would require the clearing of more than 700 acres of forest and would impact hundreds of additional acres of vegetated areas. This loss or permanent conversion of habitat would place threatened species like the spotfin chub and the tricolored, little brown, gray and long-eared bats at risk. Several other aquatic species, birds, reptiles and plants are potentially threatened by this massive project.

The pipeline would also cross cherished recreational areas like the Cumberland Trail, Lone Mountain State Forest and tributaries of the Obed Wild and Scenic River. In addition, the pipeline would cut through areas with deep Indigenous history. The pipeline company has already reported 122 Indigenous sites in their project area. It is not necessary for TVA to jeopardize these important cultural and natural sites when it could select a different alternative for replacing the Kingston plant. (Commenter: Appalachian Voices)

Response: Comments noted. The impacts of TVA's action to build a CC/Aero CT Plant and that of the related pipeline action on historic properties, indigenous lands, recreational areas and threatened or endangered species are discussed in the FEIS in Chapter 3. TVA is consulting with the TNSHPO and tribes regarding the impacts of the CC/Aero CT Plant on historic properties and indigenous lands, in addition to the consultation with the USFWS regarding the CC/Aero CT Plant's impact on threatened or endangered species.

TVA is coordinating with FERC regarding FERC's NHPA Section 106 compliance efforts for the pipeline project. As described in Section 4.4.2 of ETNG's Resource Report 4 (ETNG 2023e), consultations have been initiated with 18 federally recognized Native American tribes to provide an opportunity for comments related to traditional cultural or religious properties of significance that may be affected by its project. TVA will, prior to making a decision on its project to retire and replace generation at KIF, take the potential effects of TVA's actions on Indigenous sites and other historic properties into consideration, in consultation with federally recognized Indian tribes and the Tennessee State Historic Preservation Officer, following the process in 36 CFR Part 800.1-13.

TVA is also coordinating with FERC regarding FERC's ESA Section 7 consultation with the USFWS under Section 7 of the Endangered Species Act to ensure that the pipeline actions do not jeopardize the continued existence of federally protected species. Section 3.5 of ETNG's Resource Report 3 (ETNG 2023d) describes federal protected species, survey and consultation efforts conducted or proposed, and the status of the consultation with USFWS.

In the meantime, ETNG is in the process of preparing a Biological Assessment for the Ridgeline Project as part of FERC's consultation with the USFWS under Section 7 of the Endangered Species Act. ETNG anticipates the Biological Assessment will be the basis of a Biological Opinion and if necessary, Incidental Take authorization(s) issued by the USFWS for the pipeline project. ETNG will abide by any applicable Incidental Take requirements and other applicable avoidance and minimization measures negotiated with the USFWS as part of FERC's consultation under Section 7 of the Endangered Species Act. Coordination with Tennessee Wildlife Resources Agency and Tennessee Department of Conservation is also occurring for species of concern by TVA and ETNG.

196. The gas plant that TVA wants to build for this project would require 300 million cubic feet of methane per day, releasing emissions such as sulfur dioxide, methane, carbon monoxide and other harmful toxins and greenhouse gasses. TVA's analysis of the damages that these pollutants would have on the economy are significant â€" using current standards for calculating the social cost of greenhouse gas, that damage is valued at $7 billion dollars for the total life cycle of the gas plant. By comparison, TVA's solar and storage Alternative B would have a significantly smaller social cost at $1 billion for the total life cycle of the equipment.

Meanwhile, TVA's solar and storage option would not produce any air emissions at all. Ironically, TVA also notes in the DEIS that the impacts of climate change would have a negative impact on the efficiency of the gas turbines. (Commenter: Appalachian Voices)

Response: The $7 billion SC-GHG for Alternative A comparison to the $1.05 billion SC-GHG for Alternative B in the DEIS is only for the individual resource LCA, which does not take into account how the rest of the TVA power generation system would operate under those alternatives. In addition, the $7 billion and $1.05 billion are absolute nominal values and have been updated in the FEIS to $7.7 billion and $672 million, respectively. These nominal values correspond to $2.07 billion and $347 million, respectively, in Net Present Value (NPV, 2023 $). The system wide LCA is a more holistic analysis that accounts for how the entire TVA system would operate under each alternative. The system wide LCA analysis results in a narrower divergence between the SC-GHG savings for Alternative A ($1.85 billion NPV 2023 $) and Alternative B ($2.26 billion NPV 2023$) compared to the No Action Alternative (NAA), which is a difference of approximately $417 million NPV 2023 $.

Noise

197. Noise Impact to surrounding Community Option C Pages 666 - 669 states the USEPA 1974 guidelines recommend that Ldn not exceed 55 dBA for outdoor residential areas. An FERCs sound level requirement states that the sound attributable to a new compressor station not exceed a day-night average Ldn of 55 dBAs at any nearby noise sensitive areas (NSAs)d. Figure 13.17.1 shows 247 Residential Noise Receptors in a 0.5 mile radius. The closest sensitive receptors to the prosed site include residential subdivisions, with homes located approximately 0.4 miles south of the proposed plant site (Figure 3.17-1).
Table 3.17-3. Average sound levels

Noise Receptors (Milepost)	Location Daytime Average 1 (Leq dBA)	Nighttime Average 1 (Leq dBA)	Lowest 1-Hour (Leq dBA)
MP02	47	44	37
MP03	47	45	41
MP04	53	46	38
MP05	52	48	42

Daytime is from 7:00 a.m. to 10:00 p.m. Nighttime is from 10:00 p.m. to 7:00 a.m.
Page 683 your conclusion states Burns & McDonnell performed predictive sound modeling for the Project operation using computer aided noise abatement. Based on this study, the Project is expected to contribute a maximum absolute sound level of approximately 53 dBA at MP02, 54 dBA at MP03, 50 dBA at MP04, 51 dBA at MP05, and 55 dBA in the vicinity of the nearest residential noise receptors, approximately0.4 miles south of the proposed CC/Aero CT Plant (Appendix O). These noise levels are below both HUD and USEPA guidelines of 65 dBA and 55 dBA, respectively. Therefore, the operation of the CC/Aero CT plant would result in minor permanent noise impacts.

You predicted sound levels of the new plant is right at the previously stated USEPA 1974 guidelines recommended that Ldn not exceed 55dBA for outdoor residential areas. The current nightime sound levels measured in your Table 13.7-3 is between 44 dBA to 48dBA with lowest one hour level of 37 dBA far below the proposed 54dBA projected for the new plant 24 hours per day 7 days per week. (Start up to 80dBA) far past the 54dBA).

WHO says above 40 dBA can disturb sleep. Sound charts show 55 dBA equal to human conversation or washing machine. I would not want to listen to the constant sound of conversation or washing machine 24 hours per day 7 days per week.

As I understand this CC/Aero CT plant will not be base loaded so therefore there will be several startups and these startups (80 dBA) could occur daily. I have researched from the major complaints of having a CC/Aero CT plant nearby and one of the main concerns is that the noise level is elevated even more than usual during startup. There is no data in the Draft Environmental Impact Statement on the startup noise and the damage that could be done to local property values to the 247 residents in the zone. Not to mention specifically stated residences to the south of the proposed Option C site, which includes Ladd Landing, that receives the most noise impact from

the new plant. TVA always says they want to be good neighbors, this is an opportunity for them to move the new plant to the Option A site, and reduce the impact on their neighbors through noise pollution and site awareness. (Commenter: Appalachian Voices)

Response: Thank you for your comment. Option A was eliminated due to insufficient acreage (Page 35). TVA has considered noise impacts to the surrounding community in the design of the KIF. The proposed Project consists of one H-Class combined-cycle combustion turbine and 16 aeroderivative simple-cycle combustion turbines. The noise modeling analysis was completed for worst-case operating conditions where all combined- and simple-cycle units, as well as the auxiliary equipment, were operating at full load and accounts for noise levels during startup. It is not expected that this operating scenario would be common, and sound levels from the operation of the project would typically be less than those predicted in the study. TVA has also built in mitigation measures to limit noise generated by the project. The major noise mitigation measures included in design are listed below:

- Air cooled condenser designed as a low-noise unit limited to 62 dBA at 400 feet
- Stack exit silencer added to the combined-cycle stack exit to limit noise from the combustion stack
- Air inlet silencer added to the combined-cycle air inlet to limit noise from the combustion turbine
- Stack exit silencers added to the simple-cycle stack exits to limit noise from the combustion stacks
- Air inlet silencers added to the simple-cycle air inlets to limit noise from the combustion turbines
- Gas compression building added to limit noise from the gas compression units on-site

These mitigation measures are expected to further minimize noise impacts to levels that would not adversely impact the surrounding environment.

Visual Impact

198. Visual Impact to surrounding Community “Option C
Page 690 you show in Figure 13.18-1 247 residential visual receptors. Page 702 “ Proposed stack height is a function of air permit modeling is not yet known; however, the proposed stacks would be no more than 199 feet high. The new stacks would likely be visible to rural residential receptors near the proposed plant site.

Site Option A is further from the residential visual receptors shown than Option C and is located in an area that currently has large industrial buildings and equipment. Whereas Option C site is currently undisturbed with industrial buildings and equipment.

In conclusion I realize you can justify any location for the new CC/Aero CT Plant but I would ask for the benefit of the surrounding communities you revise your plans and choose Option A for the location, since it is an already built and environmentally disturbed site. (Commenter: Appalachian Voices)

Response: Comment noted. Option A was eliminated due to insufficient acreage (see Section 2.1.3.2.1).

Solid and Hazardous Wastes

199. TDEC, Office of Energy Programs, is encouraged by TVA’s intent to diversify its generation portfolio and resilience with more battery storage and solar as these additions will increase overall energy security in Tennessee. TDEC encourages TVA to address battery reuse

and disposal as part of its long-term programmatic and environmental strategy at KIF. (Commenter: Tennessee Department of Environment and Conservation)

Response: TVA has a standard best management practice of one-for-one battery recycling; every battery used is recycled.

Climate Education

200. If Alternative A is selected, TVA should collect data and document the performance of this configuration to inform future decisions (particularly about altering any current IRP as noted above) and share with stakeholders including:

- **Reduction in emissions compared to installing combined cycle gas turbines alone (cf. decision made on Cumberland Fossil Fuel replacement).**
- **Operational experience using Aero CT for fast startup to meet demand for electricity (e.g., when solar is not available). Particular attention should be paid to documenting differences between projected savings and actual savings achieved over time in carbon emissions.**
- **The maximum capacity of solar that could be supported by Aero CTs to inform penetration of TVA's stated goal of adding 10,000 MW of solar energy that is enabled by Alternative A.**
- **The increase in dispatchability and reliability. Aero CT can use both natural gas and ultra-low sulfur diesel if the supply of natural gas is affected.**
- **The additional expertise for operating utility-scale solar based on their experience in operating 3- to 4 MW solar generation with battery storage.**
- **Support partnerships with the federal government and other utilities to research and develop advanced technologies, such as alternative fuels for Aero CT generation (perhaps hydrogen), Carbon Capture and Sequestration (CCS), and battery storage including inverter-based resources (DEIS, Appendix C, pgs. 7, 32).**

(Commenter: Citizens' Climate Education)

Response: Comment noted. TVA releases environmental information yearly in The Annual Sustainability Report. This report highlights our partnerships and innovation. Additionally, TVA updates its generation blend and planning as part of the IRP process every 4-5 years, which is informed by TVA's experience. The information you have identified will be forwarded to the appropriate TVA staff to be considered for inclusion in these future reports and decision making. Please note that some of this stakeholder education information can be found in Section 1.6 of the FEIS, the 2019 IRP, and the Annual Sustainability Report.

Land Use

201. TVA notes that its preferred alternative – the CC/Aero CT gas plant – would have permanent impacts on land use; however, they go on to state that activities associated with this project "would not have any indirect effects on land use, as further changes to the rural area would not be expected to be stimulated by the [...] Plant." Draft EIS at 559. In discussing land use impacts with regard to Alternative B – the solar and storage alternative – TVA notes that the project would require just over 10,000 acres for solar and nearly 830 acres for battery storage facilities and converting nearly 9,000 acres of farmland to industrial use. Draft EIS at 565.

Insofar as TVA has pointed to utility-scale solar's impacts to agricultural land as a reason not to pursue renewable energy alternatives, the utility should give serious consideration to distributed

energy projects. Maximizing DER, energy efficiency, demand response, and building on degraded land could profoundly transform the TVA region and energy landscape in truly beneficial ways and reduce the transformation of agricultural land for industrial purposes. Additionally, these non-wire alternatives–which we are requesting TVA explore in a Final EIS–could also avoid additional costs associated with expanded transmission.

A recent report outlines many available options to meet our energy needs without having to build large-scale infrastructure like utility-scale solar and transmission, and especially new fossil fuel infrastructure like that proposed in the Draft EIS.11 Maximizing energy efficiency, rooftop and community solar on residential and public buildings, parking lots, canals, and other already-built surfaces, could go a long way in helping TVA meet current and future energy demand without having to build unnecessary and risky gas infrastructure. (Commenter: On Behalf of 37 Climate, Justice and Community Organizations)

Response: Please see Section 3.10 for Land Use evaluation. The land use impacts of Alternative A would be primarily isolated to the KIF Reservation which is already designated as industrial and disturbed, the existing transmission corridors, and the existing pipeline corridor with an additional green field lateral line and compressor station. Currently, TVA has programs in place for distributed renewable energy, energy efficiency, and demand response, which all work together with the target supply mix of power generation. For more information on the program please visit: Demand Response - Business & Industry - TVA EnergyRight This would not change the land use needs for the addition of solar/battery option to replace the KIF as detailed in Alternative B of the Kingston Retirement EIS. See response to *Comment No. 47*.

Pipeline

202. Alt. A had a significant risk of pipeline leak, rupture, explosion, and fire to environmental and human health for both TVA employees and the surrounding communities, far above the risks of Alt. B. The report inaccurately downplays this risk and fails to inform the community. Please adjust the project proposal to include a just and fair comparison of pipeline risks and potential impacts to the environment and human health.

This project proposal also include that the existing pipeline to which the proposed pipeline would attach has already exploded in 2018 despite all the safety protocols suggested in the EIS (https://www.naturalgasintel.com/enbridge-repairing-damaged-east-tennessee-natural-gas-line/). What additional precautions will be taken to prevent this from happening again? Please also include the risk estimate, cost and impact of a pipeline failure occurring during peak power usage in the Alt. A. (Commenter: Megan Maloney)

Response: As described in ETNG's Resource Report 11 (ETNG 2023l), the Ridgeline Expansion Project will consist of new pipeline to be constructed and operated in accordance with current applicable DOT/PHMSA requirements. As described in Resource Report 6 (ETNG 2023g), ETNG also has robust pipeline integrity management program which actively monitors and repairs its assets during operation of the Project. As described in Resource Report 6 (ETNG 2023g), ETNG also has robust pipeline Integrity Management Program which is continuously updated as new information is available. The Integrity Management Program actively monitors and repairs its assets during operation of the Project.

While pipelines are the safest form of energy transportation, the transportation of natural gas by pipeline does involve minimal incremental risk to the public due to the potential for accidental release of natural gas. The greatest hazard during pipeline construction and operation is a fire that may result in the event of a major pipeline rupture or leak. A number of precautionary systems and response measures would be in place to mitigate this risk to workers and the public. FERC will review the construction of ETNG's pipeline application and require the construction of the pipeline in accordance with DOT safety standards, and the PHMSA will provide ongoing regulation of construction, operation, and maintenance through routine inspections and enforcement of pipeline safety laws and regulations.

203. The EIS also mentions, "The greatest hazard is a fire that may result in the event of a major pipeline rupture or leak." Oak Ridge National Laboratory reported an increase in wildfire risk along corridors similar to those suggested in this proposal; TVA is responsible for wildfires in these areas. (https://www.energy.gov/sites/prod/files/2019/09/f67/Oak%20Ridge%20National%20Laboratory%20EIS%20Response.pdf).

Please include how TVA will address this increasing risk in Alt. A. (Commenter: Megan Maloney)

Response: The impacts the construction and operation of a natural gas pipeline on safety are described in Section 3.15.2.2.6 of the FEIS. Under 49 CFR §192.615, each pipeline operator must also establish an emergency plan that provides written procedures to minimize the hazards from a gas pipeline emergency. [ETNG] will implement procedures in its Emergency Plan to enable the public and officials to recognize and report a natural gas emergency. The DOT requires that each operator establish and maintain a liaison with appropriate fire, police, and public officials to learn the resources and responsibilities of each organization that may respond to a natural gas pipeline emergency, and to coordinate mutual assistance. [ETNG]'S pipeline will be equipped with remote control shutoff valves as required by the DOT regulations. This allows the shutoff valves to be operated remotely by [ETNG]'s gas control center in the event of an emergency, usually evidenced by a sudden loss of pressure on the pipeline. Remotely closing the shutoff valve allows the section of pipeline to be isolated from the rest of the pipeline system.

As described in ETNG's Resource Report 11 (ETNG 2023l), the Ridgeline Project will consist of new pipeline to be constructed and operated in accordance with current applicable DOT/PHMSA requirements. As described in Resource Report 6 (ETNG 2023g), ETNG also has robust pipeline integrity management program which actively monitors and repairs its assets during operation of the Project. Existing pipelines operations have not contributed to an increased number of wildfires.

204. Alt. A is unsafe for reasons that are not adequately considered in the project proposal, namely the instability of natural gas plants during extreme weather events (specifically freezes and heat waves), and the likelihood of natural gas plants to fail exactly when a power grid outage will have dire health effects.

It's impossible to support Alt. A while watching Texas's natural gas system fail in both extreme cold, and now this June, fail again in extreme heat. An "atypical" number of natural gas plants failed during power demand spikes during the heatwave. However, Texas avoided blackouts this month because they doubled their supply of solar power in the last year – using systems such as ones we could have in Alt. B. (https://www.theguardian.com/us-news/2023/jun/28/texas-heatwave-power-grid-solar-energy)

Even new gas plants are failing in extreme temperatures around the country, even in the Capitol: "Natural gas is widely touted as the 'bridge fuel' as the world gradually moves away from coal…The harsh reality is that natural gas plants, even relatively modern ones, are proving to

have the worst failure rate when faced with extreme weather compared with other generation methods. During last year's Arctic Blast, gas units accounted for 63% of the failures while representing just 44% of the total installed capacity. …More alarmingly, even the best gas generating facilities are showing a large degree of vulnerability. PJM Interconnection LLC is the operator of the country's largest power grid, serving 65 million people in 13 states and Washington, DC, or about a fifth of Americans. The firm's grid is generally considered to be one of the most reliable in the country thanks to its ample operating reserves and rich shale gas deposits. During the winter blast on Dec. 23, 2022, PJM called a "maximum generation emergency action," meaning standby plants were supposed to run ramp up to full power. Whereas nearly 20% of those gas plants ran at 100% or more for at least an hour, more than 20% never got above even half capacity while many dropped to 0% output at some point during the emergency. …PJM actually performed better than many neighboring grids, many of which reported widespread electricity interruptions or blackouts…a large number of new-model combined-cycle gas plants failed, with some reporting mechanical issues…" (https://oilprice.com/Energy/Energy-General/Why-The-US-Has-Become-The-Blackout-Capital-Of-The-Developed-World.html)

These observed failures of natural gas infrastructure deeply undermine TVA's repeated claims that solar is unreliable and they must select natural gas because it's "firm and dispatchable". Natural gas plants appear to be neither, failing in both cold and heat, when solar does not.

Instead of wasting time investing in fossil fuel infrastructure that is failing across the country, even at the newest plants, TVA should immediately make the necessary grid upgrades – which they will have to make soon anyway to meet their 2035 goals for solar.

TVA is instead claiming 1) they can't build solar as quickly as Texas and other locations have, 2) they can't maintain battery systems as reliable as they've already installed at Muscle Shoals and outside Nashville, both TVA-maintained solar installations, or as reliable as the ones currently preventing blackouts in Texas under heat dome conditions, and 3) even if they could, the solar option wouldn't be as reliable as natural gas plants that continue to fail exactly when need is greatest and when solar is succeeding.

Additionally, Alt. B's strength in decentralization is not adequately represented in the project proposal. Spreading infrastructure out so that it is not uniformly taxed by weather events reduces risk. Putting all our eggs in one central basket in Alt. A should be evaluated to represent the greater risk of relying on a single pipeline (which will be connected to a pipeline that's already had an explosion in 2018). Solar power could be spread across the area mapped in the EIS to spread risk of cloud cover, while a single natural gas plant is a single point of failure.

The EIS should be updated to accurately reflect the widely reported failures of natural gas power plants under extreme weather conditions, the risk reduction of having solar during these events, and the mitigation benefits of distributed solar. TN is expected to get increasing numbers of above 100 F day, e.g. the weather conditions that are currently producing natural gas infrastructure failures across Texas. We should not be paying for failing infrastructure that can't handle expected weather conditions even with the newest technology.

Please add detailed consideration in the EIS of the health risks of power grid failure when Alt. A fails during heatwave and cold events, which are increasingly likely and to which Alt. A will contribute to worsening.

Please additionally remove justifications asserting falsely that Alt. A is “firm” or “dispatchable” when it appears to fail frequently and during weather events at which power loss is hazardous to human health.

Please remove assertions that Alt. B is not “firm” or “dispatchable” when it is evidenced to be so, particularly with the extra battery storage that TVA included in the cost estimation.

The report also appears to include the cost of supplemental power during expected failures for Alt. B but not Alt. A. Since natural gas plants can be expected to fail in extreme heat and cold, the cost of supplemental power during these events should be included in Alt. A to accurately compare costs and meet the statutory obligation to conduct least-cost planning. (Commenter: Megan Maloney)

Response: Winter Storm Elliot has been characterized by the National Weather Service as a “Once in a Generation Storm” that impacted most of the eastern continental United States, bringing heavy snowfall and high winds to the Midwest and the Northeast and freezing rain and high winds to the south. As noted in TVA’s “After Action Report/Winter Storm Elliot” publication, when the storm arrived in the TVA service territory on December 22, 2023, the conditions increased energy demand beyond what had been forecast. This resulted in the highest 24-hour electricity demand supplied in TVA history on December 23 as the speed, intensity, scale, and duration of Winter Storm Elliot exceeded the design basis for some of TVA’s power plants. In total, 38 of TVA’s 232 generating units were negatively impacted, mostly due to instrumentation that froze. It is important to note that the highest winter peak demand of 33,425 MW occurred on December 23, 2022, at 7PM CDT (third-highest peak demand in TVA history) and the highest weekend peak demand in TVA history occurred on December 24, 2022 at 1AM CDT – both of which were in the evening hours when solar was not generating. Immediately following the storm TVA assembled various teams to capture lessons learned, performed a deep dive into what happened, how TVA responded, and took actions based on those findings to strengthen and increase operational resilience at TVA’s generating facilities. This includes, but it is not limited to, adjusting design standards to increase the resilience of generating facilities to withstand extreme events, leveraging data analytics to better incorporate risk and uncertainty in usage and energy markets, and updating emergency protocols and communication methods to improve awareness and information sharing.

In addition, TVA performed detailed reviews of existing facilities with internal resources and external specialists to evaluate current condition versus the new design standards and is developing site specific projects to correct any deficiencies discovered that would improve TVA’s ability to withstand future extreme weather events. This includes, but is not limited to, additions and improvements for temporary and permanent enclosures at generating facilities, enhancing insulation and heat trace circuits for critical plant instrumentation, and developing more comprehensive procedures to better equip people and plant equipment for extreme weather conditions. The actions identified in the After-Action report will be integrated into the operation of a CC/Aero CT Plant constructed or operated under Alternative A. Additionally, the dual-fuel burning capability of the Aeroderivative turbines will enhance the resiliency of the plant during extreme weather events.

Contrary to the commenter’s suggestion, Alternative B would not provide “firm, dispatchable power,” which refers to a generating resource that can adjust power output up or down on demand within the specific operating limitations of that resource. Even with the battery component included in Alternative B, under Alternative B, TVA would not necessarily be able to call on the solar generating capacity of Alternative B year-round, including during all peak load events. For example, solar resources are limited in their ability to meet maximum demand that occurs in the pre-daylight or early-daylight hours of the winter season. Although high loads caused by warm or cold weather events can last for several days in a row, battery storage facilities typically do not exceed a few hours and, as a result, there could be difficulty in sufficiently recharging storage resources.

Rates and Reliability

205. Utilities around the country often cite reliability as one of, if not the, most important factors when planning and making decisions that impact ratepayers. TVA is no different. On its website, TVA claims "99.999%" reliability when delivering energy to customers (4).

The North American Electric Reliability Corporation (NERC) sets reliability requirements that all utilities must meet in order to avoid penalties for noncompliance. TVA is subject to the same requirements, but actually performs below many when it comes to reliability. According to Energy Information Administration (EIA) data compiled by the Citizens Utility Board, Tennessee, which is entirely covered by TVA's service territory, ranks 37th in the country when it comes to its average performance on duration of power outages, time to restore power to customers, and frequency of power outages. There are many reasons for this poor performance, but one of them came into sharp focus during the winter storms of December 2022.

Winter Storm Elliot hit the Tennessee Valley hard in December 2022, resulting in the first rolling blackouts in TVA history. TVA saw a single day record for energy demand on December 23rd, and a weekend record for peak demand the next day. TVA could not meet these energy demands and asked its 153 local power companies to implement rolling blackouts. These blackouts were caused almost entirely by the failure of TVA's coal and gas plants, whose equipment could not operate in such cold weather. On the contrary, TVA's limited solar assets performed well during the storm and were even used to refill the Raccoon Mountain pumped hydro storage facility according to TVA's Don Moul during the February TVA board meeting.

In spite of the very apparent weaknesses of fossil gas plants, TVA still seems inflexibly determined to build out its gas infrastructure, posing reliability risks to the Valley in the future. There are more reliable options that TVA should be considering, yet their plans for Kingston are clearly already favoring gas. A report from Synapse Energy Economics lays out exactly how TVA could move forward with a reliable build out of renewable energy. Instead of tipping the scales toward gas, TVA should be seriously examining the potential of renewable energy alternatives such as distributed solar, storage, energy efficiency, and demand response. (Commenter: On Behalf of 37 Climate, Justice and Community Organizations)

Response: The Energy Information Administration data referenced utilized the SAIDI metric. This metric measures the average outage duration for each customer. However, since this metric assesses outage caused by both transmission and distribution, and does not differentiate between the two, it is not an accurate metric for overall TVA reliability.

During Winter Storm Elliott, there was a total of eight hours during the morning of December 23 and 24, 2022 where TVA worked with LPCs to reduce load between 5-10% in order to maintain grid stability as record cold weather conditions drove record demands for energy. These impacts were experienced by TVA across all generation asset types and TVA worked in the days and weeks following the storm to make repairs and restore damaged systems that were impacted as a result of the extreme cold weather. TVA has taken steps to improve its extreme weather preparedness, increase resiliency and secure systems, and invested in degraded assets to improve reliability moving forward. These improvements, together with the dual-fuel burning capability of the Aero-Derivative turbines, will further enhance the resiliency of a CC/Aero CT Plant built at Kingston.

Additional information on Winter Storm Elliot and steps taken by TVA in response to the event have been provided in the FEIS in Section 1.2.3.2.

The Synapse Report, “TVA Clean Energy Study” (March 2023), was considered by TVA as to its recommendations for a renewable energy build out by 2025 instead of adding any gas to the TVA system. These recommendations are not compatible with the short-term need for energy supply to replace the retiring coal generation that is reliable and resilient and that would be met through Alternative A. TVA will further consider the recommendations in the report as it develops its next IRP.

206. Another very real impact of continued reliance on gas is increased and volatile rates for Valley ratepayers. As a wholesale distributor of power, TVA passes any increases in costs directly onto ratepayers through its LPCs in fuel cost adjustment charges. More recently, the war in Ukraine and other factors led to massive spikes in the cost of gas for power generation and customers across TVA’s service territory felt the impacts of this last summer with increases in their electricity bills, including customers in Memphis whose bills doubled.

The costs of gas also have long term impacts for ratepayers when utilities pass them along to consumers, as TVA does. When new federal standards such as EPA’s proposed carbon rules for new and existing gas plants go into effect, gas plants that are designed to run for decades could become stranded assets that customers are on the hook to pay for. Additionally, should new legislation pass or if TVA is forced to comply with President Biden’s 2035 carbon-free electric sector executive order, the costs to retire a gas plant before the end of its planned lifetime will also be passed onto customers. If TVA were a responsible utility that truly had the best interests of its ratepayers in mind, it should strongly consider potential stranded assets such as a new gas plant and pipeline for Kingston.

All of these costs, in addition to a lack of meaningful investment in home weatherization and energy efficiency programs, lead to the Southeast having some of the highest energy burdens in the country, meaning residents in our region pay some of the highest percentages of their income on energy. According to the American Council for an Energy Efficient Economy (ACEEE), the East South Central Region of the U.S, has the highest percentage of households with high energy burdens at 38%. TVA can and should do more to address this disparity which impacts Black, Hispanic, and low-income families most. Investments in less volatile renewable energy and energy efficiency programs would go a long way in reducing energy use and reliance on volatile fuel sources. (Commenter: On Behalf of 37 Climate, Justice and Community Organizations)

Response: One of TVA's strengths is the diversity of its energy portfolio, not relying on any one technology but on a mixture of equipment types, which helps protect TVA’s ratepayers against any volatility that might occur with a particular fuel type, such as natural gas. This includes coal, diesel, hydro, pump storage, natural gas, nuclear, and renewables. TVA continues to work toward a robust, diverse energy portfolio that allows it to accomplish each part of the TVA mission: low energy rates, economic development, and environmental stewardship. TVA strives to achieve clean energy goals without sacrificing reliability or affordability. TVA monitors key signposts like natural gas prices and accounts for market volatility in near-term and long-term planning processes. Also see responses to *Comment Nos.* 10 and 93 for more information on gas price variability and impacts.

Additional information on TVA's Energy Right Program is available here: https://energyright.com/. TVA's Energy System of the Future highlights what TVA is currently doing in this space: https://www.tva.com/energy-system-of-the-future.

207. As a resident and homeowner in Roane County TN, has TVA taken into consideration the impact to the rate base? How will any change from coal to natural gas, solar or any other source, impact our monthly electricity bill?

I'm not talking about possible or theoretical impact on the reduction of coal or other fossil fuels, but the actual costs in today's dollars impact on our monthly bills, the current state of the power grid, and the reliability of other fuel sources. We are fortunate to have fairly inexpensive utility bills now, but how will these environmental changes impact our costs?

And lastly, what is the environmental impact and costs of building a gas pipeline to the Kingston plant going to be to those communities impacted by this construction. (Commentor: Michael Castle)

Response: TVA continues to build the energy system of the future to achieve carbon reductions, while not compromising the goal of maintaining low electric rates and the high reliability that sustains the communities we serve and is critical to achieving economy-wide decarbonization. Coal fleet end-of-life, expected by around 2035, is aligned with TVA's congressionally mandated least-cost planning and reduces economic, reliability, and environmental risks. The cost to operate and maintain the KIF coal units beyond their planned retirement date would be high given the cost to meet new regulatory requirements and the need to replace aging plant components. (see Section 8.2.6 of the 2019 IRP). Alternative A is consistent with the Target Supply Power Mix identified in the 2019 IRP consistent with TVA's least cost planning mandate.

As described in ETNG's Resource Report 5 (ETNG 2023f), construction and operation of the Ridgeline Project is not anticipated to have a significant environmental impact to affected communities with adoption of its proposed avoidance, minimization, and mitigation measures. Revenues from construction employment and local expenditures by construction companies for construction materials and non-local construction workers for temporary housing, food, and entertainment will benefit the local economy. In addition, the increased property tax base during project operation will benefit the project area in the long term.

Water Resources

208. The DEIS fails to adequately evaluate environmental impacts on water resources.

TVA's discussion of the proposed project's environmental impacts on water resources frustrates NEPA's twin aims – ensuring that agencies make informed decisions and providing relevant information to the public – with the same persistent failures.

TVA has an independent legal obligation to take a hard look at the project's environmental impacts, evaluate the combined environmental effects of the proposed pipeline and the proposed power plants on water quality, and meaningfully discuss mitigation measures. The obligation to take a "hard look" at a project's impacts means gathering and analyzing available data before implementation to ensure the agency's actions are supported by substantial evidence and reasoned decision making, rather than speculation. Moreover, an EIS "is not complete unless it

contains a ‘reasonably complete discussion of possible mitigation measures,’” and a “perfunctory description” or a “mere listing. . . , without supporting analytical data” of such measures cannot meet this standard. Finally, agencies “cannot postpone analysis of an environmental consequence to the last possible moment;” doing so thoroughly undermines informed public comment and informed decision-making, and is legally deficient under NEPA as a result.

In this respect, the DEIS’s discussion of water quality impacts is legally inadequate. The DEIS repeatedly omits assessments of the environmental consequences of the project’s activities in any meaningful detail; asserts that impacts to water will be “minor” or “minimized” by (1) Best Management Practices (“BMPs”) and other mitigation measures that are not specifically identified, much less examined, and (2) permits for which TVA has not yet applied; omits any discussion of less environmentally damaging alternatives; and states that its conclusions are based on an “independent review” of information that TVA concedes *has not yet been collected*.

TVA cannot possibly take a “hard look” at information it does not yet have, much less reach conclusions through “reasoned decision making” on this basis. Nor is TVA’s speculation about adherence to future mitigation measures and permitting requirements that it does not, or cannot, describe with specificity sufficient to meet its obligations under NEPA. And while TVA repeatedly promises that it will include the results of ETNG’s environmental studies in the final EIS, this is too late – the comment period will have closed by then. As a result, TVA must not only supplement the discussion in this DEIS but must do so in time for the public to review and comment on the information that TVA should have supplied to begin with. (SELC and Conservation Groups)

Response: Section 3.6 in the DEIS and FEIS adequately address affected water resources and potential environmental consequences that could result from the alternatives to those water resources based on best information available at the time. Section 3.6 contains thorough reviews of groundwater parameters, surface water features, water quality, and wetlands assessments, and corresponding impact analyses for these features related to the alternatives for retirement and replacement generation activities. TVA included an analysis of the impacts of the related proposed pipeline associated with Alternative A in the DEIS, utilizing site-specific results of field surveys, and where site-specific data were not available, a conservative desktop-based geospatial analysis or “worst-case” scenario based on a 200-foot-wide construction footprint for the proposed pipeline and other aboveground facilities. The FEIS has been revised to incorporate updated information provided in the final Resource Reports submitted to FERC. TVA independently reviewed the information provided by ETNG. Consistent with NEPA requirements, the FEIS also details standard practices, routine measures, and other project-specific measures to avoid and minimize effects to resources from implementation of the Proposed Action Alternatives in Section 2.3.

209. The proposed ETNG Construction ROW crosses eight natural and recreational areas, including the Old Hickory WMA and Recreation Area, Cordell Hull WMA and Recreation Area, Lone Mountain State Forest, the Cumberland Trail State Park, Dixona Farm Conservation Easement, and tributaries to the Obed Wild and Scenic River. A pipeline will cause negative impacts to recreation and visual resources in these areas, as well as ecological disruptions. What alternatives have you considered and why were those not selected? (Commenter: Megan Maloney)

Response: A discussion of the alternatives evaluated by ETNG for the Ridgeline Project was provided in the DEIS in Section 2.1.5.1, and any changes that have occurred since the release of TVA’s Kingston DEIS have been updated in the FEIS in Section 2.1.5. A full discussion of the alternatives to the proposed ETNG natural gas pipeline is provided in ETNG’s Resource Report 10 (ETNG 2023k) and are available in

FERC's eLibrary. TVA evaluated the visual impacts of the natural gas pipeline in Section 3.18.2.3.6, recreational impacts in Section 3.9.2.3.6, and ecological impacts in Section 3.8.4.2.3.6. Additional descriptions of public lands, consultations with agencies, construction effects and mitigation measures are presented by ETNG in Sections 8.4.1, 8.4.2 and 8.4.3 of Resource Report 8 (ETNG 2023i). ETNG continues to coordinate with the appropriate agencies for these areas to address concerns and minimize impacts. ETNG provides information to FERC as it becomes available.

Biological Resources

210. We support the retirement of the Kingston Fossil Plant. This action will result in reduced greenhouse gas (GHG) emissions and environmental impacts. Action Alternative B should be selected since this alternative has less GHG emissions than Alternative A. The Southern Appalachian Mountains is an area of high amphibian diversity with 101 amphibian species, including 43 endemic amphibian species. Amphibian populations are declining worldwide, and amphibians are experiencing high extinction rates due to habitat loss, chytrid fungus, pollutants, pesticides, and climate change. Alternatives A and B have the potential for significant impacts on amphibian populations. For example, the proposed natural gas pipeline would impact numerous perennial streams, ephemeral streams, intermittent streams, and ponds or impoundments as well as forested areas that provide amphibian habitat. Transmission line construction also has the potential to impact amphibian habitat. To limit impacts on amphibian populations, we recommend that the Environmental Impact Statement include amphibian mitigation measures, such as the following:

1. **Identify amphibian habitat locations;**
2. **Delineate high quality amphibian habitat that would be protected from construction activities; and**
3. **Implement a long-term amphibian population monitoring program.**

References:

Collins, J.P., and M.L. Crump. 2009. Extinction in Our Times: Global Amphibian Decline. New York, NY: Oxford University Press.

Kolbert, E. 2014. The Sixth Extinction, an Unnatural History. New York, NY: Bloomsbury.

(Commentor: Eric Johnson-Amphibian Refuge)

Response: None of the threatened or endangered amphibians identified in Table 3.8-21 are expected to occur on the Kingston Reservation based on their habitat requirements and the existing site conditions. Furthermore, few impacts are proposed to aquatic habitat on Kingston Reservation; the waterbodies and perennial feature are considered non-jurisdictional by the USACE and are unlikely to provide significant supportive habitat to aquatic or semi-aquatic life. The only jurisdictional feature proposed for impacts on the Kingston Reservation is a 227-linear foot intermittent stream that scored poorly on TDEC hydrologic determination forms and did not appear to contain baseflow, therefore it is unlikely that this feature provides substantial supportive habitat for amphibians.

Streams and wetlands within the existing off-site transmission line corridors will be avoided and temporary impacts minimized to the maximum extent possible by using best management practices. A maximum of three acres of forested areas may be removed for the off-site transmission line upgrades, however this is expected to be minimal given the corridors consist of existing ROW and structures; vegetation within the regularly experiences maintenance as needed per TVA guidelines.

No permanent impacts to surface waters including perennial or intermittent streams, ponds, or major waterbodies are proposed during the construction or operation of the natural gas pipeline. Permanent impacts to wetland within the natural gas pipeline corridor consists of 3.2 acres of forested wetlands converted to emergent/shrub wetlands; no wetlands are proposed to be filled and therefore there will be no wetland habitat loss. Routine maintenance of vegetation to an early successional stage will be limited to a 10-foot swath centered over the pipeline within the permanent ROW, with trees and shrubs selectively cleared within 15 feet of the pipeline for protection against tree roots which could compromise the integrity of the pipeline coating. Wetlands temporarily impacted during construction will be returned to their original condition with respect to contouring/drainage, soil profiles, revegetation, and other minimization measures.

Approximately 552.7 acres of forested habitat would be temporarily impacted due to construction activities within the construction ROW and would be allowed to regenerate following natural gas pipeline installation. An additional 47.2 acres of forested area within the permanent ROW would be converted to shrub or herbaceous habitat, representing a permanent impact due to permanent habitat type conversion. ETNG has conducted surveys and consultation with the USFWS, TWRA, and TDEC regarding protected species impacts. Only three species of amphibian were identified on the various threatened and endangered species lists; of these, only the hellbender (*Cryptobranchus alleganiensis*) could be present within the ETNG Construction ROW. The hellbender requires larger creeks and rivers with high oxygen content and abundant complex habitat such as gravel, cobble, boulders, and logs. Several of the larger streams and waterbodies will be crossed via HDD and will avoid all impacts. No aquatic resources will be permanently impacted during construction activities. During the construction of the Project, impacts to potential habitat for this species would be temporary and not likely to adversely affect the species.

Construction activities may result in mortality of small mammals, reptiles, and amphibians that are less mobile during clearing and grading operations. However, when habitat is removed or converted, some of the original species may use this new habitat, other species may find this change in habitat preferable. Amphibians that use emergent wetlands and streams with emergent vegetation in riparian zones are expected to re-colonize riparian areas. Buffers around wetlands and streams will provide protections for amphibian populations during and after construction actions. Species such as deer, songbirds, small mammals, pollinators, reptiles, and amphibians may find beneficial habitat in the permanent ROW, similar to electric utility ROWs.

PROCEDURE AND OPPORTUNITIES FOR PUBLIC INPUT

211. While TVA does not have shareholders that have the potential to influence resource decisions in the interest of shareholder returns, it does have a set of executive compensation metrics that could be influenced by which alternative TVA chooses to replace Kingston. Specifically, non-fuel resources and fuel-based resources are treated differently among these metrics. In a supplemental or final EIS, to dissuade the appearance of impropriety by TVA's executives, TVA should present the potential impacts each alternative would have to executive compensation through existing compensation metrics. (Southern Alliance for Clean Energy)

Response: The set of metrics used to base executive compensation can be viewed in Item 11 of TVA's Annual Report on Form 10-K, which can be found at TVA - Financial Information - SEC Filings (q4ir.com). These metrics, designed to facilitate TVA's mission as set forth in the TVA Act, use safety, reliability, non-fuel cost of power, power availability, financial obligations, and other factors in setting executive compensation. The statutory requirements to sell power at rates as low as feasible and to add any new generation consistent with least cost planning principles, among other requirements, animate these metrics. Section 2.4 of the FEIS discusses considerations that led to the selection of Alternative A as the preferred alternative. The primary consideration that led to the selection of Alternative A is that it meets the purpose and need of the proposed action to retire and replace the KIF coal generation by the time the coal units are retired at the end of their useful life in 2027.

212. Multiple commentors indicated support for the retirement of the Kingston Fossil Plant and replacing generation with Alternative A, as identified in Part C of this Appendix. (Commenters: Multiple)

Response: Your support has been noted.

213. Multiple commentors expressed opposition to the proposed retirement of Kingston Fossil Plant or support retirement but encourage TVA to select Alternative B or other renewable or clean energy option (Commentors: Multiple).

Response: Your comment has been noted.

214. TVA has not provided enough time for meaningful public participation. In late May, TVA published five significant proposals for public comment, and all five proposals established comment deadlines within a two-week window. In addition to the Kingston DEIS, published May 12 with a July 3 comment deadline, TVA also published four different Notices of Intent ("NOIs") in the Federal Register on May 19:

- **NOI requesting comments on the scope of environmental review for a new 900 MW gas fired power plant and 400 MW battery storage unit in Cheatham County, with comments initially due June 27.**
- **NOI requesting comments on the scope of a Programmatic Environmental Impact Statement ("PEIS") for solar and storage, with a June 20 comment deadline.**
- **NOI on the scope of its upcoming Integrated Resource Plan and Environmental Impact Statement, with a July 3 comment deadline.**
- **NOI requesting comments on the scope of a PEIS for Pumped Storage Hydro, with a July 5 comment deadline.**

These multiple, overlapping comment periods, with three deadlines (including the deadline for the Kingston DEIS) adjacent to a federal holiday, undermine NEPA's public comment procedures, which are at the heart of the NEPA review process. NEPA requires not merely public notice, but public participation in the evaluation of the environmental consequences of a major federal action. These proposals are significant and interrelated; they present major questions about the nature of TVA's energy generation for decades to come. By clustering the comment period deadlines in this way, TVA has made it significantly harder for members of the public to fully evaluate and comment on each of them individually. (Commentors: SELC and Conservation Groups)

Response: The comment periods provided for these projects were in full compliance with NEPA, including the timing requirements for public involvement in the Council on Environmental Quality (CEQ) 2020 Regulations § 1506.11(d). TVA provided multiple opportunities for public input throughout the EIS process for this project. See FEIS Section 1.7. With respect to the scoping comment period, because the projects that released NOIs have no "highly technical" data for the public to review at this time, and because the public would have the opportunity to comment on the substance of these projects as contemplated by NEPA once draft reviews have been released, TVA did not believe that extending the scoping period for either project was warranted.

As to the comment period on the Kingston Retirement DEIS, the commenter is aware that the public was first informed of TVA's intent to study the proposed retirement and replacement generation of the KIF in June 2021. The DEIS was posted on TVA's website on May 12, 2023, and the Notice of Availability was posted in the Federal Register on May 19, 2023. Public comments on the KIF Retirement DEIS were accepted starting on May 12, 2023, and ending on July 3rd, for a total of 52 days. TVA has also provided other opportunities for the public to express their views on the proposal through acceptance of formal comments, a virtual public meeting on June 8, 2023, or in-person at public open houses on June 13 and 14, 2023.

215. TVAs process for informing and engaging the public on energy projects, like the Kingston retirement, is significantly insufficient. If the purpose is public participation, which is mandated in the TVA Act and by the National Environmental Policy Act (NEPA), TVAs process is not geared towards that end, especially in a way that is either meaningful or impactful. The processes as they currently stand appear more appropriate to an informal public notification, than one that gains the informed consent of the public whom TVA is obligated to serve.

First, the 45-day comment period does not allow for meaningful public participation. This is simply not enough time for someone to gain an understanding of the issue and formulate an appropriate response to any proposed changes. Do any of the TVA staff have enough time, in their personal schedules, to come to any of the three open houses? And while the virtual open house is a positive in a post-Covid world, this alternative is still no solution. The virtual meetings are better suited to a Youtube video presentation, since the people who attend this session have no concrete way of interacting and posing questions to any and all presentations.

Second, TVA has not addressed the many access barriers which make it difficult for individuals to attend public comment forums in the first place. When we talk about public engagement, that begins with information sharing and allowing for people to ask questions and communicate directly with TVA staff. Yet, without accessible public comment forums TVA will only hear from a limited pool of people, and often those who have the resources, knowledge, and capacity to attend these meetings and engage with the substance of the issue. Anyone can attest to the fact that life with a family, full time & part time employment alone, make attending any public forum prohibitively difficult. Other barriers, like access to public transportation or child care, make it that much harder to attend these public forums and to engage with TVA staff over the projects that will impact them. Therefore, any scheduling with the public that has true intentions, should be at a time when the public can actually attend. This could include having a rolling period with multiple meetings and open forums.

Third, TVA has scheduled five public comment deadlines within two weeks of each other. Two of these comment periods" for the Kingston plant retirement and the Integrated Resource Plan" are due on the same day. In effect, TVA is stretching the public thin and forcing them to pick which projects to engage with. If TVA is committed to public participation and the public power model, they would spread out these comment periods and extend the deadlines. Only in doing so can TVA ensure that they are sufficiently meeting their requirements under NEPA.

Fourth, TVA provides the public little to no acknowledgement that their comments are actually being processed and addressed. By law, TVA is not required to respond to comments but is

allowed to state why a particular comment is being dismissed or used by TVA. There is currently no clear indication that anyone inside or affiliated with TVA as an organization, has actually seen and understood comments made by the public. While all submitted comments are recorded and made public, this is only a recognition that TVA received them. Our organizations have submitted hundreds of comments without any acknowledgement from TVA staff.

Finally, because TVA has no publicly elected oversight board or Office of Public Participation, there is no structure in place for robust public comment. Even more, multiple TVA board members have stated that TVA staff have told them they are not allowed to speak to the public. What sort of public utility tells its Board of Directors they do not have the right or authority to speak to members of the public on public matters when they actually do?" (Commentors: On Behalf of 37 Climate, Justice and Community Organizations)

Response: Please see *Comment No. 214*. TVA complies with the National Environmental Policy Act (NEPA), including the requirement for public participation required by Council on Environmental Quality (CEQ) 2020 Regulations. Please note that in addition to the three public meetings TVA conducted during public comment period, TVA had additional outreach to the surrounding community which is detailed in Section 1.6 of the FEIS. All comments received during the public comment period have been read and responses are provided in the FEIS.

216. The DEIS does not allow for meaningful public participation because important information is missing, incomplete, or lacking in adequate detail. TVA evaluated 3 alternatives. TVA does not provide enough information on these alternatives to satisfy NEPA, which requires a discussion of "each alternative considered in detail, including the proposed action, so that reviewers may evaluate their comparative merits." TVA must give a more detailed accounting of the impacts of each alternative, including the proposed action. (Commentors: SELC and Conservation Groups)

Response: TVA complies with NEPA, including the requirement for public participation required by CEQ 2020 Regulations. TVA provided multiple opportunities for public input throughout the EIS process for this project. See FEIS Section 1.7. The DEIS provided a thorough analysis of the no action and two action alternatives, as summarized in Table 2.2-1, which provided sufficient information for the public to review and provide comments on the alternatives analysis.

217. Having carefully considered everything that I have observed, studied and found in many government publications, newspapers, periodicals, technical evaluations and so on over the past six months I have come to firmly held personal conclusions:

a) **TVA decisions appear to have been made, prior to 2019, to favor methane gas power plant replacements for soon to be retired coal fired plants.**

b) **CEO Jeff Lyash and his team were formed for and are intent from inception upon instituting gas infrastructure construction plans including an Enbridge Inc. owned Kingston Ridgeline Expansion pipeline leading to a TVA gas fired power plan at Kingston.**

c) Every aspect of the approval process thus far is in my opinion flawed by bias. As evidenced by TVA ignoring EPA pointing out and Jeff Lyash not being forthright about TVA 2035 and 2050 emission goal achievement. This within the halls of Congress last month. One Sierra Club scientist, Joe Schiller, tells me that TVA modeling and simulation contains elements of garbage in and garbage out.

d) **As a rate payer and one of the millions of people who fund the local power companies, that fund the TVA and all of its operations, I demand that TVA reverse their biased inclinations and draft decision that adheres to internal process which favor 19th and 20th archaic solutions over 21st century solar, wing and storages solutions.**

e) To expect me to relate to the TVA how my home and immediate environment are affected by each of the points in the DEIS is not possible for me. This given the short time frame and TVA's questionable decision making processes, that due to its opacity requires more time and attention to detail than it should. That this period ends during a 4th of July holiday period shows again the insensitivity of TVA executives to those of us ratepayers who want our concerns to influence Director's decisions.(Commentor: Richard Shaffer)

Response: When planning for power generation, TVA must consider the views and opinions of all customers within the Tennessee Valley, while maintaining safe, reliable, and low-cost power for our LPCs and the communities TVA serves, consistent with a primary objective of the TVA Act to keep rates as low as feasible. TVA's activities must also comply with the Energy Policy Act of 1992, which directs TVA to use least-cost planning principles for the TVA system. TVA remains committed to fulfilling its statutory responsibilities to the people of the Valley while also striving to meet the goals of the current Administration.

Based on comments received during the scoping period, TVA included a renewable (solar/battery) replacement alternative (Alternative B) in the DEIS. TVA further considered public comments on the DEIS, including those submitted by TVA customers and ratepayers regarding a carbon-free blended alternative. The FEIS discusses the reasons why blended alternatives were not deemed reasonable at this stage. Additionally, TVA has complied with NEPA requirements for public participation. TVA provided multiple opportunities for public input throughout the EIS process for this project. See FEIS Section 1.7 and *Comment No. 202*.

TVA's NEPA process is informed by reliable data. Decisions are made at the end of the NEPA process giving due consideration to the analysis in the NEPA document. TVA periodically publishes an IRP as a comprehensive study of how TVA can best meet the future energy demand in its power service area. In June 2019, TVA published the latest 2019 IRP, which evaluated six scenarios (plausible futures) and five strategies (potential TVA responses to those futures) and identified a range of potential energy resource additions and retirements. The target power supply mix identified the addition of up to 500 mw of demand response and 2,200 mw of energy efficiency (demand-side options); 4,200 MW of wind; 5,300 MW of storage; 8,600 MW of combustion turbines (CT); 9,800 MW of combined cycle (CC); and 14,000 MW of solar by 2038. The proposed action under Alternative A implements the CC and CT components of the target supply mix.

In 2021, TVA completed an evaluation of its existing coal fleet; the Aging Coal Fleet Evaluation (2021g). This analysis considered whether the complete retirement of TVA's coal fleet, about 6,000 MW in total, should be expedited beyond the 2,200 MW of coal capacity retirement by 2038 that was identified in the Target power supply mix of the IRP. The operating cost and reliability challenges posed by the aging coal fleet drove the need for the Aging Coal Fleet Evaluation.

Based on TVA's Aging Coal Fleet Evaluation (TVA 2021g), TVA identified planned retirement dates that would advance the overall purpose of the 2019 IRP of achieving the optimal blend of energy resources to meet TVA's clean energy transition goals in a manner consistent with least-cost planning principles. To meet TVA's phased 2035 retirement plans for the coal fleet, at least 1,500 MW of operational replacement generation is needed to replace the retiring units at KIF and must be operational before the KIF units are retired by the end of 2027.

TVA is working towards carbon reductions as outlined in TVA's 2021 Strategic Intent and Guiding Principles document and 2022 Carbon Report: 70 percent carbon reductions by 2030, a path to approximately 80 percent carbon reductions by 2035, and aspiration to reach net-zero carbon emissions by 2050, based on a 2005 baseline.

COMMENTS ON GENERAL PROJECT INFORMATION

218. The cumulative environmental impact on the relevant Tennessee counties from switching the Kingston Fossil Plant from coal to mostly natural gas would be fairly positive in the long term. To the extent Alternative A were to cause negative impacts, those impacts would mostly be minimal and temporary.

For the water and wetlands, Alternative A means that waste streams at Kingston Fossil Plant associated with using coal for electricity generation would cease discharging by the end of 2027. Id. at vii. That concern is particularly salient due to the December 2008 coal fly ash slurry spill at the Kingston Fossil Plant. The "waters of Tennessee are the property of the state and are held in public trust for the use of the people of the state." Tenn. Code Ann. § 69-3-102(a).2 Alternative A appears to better protect the State's waters. Further, Alternative A would impact only a few acres of wetlands and wet weather conveyances. DEIA at x-xi. The State appreciates TVA minimizing long-term impact from the proposed natural gas pipeline by building it largely adjacent to an existing pipeline. Id. at 51. The State encourages TVA to continue working with the Tennessee Department of Energy & Conservation ("TDEC") and to obtain all necessary permits. Id. at 18-21, 315.

For air pollution, shifting from coal to natural gas would also improve long-term air quality in the relevant Tennessee counties and in neighboring parts of the State. Id. at xiii. The Kingston Fossil Plant currently operates under the conditions stipulated by a Tennessee Air Pollution Control Board operating permit. Id. at 354. Tennessee's ambient air quality standards are generally no more stringent than national standards. Id. at 342-44. The State again encourages TVA to continue coordinating with TDEC and the Tennessee Air Pollution Control Board to obtain all necessary permits and permit modifications.

For wildlife resources, the more limited geographic scope of Alternative A's footprint would likely lead to less of a negative impact than Alternative B. Alternative A's impact on wildlife would mostly be temporary, and TVA appears to have appropriately considered methods to reduce impact on Wildlife Management Areas and the Lone Mountain State Forest. Id. at 425. While Alternative A would result in some habitat removal, id. at 427, the cumulative impact on wildlife would be less than the impact of permanently devoting over 11,000 acres to solar panels and battery storage under Alternative B, id. at 55-56. Minimizing the impact of Alternative B on wildlife would be particularly challenging because TVA is separately planning to add 10,000 MW of solar power generation (easily more than 70,000 acres of solar panels and batteries) to the Tennessee Valley. Id. at 512. Nevertheless, the State encourages TVA to continue working with TDEC and the Tennessee Wildlife Resources Agency to develop and implement appropriate avoidance and mitigation efforts. Id. at 424.

For historical resources, the Tennessee State Historical Preservation Office has no objection to the implementation of the project as currently planned under Alternative A. Id. at 612. The National Historic Preservation Act requires federal agencies to give the Advisory Council on Historic Preservation the opportunity to comment, and TVA appears to have complied with this requirement. Id. at 582. Only one recorded archaeological site is within the potential plant footprint, but the State Historic Preservation Office concurred that there would be no adverse effect to the site. Id. at 612.

For transportation, increased traffic will occur mostly during construction of the new gas-fired combined cycle gas plant. Id. at 573. The State agrees that permanent impacts on traffic would be minor and encourages TVA to work with the Tennessee Department of Transportation for any necessary right-of-way permits. Id. at 20, 573. (Office of Tennessee Attorney General and Reporter)

Response: Comments acknowledged.

219. How will this project be financed? TVA is approximately $3 Billion in debt. Where will you get your financing? The government is $31+ Trillion in debt. Will our state and federal representatives have to approve your financing?

Alternative A includes solar. How can you substantiate 0.02% solar power output at the cost and size? (Commentor: Marian Penn)

Response: The Tennessee Valley Authority is a wholly-owned, but self-funded agency of the U.S. government. TVA meets its funding needs with operating revenues and power program financing. TVA's power system financings consist primarily of the sale of debt securities and secondarily of alternative forms of financing such as lease agreements. TVA is governed by the nine-member TVA Board of Directors, which is responsible for approving an annual budget. State and federal representatives do not approve TVA financing.

220. Questions from Ralph Sheffield:

1. **What is the cost of each option for replacing the Kingston Steam Plant and how is this money paid?**
2. **How long to transition to each option?**
3. **If solar is the option with energy storage locations at alternate locations, where will these "alternate" locations be?**
4. **If solar, where will the panels be and how much land is needed?**
5. **How is cyclic power needs, such as extreme cold or hot weather or cloudy condition for days and night (shorter days in winter than summer), accounted for with each option? Even with the ability we have today, during the cold period of late 2022 and early 2023, rolling power outages were conducted. Will this be the new Norm?**
6. **In order to account for changing power needs, the energy must be stored somewhere and the site indicates batteries. How large are these batteries and where are they going to be located?**
7. **Where are the batteries manufactured and what materials are used in the manufacture of the batteries (lead, Lithium, etc.)?**
8. **How and where will they be disposed when they have to be replaced? (Commentor: Ralph Sheffield)**

Response: Please refer to Appendix B for more information on assumptions and costs in TVA's Alternatives Analysis and Appendix J for costs associated with the LCA. Please refer to Section 3.10 for land requirements. Please refer to Section 1.2.3.2 on Winter Storm Elliott. Please refer to Section 3.14 for more details on TVA's disposal of solid and hazardous wastes. Also, refer to *Comment Nos. 53* and *199* for more information on the battery components and disposal.

221. Why is Kingston Reservation not considered suitable for stand-alone solar, and multiple sites are stated as needed for solar, when solar and BESS are part of Alternative A? Is the cost of upgrading transmission infrastructure for Alternative A subtracted from the cost estimate for Alternative B (since both are needed at the Kingston Reservation)? (Commentor: Lindsey Stevens of Roane County Environmental Review Board)

Response: While the Kingston Reservation is 2,254 -acres in size, acreage for solar development is heavily constrained by existing coal plant infrastructure and related components that must remain in-service until replacement generation is brought online. Additionally, the Kingston Reservation is encumbered with various topography and environmental features that limit the suitability for solar development. Recent calculations within the EIS (Section 2.1.4.2 Solar Plus Storage Approach and Reliability Analysis) indicate a need for approximately 10,950 acres of available land to replace the system energy needs from the unit retirements at KIF. Further, approximately 2,200 MW of four-hour BESS, requiring an additional 550-825 acres of land would be needed to support Alternative B, which exceeds the available acreage on the Kingston Reservation. TVA has identified space within the existing Reservation that is available and suitable for up to 3-4 MW of solar development and 100-MW BESS, as described in Section 2.1.3 of the FEIS. Additional space may become available in the future after D4 activities have been undertaken at the Reservation but the currently available acreage on the Reservation limits the solar component to 3-4MW.

222. How would TVA actually plan for net zero given the lead time for these types of projects? TVA stresses concern that the solar alternative cannot be completed in time, despite selecting it as an alternative; it appears that TVA underestimated the time it takes to fully implement alternatives since decommissioning KIF was identified. However, this should not be the case given that the lifespan of KIF was known. This calls into question TVA's current ability to conduct long term renewable projects given the poor time and resource management reflected in this project proposal.

How will TVA meet their commitments for 10,000 MW of solar by 2035 when the planning never allows for these projects to begin? (Commentor: Megan Maloney)

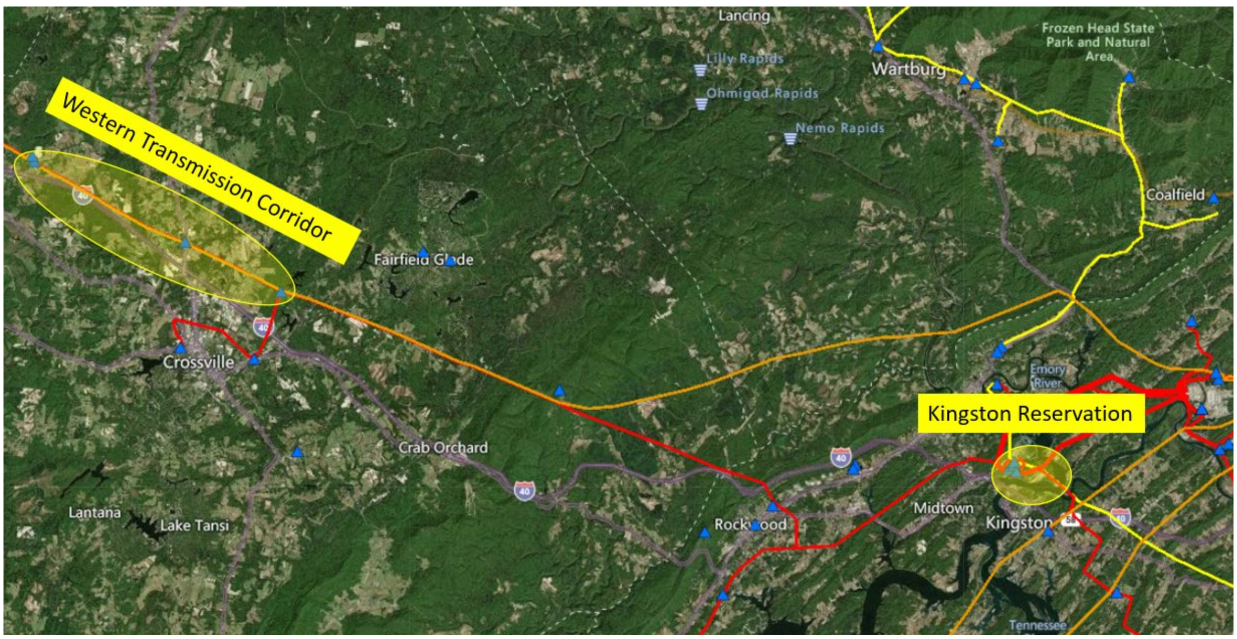
Response: TVA's 2019 IRP acknowledged continued operational challenges for the aging coal fleet and included a recommendation to conduct end-of-life evaluations on TVA's remaining coal plants. See TVA's Aging Coal Fleet Evaluation for more information. The decision associated with this EIS is a specific, discrete component of TVA's blended asset strategy. TVA is moving forward with detailed reviews of approximately 6,000 MW of solar energy and energy storage, which would more than double TVA's solar capacity.

223. Please find attached comments from the Roane County Environmental Review Board on the draft EIS for the retirement and replacement of the Kingston Fossil Plant. I am sending this email on behalf of Roane County Executive, Wade Creswell.

1) **Overall, this document reflects a great amount of good work and effort. Most of the information is thorough and comprehensive.**
2) **This document needs depictions (figures) of how the Western Transmission Corridor ties to the Kingston Reservation. (Lyndsey Stevens of the Roane County Environmental Review Board)**

Response:

The Western Transmission Corridor does not directly tie to the Kingston Reservation. There are two types of interconnection upgrades associated with adding new generation to the transmission system, direct assignment upgrades and network upgrades. Direct assignment upgrades are the transmission upgrades required to connect the generation to the transmission system. Network upgrades are the upgrades associated with absorbing the power into the broader transmission system. The Western Transmission Corridor upgrade is a network upgrade. As the power from the plant flows on the broader transmission network, it can overload existing lines. So even though the Western Transmission Corridor is not directly interconnected with the Kingston Reservation, as power from the plant flows on the network to the various loads, it can overload the Campbell Junction-Fredonia-Peavine 161 kV transmission line.



EIS EDITORIAL

224. Appendix C, page 13 indicates 2,200 MW of battery storage capacity. This unit is incorrect. (Commentor: Peter Penn)

Response: As stated in Section 2.1.4.2 of the KIF EIS, the SERVM model used by TVA accounts for uncertainties related to weather, load forecasts, and system performance. Modeling the retirement of the KIF units indicated that approximately 2,200 MW of four-hour BESS, requiring an additional 550 to 825 acres of land, paired with 1,500 MW of additional solar would maintain a 0.1 loss of load expectation (LOLE) with balanced seasonal risk. Based on this analysis, the DEIS and FEIS evaluates additions of 1,500 MW of solar paired with 2,200 MW of battery storage for Alternative B.

225. Appendix D, Alternative A Pipeline Maps is blank; however, it is provided in Figure 3.4-1. The length of the gas pipeline is stated as 7.3 miles in DEIS pg. 34 and 122 miles on DEIS pg. 36 and in Appendix C, pg. C-10. (Commentor: Jan Berry of Citizens' Climate Education)

Response: Pipeline Maps were provided as a separate PDF file in the submittal of the DEIS due to file size limitations. The 7.3-mile pipeline lateral referenced on page 34 is in reference to the smaller lateral segment of pipeline that would connect from the existing ETNG pipeline right-of-way (ROW) to the proposed CC/Aero CT Plant that would be constructed on Kingston Reservation. Further modifications by ETNG since the release of TVA's DEIS have increased the length of the pipeline lateral segment connecting the mainline to the Kingston Reservation from 7.3 to 8.0 miles. This information has been updated throughout the FEIS.

226. Section 3.8.1.1.2.5 Off-site Transmission Line Upgrades. line 8. page 391: The sentence about "Mixed mesophytic forests are described for the Western Transmission Corridor above."

> **Comment: Suggest changing the wording as the Western Transmission Corridor does not appear to be described above. It is described later in Section 3.8.1.1.2.5.1, page 392.**
>
> **Comment: Also, either number The Eastern Transmission Corridor as Section 3.8.1.1.2.5.1 and the Western as 3.8.1.1.2.5.2 or delete the 3.8.1.1.2.5.1 numbering for the Western Corridor. (Lindsey Stevens of Roane County Environmental Review Board)**

Response: The referenced error has been corrected in the FEIS. The information presented for the off-site transmission line upgrades has been updated in both the affected environment and environmental consequences section to also reflect an updated analysis based on results of field surveys of the off-site transmission corridors.

227. Section 3.8.1.1.2.5 Off-site Transmission Line Upgrades. line 8. page 391: The sentence about "Mixed mesophytic forests are described for the Western Transmission Corridor above."

> **Comment: Suggest changing the wording as the Western Transmission Corridor does not appear to be described above. It is described later in Section 3.8.1.1.2.5.1, page 392.**
>
> **Comment: Also, either number The Eastern Transmission Corridor as Section 3.8.1.1.2.5.1 and the Western as 3.8.1.1.2.5.2 or delete the 3.8.1.1.2.5.1 numbering for the Western Corridor. (Lyndsey Stevens of the Roane County Environmental Review Board)**

Response: Removed sentence regarding mesophytic forest and the Western Transmission Corridor as it did not fit. Removed Section number for Western Transmission Corridor heading to be consistent with Eastern Transmission Corridor and throughout EIS.

228. Table 3.8-11Summary of Impacts to Vegetation Communities Within the ETNG Construction ROW, page 401:

Comment: Suggest a label in the title or footnote indicating the values are in acres. (Lyndsey Stevens of the Roane County Environmental Review Board)

Table 3.8-12 Summary of Estimated Vegetation Impacts for Alternative A, page 405:7

Comment: Suggest a label in the title or footnote indicating the values are in acres.

Response: Added "(acres)" to the table label.

229. Additional editorial recommendations were provided that involved simple text edits to correct missing words for matting errors. (Lyndsey Stevens of the Roane County Environmental Review Board)

Response: The text and formatting changes recommended in the submitted comment letter were made in the FEIS.

C. Summary of Commentors

Commentor - Affiliation (Comment Response #)

37 Climate, Justice and Community Organizations – (14, 54, 74, 113, 119, 190, 201, 205, 206, 215)
Abadia, Betty – Appalachian Voices Petition (116, 196-198)
Abel, Sandy – Sierra Club Petition (213)
Abkowitz, Kendra – Office of Mayor John Cooper (69)
Adsit, Roy – Appalachian Voices Petition (116, 196-198)
Agee, James – (212)
Albright, Gary – Appalachian Voices Petition (116, 196-198)
Albritton, Phyllis T. – Appalachian Voices Petition (116, 196-198)
Alegria, Raul – Sierra Club Petition (213)
Alexander, Alice – Sierra Club Petition (213)
Allen, Randy – (213)
Almond, Jake – (212)
Anderson, Donald L. – Appalachian Voices Petition (116, 196-198)
Anderson, Dorothy – Appalachian Voices Petition (116, 196-198)
Andes, David – Appalachian Voices Petition (116, 196-198)
Andrews, Geneva – Sierra Club Petition (213)
Andrews, Robert – Appalachian Voices Petition (116, 196-198)
Armstrong, Michelle – Sierra Club Petition (213)
Arnett, Brian – Sierra Club Petition (213)
Averitt, Jill – Appalachian Voices Petition (116, 196-198)
Babb, Roger – Tennessee Valley Energy Consumers Group (TVECG) (2, 6, 47, 131)
Banks, Hannah – Appalachian Voices Petition (116, 196-198)
Barger, Mickey – (213)
Barger, Pat – (213)
Barnes, Lara – Sierra Club Petition (213)
Barnette, Perish – Appalachian Voices Petition (116, 196-198)
Barrios, Carla – Sierra Club Petition (213)
Bartell, Lee – Appalachian Voices Petition (116, 196-198)
Barthel, Carolyn – Appalachian Voices Petition (116, 196-198)
Baxter, Deborah A. – (212)
Bender, Albert – Indigenous Peoples Coalition (64)
Benison, Chris – Appalachian Voices Petition (116, 196-198)
Berg, Rosemary – (212)
Berkowitz, Henry – Appalachian Voices Petition (116, 196-198)
Berry, Jan – Citizens' Climate Education (1, 13, 36, 37, 43, 51, 63, 65, 66, 75, 76, 98-103, 125-128, 200)
Bhakti, Sara – Appalachian Voices Petition (116, 196-198)
Binello, Derek – Appalachian Voices Petition (116, 196-198)
Binseel, John – (213)
Birrell, Tracy – Appalachian Voices Petition (116, 196-198)
Black, Annie – Appalachian Voices Petition (116, 196-198)
Black, Rosemarie – (213)
Black, Ruth – (213)
Black, Stephen – (213)
Black, Vania – Appalachian Voices Petition (116, 196-198)
Blackman, Jeffrey – Appalachian Voices Petition (116, 196-198)
Bledsoe, Julie – Appalachian Voices Petition (116, 196-198)
Bledsoe, Julie – Appalachian Voices Petition (116, 196-198)
Block, MD – Appalachian Voices Petition (116, 196-198)
Bolgiano, Chris – Appalachian Voices Petition (116, 196-198)
Bond, S. Thomas – Appalachian Voices Petition (116, 196-198)
Bowden, Ralph – Statewide Organizing for Community eMpowerment (SOCM)/ 37 Climate, Justice and Community Organizations (14, 54, 74, 113, 119, 190, 201, 205, 206, 215)
Bowers, Ed – (212)
Boyd, Tobias – Appalachian Voices Petition (116, 196-198)
Breslau, Esther – Appalachian Voices Petition (116, 196-198)
Brine, Diane – Appalachian Voices Petition (116, 196-198)
Bryan, Barbara – Sierra Club Petition (213)
Bryan, David – Appalachian Voices Petition (116, 196-198)
Brydges, Bonnie – Appalachian Voices Petition (116, 196-198)

Buck, Susan – (213)
Buckley, Cathy – Appalachian Voices Petition (116, 196-198)
Burr-Lonnon, Jacqueline – Appalachian Voices Petition (116, 196-198)
Byers, Sharon – Appalachian Voices Petition (116, 196-198)
Calahan, Sharyn – Sierra Club Petition (213)
Campbell, Allan – Appalachian Voices Petition (116, 196-198)
Canfield, Alan – Appalachian Voices Petition (116, 196-198)
Cantrell, Charlie – Sierra Club Petition (213)
Caredda, Christine – Appalachian Voices Petition (116, 196-198)
Carley, Edward – Appalachian Voices Petition (116, 196-198)
Carlson-Bancroft, Sally – (212)
Carter, Micahel – Appalachian Voices Petition (116, 196-198)
Castle, Michael – (213)
Center for Biological Diversity – (4, 5, 18, 38, 39, 112, 113, 115-118)
Chambers, Augusta – Sierra Club Petition (213)
Chapman, Joan – Appalachian Voices Petition (116, 196-198)
Chapman, Susan – Appalachian Voices Petition (116, 196-198)
Chasteen, Jessica – (213)
Chattham, Beth – Tennessee Interfaith Power and Light (32-34, 77)
Citizens' Climate Education – (1, 13, 36, 37, 43, 51, 63, 65, 66, 75, 76, 98-103, 125-128, 200)
Clear, Mark – Appalachian Voices Petition (116, 196-198)
Clemson, G – Appalachian Voices Petition (116, 196-198)
Clipsham, Mark – Appalachian Voices Petition (116, 196-198)
Cobb, Sandra – Appalachian Voices Petition (116, 196-198)
Coen, Amy – (212)
Cole, James – Antioch United Methodist Church (213)
Cole, Julian – Appalachian Voices Petition (116, 196-198)
Conger, Nancy – Appalachian Voices Petition (116, 196-198)
Conley, Patrick – Sierra Club Petition (213)
Considine, Kate – Appalachian Voices Petition (116, 196-198)
Conway, John – Appalachian Voices Petition (116, 196-198)
Coppala, Jeff – (212)
Corona, Roberta – Appalachian Voices Petition (116, 196-198)
Coston, Bruce – Appalachian Voices Petition (116, 196-198)
Cowan, Kathy – Appalachian Voices Petition (116, 196-198)
Cowen, Anna – Appalachian Voices Petition (116, 196-198)
Cox, Bettina – (62)
Cramer, Chris – Appalachian Voices Petition (116, 196-198)
Crudgington, Keith – Appalachian Voices Petition (116, 196-198)
Cupit, Danielle – (213)
Curfman, Aileen – Appalachian Voices Petition (116, 196-198)
Dacus, Chris – Sierra Club Petition (213)
Dale, Barbara and Jim – Appalachian Voices Petition (116, 196-198)
Daniels, Celia – Appalachian Voices Petition (116, 196-198)
Davidge, Hayden – (212)
Davis, Billy – (213)
DeCristofaro, Jeffery – Appalachian Voices Petition (116, 196-198)
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Delanoy, Katherine – Appalachian Voices Petition (116, 196-198)
Delin, Donna – Appalachian Voices Petition (116, 196-198)
Denison, Laura – (212)
Denman, Desiree – Appalachian Voices Petition (116, 196-198)
Detmers, Peggy – Appalachian Voices Petition (116, 196-198)
Deutch, Darlene – Appalachian Voices Petition (116, 196-198)
Devault, Randall – (213)
Devault, Randall – (213)
Dimitrijevic, Sanja – Appalachian Voices Petition (116, 196-198)
Dolcini, Jerry – Appalachian Voices Petition (116, 196-198)
Donovan, Stephan – Appalachian Voices Petition (116, 196-198)
Donovan, Stephan – Appalachian Voices Petition (116, 196-198)
Dooley, Gerald – Gerald W Dooley, CPA (213)
Dorais, Mark – (212)
Dougherty, Kate – Appalachian Voices Petition (116, 196-198)
Dowdell, Irene – Sierra Club Petition (213)
Drinkwater, Edward – Appalachian Voices Petition (116, 196-198)
Dubois, Jennifer – ()
Duck, Stephen – Appalachian Voices Petition (116, 196-198)
Duggan, John – Appalachian Voices Petition (116, 196-198)

Kellermeyer, John – Appalachian Voices Petition (116, 196-198)
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Keyes, Jeannie – Appalachian Voices Petition (116, 196-198)
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Klinger, Barbara – Appalachian Voices Petition (116, 196-198)
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Kornrich, Bill – Appalachian Voices Petition (116, 196-198)
Krimsky, Pam – Appalachian Voices Petition (116, 196-198)
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Lane, Jenny – Appalachian Voices Petition (116, 196-198)
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Nielenz, Joanne – (212)
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Owen, Don – Sierra Club Petition (213)
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Paddock, Brian – Brian Paddock Attorney at Law (59)
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Papajcik, Doreen – Appalachian Voices Petition (116, 196-198)
Parciak, Sandra – Appalachian Voices Petition (116, 196-198)
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Parr, Nettie – Sierra Club Petition (213)
Parshall, Dorothy – Appalachian Voices Petition (116, 196-198)
Parti, Artie – Appalachian Voices Petition (116, 196-198)
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Penn, Peter – (224)
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Pfafffe, Barbara – Sierra Club Petition (213)
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Ranker, Natalie – Appalachian Voices Petition (116, 196-198)
Ray, Barbara A. – (212)
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Regester, Rolland – (213)
Reynolds, Thomas – Sierra Club Petition (213)
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Richards, Bill – Appalachian Voices Petition (116, 196-198)
Richards, Mark – Sierra Club Petition (213)
Richardson, Rebecca – Appalachian Voices Petition (116, 196-198)
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Ridella, Gerard – Appalachian Voices Petition (116, 196-198)
Ridenour, Patty – Appalachian Voices Petition (116, 196-198)
ring-revotskie, Peter – Appalachian Voices Petition (116, 196-198)
Rinke, John – ()
Roberts, Karen – (212)
Robertson, Nora – Sierra Club Petition (213)
Robertson, Penny – Sierra Club Petition (213)
Robinson, Alan – Appalachian Voices Petition (116, 196-198)
Rosen, Beth – Appalachian Voices Petition (116, 196-198)
Rosenberger, Amanda – (212)
Ross, Charlotta – Appalachian Voices Petition (116, 196-198)
Ross, Sandra K. – Tennessee Citizens for Wilderness Planning (TCWP) (212)
Ross, Timothy – (212)
Rotar, Bob – (213)
Rowan, Thomas – Appalachian Voices Petition (116, 196-198)
Ryden, Wendy – Appalachian Voices Petition (116, 196-198)
Sacchetti, Diane – Appalachian Voices Petition (116, 196-198)
Sallee, Jack – (212)
Salzman, Lee – (213)
Sandrock, Laura – Appalachian Voices Petition (116, 196-198)
Santana, Lorraine – Sierra Club Petition (213)
Saunders, Marilyn – (212)
Schaeffer, Lisa – Sierra Club Petition (213)
Schiff, Stephen – Appalachian Voices Petition (116, 196-198)
Schiller, Joe – (3, 8, 16, 24, 35, 38, 78, 114, 129, 130, 145, 146)
Schmotzer, Michael – Appalachian Voices Petition (116, 196-198)
Scholnick, Daniel – Appalachian Voices Petition (116, 196-198)
Schrade, Breika – Sierra Club Petition (213)
Scott, Aaron – (212)
Scott, Desiree – Sierra Club Petition (213)
Scruggs, Jerry – Sierra Club Petition (213)
Sears, Jimmy – (212)
Seltzer, Elizabeth – Appalachian Voices Petition (116, 196-198)
Shaffer, Richard Carl – (217)
Shalev, Lasita – Appalachian Voices Petition (116, 196-198)
Shayne, AF – Appalachian Voices Petition (116, 196-198)
Sheets, Ruth – Appalachian Voices Petition (116, 196-198)

Westmeyer, Anelisse – Sierra Club Petition (213)
Wetherall, J – Appalachian Voices Petition (116, 196-198)
Wheeler, Tara – Appalachian Voices Petition (116, 196-198)
White, Barbara – Appalachian Voices Petition (116, 196-198)
White, Don – City of Kingston and Rockwood City Council (213)
White, Joean-Pierrre – Sierra Club Petition (213)
Whitten, Phyllis – Appalachian Voices Petition (116, 196-198)
Wieland, Loren – Appalachian Voices Petition (116, 196-198)
Wiercioch, John – Appalachian Voices Petition (116, 196-198)
Wilcox, James – Appalachian Voices Petition (116, 196-198)
Williams, Jenna – Sierra Club Petition (213)
Williams, John – (212)
Williams, Lloyd – Appalachian Voices Petition (116, 196-198)
Wilson, Deborah – (213)
Winner, Thomas – Appalachian Voices Petition (116, 196-198)
Wisemeyer, Roger – Sierra Club Petition (213)
Withers, J. – Sierra Club Petition (213)
Wolfson, Andrea – Appalachian Voices Petition (116, 196-198)
Wright, Bob – Appalachian Voices Petition (116, 196-198)
Wright, Sara – (212)
Yancey, Brent – Appalachian Voices Petition (116, 196-198)
Yates, Mary (Peggy) – (212)
Young, Don – Appalachian Voices Petition (116, 196-198)
Zeller, Jean – Sierra Club Petition (213)
Zielinski, David – Appalachian Voices Petition (116, 196-198)
Zinkiewicz, Crys – Sierra Club Petition (213)
Zurcher, Naomi – Appalachian Voices Petition (116, 196-198)

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Appendix E – Aquatic Resources

Appendix E.1 –TVA’s Surface Waters Survey Report for Kingston Reservation

Stream Crossings Within the Proposed Areas of Impact on the Kingston Reservation Associated with the Kingston Fossil Plant Retirement Project

Sequence ID	Stream Type	Streamside Management Zone Category	Stream Name	Field Notes	Cowardin Code	HGM Code	Coordinates*	
							Begin	End
001	Perennial	SMZ Category A (50) ft	Unnamed tributary to Clinch River	Man-made with aquatic life, 2'W x 1'Deep. culverted, flows to POND1,POND2,POND3, and then into the emory river. Snails, eggs, leaches present.	R3	Riverine	35.8958, -84.5194	35.8958, -84.5194
002	Intermittent	SMZ Category A (50) ft	Unnamed tributary to Clinch River	Flowing water in channel and greater than 7 days since rain event in watershed. 3' x 1' flowing out of a wetland. silt subsrtate.	R3	Riverine	35.8952, -84.4977	35.894, -84.5001
e001	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)	Unnamed tributary to Clinch River	BWA001 is a grassy, man-made WWC on the SE side of the swtich yard. it is culverted at road and is draining into BWA008	R6	Riverine	35.8989, -84.5147	35.8959, -84.5188
e002	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)	Unnamed tributary to Clinch River	BWA002 is a grassy, bedless/bankless WWC that is culverted under road.	R6	Riverine	35.8982, -84.5146	35.8984, -84.5151
e003	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)	Unnamed tributary to Clinch River	6'W man made concrete WWC, culverted to Emory River	R6	Riverine	35.8946, -84.517	35.8941, -84.5175

e004	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)	Unnamed tributary to Clinch River	culverted, man-made WWC leading to Emory River	R6	Riverine	35.8941, -84.5157	35.8937, -84.516
e005	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)	Unnamed Tributary to Emory River	Bed/bank present, but it met the 3rd primary indicator on the TDEC HD form making it a WWC. 1'Wx<1'Deep. DATOS	R6	Riverine	35.9001, -84.5144	35.9011, -84.5114
e006	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)	Unnamed tributary to Clinch River	1' x 1' man made WWC	R6	Riverine	35.8972, -84.5155	35.8973, -84.5151
e007	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)	Unnamed tributary to Emory River	DATOS, 1'w x <1'Deep, culverted under road	R6	Riverine	35.9002, -84.5127	35.9005, -84.5114
e008	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)	Unnamed Tributary to Emory Rive	1' x 1' man-made WWC, rip-rap along the road.	R6	Riverine	35.9004, -84.5118	35.8996, -84.5093
e009	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)	Unnamed tributary to Clinch River	man made, WWW, culverted	R6	Riverine	35.8942, -84.5109	35.8941, -84.5157
e010	Ephemeral	Best Management Practices (BMP's)	Unnamed Tributary to Emory Rive	1' x 1' somewhat of a bed/bank present, DATOS, culverted under road	R6	Riverine	35.9002, -84.5106	35.9001, -84.5107

e011	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)	Unnamed Tributary to Emory Rive	WWC, coming from pond 6, culverted	R6	Riverine	35.902, -84.5037	35.9021, -84.5046
e012	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)		Man made WWC	R6	Riverine	35.8999, -84.5016	35.8988, -84.5025
e013	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)		man mad WWC	R6	Riverine	35.8987, -84.5017	35.8998, -84.5015
e014	Ephemeral	Best Management Practices (BMP's)		TDEC score of 17, 3'w x <1'Deep. ponded water, with no flow, leading to Emory River.	R6	Riverine	35.8947, -84.5002	35.8942, -84.5001
e015	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)		8'W x 3'D Man-made WWC DATOs	R6	Riverine	35.8972, -84.5055	35.8954, -84.5009
e016	Wet Weather Conveyance (WWC) / Ephemeral Stream	Best Management Practices (BMP's)		3'x3' Manmade WWC, riprap	R6	Riverine	35.8991, -84.4995	35.8986, -84.5016
e017	Ephemeral	Best Management Practices (BMP's)		steep slopes, running through wetland and into BWA13. Ephemeral	R6	Riverine	35.8942, -84.4985	35.8943, -84.4991
e018	Ephemeral	Best Management Practices (BMP's)		7x1 culverted channelized stream riprap sides dominated by upland and wetland vegetation	R6	Riverine	35.9016, -84.5231	35.9015, -84.523

e019	Ephemeral	Best Management Practices (BMP's)		Iron oxidizing bacteria, algae present, weak sinuosity,	R6	Riverine	35.9018, -84.5221	35.9006, -84.5244

*Denotes extent of reach assessed.

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e001	
HUC (12 digit): Two HUC 12's 060102080408 & 060102070405	Lat/Long: 84.5165089°W 35.8967611°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : First: 40647.238152 acres Second:40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes : e001 is a grassy, man-made WWC on the SE side of the switch yard. it is culverted at road and is draining into STR-001

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e002	
HUC (12 digit): 060102080408	Lat/Long: 84.5148786°W 35.8983066°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40647.238152 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes : e002 is a grassy, bedless/bankless WWC that is culverted under road.

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e003	
HUC (12 digit): 060102070405	Lat/Long: 84.5172189°W 35.8943191°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes :

6'W man made concrete WWC, culverted to Emory River

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Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e004	
HUC (12 digit): 060102070405	Lat/Long: 84.5159226°W 35.8938820°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes :

culverted, man-made WWC leading to Emory River

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e005	
HUC (12 digit): 060102080408	Lat/Long: 84.5127186°W 35.9004193°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40647.238152 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes : Bed/bank present, but it met the 3rd primary indicator on the TDEC HD form making it a WWC. 1'Wx<1'Deep. DATOS

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e006	
HUC (12 digit): 060102080408	Lat/Long: 84.5153064°W 35.8972555°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40647.238152 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes : 1' x 1' man made WWC. DATOS

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e007	
HUC (12 digit): 060102080408	Lat/Long: 84.5120628°W 35.9003800°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40647.238152 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1” in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = “Yes”, then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes : DATOS, 1'w x <1'Deep, culverted under road

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e008	
HUC (12 digit): 060102080408	Lat/Long: 84.5105413°W 35.9000299°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40647.238152 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes : 1' x 1' man-made WWC, rip-rap along the road.

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e009	
HUC (12 digit): 060102070405	Lat/Long: 84.5133563°W 35.8940884°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes :

Man-made WWC, culverted under roadway

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e010	
HUC (12 digit): 060102080408	Lat/Long: 84.5105786°W 35.9001492°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40647.238152 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes : 1' x 1' somewhat of a bed/bank present, DATOS, culverted under road

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e011	
HUC (12 digit): 060102080408	Lat/Long: 84.5041794°W 35.9018821°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40647.238152 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes :

Man-made WWC, coming from pond 6, culverted under roadway

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e012	
HUC (12 digit): 060102070405	Lat/Long: 84.5017540°W 35.8991534°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes :

3'x3' Man-made WWC, riprap DATOS

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e013	
HUC (12 digit): 060102070405	Lat/Long: 84.5005624°W 35.8988104°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes :

3'x3' Man-made WWC, riprap DATOS

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e014	
HUC (12 digit): 060102070405	Lat/Long: 84.5000428°W 35.8944576°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology : Source:	
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

**Overall Hydrologic Determination = ** WWC

**Secondary Indicator Score (if applicable) = ** 17

Justification / Notes :

TDEC score of 17, 3'w x <1'Deep. ponded water, with no flow, leading to Emory River.

Secondary Field Indicator Evaluation

A. Geomorphology (Subtotal = 6)	**Absent**	**Weak**	**Moderate**	**Strong**
1. Continuous bed and bank	0	1	2	3
2. Sinuous channel	0	1	2	3
3. In-channel structure: riffle-pool sequences	0	1	2	3
4. Sorting of soil textures or other substrate	0	1	2	3
5. Active/relic floodplain	0	0.5	1	1.5
6. Depositional bars or benches	0	1	2	3
7. Braided channel	0	1	2	3
8. Recent alluvial deposits	0	0.5	1	1.5
9. Natural levees	0	1	2	3
10. Headcuts	0	1	2	3
11. Grade controls	0	0.5	1	1.5
12. Natural valley or drainageway	0	0.5	1	1.5
13. At least second order channel on existing USGS or NRCS map	No = 0		Yes = 3	

B. Hydrology (Subtotal = 5)	**Absent**	**Weak**	**Moderate**	**Strong**
14. Subsurface flow/discharge into channel	0	1	2	3
15. Water in channel and >48 hours since sig. rain	0	1	1.5 2	3
16. Leaf litter in channel (January – September)	1.5	1	0.5	0
17. Sediment on plants or on debris	0	0.5	1	1.5
18. Organic debris lines or piles (wrack lines)	0	0.5	1	1.5
19. Hydric soils in channel bed or sides of channel	No = 0		Yes = 1.5	

C. Biology (Subtotal = 6)	**Absent**	**Weak**	**Moderate**	**Strong**
20. Fibrous roots in channel bed [1]	3	2	1	0
21. Rooted plants in the thalweg [1]	3	2	1	0
22. Crayfish in stream (exclude in floodplain)	0	1	2	3
23. Bivalves/mussels	0	1	2	3
24. Amphibians	0	0.5	1	1.5
25. Macrobenthos (record type & abundance)	0	1	2	3
26. Filamentous algae; periphyton	0	1	2	3
27. Iron oxidizing bacteria/fungus	0	0.5	1	1.5
28. Wetland plants in channel bed [2]	0	0.5	1	1.5

[1] Focus is on the presence of terrestrial plants.
[2] Focus is on the presence of aquatic or wetland plants.

Total Points = 17

Under Normal Conditions, Watercourse is a Wet Weather Conveyance if Secondary Indicator Score < 19 points

Notes :

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e015	
HUC (12 digit): 060102070405	Lat/Long: 84.5000428°W 35.8944576°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes :

8'W x 3'D Man-made WWC DATOs

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e016	
HUC (12 digit): 060102070405	Lat/Long: 84.5005624°W 35.8988104°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

**Overall Hydrologic Determination = ** WWC

**Secondary Indicator Score (if applicable) = ** N/A

Justification / Notes :

3'x3' Man-made WWC, riprap DATOS

Hydrologic Determination Field Data Sheet
Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: e017	
HUC (12 digit): 060102070405	Lat/Long: 84.4987931°W 35.8942595°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated average low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		Stream
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WWC

Secondary Indicator Score (if applicable) = N/A

Justification / Notes :

steep slopes, running through wetland and into BWA13. Ephemeral DATOS

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: STR-001	
HUC (12 digit): 060102070405	Lat/Long: 84.5194740°W 35.8954959°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Moderate Slight Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed		
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = Stream

Secondary Indicator Score (if applicable) = N/A

Justification / Notes :

Man-made/altered with aquatic life, 2'W x 1'Deep. culverted, flows to POND1,POND2,POND3, and then into the Emory river. Snails, eggs, leaches present.

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Pollution Control, Version 1.5

Named Waterbody: N/a	Date/Time: 3/30/22
Assessors/Affiliation: Brandon Whitley/Cory Chapman TVA	Project ID : KIF
Site Name/Description:	
Site Location: Sequence ID: STR-002	
HUC (12 digit): 060102070405	Lat/Long: 84.5000428°W 35.8944576°N
Previous Rainfall (7-days) : 0.00	
Precipitation this Season vs. Normal : abnormally wet elevated low abnormally dry unknown Source of recent & seasonal precip data :	
Watershed Size : 40176.038528 acres	County: Roane, Tennessee
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Industrial	
Degree of historical alteration to natural channel morphology & hydrology (circle one & describe fully in Notes) : Severe Moderate Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge		WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species		WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions		WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall		WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase		Stream
6. Presence of fish (except *Gambusia*)		Stream
7. Presence of naturally occurring ground water table connection		Stream
8. Flowing water in channel and 7 days since last precip >0.1” in local watershed		
9. Evidence watercourse has been used as a supply of drinking water		Stream

NOTE: If any Primary Indicators 1-9 = “Yes”, then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary & secondary indicators is provided in *TDEC-WPC Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = Stream

Secondary Indicator Score (if applicable) = N/A

Justification / Notes :

Flowing water in channel and greater than 7 days since rain event in watershed. 3' x 1' flowing out of a wetland. silt substrate.

Tennessee Department of Environment and Conservation - Division of Water Resources
312 Rosa L. Parks Ave. 11th Floor. Nashville, TN 37243

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Resources, Version 1.5 Fillable Form)

Named Waterbody: Unnamed trib to the Clinch River	Date/Time: 01/19/2023
Assessors/Affiliation: Zach Luttrell - TVA	Project ID : 39170
Site Name/Description: E018	
Site Location: Kingston Fossil Plant	
HUC (12 digit): 060102070405	Latitude: 35.90157067
Previous Rainfall (7-days) : 1.73	Longitude: -84.52306353
Precipitation this Season vs. Normal : average Source of recent seasonal precip. data :	
Watershed Size :	County: Roane
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Rural	
Degree of historical alteration to natural channel morphology hydrology (select one describe fully in Notes : Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge	☐	WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species	☐	WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions N/A	☐	WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall	☐	WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase	☐	Stream
6. Presence of fish (except *Gambusia*	☐	Stream
7. Presence of naturally occurring ground water table connection	☐	Stream
8. Flowing water in channel and 7 days since last precip >0.1" in local watershed	☐	Stream
9. Evidence watercourse has been used as a supply of drinking water	☐	Stream

NOTE: If any Primary Indicators 1-9 = "Yes", then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary secondary indicators is provided in *TDEC-DWR Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WET WEATHER CONVEYANCE

Secondary Indicator Score (if applicable) = 9.00

Justification / Notes :

7x1 culverted channelized stream riprap sides dominated by upland and wetland vegetation

Secondary Field Indicator Evaluation

A. Geomorphology (Subtotal = 3.00	**Absent**	**Weak**	**Moderate**	**Strong**	
1. Continuous bed and bank	0	1	2	3	1.5
2. Sinuous channel	0	1	2	3	0
3. In-channel structure: riffle-pool sequences	0	1	2	3	0
4. Sorting of soil textures or other substrate	0	1	2	3	0
5. Active/relic floodplain	0	0.5	1	1.5	0
6. Depositional bars or benches	0	1	2	3	0
7. Braided channel	0	1	2	3	0
8. Recent alluvial deposits	0	0.5	1	1.5	0
9. Natural levees	0	1	2	3	0
10. Headcuts	0	1	2	3	0
11. Grade controls	0	0.5	1	1.5	0
12. Natural valley or drainageway	0	0.5	1	1.5	1.5
13. At least second order channel on existing USGS or NRCS map	0	1	2	3	0

B. Hydrology (Subtotal = 2.00	**Absent**	**Weak**	**Moderate**	**Strong**	
14. Subsurface flow/discharge into channel	0	1	2	3	2
15. Water in channel and >48 hours since sig. rain	0	1	2	3	NA
16. Leaf litter in channel	1.5	1	0.5	0	NA
17. Sediment on plants or on debris	0	0.5	1	1.5	0
18. Organic debris lines or piles (wrack lines)	0	0.5	1	1.5	0
19. Hydric soils in channel bed or sides of channel	No = 0		Yes 1.5		0

C. Biology (Subtotal = 4.00	**Absent**	**Weak**	**Moderate**	**Strong**	
20. Fibrous roots in channel bed [1]	3	2	1	0	1
21. Rooted plants in the thalweg [1]	3	2	1	0	1
22. Crayfish in stream (exclude in floodplain)	0	1	2	3	0
23. Bivalves/mussels	0	1	2	3	0
24. Amphibians	0	0.5	1	1.5	0
25. Macrobenthos (record type & abundance)	0	1	2	3	0
26. Filamentous algae; periphyton	0	1	2	3	1
27. Iron oxidizing bacteria/fungus	0	0.5	1	1.5	0
28. Wetland plants in channel bed [2]	0	0.5	1	1.5	1

[1] Focus is on the presence of terrestrial plants. [2] Focus is on the presence of aquatic or wetland plants.

Total Points = 9.00

Under Normal Conditions, Watercourse is a Wet Weather Conveyance if Secondary Indicator Score < 19 points

Notes :

Tennessee Department of Environment and Conservation - Division of Water Resources
312 Rosa L. Parks Ave. 11th Floor. Nashville, TN 37243

Hydrologic Determination Field Data Sheet

Tennessee Division of Water Resources, Version 1.5 Fillable Form)

Named Waterbody: Unnamed trib to the Clinch River	Date/Time: 01/19/2023
Assessors/Affiliation: Zach Luttrell - TVA	Project ID : 39170
Site Name/Description: E019	
Site Location: Kingston Fossil Plant	
HUC (12 digit): 060102070405	Latitude: 35.90130584
Previous Rainfall (7-days) : 1.73	Longitude: -84.52331354
Precipitation this Season vs. Normal : average Source of recent seasonal precip. data :	
Watershed Size :	County: Roane
Soil Type(s) / Geology :	Source:
Surrounding Land Use : Rural	
Degree of historical alteration to natural channel morphology hydrology (select one describe fully in Notes : Absent	

Primary Field Indicators Observed

Primary Indicators	NO	YES
1. Hydrologic feature exists solely due to a process discharge	☐	WWC
2. Defined bed and bank absent, vegetation composed of upland and FACU species	☐	WWC
3. Watercourse dry anytime during February through April 15th, under normal precipitation / groundwater conditions N/A	☐	WWC
4. Daily flow and precipitation records showing feature only flows in direct response to rainfall	☐	WWC
5. Presence of multiple populations of obligate lotic organisms with ≥ 2 month aquatic phase	☐	Stream
6. Presence of fish (except *Gambusia*	☐	Stream
7. Presence of naturally occurring ground water table connection	☐	Stream
8. Flowing water in channel and 7 days since last precip >0.1” in local watershed	☐	Stream
9. Evidence watercourse has been used as a supply of drinking water	☐	Stream

NOTE: If any Primary Indicators 1-9 = “Yes”, then no further investigation is necessary. However, assessors may choose to score secondary indicators as supporting evidence.

In the absence of a primary indicator, or other definitive evidence, complete the secondary indicator table on page 2 of this sheet, and provide score below.

Guidance for the interpretation and scoring of both the primary secondary indicators is provided in *TDEC-DWR Guidance For Making Hydrologic Determinations, Version 1.5*

Overall Hydrologic Determination = WET WEATHER CONVEYANCE

Secondary Indicator Score (if applicable) = 14.00

Justification / Notes :

Iron oxidizing bacteria, algae present, weak sinuosity,

Secondary Field Indicator Evaluation

A. **Geomorphology** (Subtotal = 5.00	Absent	Weak	Moderate	Strong	
1. Continuous bed and bank	0	1	2	3	1.5
2. Sinuous channel	0	1	2	3	1
3. In-channel structure: riffle-pool sequences	0	1	2	3	1
4. Sorting of soil textures or other substrate	0	1	2	3	0
5. Active/relic floodplain	0	0.5	1	1.5	0
6. Depositional bars or benches	0	1	2	3	0
7. Braided channel	0	1	2	3	0
8. Recent alluvial deposits	0	0.5	1	1.5	0
9. Natural levees	0	1	2	3	0
10. Headcuts	0	1	2	3	0
11. Grade controls	0	0.5	1	1.5	0
12. Natural valley or drainageway	0	0.5	1	1.5	1.5
13. At least second order channel on existing USGS or NRCS map	0	1	2	3	0

B. **Hydrology** (Subtotal = 2.00	Absent	Weak	Moderate	Strong	
14. Subsurface flow/discharge into channel	0	1	2	3	2
15. Water in channel and >48 hours since sig. rain	0	1	2	3	NA
16. Leaf litter in channel	1.5	1	0.5	0	NA
17. Sediment on plants or on debris	0	0.5	1	1.5	0
18. Organic debris lines or piles (wrack lines)	0	0.5	1	1.5	0
19. Hydric soils in channel bed or sides of channel	No = 0		Yes 1.5		0

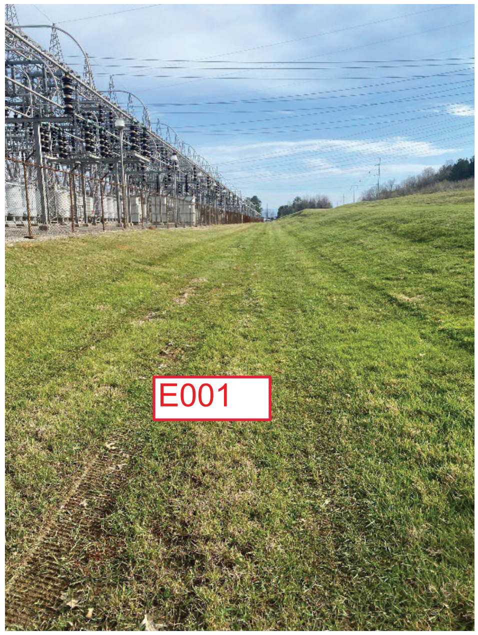
C. **Biology** (Subtotal = 7.00	Absent	Weak	Moderate	Strong	
20. Fibrous roots in channel bed [1]	3	2	1	0	1.5
21. Rooted plants in the thalweg [1]	3	2	1	0	1.5
22. Crayfish in stream (exclude in floodplain)	0	1	2	3	0
23. Bivalves/mussels	0	1	2	3	0
24. Amphibians	0	0.5	1	1.5	0
25. Macrobenthos (record type & abundance)	0	1	2	3	0
26. Filamentous algae; periphyton	0	1	2	3	2
27. Iron oxidizing bacteria/fungus	0	0.5	1	1.5	1
28. Wetland plants in channel bed [2]	0	0.5	1	1.5	1

[1] Focus is on the presence of terrestrial plants. [2] Focus is on the presence of aquatic or wetland plants.

Total Points = 14.00

Under Normal Conditions, Watercourse is a Wet Weather Conveyance if Secondary Indicator Score < 19 points

Notes :

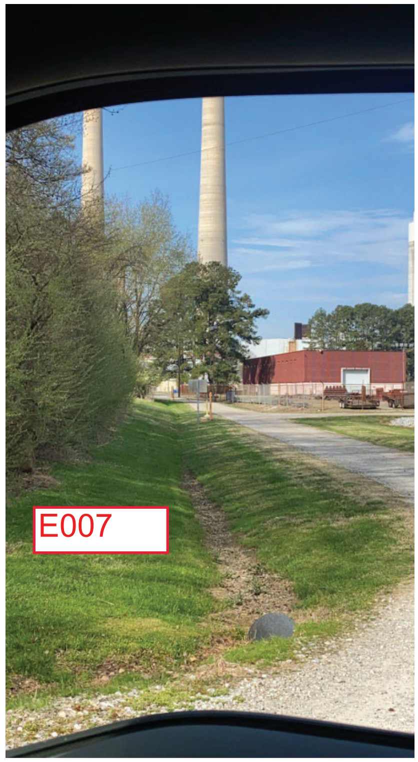


Sequence ID: E001

Sequence ID: E003

Sequence ID: E005

Sequence ID: E006



Sequence ID: E007

Sequence ID: E008

Sequence ID: E010

Sequence ID: E011

Sequence ID: E014

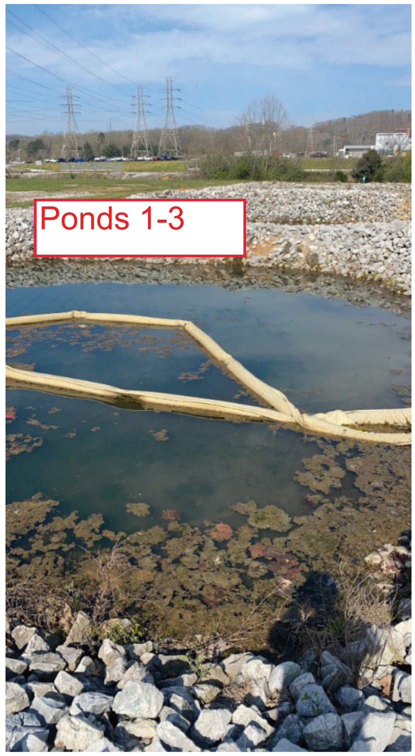
Sequence ID: E015

Sequence ID: E016

Sequence ID: E017

Sequence ID: STR-001

Sequence ID: STR-002



Sequence ID: Ponds 1-3

Sequence ID: Pond 4

Sequence ID: Pond 5

Kingston Retirement
ESCS 39170
2023

Seq. ID: E018

Latitude: 35.90157067
Longitude: -84.52306353

Notes: 7x1 culverted channelized stream riprap sides dominated by upland and wetland vegetation

Kingston Retirement
ESCS 39170
2023

Seq. ID: E019

Latitude: 35.90130584
Longitude: -84.52331354

Notes: Iron oxidizing bacteria, algae present, weak sinuosity,

Appendix E.2 – TVA Wetlands Field Survey Memo

TVA INPUT – WETLANDS

DATE:	April, 11 2022 Updated to include January 2023 Delineation
REQ /PSO#:	39170/537599
PROJECT TITLE:	KINGSTON FOSSIL PLANT RETIREMENT EIS
CUSTOMER:	Chevales Williams, NEPA
PREPARED BY:	Fallon Parker Hutcheon, Biological Compliance-Wetlands

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Field surveys were conducted in March, 2022 to map wetlands on the proposed on-site KIF Retirement Alternative A CC/CT project area. Seven wetlands were mapped on the KIF on-site potential project area. In January 2023 a supplemental field survey was conducted to review the expanded project area to include the KIF D4 area. Two wetlands were mapped within the KIF D4 project area. This wetland report does not include any associated off site transmission line or pipeline project area for KIF retirement CC/CT project. Wetland boundaries were mapped with a Trimble ProHX geographic positioning system and ESRI ArcGIS Pro mapping software.

Activities in wetlands are regulated by state and federal agencies to ensure no net loss of wetland resources. Under the Clean Water Act (CWA) §404, activities resulting in the discharge of dredge, fill, and potential secondary impacts resulting in degradation to waters of the U. S., including wetlands, must be authorized by the U.S. Army Corps of Engineers (USACE) through a Nationwide, Regional, or Individual Permit. CWA §401 of the Clean Water Act requires state water quality certification for projects requiring USACE approval. In Tennessee, the Department of Environment and Conservation (TDEC) is responsible for issuance of water quality certifications pursuant to Section 401. Lastly, Executive Order 11990 requires federal agencies to avoid construction in wetlands and minimize wetland degradation to the extent practicable. Wetland determinations were performed according to the USACE standards, which require documentation of hydrophytic (wet-site) vegetation, hydric soil, and wetland hydrology (Environmental Laboratory 1987; USACE 2012, 2020).

Using the Tennessee Rapid Assessment Method (TRAM) wetlands were evaluated by their functions and classified into three categories: low, moderate quality, or exceptional resource value (TDEC 2017). Low quality wetlands are degraded aquatic resources which may exhibit low species diversity, minimal hydrologic input and connectivity, recent or on-going disturbance regimes, and/or predominance of non-native species. These wetlands provide low functionality and are considered of low value. Moderate quality wetlands provide functions at a greater value due to a lesser degree of degradation and/or due to their habitat, landscape position, or hydrologic input. Moderate quality wetlands are considered healthy water resources of value. Disturbance to hydrology, substrate and/or vegetation may be present to a degree at which valuable functional capacity is sustained and there is reasonable potential for restoration. Exceptional resource value wetlands offer high functions and values within a watershed or are of regional/statewide concern. These wetlands may exhibit little, if any, recent disturbance, provide essential and/or large scale stormwater storage, sediment retention, and toxin absorption, contain mature vegetation communities, and/or offer habitat to rare species.

Conditions found in superior quality wetlands often represent restoration goals for wetlands functioning at a lower capacity.

Table 1. Wetlands within the on-site KIF Retirement Alternative A CC/CT project and KIF D4 area.

Wetland ID	Type[1]	TRAM Category (score)	Location	Wetland Acreage in Review Area	Wetland Impacts
W001	PFO1E	Low (39)	35.8941708, -84.5002456	0.13	Specific Impacts TBD
W002	PEM1E	Low (13)	35.8948153, -84.5002172	0.03	Specific Impacts TBD
W003	PEM1Hr	Low (23)	35.8961844, -84.4990040	0.11	Specific Impacts TBD
W004	PEM1E	Low (23)	35.8951150, -84.4974135	0.43	Specific Impacts TBD
W005	PFO1E	Low (43)	35.8942878 -84.4989506	0.10	Specific Impacts TBD
W006	PEM1E	Low (36)	35.8979714, -84.5008612	0.11	Specific Impacts TBD
W007	PEM1E	Low (15)	35.8982769, -84.5007154	0.01	Specific Impacts TBD
W008*	PEM1	Low (11)	35.9015565, -84.5225601	<0.01	Specific Impacts TBD
W009*	PEM1	Low (11)	35.9014755, -84.5227871	0.01	Specific Impacts TBD
			TOTAL	**0.94 Acres**	

[1]Classification codes as defined in Cowardin et al. (1979): PEM1 = Palustrine emergent, persistent vegetation; E = Seasonally flooded/saturated; FO1=Forested broadleaf deciduous; H= Permanently flooded; r= Artificial substrate.

*W001-W007 were delineated in March 2022. W008-W009 were delineated in January 2023.

W001 is a forested wetland fringe to Watts bar reservoir on the south side of the KIF plant property. This wetland exhibited soil profile coloration that is grey and mottled, indicating the presence of hydric conditions. This wetland was dominated by hydrophytic vegetation including tag alder, sycamore, and soft rush. W001 scored as low value wetland resource due primarily to its small size and lack of hydrologic influence seasonally.

W002 is a mowed emergent wetland swale draining to Watts bar reservoir. This wetland exhibited saturated soils, which has resulted in soil profile coloration that is grey and mottled, indicating sustained hydric conditions. This wetland was dominated by hydrophytic vegetation including fox sedge and soft rush. W002 scored as low value wetland resource due to surrounding land use and lack of buffer.

W003 is an emergent wetland fringe in a manmade pond within a transmission line right-of-way. This wetland exhibited standing water and saturated soils, which has resulted in soil profile coloration that is grey and mottled, indicating sustained hydric conditions. This wetland was dominated by hydrophytic vegetation including cattails and black willow. W003 scored as low value wetland resource due to surrounding land use and lack of buffer.

W004 is an emergent wetland swale within a transmission line right-of-way; W004 extends outside of the project area to the east within the transmission line right-of-way. This wetland exhibited standing water and saturated soils, which has resulted in soil profile coloration that is grey and mottled, indicating sustained hydric conditions. This wetland was dominated by hydrophytic vegetation including soft rush and bushy bluestem. W004 scored as low value wetland resource due to size and lack of buffer.

W005 is a forested wetland depression surrounding conveyances. This wetland exhibited standing water and saturated soils, which has resulted in soil profile coloration that is grey and mottled, indicating sustained hydric conditions. This wetland was dominated by hydrophytic vegetation including sycamore and sedge species. W005 scored as low value wetland resource due to size.

W006 is an emergent man-made depression retaining drainage. This wetland exhibited standing water and saturated soils, which has resulted in soil profile coloration that is grey and mottled, indicating sustained hydric conditions. This wetland was dominated by hydrophytic vegetation including cattails and black willow. W006 scored as low value wetland resource due to size and surrounding land use.

W007 is a saturated emergent wetland depression. This wetland exhibited saturated soils, which has resulted in soil profile coloration that is grey and mottled, indicating sustained hydric conditions. This wetland was dominated by hydrophytic vegetation including cattails and soft rush. W007 scored as low value wetland resource due to size and surrounding land use.

W008 and W009 are emergent wetlands located in linear drainage ditches with riprap substrate. These features are associated with onsite stormwater/process water conveyance and water is discharged through an NPDES permitted outfall. These features are not regulated by TDEC, but USACE jurisdictional status is not known at this time. Sediment and deposition above the riprap substrate and saturated conditions have resulted in a soil profile of hydric coloration. These wetlands were dominated by hydrophytic vegetation including cattails and soft rush. W008 and W009 scored as low value wetland resources due to size, disturbance, and surrounding land use.

0.94 acres of wetland (0.23 acres of forested wetland; 0.71 acres of emergent wetland) were identified within the on-site KIF Retirement Alternative A CC/CT project area and KIF D4 area. This wetland report does not include any associated off site transmission line or pipeline project area for KIF retirement CC/CT project area.

Specific wetland disturbances within the larger on-site KIF Retirement Alternative A CC/CT project area and KIF D4 have not yet been determined. Any proposed impacts will be permitted and in compliance with TDEC/USACE CWA 404/401 regulations, including any necessary mitigation. TVA BMPs will be instituted for work associated with on-site KIF Retirement Alternative A CC/CT and KIF D4 (TVA 2022).

Literature Cited

Cowardin, L.M., V. Carter, F.C. Golet, and E.T. LaRoe. 1979. *Classification of Wetland and Deepwater Habitats of the United States*. Washington, D.C.: U.S. Fish and Wildlife Publication FWS/OBS-79/31.

Environmental Laboratory. 1987. *Corps of Engineers Wetland Delineation Manual*. Vicksburg, Miss.: U.S. Army Corps of Engineers Waterways Experiment Station. Technical Report Y-87-1

Tennessee Department of Environment and Conservation. 2017. *Tennessee Rapid Assessment Method for Wetlands.* Nashville Tennessee: Division of Water Resources, Natural Resources Unit.

Tennessee Valley Authority (TVA). 2022. A Guide for Environmental Protection and Best Management Practices for Tennessee Valley Authority Construction and Maintenance Activities, Revision 4. Edited by G. Behel, S. Benefield, R. Brannon, C. Buttram, G. Dalton, C. Ellis, C. Henley, T. Korth, T. Giles, A. Masters, J. Melton, R. Smith, J.Turk, T. White, and R.Wilson. Chattanooga, TN.: Available at [URL}: https://www.tva.com/energy/transmission/transmission-system-projects Accessed: November 2022

U.S. Army Corps of Engineers. 2012. *Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Eastern Mountains and Piedmont Region Version 2.0*, ed. J. F. Berkowitz, J. S. Wakeley, R. W.Lichvar, C. V. Noble. ERDC/EL TR-12-9. Vicksburg, MS: U.S. Army Engineer Research and Development Center.

U.S. Army Corps of Engineers. 2020. National Wetland Plant List, Version 3.5. https://wetland-plants.usace.army.mil/nwpl_static/v34/species/species.html?DET=001100 U.S. Army Corps of Engineers Research and Development Center. Cold Regions Research and Engineering Laboratory, Hanover, NH.

WETLAND DETERMINATION DATA FORM - Eastern Mountains and Piedmont Region

Project/Site: KIF Retirement 39170 **City/County:** ROANE **Sampling Date:** 30-Mar-22

Applicant/Owner: TVA **State:** TN **Sampling Point:** **W001**

Investigator(s): Fallon Parker Hutcheon **Section, Township, Range: S** **T** **R**

Landform (hillslope, terrace, etc.): Shoreline **Local relief (concave, convex, none):** hummocky **Slope:** 0.0% / 0.0 °

Subregion (LRR or MLRA): LRR N **Lat.:** 35.8941708 **Long.:** -84.5002456 **Datum:** NAD83

Soil Map Unit Name: Waynesboro loam **NWI classification:** PFO1E

Are climatic/hydrologic conditions on the site typical for this time of year? Yes ○ No ○ **(If no, explain in Remarks.)**

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **significantly disturbed?** **Are "Normal Circumstances" present?** Yes ◉ No ○

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **naturally problematic?** **(If needed, explain any answers in Remarks.)**

Summary of Findings - Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ◉ No ○	**Is the Sampled Area within a Wetland?** Yes ◉ No ○
Hydric Soil Present?	Yes ◉ No ○	
Wetland Hydrology Present?	Yes ◉ No ○	

Remarks:

Forested wetland fringe to reservoir. 0.13 acres. FPH_Photo#DSCN5904-05. TRAM score = (39) Low

Hydrology

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ☐ Surface Water (A1)
- ☐ High Water Table (A2)
- ☐ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Water-Stained Leaves (B9)
- ☐ Aquatic Fauna (B13)
- ☐ True Aquatic Plants (B14)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Thin Muck Surface (C7)
- ☐ Other (Explain in Remarks)

Secondary Indicators (minimum of two required)

- ☐ Surface Soil Cracks (B6)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Drainage Patterns (B10)
- ☐ Moss Trim Lines (B16)
- ☐ Dry Season Water Table (C2)
- ☐ Crayfish Burrows (C8)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Stunted or Stressed Plants (D1)
- ☑ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ Microtopographic Relief (D4)
- ☑ FAC-neutral Test (D5)

Field Observations:

Surface Water Present?	Yes ○ No ◉	Depth (inches):	
Water Table Present?	Yes ○ No ◉	Depth (inches):	
Saturation Present? (includes capillary fringe)	Yes ○ No ◉	Depth (inches):	

Wetland Hydrology Present? Yes ◉ No ○

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

VEGETATION (Five/Four Strata)- Use scientific names of plants.

Sampling Point: W001

Tree Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1. Platanus occidentalis	40	☑	50.0%	FACW
2. Salix nigra	10	☐	12.5%	OBL
3. Alnus serrulata	30	☑	37.5%	OBL
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
	80	= Total Cover		
Sapling-Sapling/Shrub Stratum (Plot size:)				
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
	0	= Total Cover		
Shrub Stratum (Plot size:)				
1. Ligustrum sinense	10	☑	100.0%	FACU
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
	10	= Total Cover		
Herb Stratum (Plot size:)				
1. Carex vulpinoidea	15	☑	60.0%	OBL
2. Juncus effusus	10	☑	40.0%	FACW
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
11.	0	☐	0.0%	
12.	0	☐	0.0%	
	25	= Total Cover		
Woody Vine Stratum (Plot size:)				
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
	0	= Total Cover		

Dominance Test worksheet:

Number of Dominant Species That are OBL, FACW, or FAC: 4 (A)

Total Number of Dominant Species Across All Strata: 5 (B)

Percent of dominant Species That Are OBL, FACW, or FAC: 80.0% (A/B)

Prevalence Index worksheet:

	Total % Cover of:		Multiply by:
OBL species	55	x 1 =	55
FACW species	50	x 2 =	100
FAC species	0	x 3 =	0
FACU species	10	x 4 =	40
UPL species	0	x 5 =	0
Column Totals:	115	(A)	195 (B)

Prevalence Index = B/A = 1.696

Hydrophytic Vegetation Indicators:

- ☐ **Rapid Test for Hydrophytic Vegetation**
- ☑ **Dominance Test is > 50%**
- ☑ **Prevalence Index is ≤3.0** [1]
- ☐ **Morphological Adaptations** [1] **(Provide supporting data in Remarks or on a separate sheet)**
- ☐ **Problematic Hydrophytic Vegetation** [1] **(Explain)**

[1] **Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.**

Definition of Vegetation Strata:

Four Vegetation Strata:

Tree stratum – Consists of woody plants, excluding vines, 3 in. (7.6 cm) or more in diameter at breast height (DBH), regardless of height.

Sapling/shrub stratum – Consists of woody plants, excluding vines, less than 3 in. DBH and greater than 3.28 ft (1 m) tall.

Herb stratum – Consists of all herbaceous (non-woody) plants, regardless of size, and all other plants less than 3.28 ft tall.

Woody vines – Consists of all woody vines greater than 3.28 ft in height.

Five Vegetation Strata:

Tree - Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and 3 in. (7.6 cm) or larger in diameter at breast height (DBH).

Sapling stratum – Consists of woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and less than 3 in. (7.6 cm) DBH.

Shrub stratum – Consists of woody plants, excluding woody vines, approximately 3 to 20 ft (1 to 6 m) in height.

Herb stratum – Consists of all herbaceous (non-woody) plants, including herbaceous vines, regardless of size, and woody species, except woody vines, less than approximately 3 ft (1 m) in height.

Woody vines – Consists of all woody vines, regardless of height.

Hydrophytic Vegetation Present? Yes ◉ No ○

Remarks: (Include photo numbers here or on a separate sheet.)

*Indicator suffix = National status or professional decision assigned because Regional status not defined by FWS.

Soil

Sampling Point: W001

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)		Matrix %	Redox Features Color (moist)		Redox %	Type[1]	Loc²	Texture	Remarks
0-2	7.5YR	3/1	100						Loam	
2-12	10YR	4/6	75	10YR	6/4	15	C	M	Sandy Loam	

[1] Type: C=Concentration. D=Depletion. RM=Reduced Matrix, CS=Covered or Coated Sand Grains ²Location: PL=Pore Lining. M=Matrix

Hydric Soil Indicators:

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Stratified Layers (A5)
- ☐ 2 cm Muck (A10) (LRR N)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Muck Mineral (S1) (LRR N, MLRA 147, 148)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Dark Surface (S7)
- ☐ Polyvalue Below Surface (S8) (MLRA 147,148)
- ☐ Thin Dark Surface (S9) (MLRA 147, 148)
- ☐ Loamy Gleyed Matrix (F2)
- ☑ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)
- ☐ Iron-Manganese Masses (F12) (LRR N, MLRA 136)
- ☐ Umbric Surface (F13) (MLRA 136, 122)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 148)
- ☐ Red Parent Material (F21) (MLRA 127, 147)

Indicators for Problematic Hydric Soils[3]:

- ☐ 2 cm Muck (A10) (MLRA 147)
- ☐ Coast Prairie Redox (A16) (MLRA 147,148)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 136, 147)
- ☐ Very Shallow Dark Surface (TF12)
- ☐ Other (Explain in Remarks)

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if observed):

Type:

Depth (inches):

Hydric Soil Present? Yes ◉ No ○

Remarks:

* roots too obstructing after 12 inches

WETLAND DETERMINATION DATA FORM - Eastern Mountains and Piedmont Region

Project/Site: KIF Retirement 39170 **City/County:** ROANE **Sampling Date:** 30-Mar-22

Applicant/Owner: TVA **State:** TN **Sampling Point:** **W002**

Investigator(s): Fallon Parker Hutcheon **Section, Township, Range: S** **T** **R**

Landform (hillslope, terrace, etc.): Swale **Local relief (concave, convex, none):** concave **Slope:** 0.0% / 0.0 °

Subregion (LRR or MLRA): LRR N **Lat.:** 35.8948153 **Long.:** -84.5002172 **Datum:** NAD83

Soil Map Unit Name: Waynesboro loam **NWI classification:** PEM1E

Are climatic/hydrologic conditions on the site typical for this time of year? Yes ○ No ○ **(If no, explain in Remarks.)**

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **significantly disturbed?** **Are "Normal Circumstances" present?** Yes ◉ No ○

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **naturally problematic?** **(If needed, explain any answers in Remarks.)**

Summary of Findings - Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ◉ No ○	**Is the Sampled Area within a Wetland?** Yes ◉ No ○
Hydric Soil Present?	Yes ◉ No ○	
Wetland Hydrology Present?	Yes ◉ No ○	

Remarks:

Emergent wetland swale draining to reservoir, mowed. 0.03 acres. FPH_Photo#DSCN5915. TRAM score = (13) Low

Hydrology

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ☐ Surface Water (A1)
- ☐ High Water Table (A2)
- ☑ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Water-Stained Leaves (B9)
- ☐ Aquatic Fauna (B13)
- ☐ True Aquatic Plants (B14)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Thin Muck Surface (C7)
- ☐ Other (Explain in Remarks)

Secondary Indicators (minimum of two required)

- ☐ Surface Soil Cracks (B6)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Drainage Patterns (B10)
- ☐ Moss Trim Lines (B16)
- ☐ Dry Season Water Table (C2)
- ☐ Crayfish Burrows (C8)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Stunted or Stressed Plants (D1)
- ☑ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ Microtopographic Relief (D4)
- ☑ FAC-neutral Test (D5)

Field Observations:

Surface Water Present?	Yes ○ No ◉	Depth (inches):	
Water Table Present?	Yes ○ No ◉	Depth (inches):	
Saturation Present? (includes capillary fringe)	Yes ◉ No ○	Depth (inches):	

Wetland Hydrology Present? Yes ◉ No ○

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

VEGETATION (Five/Four Strata)- Use scientific names of plants.

Sampling Point: W002

Tree Stratum (Plot size: ______)

	Absolute % Cover	Dominant Species? Rel.Strat. Cover		Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
	0	= Total Cover		

Sapling-Sapling/Shrub Stratum (Plot size: ______)

	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
	0	= Total Cover		

Shrub Stratum (Plot size: ______)

	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
	0	= Total Cover		

Herb Stratum (Plot size: ______)

	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1. Carex vulpinoidea	30	☑	35.3%	OBL
2. Juncus effusus	20	☑	23.5%	FACW
3. Rumex crispus	5	☐	5.9%	FAC
4. Festuca arundinacea	30	☑	35.3%	FACU
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
11.	0	☐	0.0%	
12.	0	☐	0.0%	
	85	= Total Cover		

Woody Vine Stratum (Plot size: ______)

	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
	0	= Total Cover		

Dominance Test worksheet:

Number of Dominant Species That are OBL, FACW, or FAC: 2 (A)

Total Number of Dominant Species Across All Strata: 3 (B)

Percent of dominant Species That Are OBL, FACW, or FAC: 66.7% (A/B)

Prevalence Index worksheet:

Total % Cover of:		Multiply by:	
OBL species	30	x 1 =	30
FACW species	20	x 2 =	40
FAC species	5	x 3 =	15
FACU species	30	x 4 =	120
UPL species	0	x 5 =	0
Column Totals:	85 (A)		205 (B)

Prevalence Index = B/A = 2.412

Hydrophytic Vegetation Indicators:

- ☐ **Rapid Test for Hydrophytic Vegetation**
- ☑ **Dominance Test is > 50%**
- ☑ **Prevalence Index is ≤3.0** [1]
- ☐ **Morphological Adaptations** [1] **(Provide supporting data in Remarks or on a separate sheet)**
- ☐ **Problematic Hydrophytic Vegetation** [1] **(Explain)**

[1] **Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.**

Definition of Vegetation Strata:

Four Vegetation Strata:

Tree stratum – Consists of woody plants, excluding vines, 3 in. (7.6 cm) or more in diameter at breast height (DBH), regardless of height.

Sapling/shrub stratum – Consists of woody plants, excluding vines, less than 3 in. DBH and greater than 3.28 ft (1 m) tall.

Herb stratum – Consists of all herbaceous (non-woody) plants, regardless of size, and all other plants less than 3.28 ft tall.

Woody vines – Consists of all woody vines greater than 3.28 ft in height.

Five Vegetation Strata:

Tree - Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and 3 in. (7.6 cm) or larger in diameter at breast height (DBH).

Sapling stratum – Consists of woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and less than 3 in. (7.6 cm) DBH.

Shrub stratum – Consists of woody plants, excluding woody vines, approximately 3 to 20 ft (1 to 6 m) in height.

Herb stratum – Consists of all herbaceous (non-woody) plants, including herbaceous vines, regardless of size, and woody species, except woody vines, less than approximately 3 ft (1 m) in height.

Woody vines – Consists of all woody vines, regardless of height.

Hydrophytic Vegetation Present? Yes ◉ No ○

Remarks: (Include photo numbers here or on a separate sheet.)

*Indicator suffix = National status or professional decision assigned because Regional status not defined by FWS.

Soil

Sampling Point: W002

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)		Matrix %	Redox Features Color (moist)		Redox %	Type[1]	Loc²	Texture	Remarks
0-2	7.5YR	3/1	100						Loam	
2-16	10YR	4/6	75	10YR	6/4	15	C	M	Sandy Loam	

[1] Type: C=Concentration. D=Depletion. RM=Reduced Matrix, CS=Covered or Coated Sand Grains ²Location: PL=Pore Lining. M=Matrix

Hydric Soil Indicators:

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Stratified Layers (A5)
- ☐ 2 cm Muck (A10) (LRR N)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Muck Mineral (S1) (LRR N, MLRA 147, 148)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Dark Surface (S7)
- ☐ Polyvalue Below Surface (S8) (MLRA 147,148)
- ☐ Thin Dark Surface (S9) (MLRA 147, 148)
- ☐ Loamy Gleyed Matrix (F2)
- ☑ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)
- ☐ Iron-Manganese Masses (F12) (LRR N, MLRA 136)
- ☐ Umbric Surface (F13) (MLRA 136, 122)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 148)
- ☐ Red Parent Material (F21) (MLRA 127, 147)

Indicators for Problematic Hydric Soils[3]:

- ☐ 2 cm Muck (A10) (MLRA 147)
- ☐ Coast Prairie Redox (A16) (MLRA 147,148)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 136, 147)
- ☐ Very Shallow Dark Surface (TF12)
- ☐ Other (Explain in Remarks)

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if observed):

Type:

Depth (inches):

Hydric Soil Present? Yes ◉ No ○

Remarks:

WETLAND DETERMINATION DATA FORM - Eastern Mountains and Piedmont Region

Project/Site: KIF Retirement 39170 **City/County:** ROANE **Sampling Date:** 30-Mar-22

Applicant/Owner: TVA **State:** TN **Sampling Point:** W003

Investigator(s): Fallon Parker Hutcheon **Section, Township, Range: S** **T** **R**

Landform (hillslope, terrace, etc.): Shoreline **Local relief (concave, convex, none):** concave **Slope:** 0.0% / 0.0 °

Subregion (LRR or MLRA): LRR N **Lat.:** 35.8961844 **Long.:** -84.4990040 **Datum:** NAD83

Soil Map Unit Name: Waynesboro loam **NWI classification:** PEM1Hr

Are climatic/hydrologic conditions on the site typical for this time of year? Yes ○ No ○ **(If no, explain in Remarks.)**

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **significantly disturbed?** **Are "Normal Circumstances" present?** Yes ◉ No ○

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **naturally problematic?** **(If needed, explain any answers in Remarks.)**

Summary of Findings - Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ◉ No ○	**Is the Sampled Area within a Wetland?** Yes ◉ No ○
Hydric Soil Present?	Yes ◉ No ○	
Wetland Hydrology Present?	Yes ◉ No ○	

Remarks:

Emergent wetland fringe in manmade pond, disturbed. 0.11 acres. FPH_Photo#DSCN5930-31. TRAM score = (23) Low

Hydrology

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ☑ Surface Water (A1)
- ☑ High Water Table (A2)
- ☑ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Water-Stained Leaves (B9)
- ☐ Aquatic Fauna (B13)
- ☐ True Aquatic Plants (B14)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Thin Muck Surface (C7)
- ☐ Other (Explain in Remarks)

Secondary Indicators (minimum of two required)

- ☐ Surface Soil Cracks (B6)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Drainage Patterns (B10)
- ☐ Moss Trim Lines (B16)
- ☐ Dry Season Water Table (C2)
- ☐ Crayfish Burrows (C8)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Stunted or Stressed Plants (D1)
- ☑ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ Microtopographic Relief (D4)
- ☑ FAC-neutral Test (D5)

Field Observations:

Surface Water Present?	Yes ◉ No ○	Depth (inches): 10
Water Table Present?	Yes ◉ No ○	Depth (inches):
Saturation Present? (includes capillary fringe)	Yes ◉ No ○	Depth (inches):

Wetland Hydrology Present? Yes ◉ No ○

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

VEGETATION (Five/Four Strata)- Use scientific names of plants.

Sampling Point: W003

Tree Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
	0	= Total Cover		
Sapling-Sapling/Shrub Stratum (Plot size:)				
1. Salix nigra	5	☑	100.0%	OBL
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
	5	= Total Cover		
Shrub Stratum (Plot size:)				
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
	0	= Total Cover		
Herb Stratum (Plot size:)				
1. Typha latifolia	70	☑	87.5%	OBL
2. Andropogon glomeratus	10	☐	12.5%	FACW
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
11.	0	☐	0.0%	
12.	0	☐	0.0%	
	80	= Total Cover		
Woody Vine Stratum (Plot size:)				
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
	0	= Total Cover		

Dominance Test worksheet:

Number of Dominant Species That are OBL, FACW, or FAC: 2 (A)

Total Number of Dominant Species Across All Strata: 2 (B)

Percent of dominant Species That Are OBL, FACW, or FAC: 100.0% (A/B)

Prevalence Index worksheet:

	Total % Cover of:		Multiply by:
OBL species	75	x 1 =	75
FACW species	10	x 2 =	20
FAC species	0	x 3 =	0
FACU species	0	x 4 =	0
UPL species	0	x 5 =	0
Column Totals:	85 (A)		95 (B)

Prevalence Index = B/A = 1.118

Hydrophytic Vegetation Indicators:

- ☑ **Rapid Test for Hydrophytic Vegetation**
- ☑ **Dominance Test is > 50%**
- ☑ **Prevalence Index is ≤3.0** [1]
- ☐ **Morphological Adaptations** [1] **(Provide supporting data in Remarks or on a separate sheet)**
- ☐ **Problematic Hydrophytic Vegetation** [1] **(Explain)**

[1] **Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.**

Definition of Vegetation Strata:

Four Vegetation Strata:

Tree stratum – Consists of woody plants, excluding vines, 3 in. (7.6 cm) or more in diameter at breast height (DBH), regardless of height.

Sapling/shrub stratum – Consists of woody plants, excluding vines, less than 3 in. DBH and greater than 3.28 ft (1 m) tall.

Herb stratum – Consists of all herbaceous (non-woody) plants, regardless of size, and all other plants less than 3.28 ft tall.

Woody vines – Consists of all woody vines greater than 3.28 ft in height.

Five Vegetation Strata:

Tree - Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and 3 in. (7.6 cm) or larger in diameter at breast height (DBH).

Sapling stratum – Consists of woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and less than 3 in. (7.6 cm) DBH.

Shrub stratum – Consists of woody plants, excluding woody vines, approximately 3 to 20 ft (1 to 6 m) in height.

Herb stratum – Consists of all herbaceous (non-woody) plants, including herbaceous vines, regardless of size, and woody species, except woody vines, less than approximately 3 ft (1 m) in height.

Woody vines – Consists of all woody vines, regardless of height.

Hydrophytic Vegetation Present? Yes ◉ No ○

Remarks: (Include photo numbers here or on a separate sheet.)

*Indicator suffix = National status or professional decision assigned because Regional status not defined by FWS.

Soil

Sampling Point: W003

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)		Matrix %	Redox Features Color (moist)		Redox %	Type[1]	Loc[2]	Texture	Remarks
0-5	10YR	4/6	95	10YR	6/4	5	C	M	Sandy Loam	

[1] Type: C=Concentration. D=Depletion. RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Location: PL=Pore Lining. M=Matrix

Hydric Soil Indicators:

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Stratified Layers (A5)
- ☐ 2 cm Muck (A10) (LRR N)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Muck Mineral (S1) (LRR N, MLRA 147, 148)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Dark Surface (S7)
- ☐ Polyvalue Below Surface (S8) (MLRA 147,148)
- ☐ Thin Dark Surface (S9) (MLRA 147, 148)
- ☐ Loamy Gleyed Matrix (F2)
- ☑ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)
- ☐ Iron-Manganese Masses (F12) (LRR N, MLRA 136)
- ☐ Umbric Surface (F13) (MLRA 136, 122)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 148)
- ☐ Red Parent Material (F21) (MLRA 127, 147)

Indicators for Problematic Hydric Soils[3]:

- ☐ 2 cm Muck (A10) (MLRA 147)
- ☐ Coast Prairie Redox (A16) (MLRA 147,148)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 136, 147)
- ☐ Very Shallow Dark Surface (TF12)
- ☐ Other (Explain in Remarks)

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if observed):

Type:

Depth (inches):

Hydric Soil Present? Yes ◉ No ○

Remarks: *Riprap below 5"

WETLAND DETERMINATION DATA FORM - Eastern Mountains and Piedmont Region

Project/Site: KIF Retirement 39170 **City/County:** ROANE **Sampling Date:** 30-Mar-22

Applicant/Owner: TVA **State:** TN **Sampling Point:** W004

Investigator(s): Fallon Parker Hutcheon **Section, Township, Range:** S T R

Landform (hillslope, terrace, etc.): Swale **Local relief (concave, convex, none):** concave **Slope:** 0.0% / 0.0 °

Subregion (LRR or MLRA): LRR N **Lat.:** 35.8951150 **Long.:** -84.4974135 **Datum:** NAD83

Soil Map Unit Name: Waynesboro loam **NWI classification:** PEM1E

Are climatic/hydrologic conditions on the site typical for this time of year? Yes ○ No ○ **(If no, explain in Remarks.)**

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **significantly disturbed?** **Are "Normal Circumstances" present?** Yes ◉ No ○

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **naturally problematic?** **(If needed, explain any answers in Remarks.)**

Summary of Findings - Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ◉ No ○	**Is the Sampled Area within a Wetland?** Yes ◉ No ○
Hydric Soil Present?	Yes ◉ No ○	
Wetland Hydrology Present?	Yes ◉ No ○	

Remarks:

Emergent wetland swale in TL ROW. 0.43 acres. FPH_Photo#DSCN5934. TRAM score = (23) Low

Hydrology

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ☑ Surface Water (A1)
- ☑ High Water Table (A2)
- ☑ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Water-Stained Leaves (B9)
- ☐ Aquatic Fauna (B13)
- ☐ True Aquatic Plants (B14)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Thin Muck Surface (C7)
- ☐ Other (Explain in Remarks)

Secondary Indicators (minimum of two required)

- ☐ Surface Soil Cracks (B6)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Drainage Patterns (B10)
- ☐ Moss Trim Lines (B16)
- ☐ Dry Season Water Table (C2)
- ☐ Crayfish Burrows (C8)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Stunted or Stressed Plants (D1)
- ☑ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ Microtopographic Relief (D4)
- ☑ FAC-neutral Test (D5)

Field Observations:

Surface Water Present?	Yes ◉ No ○	Depth (inches): 0.5
Water Table Present?	Yes ◉ No ○	Depth (inches):
Saturation Present? (includes capillary fringe)	Yes ◉ No ○	Depth (inches):

Wetland Hydrology Present? Yes ◉ No ○

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

VEGETATION (Five/Four Strata)- Use scientific names of plants.

Sampling Point: W004

Tree Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
	0	= Total Cover		

Sapling-Sapling/Shrub Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1. Salix nigra	5	☑	100.0%	OBL
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
	5	= Total Cover		

Shrub Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
	0	= Total Cover		

Herb Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1. Juncus effusus	30	☑	31.6%	FACW
2. Andropogon glomeratus	30	☑	31.6%	FACW
3. Carex vulpinoidea	10	☐	10.5%	OBL
4. Scirpus atrovirens	5	☐	5.3%	OBL
5. Festuca arundinacea	20	☑	21.1%	FACU
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
11.	0	☐	0.0%	
12.	0	☐	0.0%	
	95	= Total Cover		

Woody Vine Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
	0	= Total Cover		

Dominance Test worksheet:

Number of Dominant Species That are OBL, FACW, or FAC: 3 (A)

Total Number of Dominant Species Across All Strata: 4 (B)

Percent of dominant Species That Are OBL, FACW, or FAC: 75.0% (A/B)

Prevalence Index worksheet:

Total % Cover of:		Multiply by:	
OBL species	20	x 1 =	20
FACW species	60	x 2 =	120
FAC species	0	x 3 =	0
FACU species	20	x 4 =	80
UPL species	0	x 5 =	0
Column Totals:	100 (A)		220 (B)

Prevalence Index = B/A = 2.200

Hydrophytic Vegetation Indicators:

- ☐ **Rapid Test for Hydrophytic Vegetation**
- ☑ **Dominance Test is > 50%**
- ☑ **Prevalence Index is ≤3.0** [1]
- ☐ **Morphological Adaptations** [1] **(Provide supporting data in Remarks or on a separate sheet)**
- ☐ **Problematic Hydrophytic Vegetation** [1] **(Explain)**

[1] **Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.**

Definition of Vegetation Strata:

Four Vegetation Strata:

Tree stratum – Consists of woody plants, excluding vines, 3 in. (7.6 cm) or more in diameter at breast height (DBH), regardless of height.

Sapling/shrub stratum – Consists of woody plants, excluding vines, less than 3 in. DBH and greater than 3.28 ft (1 m) tall.

Herb stratum – Consists of all herbaceous (non-woody) plants, regardless of size, and all other plants less than 3.28 ft tall.

Woody vines – Consists of all woody vines greater than 3.28 ft in height.

Five Vegetation Strata:

Tree - Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and 3 in. (7.6 cm) or larger in diameter at breast height (DBH).

Sapling stratum – Consists of woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and less than 3 in. (7.6 cm) DBH.

Shrub stratum – Consists of woody plants, excluding woody vines, approximately 3 to 20 ft (1 to 6 m) in height.

Herb stratum – Consists of all herbaceous (non-woody) plants, including herbaceous vines, regardless of size, and woody species, except woody vines, less than approximately 3 ft (1 m) in height.

Woody vines – Consists of all woody vines, regardless of height.

Hydrophytic Vegetation Present? Yes ◉ No ○

Remarks: (Include photo numbers here or on a separate sheet.)

*Indicator suffix = National status or professional decision assigned because Regional status not defined by FWS.

Soil

Sampling Point: W004

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)		Matrix %	Redox Features Color (moist)		Redox %	Type[1]	Loc²	Texture	Remarks
0-18	10YR	4/6	95	10YR	6/4	5	C	M	Sandy Loam	

[1] Type: C=Concentration. D=Depletion. RM=Reduced Matrix, CS=Covered or Coated Sand Grains ²Location: PL=Pore Lining. M=Matrix

Hydric Soil Indicators:

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Stratified Layers (A5)
- ☐ 2 cm Muck (A10) (LRR N)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Muck Mineral (S1) (LRR N, MLRA 147, 148)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Dark Surface (S7)
- ☐ Polyvalue Below Surface (S8) (MLRA 147,148)
- ☐ Thin Dark Surface (S9) (MLRA 147, 148)
- ☐ Loamy Gleyed Matrix (F2)
- ☑ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)
- ☐ Iron-Manganese Masses (F12) (LRR N, MLRA 136)
- ☐ Umbric Surface (F13) (MLRA 136, 122)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 148)
- ☐ Red Parent Material (F21) (MLRA 127, 147)

Indicators for Problematic Hydric Soils[3]:

- ☐ 2 cm Muck (A10) (MLRA 147)
- ☐ Coast Prairie Redox (A16) (MLRA 147,148)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 136, 147)
- ☐ Very Shallow Dark Surface (TF12)
- ☐ Other (Explain in Remarks)

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if observed):

Type:

Depth (inches):

Hydric Soil Present? Yes ◉ No ○

Remarks:

WETLAND DETERMINATION DATA FORM - Eastern Mountains and Piedmont Region

Project/Site: KIF Retirement 39170 **City/County:** ROANE **Sampling Date:** 30-Mar-22

Applicant/Owner: TVA **State:** TN **Sampling Point:** **W005**

Investigator(s): Fallon Parker Hutcheon **Section, Township, Range: S** **T** **R**

Landform (hillslope, terrace, etc.): Gulch or Gully **Local relief (concave, convex, none):** concave **Slope:** 0.0% / 0.0 °

Subregion (LRR or MLRA): LRR N **Lat.:** 35.8942878 **Long.:** -84.4989506 **Datum:** NAD83

Soil Map Unit Name: Waynesboro loam **NWI classification:** PFO1E

Are climatic/hydrologic conditions on the site typical for this time of year? Yes ○ No ○ **(If no, explain in Remarks.)**

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **significantly disturbed?** **Are "Normal Circumstances" present?** Yes ◉ No ○

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **naturally problematic?** **(If needed, explain any answers in Remarks.)**

Summary of Findings - Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ◉ No ○	**Is the Sampled Area within a Wetland?** Yes ◉ No ○
Hydric Soil Present?	Yes ◉ No ○	
Wetland Hydrology Present?	Yes ◉ No ○	

Remarks:

Forested wetland depression surrounding conveyances. 0.10 acres. FPH_Photo#DSCN5936. TRAM score = (43) Low

Hydrology

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ☑ Surface Water (A1)
- ☑ High Water Table (A2)
- ☑ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Water-Stained Leaves (B9)
- ☐ Aquatic Fauna (B13)
- ☐ True Aquatic Plants (B14)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Thin Muck Surface (C7)
- ☐ Other (Explain in Remarks)

Secondary Indicators (minimum of two required)

- ☐ Surface Soil Cracks (B6)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Drainage Patterns (B10)
- ☐ Moss Trim Lines (B16)
- ☐ Dry Season Water Table (C2)
- ☐ Crayfish Burrows (C8)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Stunted or Stressed Plants (D1)
- ☑ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ Microtopographic Relief (D4)
- ☑ FAC-neutral Test (D5)

Field Observations:

Surface Water Present?	Yes ◉ No ○	Depth (inches): 0.5
Water Table Present?	Yes ◉ No ○	Depth (inches):
Saturation Present? (includes capillary fringe)	Yes ◉ No ○	Depth (inches):

Wetland Hydrology Present? Yes ◉ No ○

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

VEGETATION (Five/Four Strata)- Use scientific names of plants.

Sampling Point: W005

Tree Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1. Acer rubrum	30	☑	37.5%	FAC
2. Liquidambar styraciflua	20	☑	25.0%	FAC
3. Platanus occidentalis	30	☑	37.5%	FACW
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
	80	= Total Cover		

Sapling-Sapling/Shrub Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
	0	= Total Cover		

Shrub Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
	0	= Total Cover		

Herb Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
11.	0	☐	0.0%	
12.	0	☐	0.0%	
	0	= Total Cover		

Woody Vine Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
	0	= Total Cover		

Dominance Test worksheet:

Number of Dominant Species That are OBL, FACW, or FAC: 3 (A)

Total Number of Dominant Species Across All Strata: 3 (B)

Percent of dominant Species That Are OBL, FACW, or FAC: 100.0% (A/B)

Prevalence Index worksheet:

Total % Cover of:		Multiply by:	
OBL species	0	x 1 =	0
FACW species	30	x 2 =	60
FAC species	50	x 3 =	150
FACU species	0	x 4 =	0
UPL species	0	x 5 =	0
Column Totals:	80 (A)		210 (B)

Prevalence Index = B/A = 2.625

Hydrophytic Vegetation Indicators:

- ☐ **Rapid Test for Hydrophytic Vegetation**
- ☑ **Dominance Test is > 50%**
- ☑ **Prevalence Index is ≤3.0** [1]
- ☐ **Morphological Adaptations** [1] **(Provide supporting data in Remarks or on a separate sheet)**
- ☐ **Problematic Hydrophytic Vegetation** [1] **(Explain)**

[1] **Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.**

Definition of Vegetation Strata:

Four Vegetation Strata:

Tree stratum – Consists of woody plants, excluding vines, 3 in. (7.6 cm) or more in diameter at breast height (DBH), regardless of height.

Sapling/shrub stratum – Consists of woody plants, excluding vines, less than 3 in. DBH and greater than 3.28 ft (1 m) tall.

Herb stratum – Consists of all herbaceous (non-woody) plants, regardless of size, and all other plants less than 3.28 ft tall.

Woody vines – Consists of all woody vines greater than 3.28 ft in height.

Five Vegetation Strata:

Tree - Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and 3 in. (7.6 cm) or larger in diameter at breast height (DBH).

Sapling stratum – Consists of woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and less than 3 in. (7.6 cm) DBH.

Shrub stratum – Consists of woody plants, excluding woody vines, approximately 3 to 20 ft (1 to 6 m) in height.

Herb stratum – Consists of all herbaceous (non-woody) plants, including herbaceous vines, regardless of size, and woody species, except woody vines, less than approximately 3 ft (1 m) in height.

Woody vines – Consists of all woody vines, regardless of height.

Hydrophytic Vegetation Present? Yes ◉ No ○

Remarks: (Include photo numbers here or on a separate sheet.)

Unidentifiable sedge species

*Indicator suffix = National status or professional decision assigned because Regional status not defined by FWS.

Soil

Sampling Point: W005

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)		%	Redox Features Color (moist)		%	Type[1]	Loc²	Texture	Remarks
0-18	10YR	4/6	95	10YR	6/4	5	C	M	Sandy Loam	

[1] Type: C=Concentration. D=Depletion. RM=Reduced Matrix, CS=Covered or Coated Sand Grains ²Location: PL=Pore Lining. M=Matrix

Hydric Soil Indicators:

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Stratified Layers (A5)
- ☐ 2 cm Muck (A10) (LRR N)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Muck Mineral (S1) (LRR N, MLRA 147, 148)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Dark Surface (S7)
- ☐ Polyvalue Below Surface (S8) (MLRA 147,148)
- ☐ Thin Dark Surface (S9) (MLRA 147, 148)
- ☐ Loamy Gleyed Matrix (F2)
- ☑ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)
- ☐ Iron-Manganese Masses (F12) (LRR N, MLRA 136)
- ☐ Umbric Surface (F13) (MLRA 136, 122)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 148)
- ☐ Red Parent Material (F21) (MLRA 127, 147)

Indicators for Problematic Hydric Soils[3]:

- ☐ 2 cm Muck (A10) (MLRA 147)
- ☐ Coast Prairie Redox (A16) (MLRA 147,148)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 136, 147)
- ☐ Very Shallow Dark Surface (TF12)
- ☐ Other (Explain in Remarks)

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if observed):

Type:

Depth (inches):

Hydric Soil Present? Yes ◉ No ○

Remarks:

WETLAND DETERMINATION DATA FORM - Eastern Mountains and Piedmont Region

Project/Site: KIF Retirement 39170 **City/County:** ROANE **Sampling Date:** 30-Mar-22

Applicant/Owner: TVA **State:** TN **Sampling Point:** **W006**

Investigator(s): Fallon Parker Hutcheon **Section, Township, Range: S** **T** **R**

Landform (hillslope, terrace, etc.): Gulch or Gully **Local relief (concave, convex, none):** concave **Slope:** 0.0% / 0.0 °

Subregion (LRR or MLRA): LRR N **Lat.:** 35.8979714 **Long.:** -84.5008612 **Datum:** NAD83

Soil Map Unit Name: Waynesboro loam **NWI classification:** PEM1E

Are climatic/hydrologic conditions on the site typical for this time of year? Yes ( ) No ( ) **(If no, explain in Remarks.)**

Are Vegetation [ ] **, Soil** [ ] **, or Hydrology** [ ] **significantly disturbed?** **Are "Normal Circumstances" present?** Yes (•) No ( )

Are Vegetation [ ] **, Soil** [ ] **, or Hydrology** [ ] **naturally problematic?** **(If needed, explain any answers in Remarks.)**

Summary of Findings - Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes (•) No ( )	**Is the Sampled Area within a Wetland?** Yes (•) No ( )
Hydric Soil Present?	Yes (•) No ( )	
Wetland Hydrology Present?	Yes (•) No ( )	

Remarks:

Emergent wetland depression retaining drainage. 0.11 acres. FPH_Photo#DSCN5939-40. TRAM score = (36) Low

Hydrology

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- [x] Surface Water (A1)
- [x] High Water Table (A2)
- [x] Saturation (A3)
- [ ] Water Marks (B1)
- [ ] Sediment Deposits (B2)
- [ ] Drift deposits (B3)
- [ ] Algal Mat or Crust (B4)
- [x] Iron Deposits (B5)
- [ ] Inundation Visible on Aerial Imagery (B7)
- [ ] Water-Stained Leaves (B9)
- [ ] Aquatic Fauna (B13)
- [ ] True Aquatic Plants (B14)
- [ ] Hydrogen Sulfide Odor (C1)
- [ ] Oxidized Rhizospheres along Living Roots (C3)
- [ ] Presence of Reduced Iron (C4)
- [ ] Recent Iron Reduction in Tilled Soils (C6)
- [ ] Thin Muck Surface (C7)
- [ ] Other (Explain in Remarks)

Secondary Indicators (minimum of two required)

- [ ] Surface Soil Cracks (B6)
- [ ] Sparsely Vegetated Concave Surface (B8)
- [ ] Drainage Patterns (B10)
- [ ] Moss Trim Lines (B16)
- [ ] Dry Season Water Table (C2)
- [ ] Crayfish Burrows (C8)
- [ ] Saturation Visible on Aerial Imagery (C9)
- [ ] Stunted or Stressed Plants (D1)
- [x] Geomorphic Position (D2)
- [ ] Shallow Aquitard (D3)
- [ ] Microtopographic Relief (D4)
- [x] FAC-neutral Test (D5)

Field Observations:

Surface Water Present?	Yes (•) No ( )	Depth (inches):	3
Water Table Present?	Yes (•) No ( )	Depth (inches):	
Saturation Present? (includes capillary fringe)	Yes (•) No ( )	Depth (inches):	

Wetland Hydrology Present? Yes (•) No ( )

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

VEGETATION (Five/Four Strata)- Use scientific names of plants.

Sampling Point: W006

Tree Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
	0	= Total Cover		
Sapling-Sapling/Shrub Stratum (Plot size:)				
1. Salix nigra	10	☑	100.0%	OBL
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
	10	= Total Cover		
Shrub Stratum (Plot size:)				
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
	0	= Total Cover		
Herb Stratum (Plot size:)				
1. Typha latifolia	95	☑	90.5%	OBL
2. Scirpus atrovirens	10	☐	9.5%	OBL
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
11.	0	☐	0.0%	
12.	0	☐	0.0%	
	105	= Total Cover		
Woody Vine Stratum (Plot size:)				
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
	0	= Total Cover		

Dominance Test worksheet:

Number of Dominant Species That are OBL, FACW, or FAC: 2 (A)

Total Number of Dominant Species Across All Strata: 2 (B)

Percent of dominant Species That Are OBL, FACW, or FAC: 100.0% (A/B)

Prevalence Index worksheet:

Total % Cover of:		Multiply by:	
OBL species	115	x 1 =	115
FACW species	0	x 2 =	0
FAC species	0	x 3 =	0
FACU species	0	x 4 =	0
UPL species	0	x 5 =	0
Column Totals:	115	(A)	115 (B)

Prevalence Index = B/A = 1.000

Hydrophytic Vegetation Indicators:

- ☑ **Rapid Test for Hydrophytic Vegetation**
- ☑ **Dominance Test is > 50%**
- ☑ **Prevalence Index is ≤3.0** [1]
- ☐ **Morphological Adaptations** [1] **(Provide supporting data in Remarks or on a separate sheet)**
- ☐ **Problematic Hydrophytic Vegetation** [1] **(Explain)**

[1] **Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.**

Definition of Vegetation Strata:

Four Vegetation Strata:

Tree stratum – Consists of woody plants, excluding vines, 3 in. (7.6 cm) or more in diameter at breast height (DBH), regardless of height.

Sapling/shrub stratum – Consists of woody plants, excluding vines, less than 3 in. DBH and greater than 3.28 ft (1 m) tall.

Herb stratum – Consists of all herbaceous (non-woody) plants, regardless of size, and all other plants less than 3.28 ft tall.

Woody vines – Consists of all woody vines greater than 3.28 ft in height.

Five Vegetation Strata:

Tree - Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and 3 in. (7.6 cm) or larger in diameter at breast height (DBH).

Sapling stratum – Consists of woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and less than 3 in. (7.6 cm) DBH.

Shrub stratum – Consists of woody plants, excluding woody vines, approximately 3 to 20 ft (1 to 6 m) in height.

Herb stratum – Consists of all herbaceous (non-woody) plants, including herbaceous vines, regardless of size, and woody species, except woody vines, less than approximately 3 ft (1 m) in height.

Woody vines – Consists of all woody vines, regardless of height.

Hydrophytic Vegetation Present? Yes ◉ No ○

Remarks: (Include photo numbers here or on a separate sheet.)

Unidentifiable sedge species

*Indicator suffix = National status or professional decision assigned because Regional status not defined by FWS.

Soil

Sampling Point: W006

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)		Matrix %	Redox Color (moist)		Redox %	Type[1]	Loc[2]	Texture	Remarks
0-18	10YR	4/6	95	10YR	6/4	5	C	M	Sandy Loam	

[1] Type: C=Concentration. D=Depletion. RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Location: PL=Pore Lining. M=Matrix

Hydric Soil Indicators:

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Stratified Layers (A5)
- ☐ 2 cm Muck (A10) (LRR N)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Muck Mineral (S1) (LRR N, MLRA 147, 148)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Dark Surface (S7)
- ☐ Polyvalue Below Surface (S8) (MLRA 147,148)
- ☐ Thin Dark Surface (S9) (MLRA 147, 148)
- ☐ Loamy Gleyed Matrix (F2)
- ☑ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)
- ☐ Iron-Manganese Masses (F12) (LRR N, MLRA 136)
- ☐ Umbric Surface (F13) (MLRA 136, 122)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 148)
- ☐ Red Parent Material (F21) (MLRA 127, 147)

Indicators for Problematic Hydric Soils[3]:

- ☐ 2 cm Muck (A10) (MLRA 147)
- ☐ Coast Prairie Redox (A16) (MLRA 147,148)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 136, 147)
- ☐ Very Shallow Dark Surface (TF12)
- ☐ Other (Explain in Remarks)

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if observed):

Type:

Depth (inches):

Hydric Soil Present? Yes ◉ No ○

Remarks:

WETLAND DETERMINATION DATA FORM - Eastern Mountains and Piedmont Region

Project/Site: KIF Retirement 39170 **City/County:** ROANE **Sampling Date:** 30-Mar-22

Applicant/Owner: TVA **State:** TN **Sampling Point:** **W007**

Investigator(s): Fallon Parker Hutcheon **Section, Township, Range: S** **T** **R**

Landform (hillslope, terrace, etc.): Swale **Local relief (concave, convex, none):** concave **Slope:** 0.0% / 0.0 °

Subregion (LRR or MLRA): LRR N **Lat.:** 35.8982769 **Long.:** -84.5007154 **Datum:** NAD83

Soil Map Unit Name: Waynesboro loam **NWI classification:** PEM1E

Are climatic/hydrologic conditions on the site typical for this time of year? Yes ○ No ○ **(If no, explain in Remarks.)**

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **significantly disturbed?** **Are "Normal Circumstances" present?** Yes ◉ No ○

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **naturally problematic?** **(If needed, explain any answers in Remarks.)**

Summary of Findings - Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ◉ No ○	**Is the Sampled Area within a Wetland?** Yes ◉ No ○
Hydric Soil Present?	Yes ◉ No ○	
Wetland Hydrology Present?	Yes ◉ No ○	

Remarks:

Emergent wetland depression, saturated. 0.01 acres. FPH_Photo#W007. TRAM score = (15) Low

Hydrology

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ☐ Surface Water (A1)
- ☐ High Water Table (A2)
- ☑ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☑ Iron Deposits (B5)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Water-Stained Leaves (B9)
- ☐ Aquatic Fauna (B13)
- ☐ True Aquatic Plants (B14)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Thin Muck Surface (C7)
- ☐ Other (Explain in Remarks)

Secondary Indicators (minimum of two required)

- ☐ Surface Soil Cracks (B6)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Drainage Patterns (B10)
- ☐ Moss Trim Lines (B16)
- ☐ Dry Season Water Table (C2)
- ☐ Crayfish Burrows (C8)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Stunted or Stressed Plants (D1)
- ☑ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ Microtopographic Relief (D4)
- ☑ FAC-neutral Test (D5)

Field Observations:

Surface Water Present?	Yes ○ No ◉	Depth (inches):	
Water Table Present?	Yes ○ No ◉	Depth (inches):	
Saturation Present? (includes capillary fringe)	Yes ◉ No ○	Depth (inches):	

Wetland Hydrology Present? Yes ◉ No ○

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

VEGETATION (Five/Four Strata)- Use scientific names of plants.

Sampling Point: W007

Tree Stratum (Plot size:)

Tree Stratum	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
	0	= Total Cover		

Sapling-Sapling/Shrub Stratum (Plot size:)

Sapling-Sapling/Shrub Stratum	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
	0	= Total Cover		

Shrub Stratum (Plot size:)

Shrub Stratum	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
	0	= Total Cover		

Herb Stratum (Plot size:)

Herb Stratum	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1. Typha latifolia	40	☑	50.0%	OBL
2. Juncus effusus	20	☑	25.0%	FACW
3. Carex vulpinoidea	10	☐	12.5%	OBL
4. Eleocharis acicularis	10	☐	12.5%	OBL
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
11.	0	☐	0.0%	
12.	0	☐	0.0%	
	80	= Total Cover		

Woody Vine Stratum (Plot size:)

Woody Vine Stratum	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
	0	= Total Cover		

Dominance Test worksheet:

Number of Dominant Species That are OBL, FACW, or FAC: 2 (A)

Total Number of Dominant Species Across All Strata: 2 (B)

Percent of dominant Species That Are OBL, FACW, or FAC: 100.0% (A/B)

Prevalence Index worksheet:

Total % Cover of:		Multiply by:	
OBL species	60	x 1 =	60
FACW species	20	x 2 =	40
FAC species	0	x 3 =	0
FACU species	0	x 4 =	0
UPL species	0	x 5 =	0
Column Totals:	80 (A)		100 (B)

Prevalence Index = B/A = 1.250

Hydrophytic Vegetation Indicators:

- ☑ **Rapid Test for Hydrophytic Vegetation**
- ☑ **Dominance Test is > 50%**
- ☑ **Prevalence Index is ≤3.0** [1]
- ☐ **Morphological Adaptations** [1] **(Provide supporting data in Remarks or on a separate sheet)**
- ☐ **Problematic Hydrophytic Vegetation** [1] **(Explain)**

[1] **Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.**

Definition of Vegetation Strata:

Four Vegetation Strata:

Tree stratum – Consists of woody plants, excluding vines, 3 in. (7.6 cm) or more in diameter at breast height (DBH), regardless of height.

Sapling/shrub stratum – Consists of woody plants, excluding vines, less than 3 in. DBH and greater than 3.28 ft (1 m) tall.

Herb stratum – Consists of all herbaceous (non-woody) plants, regardless of size, and all other plants less than 3.28 ft tall.

Woody vines – Consists of all woody vines greater than 3.28 ft in height.

Five Vegetation Strata:

Tree - Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and 3 in. (7.6 cm) or larger in diameter at breast height (DBH).

Sapling stratum – Consists of woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and less than 3 in. (7.6 cm) DBH.

Shrub stratum – Consists of woody plants, excluding woody vines, approximately 3 to 20 ft (1 to 6 m) in height.

Herb stratum – Consists of all herbaceous (non-woody) plants, including herbaceous vines, regardless of size, and woody species, except woody vines, less than approximately 3 ft (1 m) in height.

Woody vines – Consists of all woody vines, regardless of height.

Hydrophytic Vegetation Present? Yes ◉ No ○

Remarks: (Include photo numbers here or on a separate sheet.)

Unidentifiable sedge species

*Indicator suffix = National status or professional decision assigned because Regional status not defined by FWS.

Soil

Sampling Point: W007

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)		Matrix %	Redox Features Color (moist)		Redox %	Type[1]	Loc[2]	Texture	Remarks
0-18	10YR	4/6	95	10YR	6/4	5	C	M	Sandy Loam	

[1] Type: C=Concentration. D=Depletion. RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Location: PL=Pore Lining. M=Matrix

Hydric Soil Indicators:

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Stratified Layers (A5)
- ☐ 2 cm Muck (A10) (LRR N)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Muck Mineral (S1) (LRR N, MLRA 147, 148)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Dark Surface (S7)
- ☐ Polyvalue Below Surface (S8) (MLRA 147,148)
- ☐ Thin Dark Surface (S9) (MLRA 147, 148)
- ☐ Loamy Gleyed Matrix (F2)
- ☑ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)
- ☐ Iron-Manganese Masses (F12) (LRR N, MLRA 136)
- ☐ Umbric Surface (F13) (MLRA 136, 122)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 148)
- ☐ Red Parent Material (F21) (MLRA 127, 147)

Indicators for Problematic Hydric Soils[3]:

- ☐ 2 cm Muck (A10) (MLRA 147)
- ☐ Coast Prairie Redox (A16) (MLRA 147,148)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 136, 147)
- ☐ Very Shallow Dark Surface (TF12)
- ☐ Other (Explain in Remarks)

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if observed):

Type:

Depth (inches):

Hydric Soil Present? Yes ◉ No ○

Remarks:

WETLAND DETERMINATION DATA FORM - Eastern Mountains and Piedmont Region

Project/Site: 39170 KIF D4 **City/County:** Roane county **Sampling Date:** 19-Jan-23

Applicant/Owner: Tennessee Valley Authority **State:** TN **Sampling Point:** **W008**

Investigator(s): FPH **Section, Township, Range:** S T R

Landform (hillslope, terrace, etc.): Ditch **Local relief (concave, convex, none):** concave **Slope:** 0.0% / 0.0 °

Subregion (LRR or MLRA): LRR N **Lat.:** 35.9015565°N **Long.:** 84.5225601°W **Datum:** NAD83

Soil Map Unit Name: Urban land **NWI classification:** PEM

Are climatic/hydrologic conditions on the site typical for this time of year? Yes ○ No ○ **(If no, explain in Remarks.)**

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **significantly disturbed?** **Are "Normal Circumstances" present?** Yes ○ No ●

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **naturally problematic?** **(If needed, explain any answers in Remarks.)**

Summary of Findings - Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ● No ○	**Is the Sampled Area within a Wetland?** Yes ● No ○
Hydric Soil Present?	Yes ● No ○	
Wetland Hydrology Present?	Yes ● No ○	

Remarks:
W008 is an emergent wetland in a concrete bottomed drainage ditch. <0.01 acrea. TRAM Score = Low (11).

Hydrology

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ☑ Surface Water (A1)
- ☑ High Water Table (A2)
- ☑ Saturation (A3)
- ☑ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Water-Stained Leaves (B9)
- ☐ Aquatic Fauna (B13)
- ☐ True Aquatic Plants (B14)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Thin Muck Surface (C7)
- ☐ Other (Explain in Remarks)

Secondary Indicators (minimum of two required)

- ☐ Surface Soil Cracks (B6)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Drainage Patterns (B10)
- ☐ Moss Trim Lines (B16)
- ☐ Dry Season Water Table (C2)
- ☐ Crayfish Burrows (C8)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Stunted or Stressed Plants (D1)
- ☑ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ Microtopographic Relief (D4)
- ☑ FAC-neutral Test (D5)

Field Observations:

Surface Water Present?	Yes ● No ○	Depth (inches): 0.05
Water Table Present?	Yes ● No ○	Depth (inches):
Saturation Present? (includes capillary fringe)	Yes ● No ○	Depth (inches):

Wetland Hydrology Present? Yes ● No ○

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

VEGETATION (Five/Four Strata)- Use scientific names of plants.

Sampling Point: W008

Tree Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
	0	= Total Cover		
Sapling-Sapling/Shrub Stratum (Plot size:)				
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
	0	= Total Cover		
Shrub Stratum (Plot size:)				
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
	0	= Total Cover		
Herb Stratum (Plot size:)				
1. Typha latifolia	35	☑	48.6%	OBL
2. Juncus effusus	10	☑	13.9%	FACW
3. Carex vulpinoidea	10	☑	13.9%	OBL
4. Rumex crispus	2	☐	2.8%	FAC
5. Andropogon glomeratus	10	☑	13.9%	FACW
6. Solidago gigantea	5	☐	6.9%	FACW
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
11.	0	☐	0.0%	
12.	0	☐	0.0%	
	72	= Total Cover		
Woody Vine Stratum (Plot size:)				
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
	0	= Total Cover		

Dominance Test worksheet:

Number of Dominant Species That are OBL, FACW, or FAC:	4	(A)
Total Number of Dominant Species Across All Strata:	4	(B)
Percent of dominant Species That Are OBL, FACW, or FAC:	100.0%	(A/B)

Prevalence Index worksheet:

Total % Cover of:		Multiply by:		
OBL species	45	x 1 =	45	
FACW species	25	x 2 =	50	
FAC species	2	x 3 =	6	
FACU species	0	x 4 =	0	
UPL species	0	x 5 =	0	
Column Totals:	72	(A)	101	(B)

Prevalence Index = B/A = 1.403

Hydrophytic Vegetation Indicators:

- ☑ **Rapid Test for Hydrophytic Vegetation**
- ☑ **Dominance Test is > 50%**
- ☑ **Prevalence Index is ≤3.0** [1]
- ☐ **Morphological Adaptations** [1] **(Provide supporting data in Remarks or on a separate sheet)**
- ☐ **Problematic Hydrophytic Vegetation** [1] **(Explain)**

[1] **Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.**

Definition of Vegetation Strata:

Four Vegetation Strata:

Tree stratum – Consists of woody plants, excluding vines, 3 in. (7.6 cm) or more in diameter at breast height (DBH), regardless of height.

Sapling/shrub stratum – Consists of woody plants, excluding vines, less than 3 in. DBH and greater than 3.28 ft (1 m) tall.

Herb stratum – Consists of all herbaceous (non-woody) plants, regardless of size, and all other plants less than 3.28 ft tall.

Woody vines – Consists of all woody vines greater than 3.28 ft in height.

Five Vegetation Strata:

Tree - Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and 3 in. (7.6 cm) or larger in diameter at breast height (DBH).

Sapling stratum – Consists of woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and less than 3 in. (7.6 cm) DBH.

Shrub stratum – Consists of woody plants, excluding woody vines, approximately 3 to 20 ft (1 to 6 m) in height.

Herb stratum – Consists of all herbaceous (non-woody) plants, including herbaceous vines, regardless of size, and woody species, except woody vines, less than approximately 3 ft (1 m) in height.

Woody vines – Consists of all woody vines, regardless of height.

Hydrophytic Vegetation Present? Yes ◉ No ○

Remarks: (Include photo numbers here or on a separate sheet.)

*Indicator suffix = National status or professional decision assigned because Regional status not defined by FWS.

Soil

Sampling Point: W008

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)		Matrix %	Redox Color (moist)		Redox %	Type[1]	Loc²	Texture	Remarks
0-2	10YR	4/2	100				D	M	Clay Loam	
2+										Riprap

[1] Type: C=Concentration. D=Depletion. RM=Reduced Matrix, CS=Covered or Coated Sand Grains ²Location: PL=Pore Lining. M=Matrix

Hydric Soil Indicators:

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Stratified Layers (A5)
- ☐ 2 cm Muck (A10) (LRR N)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Muck Mineral (S1) (LRR N, MLRA 147, 148)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Dark Surface (S7)
- ☐ Polyvalue Below Surface (S8) (MLRA 147,148)
- ☐ Thin Dark Surface (S9) (MLRA 147, 148)
- ☐ Loamy Gleyed Matrix (F2)
- ☑ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)
- ☐ Iron-Manganese Masses (F12) (LRR N, MLRA 136)
- ☐ Umbric Surface (F13) (MLRA 136, 122)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 148)
- ☐ Red Parent Material (F21) (MLRA 127, 147)

Indicators for Problematic Hydric Soils[3]:

- ☐ 2 cm Muck (A10) (MLRA 147)
- ☐ Coast Prairie Redox (A16) (MLRA 147,148)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 136, 147)
- ☐ Very Shallow Dark Surface (TF12)
- ☐ Other (Explain in Remarks)

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if observed):

Type: RIPRAP

Depth (inches): 2+

Hydric Soil Present? Yes ◉ No ○

Remarks:

WETLAND DETERMINATION DATA FORM - Eastern Mountains and Piedmont Region

Project/Site: 39170 KIF D4 **City/County:** Roane county **Sampling Date:** 19-Jan-23

Applicant/Owner: Tennessee Valley Authority **State:** TN **Sampling Point:** **W009**

Investigator(s): FPH **Section, Township, Range: S** T R

Landform (hillslope, terrace, etc.): Ditch **Local relief (concave, convex, none):** concave **Slope:** 0.0% / 0.0 °

Subregion (LRR or MLRA): LRR N **Lat.:** 35.9014755°N **Long.:** 84.5227871°W **Datum:** NAD83

Soil Map Unit Name: Urban land **NWI classification:** PEM

Are climatic/hydrologic conditions on the site typical for this time of year? Yes ○ No ○ **(If no, explain in Remarks.)**

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **significantly disturbed?** **Are "Normal Circumstances" present?** Yes ○ No ◉

Are Vegetation ☐ **, Soil** ☐ **, or Hydrology** ☐ **naturally problematic?** **(If needed, explain any answers in Remarks.)**

Summary of Findings - Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ◉ No ○	**Is the Sampled Area within a Wetland?** Yes ◉ No ○
Hydric Soil Present?	Yes ◉ No ○	
Wetland Hydrology Present?	Yes ◉ No ○	

Remarks:

W009 is an emergent wetland in a concrete bottomed drainage ditch. 0.01 acrea. TRAM Score = Low (11).

Hydrology

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ☑ Surface Water (A1)
- ☑ High Water Table (A2)
- ☑ Saturation (A3)
- ☑ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Water-Stained Leaves (B9)
- ☐ Aquatic Fauna (B13)
- ☐ True Aquatic Plants (B14)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Thin Muck Surface (C7)
- ☐ Other (Explain in Remarks)

Secondary Indicators (minimum of two required)

- ☐ Surface Soil Cracks (B6)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Drainage Patterns (B10)
- ☐ Moss Trim Lines (B16)
- ☐ Dry Season Water Table (C2)
- ☐ Crayfish Burrows (C8)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Stunted or Stressed Plants (D1)
- ☑ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ Microtopographic Relief (D4)
- ☑ FAC-neutral Test (D5)

Field Observations:

Surface Water Present?	Yes ◉ No ○	Depth (inches):	0.05
Water Table Present?	Yes ◉ No ○	Depth (inches):	
Saturation Present? (includes capillary fringe)	Yes ◉ No ○	Depth (inches):	

Wetland Hydrology Present? Yes ◉ No ○

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

VEGETATION (Five/Four Strata)- Use scientific names of plants.

Sampling Point: W009

Tree Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
	0	= Total Cover		

Sapling-Sapling/Shrub Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
	0	= Total Cover		

Shrub Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
7.	0	☐	0.0%	
	0	= Total Cover		

Herb Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1. Typha latifolia	35	☑	48.6%	OBL
2. Juncus effusus	10	☑	13.9%	FACW
3. Carex vulpinoidea	10	☑	13.9%	OBL
4. Rumex crispus	2	☐	2.8%	FAC
5. Andropogon glomeratus	10	☑	13.9%	FACW
6. Solidago gigantea	5	☐	6.9%	FACW
7.	0	☐	0.0%	
8.	0	☐	0.0%	
9.	0	☐	0.0%	
10.	0	☐	0.0%	
11.	0	☐	0.0%	
12.	0	☐	0.0%	
	72	= Total Cover		

Woody Vine Stratum (Plot size:)	Absolute % Cover	Dominant Species?	Rel.Strat. Cover	Indicator Status
1.	0	☐	0.0%	
2.	0	☐	0.0%	
3.	0	☐	0.0%	
4.	0	☐	0.0%	
5.	0	☐	0.0%	
6.	0	☐	0.0%	
	0	= Total Cover		

Dominance Test worksheet:

Number of Dominant Species That are OBL, FACW, or FAC: 4 (A)

Total Number of Dominant Species Across All Strata: 4 (B)

Percent of dominant Species That Are OBL, FACW, or FAC: 100.0% (A/B)

Prevalence Index worksheet:

Total % Cover of:		Multiply by:	
OBL species	45	x 1 =	45
FACW species	25	x 2 =	50
FAC species	2	x 3 =	6
FACU species	0	x 4 =	0
UPL species	0	x 5 =	0
Column Totals:	72	(A)	101 (B)

Prevalence Index = B/A = 1.403

Hydrophytic Vegetation Indicators:

- ☑ **Rapid Test for Hydrophytic Vegetation**
- ☑ **Dominance Test is > 50%**
- ☑ **Prevalence Index is ≤3.0** [1]
- ☐ **Morphological Adaptations** [1] **(Provide supporting data in Remarks or on a separate sheet)**
- ☐ **Problematic Hydrophytic Vegetation** [1] **(Explain)**

[1] **Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.**

Definition of Vegetation Strata:

Four Vegetation Strata:

Tree stratum – Consists of woody plants, excluding vines, 3 in. (7.6 cm) or more in diameter at breast height (DBH), regardless of height.

Sapling/shrub stratum – Consists of woody plants, excluding vines, less than 3 in. DBH and greater than 3.28 ft (1 m) tall.

Herb stratum – Consists of all herbaceous (non-woody) plants, regardless of size, and all other plants less than 3.28 ft tall.

Woody vines – Consists of all woody vines greater than 3.28 ft in height.

Five Vegetation Strata:

Tree - Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and 3 in. (7.6 cm) or larger in diameter at breast height (DBH).

Sapling stratum – Consists of woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and less than 3 in. (7.6 cm) DBH.

Shrub stratum – Consists of woody plants, excluding woody vines, approximately 3 to 20 ft (1 to 6 m) in height.

Herb stratum – Consists of all herbaceous (non-woody) plants, including herbaceous vines, regardless of size, and woody species, except woody vines, less than approximately 3 ft (1 m) in height.

Woody vines – Consists of all woody vines, regardless of height.

Hydrophytic Vegetation Present? Yes ◉ No ○

Remarks: (Include photo numbers here or on a separate sheet.)

*Indicator suffix = National status or professional decision assigned because Regional status not defined by FWS.

Soil

Sampling Point: W009

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)		Matrix %	Redox Features Color (moist)	Redox Features %	Type[1]	Loc[2]	Texture	Remarks
0-2	10YR	4/2	100			D	M	Clay Loam	
2+									Riprap

[1] Type: C=Concentration. D=Depletion. RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Location: PL=Pore Lining. M=Matrix

Hydric Soil Indicators:

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Stratified Layers (A5)
- ☐ 2 cm Muck (A10) (LRR N)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Muck Mineral (S1) (LRR N, MLRA 147, 148)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Dark Surface (S7)
- ☐ Polyvalue Below Surface (S8) (MLRA 147,148)
- ☐ Thin Dark Surface (S9) (MLRA 147, 148)
- ☐ Loamy Gleyed Matrix (F2)
- ☑ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)
- ☐ Iron-Manganese Masses (F12) (LRR N, MLRA 136)
- ☐ Umbric Surface (F13) (MLRA 136, 122)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 148)
- ☐ Red Parent Material (F21) (MLRA 127, 147)

Indicators for Problematic Hydric Soils[3]:

- ☐ 2 cm Muck (A10) (MLRA 147)
- ☐ Coast Prairie Redox (A16) (MLRA 147,148)
- ☐ Piedmont Floodplain Soils (F19) (MLRA 136, 147)
- ☐ Very Shallow Dark Surface (TF12)
- ☐ Other (Explain in Remarks)

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if observed):

Type: RIPRAP

Depth (inches): 2+

Hydric Soil Present? Yes ◉ No ○

Remarks:

Quantitative Rating
Tennessee Rapid Assessment Method

Metric 1. Wetland area (max 6 pts). Estimate the area of wetland and select the appropriate size class and assign score. Estimated areas should clearly place the wetland within the appropriate class.

6pts	>50 acres (west TN)	>25 acres (middle TN)	>10 acres (east TN *)	
5pts	25 - <50 acres (west TN)	10- 25 acres (middle TN)	7-<10 acres (east TN*)	
4pts	10 - <25 acres (west TN)	7-< 25acres (middle TN)	3-<7 acres (east TN*)	
3pts	3 - <10 acres(west TN)	3< 7 acres (middle TN)	1-<3 acres (east TN)	
2pts	0.3 - <3 acres (west TN)	0.5- <3 acres (middle TN)	0.5-<1 acres (east TN)	
1pt	0.1 - <0.3 acres(west TN)	<0.5 acres (middle TN)	<0.5 acres (east TN)	1

*More applicable to West Tennessee; use with discretion in Middle Tennessee, Consult TDEC-DWR Natural Resources Unit for use in East Tennessee.

Table 2. Metric to English conversion table with visual estimation sizes.

acres	ft^2	yd^2	ft on side	yd on side	ha	m^2	m on side
50	2,177,983	241,998	1476	492	20.2	202,000	449
25	1,088,992	120,999	1044	348	10.1	101,000	318
10	435,596	48,340	660	220	4.1	41,000	203
3	130,679	14,520	362	121	1.2	12,000	110
0.3	13,067	1,452	114	38	0.12	1,200	35
0.1	4,356	484	66	22	0.04	400	20

Metric 1 Total 1

Metric 2. Upland buffers and intensity of surrounding land uses (Max 14 points). Wetlands without upland "buffers", or that are located where human land use is more intensive, are often, but not always, more degraded and often have lower wildlife habitat resource value.

2a. Average Buffer Width (ABW). Calculate the average buffer width and select only one score. To calculate ABW, estimate buffer width on each side (max of 50m) and divide by the number of sides. Example: ABW of a wetland with buffers of 100m, 25m, 10m and 0m would be calculated as follows: ABW = (50m + 25m + 10m + 0m)/4 = 21.25m. Intensive land uses are not buffers, e.g. active row cropping, paved areas, housing developments, etc.			
7pts	WIDE. >50m (164ft) or more around perimeter.		
4pts	MEDIUM. 25m to <50m (82 to <164ft) around the perimeter.		
1pt	NARROW. 10m to <25m (32 to <82ft) around the perimeter.	1	
0pts	VERY NARROW. <10m (<32ft) around perimeter.	0	2a Avg.= 0.50
2b. Intensity of predominant surrounding land use(s) Select one, or choose up to two and average score, for the intensity of the predominant land use(s) outside the wetland's buffer zone.			
7pts	VERY LOW. 2^{nd} growth or older forest, prairie, barren, wildlife area, etc.		
5pts	LOW. Old fallow field, shrub land, early successional young forest, etc.	5	
3pts	MODERATELY HIGH. Residential, pasture, orchard, park, conservation tillage, mowed field, etc.	3	
1pt	HIGH. urban, industrial, row cropping, mining, construction, etc.		2b Avg.= 4.00

KIF Retirement

PID#39170

W001

Metric 2 Total 4.50

Metric 3. Hydrology (Max 30 points). This metric evaluates the wetland's water budget, hydroperiod, the hydrologic connectivity of the wetland to other surface waters, and the degree to which the wetland's hydrology has been altered by human activity. **A wetland can receive no more than 30 points for Metric 3 even though it is possible to score more than 30 points.**

3a. Sources of Water. Select all that apply and sum the score. This question relates to a wetland's water budget. It also is reflective that wetlands with certain types of water sources, or multiple water sources, e.g. high pH groundwater or perennial surface water connections, can be very high quality wetlands or can have high functions and values.		
5pts	High pH groundwater (7.5-9.0)	
3pts	Other groundwater	
1pts	Precipitation	1
3pts	Seasonal surface water	3
5pts	Perennial surface water (lake or stream)	
3b. Connectivity. Select all that apply and sum score		
1pt	**100 year floodplain.** "Floodplain" is defined as "...the relatively level land next to a stream or river channel that is periodically submerged by flood waters. It is composed of alluvium deposited by the present stream or river when it floods." Where they are available, flood insurance rate maps (FIRMs) and flood boundary and floodway maps may be used.	1
1pt	**Between stream/lake and other human land use.** This question asks whether the wetland is located <u>between</u> a surface water and a different adjacent land use, such that run-off from the adjacent land use could flow through wetland before it discharges into the surface water buffering it. "Different adjacent land uses" include agricultural, commercial, industrial, mining, or residential uses.	1
1pt	**Part of a larger wetland or upland complex.** This question asks whether the wetland is in physical proximity to, or a other nearby wetland or upland habitat areas.	
1pt	**Part of riparian corridor**.	1
3c. Maximum water depth. Select only one and assign score. The evaluator *does not* need to actually observe the wetland when its water depth is greatest in order to award the maximum points for this question. The use of secondary indicators, as outlined in the 1987 Manual will be useful in answering this question.		
3 pts	>0.7m (27.6in)	
2pts	0.4 to 0.7m (15.7 to 27.6in)	
1pt	<0.4m (<15.7in)	1
3d. Duration of inundation/saturation. Select one or double check and average the scores if duration is uncertain. The use of ACOE 1987 Manual secondary indicators is necessary and expected in order to properly answer this question.		
4pts	Semi-permanently to permanently inundated or saturated	
3pts	Regularly inundated or saturated	
2pts	Seasonally inundated	
1pt	Seasonally saturated in the upper 30cm (12in) of soil	1

3d Avg.= 1.00

KIF Retirement

PID#39170

W001

3e. Modifications to natural hydrologic regime. Check all observable modifications from list below. Score by selecting the most appropriate description of the wetland. Scores may be double checked and averaged. This question asks the evaluator to assess the “intactness” of, or lack of disturbance to, the natural hydrologic regime of the type of wetland that is being evaluated.

Once the evaluator has listed all possible past and ongoing disturbances, the evaluator should check the most appropriate category to describe the present state of the wetland. In instances where the evaluator believes that a wetland falls between two categories, or where the evaluator is uncertain as to which category is appropriate, it is appropriate to choose more than one and average the score.

The evaluator may check one or several of these possible disturbances, yet still determine that the natural hydrologic regime is intact. However, see Metric 4 where these same disturbances may be habitat alterations.

Check all that are observed present in or near the wetland.

	ditch(es), in or near the wetland		point source discharges to the (non-stormwater)
	tile(s), in or near the wetland		filling/grading activities in or near the wetland
	dike(s), in or near the wetland		road beds/RR beds in or near the wetland
	weir(s), in or near the wetland		dredging activities in or near the wetland
	stormwater inputs (addition of water)		other (specify)

	YES	NO	NOT SURE
Have any of the disturbances identified above caused or appear to have caused more than trivial alterations to the wetland's natural hydrologic regime.	Assign a score 1, 3 or 7, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 12 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 9.5.

Select one or double check adjoining numbers and average the score.		**score**
12pts	NONE OR NONE APPARENT. There are no modifications or no modifications that are apparent to the evaluator.	
7pts	RECOVERED. The wetland appears to have recovered from past modifications.	7.00
3pts	RECOVERING. The wetland appears to be in the process of recovering from past modifications.	
1pt	RECENT OR NO RECOVERY. The modifications have occurred recently occurred, and/or the wetland has not recovered from past modifications, and/or the modifications are ongoing.	

3e Avg=
7.00

KIF Retirement

Metric 3 Total 16.00

PID#39170

W001

Metric 4. Habitat Alteration and Development (Max 20 points). While hydrology may be the single most important determinant for the establishment and maintenance of specific types of wetlands and wetland processes, there is a range of other factors and activities which affect wetland quality and cause disturbances to wetlands that are unrelated to hydrology. These disturbances are termed "habitat alteration." In many instances, items checked as hydrologic disturbances in Question 3e will present as alterations to a wetland's habitat or disruptions in its development (successional state). In some instances, a disturbance may be appropriately considered under both Metric 3 and Metric 4. To determine the appropriate metric scores, the evaluator should carefully determine the actual cause of the disturbance to the wetland.

4a. Substrate/Soil Disturbance. Select one or double check and average. This question evaluates physical disturbances to the soil and surface substrates of the wetland. Note also that the labels on the scoring categories are intended to be descriptive but not controlling. In some instances, it may be more appropriate to consider the scoring categories as fixed locations on a disturbance continuum, from very high to very low or no disturbance.	Examples of substrate/soil disturbance include (circle all that apply): ____filling and grading ____plowing ____grazing (hooves) ____vehicle use (off-road vehicles, construction vehicles) ____sedimentation ____dredging, and other mechanical disturbances to the soil

	YES	NO	NOT SURE
Have any of soil or substrate disturbances caused or appear to have caused more than trivial alterations to the wetland's natural soils	Assign a score 1, 2 or 3, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 4 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 3.5.

Select one or double check adjoining numbers and average the score.		
4pts	NONE OR NONE APPARENT. There are no disturbances or no disturbances apparent to the evaluator.	
3pts	RECOVERED. The wetland appears to have recovered from past disturbances.	3.0
2pts	RECOVERING. The wetland appears to be in the process of recovering from past disturbances.	
1pt	RECENT OR NO RECOVERY. The disturbances have occurred recently, and/or the wetland has not recovered from past disturbances, and/or the disturbances are ongoing.	

4a Avg.=
3.00

4b. Habitat development. Select only one and assign score. This question asks the evaluator to assign an overall qualitative rating of how well-developed the wetland is in comparison to other ecologically and/or hydrogeomorphically similar wetlands. This question presumes knowledge of the types of wetlands and the range in quality typical of the region or access to data from reference standard examples. If unsure, score as GOOD or MODERATELY GOOD.

7pts	EXCELLENT. Wetland appears to represent the best of its type or class.	
6pts	VERY GOOD. Wetland appears to be a very good example of its type or class but is lacking in characteristics which would make it excellent.	
5pts	GOOD. Wetland appears to be a good example of its type or class but because of past or present disturbances, successional state, or other reasons, is not excellent.	5.0
4pts	MODERATELY GOOD. Wetland appears to be a fair to good example of its type or class.	
3pts	FAIR. Wetland appears to be a moderately good example of its type or class but because of past or present disturbances, successional state, etc. is not good.	
2pts	POOR TO FAIR. Wetland appears to be a poor to fair example of its type or class.	
1pt	POOR. Wetland appears <u>not</u> to be a good example of its type or class because of past or present disturbances, successional state, etc.	

4b Avg.=
5.00

4c. Habitat alteration. This question evaluates the "intactness" the natural habitat of the type of wetland that is being evaluated. This question does not discriminate between wetlands with different types of habitat. Check all possible alterations that are observed. All available information, field visits, aerial photos, maps, etc. can be used to identify possible alterations. Evaluate whether the alteration is trivial in relation to the wetlands overall habitat. Select the most appropriate score that best describes the present state of the wetland. It is appropriate to "double check" and average scores. **The evaluator may check one or several of these possible disturbances, yet still determine that the natural habitat is intact.**

Check all that are observed present in or near the wetland

	Mowing		Herbaceous layer/aquatic bed removal
	Grazing (cattle, horses, etc.)		Sedimentation
	Clearcutting		Dredging
	Selective cutting		Row-crop or orchard farming
	Woody debris removal		Nutrient enrichment, e.g. nuisance algae
	Toxic pollutants		Other (specify):
	Shrub/sapling removal		Other (specify):

Have any of the disturbances identified above caused or appeared to cause more than trivial alterations to the wetland's natural habitat.	YES Assign a score 1, 3 or 6, or an intermediate score, depending on degree of recovery from the disturbance.	NO Assign a score of 9 since there are no or no apparent modifications.	NOT SURE Choose "recovered" and assign a score of 6.

Select one score or double check adjoining numbers and average the score.		Score
9pts	NONE OR NONE APPARENT. There are no past or current alterations that are apparent to the evaluator.	
6pts	RECOVERED. The wetland appears to have recovered from past alterations.	6.00
3pts	RECOVERING. The wetland appears to be in the process of recovering from past alterations.	
1pt	RECENT OR NO RECOVERY. The alterations have occurred recently, and/or the wetland has not recovered from past alterations, and/or the alterations are ongoing.	

4c Avg. = 6.00

Metric 4 Total 14

Metric 5. Special wetland communities. Assign points in left column if the wetland meets the associated criteria below. Refer to Narrative Rating for guidance. If wetland scores over 30 points within Metric 5 further determination needed to assess if the wetland exhibits outstanding ecological or recreational values as discussed in the Narrative Rating Section.

	5pts - >10m sq sphagnum or other moss or other vernal pools		5 pts - Superior fish, waterfowl, bat, or amphibian breeding habitat
	Ecological community with global rank (NatureServe): G1 (10pts), G2 (5pts), G2/G3 (3pts) or uncommon ecological resource in the ecoregion (habitat and/or species diversity, geology, wetland type, distribution/ occurrence) (10 pts)		5 pts - Wetland contains and is a buffer for a headwater stream or wetland contributes significantly to the water water quality of 303(d) listed stream and/or to surface or and/or to ground water
	10 pts - Older-aged mature forested wetland avg. DBH >= 30 inches		10 pts - Supports species Deemed in Need of Management by TWRA or TN Special Concern by TDEC

Metric 5 Total 0

Metric 6. Vegetation, Interspersion, and Microtopography (Max 20 points). **6a. Wetland Vegetation Communities** Check each community present both vertically and horizontally within the wetland with an area of at least 0.1 hectares or 1000m^2 (0.2471 acres). Assign a score of 0 to 3 using Table 3 for 1-4 or Table 5 for 5-6. Sum the scores for the classes present.	Score
1)Aquatic Bed Includes areas of wetlands dominated by plants that grow principally on or below the surface of the water for most of the growing season in most years. Floating aquatic species like duckweed (*Lemna* spp., *Spirodela* spp.) are excluded from definition of "aquatic bed." Aquatic beds often occur as a distinct zone as an "understory" below shrubs or trees.	
2)Emergent Includes areas of wetlands dominated by erect, rooted, herbaceous hydrophytes, excluding mosses and lichens. This vegetation is present for most of the growing season in most years. Common names for emergent communities include marsh, wet meadow, wet prairie, sedge meadow, and fens.	
3)Shrub Includes areas of wetlands dominated by woody vegetation less than 1m (3ft.) - 6m (20 ft) tall with a dbh of <3in. The plant species include true shrubs, young trees, or trees or shrubs that are small or stunted because of environmental conditions. Shrub wetlands may represent a successional stage leading to a forested wetland or they may be relatively stable plant communities.	
4)Forested Includes wetlands or areas of wetlands characterized by woody vegetation greater than 6m (20ft) or taller. Forested wetlands have an overstory of trees and often contain an understory of young trees and shrubs and an herbaceous layer, although the young tree/shrub and herbaceous layers can be largely missing from some types of forested wetlands. Some forested wetlands are "vernal pools".	0.00
5)Mudflats The "mudflat" class is equivalent to the "unconsolidated bottom/mud" class/subclass (PUB_3) described in Cowardin et al. (1979) and includes areas of wetlands characterized by exposed or shallowly inundated substrates with vegetative cover less than 30%.	
6)Open water The "open water" class is equivalent to the "open water - unknown bottom" class in Cowardin et al. (1979) and includes areas that are 1) inundated, 2) un-vegetated, and 3) and "open", i.e. there is no "canopy" of any type of vegetation.	

Table 3. Use this table to assign a cover score for Metric 6a to each of the vegetation communities identified on the preceding page. Refer to Table 4 for narrative description of "low," "moderate," and "high" quality.

Cover Scale	Description
0	The vegetation community is either 1) absent from wetland or 2) Comprises less than 0.1 ha (.2471 acres) of contiguous area within the wetland
1	Vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of low or moderate quality, or 2) if it comprises a significant part of the wetland's vegetation and is of low quality
2	Thee vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of moderate quality, or 2) the vegetation community comprises a small part of the wetland's vegetation but is of high quality
3	The vegetation community is of high quality and comprises a significant part, or more, of the wetland's vegetation

Table 4. Use this table in conjunction with Table 3 to determine what is a "low", "moderate," or " high" quality community.

Narrative	Description
Low	Low species richness and a predominance of invasive, non-native, or disturbance tolerant "weedy" species.
Moderate	Native species are the dominant component of the vegetation, although non-native or disturbance tolerant "weedy" species can also be present, and species richness is moderate to moderately high, but generally without the presence of rare, threatened, or endangered species.
High	A predominance of native species, with non-native species absent or virtually absent, and high species diversity and/or the presence of rare, threatened or endangered species.

Table 5. Mudflat and open water community cover scale.

0	Absent <0.1 ha (0.247 acres)
1	Low 0.1 to <1ha (0.247 to 2.47 acres)
2	Moderate 1 ha to < 4 ha (2.47 to 9.88 acres)
3	High 4 ha (9.88 acres) or more

6b. Horizontal (plan view) interspersion. Evaluate the wetland from a "plan view," i.e. as if the looking down upon it. See Figure 1.	Score
5pts HIGH Wetland has a high degree of interspersion	
4pts MODERATELY HIGH Wetland has a moderately high degree of interspersion	
3pts MODERATE Wetland has a moderate degree of interspersion	3.0
2pts MODERATELY LOW Wetland has a moderately low degree of interspersion	
1pt LOW Wetland has a low degree of interspersion.	
0pt NONE Wetland has no plan view interspersion	

KIF Retirement

W001

PID#39170

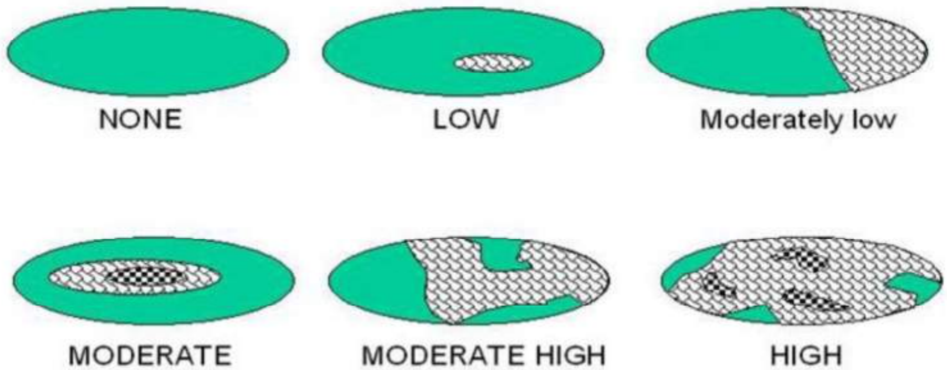

Figure 1. Hypothetical Wetlands for estimating degree of interspersion

6c. Coverage of Invasive Plant Species. Refer to Tennessee Exotic Pest Plant Council (http://www.tneppc.org/) for official list. Select only one and assign score.		Score
-5pts	Extensive >75% areal cover of invasive species	
-3pts	Moderate 25-75% areal cover of invasive species	
-1pts	Sparse 5-25% areal cover of invasive species	
0pt	Nearly absent. <5% areal cover of invasive species	0
1pt	Absent	

6d. Microtopography. Check each feature present in the wetland. Assign cover score of 0 to 3 using Table 6. Evaluate various microtopograhic habitat features often present in wetlands.	Score
Vegetated hummocks and tussocks	
Coarse woody debris >15cm (6in) in diameter	
Standing dead trees >25cm (10in) diameter at breast height	
Amphibian breeding habitat, e.g. vernal pools with standing water of sufficient duration and depth to support reproduction, or habitat for frog reproduction	

Table 6. Cover scale for microtopographic habitat features

Microtopographic habitat quality	**Narrative description**
0	Feature is absent or functionally absent from the wetland
1	Feature is present in the wetland in very small amounts or if more common, of low quality
2	Feature is present in moderate amounts, but not of highest quality or in small amounts of highest quality
3	Present in moderate or greater amounts and of the highest quality

Metric 6 Total 3

NON-HGM TRAM Summary Worksheet

Non-HGM Quantitative Rating	Metric 1: Size	1
	Metric 2: Buffers and surrounding land use	4.5
	Metric 3: Hydrology	16
	Metric 4: Habitat	14
	Metric 5: Special Wetland Communities	0
	Metric 6: Plant communities, interspersion, microtopography	3
	TOTAL SCORE	39

KIF Retirement

PID#39170

W001

Rank = Low

"Wetland Conditions with an overall score of 100-75 are considered Exceptional Tennessee Waters. Wetlands with a score of 74-45 are considered to have moderate resource value, and wetland with a score of 44 and below have a low resource value."
(TRAM 2015, pg 2)

Quantitative Rating
Tennessee Rapid Assessment Method

W002
3/30/2022
FPH

Metric 1. Wetland area (max 6 pts). Estimate the area of wetland and select the appropriate size class and assign score. Estimated areas should clearly place the wetland within the appropriate class.

6pts	>50 acres (west TN)	>25 acres (middle TN)	>10 acres (east TN *)	
5pts	25 - <50 acres (west TN)	10- 25 acres (middle TN)	7-<10 acres (east TN*)	
4pts	10 - <25 acres (west TN)	7-< 25acres (middle TN)	3-<7 acres (east TN*)	
3pts	3 - <10 acres(west TN)	3< 7 acres (middle TN)	1-<3 acres (east TN)	
2pts	0.3 - <3 acres (west TN)	0.5- <3 acres (middle TN)	0.5-<1 acres (east TN)	
1pt	0.1 - <0.3 acres(west TN)	<0.5 acres (middle TN)	<0.5 acres (east TN)	1

*More applicable to West Tennessee; use with discretion in Middle Tennessee, Consult TDEC-DWR Natural Resources Unit for use in East Tennessee.

Table 2. Metric to English conversion table with visual estimation sizes.

acres	ft^2	yd^2	ft on side	yd on side	ha	m^2	m on side
50	2,177,983	241,998	1476	492	20.2	202,000	449
25	1,088,992	120,999	1044	348	10.1	101,000	318
10	435,596	48,340	660	220	4.1	41,000	203
3	130,679	14,520	362	121	1.2	12,000	110
0.3	13,067	1,452	114	38	0.12	1,200	35
0.1	4,356	484	66	22	0.04	400	20

Metric 1 Total 1

Metric 2. Upland buffers and intensity of surrounding land uses (Max 14 points). Wetlands without upland "buffers", or that are located where human land use is more intensive, are often, but not always, more degraded and often have lower wildlife habitat resource value.

2a. Average Buffer Width (ABW). Calculate the average buffer width and select only one score. To calculate ABW, estimate buffer width on each side (max of 50m) and divide by the number of sides. Example: ABW of a wetland with buffers of 100m, 25m, 10m and 0m would be calculated as follows: ABW = (50m + 25m + 10m + 0m)/4 = 21.25m. Intensive land uses are not buffers, e.g. active row cropping, paved areas, housing developments, etc.			
7pts	WIDE. >50m (164ft) or more around perimeter.		
4pts	MEDIUM. 25m to <50m (82 to <164ft) around the perimeter.		
1pt	NARROW. 10m to <25m (32 to <82ft) around the perimeter.		
0pts	VERY NARROW. <10m (<32ft) around perimeter.	0	2a Avg.= 0.00
2b. Intensity of predominant surrounding land use(s) Select one, or choose up to two and average score, for the intensity of the predominant land use(s) outside the wetland's buffer zone.			
7pts	VERY LOW. 2nd growth or older forest, prairie, barren, wildlife area, etc.		
5pts	LOW. Old fallow field, shrub land, early successional young forest, etc.		
3pts	MODERATELY HIGH. Residential, pasture, orchard, park, conservation tillage, mowed field, etc.	3	
1pt	HIGH. urban, industrial, row cropping, mining, construction, etc.	1	2b Avg.= 2.00

KIF Retirement

PID#39170

W002

Metric 2 Total 2.00

Metric 3. Hydrology (Max 30 points). This metric evaluates the wetland's water budget, hydroperiod, the hydrologic connectivity of the wetland to other surface waters, and the degree to which the wetland's hydrology has been altered by human activity. **A wetland can receive no more than 30 points for Metric 3 even though it is possible to score more than 30 points.**

3a. Sources of Water. Select all that apply and sum the score. This question relates to a wetland's water budget. It also is reflective that wetlands with certain types of water sources, or multiple water sources, e.g. high pH groundwater or perennial surface water connections, can be very high quality wetlands or can have high functions and values.		
5pts	High pH groundwater (7.5-9.0)	
3pts	Other groundwater	
1pts	Precipitation	1
3pts	Seasonal surface water	
5pts	Perennial surface water (lake or stream)	
3b. Connectivity. Select all that apply and sum score		
1pt	**100 year floodplain.** "Floodplain" is defined as "...the relatively level land next to a stream or river channel that is periodically submerged by flood waters. It is composed of alluvium deposited by the present stream or river when it floods." Where they are available, flood insurance rate maps (FIRMs) and flood boundary and floodway maps may be used.	
1pt	**Between stream/lake and other human land use.** This question asks whether the wetland is located between a surface water and a different adjacent land use, such that run-off from the adjacent land use could flow through wetland before it discharges into the surface water buffering it. "Different adjacent land uses" include agricultural, commercial, industrial, mining, or residential uses.	
1pt	**Part of a larger wetland or upland complex.** This question asks whether the wetland is in physical proximity to, or a other nearby wetland or upland habitat areas.	
1pt	**Part of riparian corridor**.	
3c. Maximum water depth. Select only one and assign score. The evaluator *does not* need to actually observe the wetland when its water depth is greatest in order to award the maximum points for this question. The use of secondary indicators, as outlined in the 1987 Manual will be useful in answering this question.		
3 pts	>0.7m (27.6in)	
2pts	0.4 to 0.7m (15.7 to 27.6in)	
1pt	<0.4m (<15.7in)	1
3d. Duration of inundation/saturation. Select one or double check and average the scores if duration is uncertain. The use of ACOE 1987 Manual secondary indicators is necessary and expected in order to properly answer this question.		
4pts	Semi-permanently to permanently inundated or saturated	
3pts	Regularly inundated or saturated	
2pts	Seasonally inundated	
1pt	Seasonally saturated in the upper 30cm (12in) of soil	1

3d Avg.= 1.00

KIF Retirement

PID#39170

W002

3e. Modifications to natural hydrologic regime. Check all observable modifications from list below. Score by selecting the most appropriate description of the wetland. Scores may be double checked and averaged. This question asks the evaluator to assess the “intactness” of, or lack of disturbance to, the natural hydrologic regime of the type of wetland that is being evaluated.

Once the evaluator has listed all possible past and ongoing disturbances, the evaluator should check the most appropriate category to describe the present state of the wetland. In instances where the evaluator believes that a wetland falls between two categories, or where the evaluator is uncertain as to which category is appropriate, it is appropriate to choose more than one and average the score.

The evaluator may check one or several of these possible disturbances, yet still determine that the natural hydrologic regime is intact. However, see Metric 4 where these same disturbances may be habitat alterations.

Check all that are observed present in or near the wetland.

	ditch(es), in or near the wetland		point source discharges to the (non-stormwater)
	tile(s), in or near the wetland		filling/grading activities in or near the wetland
	dike(s), in or near the wetland		road beds/RR beds in or near the wetland
	weir(s), in or near the wetland		dredging activities in or near the wetland
	stormwater inputs (addition of water)		other (specify)

Have any of the disturbances identified above caused or appear to have caused more than trivial alterations to the wetland's natural hydrologic regime.	YES Assign a score 1, 3 or 7, or an intermediate score, depending on degree of recovery from the disturbance.	NO Assign a score of 12 since there are no or no apparent modifications.	NOT SURE Choose "recovered" and assign a score of 9.5.

	Select one or double check adjoining numbers and average the score.	**score**
12pts	NONE OR NONE APPARENT. There are no modifications or no modifications that are apparent to the evaluator.	
7pts	RECOVERED. The wetland appears to have recovered from past modifications.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past modifications.	
1pt	RECENT OR NO RECOVERY. The modifications have occurred recently occurred, and/or the wetland has not recovered from past modifications, and/or the modifications are ongoing.	1

3e Avg= 1.00

KIF Retirement

Metric 3 Total 4.00

PID#39170

W002

Metric 4. Habitat Alteration and Development (Max 20 points). While hydrology may be the single most important determinant for the establishment and maintenance of specific types of wetlands and wetland processes, there is a range of other factors and activities which affect wetland quality and cause disturbances to wetlands that are unrelated to hydrology. These disturbances are termed "habitat alteration." In many instances, items checked as hydrologic disturbances in Question 3e will present as alterations to a wetland's habitat or disruptions in its development (successional state). In some instances, a disturbance may be appropriately considered under both Metric 3 and Metric 4. To determine the appropriate metric scores, the evaluator should carefully determine the actual cause of the disturbance to the wetland.

4a. Substrate/Soil Disturbance. Select one or double check and average. This question evaluates physical disturbances to the soil and surface substrates of the wetland. Note also that the labels on the scoring categories are intended to be descriptive but not controlling. In some instances, it may be more appropriate to consider the scoring categories as fixed locations on a disturbance continuum, from very high to very low or no disturbance.

Examples of substrate/soil disturbance include (circle all that apply):

____filling and grading
____plowing
____grazing (hooves)
____vehicle use (off-road vehicles, construction vehicles)
____sedimentation
____dredging, and other mechanical disturbances to the soil

Have any of soil or substrate disturbances caused or appear to have caused more than trivial alterations to the wetland's natural soils	YES Assign a score 1, 2 or 3, or an intermediate score, depending on degree of recovery from the disturbance.	NO Assign a score of 4 since there are no or no apparent modifications.	NOT SURE Choose "recovered" and assign a score of 3.5.

Select one or double check adjoining numbers and average the score.		
4pts	NONE OR NONE APPARENT. There are no disturbances or no disturbances apparent to the evaluator.	
3pts	RECOVERED. The wetland appears to have recovered from past disturbances.	
2pts	RECOVERING. The wetland appears to be in the process of recovering from past disturbances.	2.0
1pt	RECENT OR NO RECOVERY. The disturbances have occurred recently, and/or the wetland has not recovered from past disturbances, and/or the disturbances are ongoing.	

4a Avg.= 2.00

4b. Habitat development. Select only one and assign score. This question asks the evaluator to assign an overall qualitative rating of how well-developed the wetland is in comparison to other ecologically and/or hydrogeomorphically similar wetlands. This question presumes knowledge of the types of wetlands and the range in quality typical of the region or access to data from reference standard examples. If unsure, score as GOOD or MODERATELY GOOD.

7pts	EXCELLENT. Wetland appears to represent the best of its type or class.	
6pts	VERY GOOD. Wetland appears to be a very good example of its type or class but is lacking in characteristics which would make it excellent.	
5pts	GOOD. Wetland appears to be a good example of its type or class but because of past or present disturbances, successional state, or other reasons, is not excellent.	
4pts	MODERATELY GOOD. Wetland appears to be a fair to good example of its type or class.	
3pts	FAIR. Wetland appears to be a moderately good example of its type or class but because of past or present disturbances, successional state, etc. is not good.	
2pts	POOR TO FAIR. Wetland appears to be a poor to fair example of its type or class.	2.0
1pt	POOR. Wetland appears not to be a good example of its type or class because of past or present disturbances, successional state, etc.	

4b Avg.= 2.00

4c. Habitat alteration. This question evaluates the "intactness" the natural habitat of the type of wetland that is being evaluated. This question does not discriminate between wetlands with different types of habitat. Check all possible alterations that are observed. All available information, field visits, aerial photos, maps, etc. can be used to identify possible alterations. Evaluate whether the alteration is trivial in relation to the wetlands overall habitat. Select the most appropriate score that best describes the present state of the wetland. It is appropriate to "double check" and average scores. **The evaluator may check one or several of these possible disturbances, yet still determine that the natural habitat is intact.**

Check all that are observed present in or near the wetland

X	Mowing		Herbaceous layer/aquatic bed removal
	Grazing (cattle, horses, etc.)		Sedimentation
	Clearcutting		Dredging
	Selective cutting		Row-crop or orchard farming
	Woody debris removal		Nutrient enrichment, e.g. nuisance algae
	Toxic pollutants		Other (specify):
	Shrub/sapling removal		Other (specify):

Have any of the disturbances identified above caused or appeared to cause more than trivial alterations to the wetland's natural habitat.	YES Assign a score 1, 3 or 6, or an intermediate score, depending on degree of recovery from the disturbance.	NO Assign a score of 9 since there are no or no apparent modifications.	NOT SURE Choose "recovered" and assign a score of 6.

Select one score or double check adjoining numbers and average the score.		Score
9pts	NONE OR NONE APPARENT. There are no past or current alterations that are apparent to the evaluator.	
6pts	RECOVERED. The wetland appears to have recovered from past alterations.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past alterations.	
1pt	RECENT OR NO RECOVERY. The alterations have occurred recently, and/or the wetland has not recovered from past alterations, and/or the alterations are ongoing.	1.00

4c Avg. = 1.00

Metric 4 Total 5

Quantitative Rating

Tennessee Rapid Assessment Method

Metric 5. Special wetland communities. Assign points in left column if the wetland meets the associated criteria below. Refer to Narrative Rating for guidance. If wetland scores over 30 points within Metric 5 further determination needed to assess if the wetland exhibits outstanding ecological or recreational values as discussed in the Narrative Rating Section.

	5pts - >10m sq sphagnum or other moss or other vernal pools		5 pts - Superior fish, waterfowl, bat, or amphibian breeding habitat
	Ecological community with global rank (NatureServe): G1 (10pts), G2 (5pts), G2/G3 (3pts) or uncommon ecological resource in the ecoregion (habitat and/or species diversity, geology, wetland type, distribution/ occurrence) (10 pts)		5 pts - Wetland contains and is a buffer for a headwater stream or wetland contributes significantly to the water water quality of 303(d) listed stream and/or to surface or and/or to ground water
	10 pts - Older-aged mature forested wetland avg. DBH >= 30 inches		10 pts - Supports species Deemed in Need of Management by TWRA or TN Special Concern by TDEC

Metric 5 Total 0

Metric 6. Vegetation, Interspersion, and Microtopography (Max 20 points). **6a. Wetland Vegetation Communities** Check each community present both vertically and horizontally within the wetland with an area of at least 0.1 hectares or 1000m^2 (0.2471 acres). Assign a score of 0 to 3 using Table 3 for 1-4 or Table 5 for 5-6. Sum the scores for the classes present.	Score
1)Aquatic Bed Includes areas of wetlands dominated by plants that grow principally on or below the surface of the water for most of the growing season in most years. Floating aquatic species like duckweed (*Lemna* spp., *Spirodela* spp.) are excluded from definition of "aquatic bed." Aquatic beds often occur as a distinct zone as an "understory" below shrubs or trees.	
2)Emergent Includes areas of wetlands dominated by erect, rooted, herbaceous hydrophytes, excluding mosses and lichens. This vegetation is present for most of the growing season in most years. Common names for emergent communities include marsh, wet meadow, wet prairie, sedge meadow, and fens.	0.00
3)Shrub Includes areas of wetlands dominated by woody vegetation less than 1m (3ft.) - 6m (20 ft) tall with a dbh of <3in. The plant species include true shrubs, young trees, or trees or shrubs that are small or stunted because of environmental conditions. Shrub wetlands may represent a successional stage leading to a forested wetland or they may be relatively stable plant communities.	
4)Forested Includes wetlands or areas of wetlands characterized by woody vegetation greater than 6m (20ft) or taller. Forested wetlands have an overstory of trees and often contain an understory of young trees and shrubs and an herbaceous layer, although the young tree/shrub and herbaceous layers can be largely missing from some types of forested wetlands. Some forested wetlands are "vernal pools".	
5)Mudflats The "mudflat" class is equivalent to the "unconsolidated bottom/mud" class/subclass (PUB_3) described in Cowardin et al. (1979) and includes areas of wetlands characterized by exposed or shallowly inundated substrates with vegetative cover less than 30%.	
6)Open water The "open water" class is equivalent to the "open water - unknown bottom" class in Cowardin et al. (1979) and includes areas that are 1) inundated, 2) un-vegetated, and 3) and "open", i.e. there is no "canopy" of any type of vegetation.	

Table 3. Use this table to assign a cover score for Metric 6a to each of the vegetation communities identified on the preceding page. Refer to Table 4 for narrative description of "low," "moderate," and "high" quality.

Cover Scale	Description
0	The vegetation community is either 1) absent from wetland or 2) Comprises less than 0.1 ha (.2471 acres) of contiguous area within the wetland
1	Vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of low or moderate quality, or 2) if it comprises a significant part of the wetland's vegetation and is of low quality
2	Thee vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of moderate quality, or 2) the vegetation community comprises a small part of the wetland's vegetation but is of high quality
3	The vegetation community is of high quality and comprises a significant part, or more, of the wetland's vegetation

Table 4. Use this table in conjunction with Table 3 to determine what is a "low", "moderate," or " high" quality community.

Narrative	Description
Low	Low species richness and a predominance of invasive, non-native, or disturbance tolerant "weedy" species.
Moderate	Native species are the dominant component of the vegetation, although non-native or disturbance tolerant "weedy" species can also be present, and species richness is moderate to moderately high, but generally without the presence of rare, threatened, or endangered species.
High	A predominance of native species, with non-native species absent or virtually absent, and high species diversity and/or the presence of rare, threatened or endangered species.

Table 5. Mudflat and open water community cover scale.

0	Absent <0.1 ha (0.247 acres)
1	Low 0.1 to <1ha (0.247 to 2.47 acres)
2	Moderate 1 ha to < 4 ha (2.47 to 9.88 acres)
3	High 4 ha (9.88 acres) or more

6b. Horizontal (plan view) interspersion. Evaluate the wetland from a "plan view," i.e. as if the looking down upon it. See Figure 1.	Score
5pts HIGH Wetland has a high degree of interspersion	
4pts MODERATELY HIGH Wetland has a moderately high degree of interspersion	
3pts MODERATE Wetland has a moderate degree of interspersion	
2pts MODERATELY LOW Wetland has a moderately low degree of interspersion	
1pt LOW Wetland has a low degree of interspersion.	1.00
0pt NONE Wetland has no plan view interspersion	

KIF Retirement

W002

PID#39170

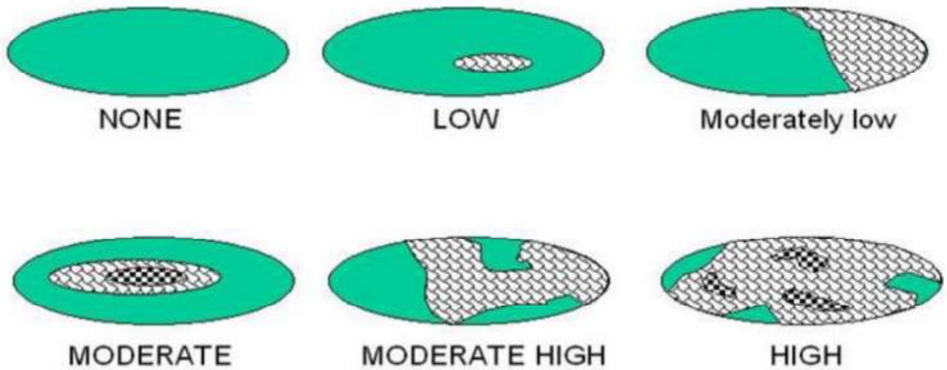

Figure 1. Hypothetical Wetlands for estimating degree of interspersion

6c. Coverage of Invasive Plant Species. Refer to Tennessee Exotic Pest Plant Council (http://www.tneppc.org/) for official list. Select only one and assign score.	Score
-5pts Extensive >75% areal cover of invasive species	
-3pts Moderate 25-75% areal cover of invasive species	
-1pts Sparse 5-25% areal cover of invasive species	
0pt Nearly absent. <5% areal cover of invasive species	0
1pt Absent	
6d. Microtopography. Check each feature present in the wetland. Assign cover score of 0 to 3 using Table 6. Evaluate various microtopograhic habitat features often present in wetlands.	Score
Vegetated hummocks and tussocks	
Coarse woody debris >15cm (6in) in diameter	
Standing dead trees >25cm (10in) diameter at breast height	
Amphibian breeding habitat, e.g. vernal pools with standing water of sufficient duration and depth to support reproduction, or habitat for frog reproduction	

Table 6. Cover scale for microtopographic habitat features

Microtopographic habitat quality	**Narrative description**
0	Feature is absent or functionally absent from the wetland
1	Feature is present in the wetland in very small amounts or if more common, of low quality
2	Feature is present in moderate amounts, but not of highest quality or in small amounts of highest quality
3	Present in moderate or greater amounts and of the highest quality

Metric 6 Total 1

NON-HGM TRAM Summary Worksheet

Non-HGM Quantitative Rating	Metric 1: Size	1
	Metric 2: Buffers and surrounding land use	2
	Metric 3: Hydrology	4
	Metric 4: Habitat	5
	Metric 5: Special Wetland Communities	0
	Metric 6: Plant communities, interspersion, microtopography	1
	TOTAL SCORE	13

KIF Retirement

PID#39170

W002

Rank = Low

"Wetland Conditions with an overall score of 100-75 are considered Exceptional Tennessee Waters. Wetlands with a score of 74-45 are considered to have moderate resource value, and wetland with a score of 44 and below have a low resource value."
(TRAM 2015, pg 2)

Quantitative Rating
Tennessee Rapid Assessment Method

Metric 1. Wetland area (max 6 pts). Estimate the area of wetland and select the appropriate size class and assign score. Estimated areas should clearly place the wetland within the appropriate class.

6pts	>50 acres (west TN)	>25 acres (middle TN)	>10 acres (east TN *)	
5pts	25 - <50 acres (west TN)	10- 25 acres (middle TN)	7-<10 acres (east TN*)	
4pts	10 - <25 acres (west TN)	7-< 25acres (middle TN)	3-<7 acres (east TN*)	
3pts	3 - <10 acres(west TN)	3< 7 acres (middle TN)	1-<3 acres (east TN)	
2pts	0.3 - <3 acres (west TN)	0.5- <3 acres (middle TN)	0.5-<1 acres (east TN)	
1pt	0.1 - <0.3 acres(west TN)	<0.5 acres (middle TN)	<0.5 acres (east TN)	1

*More applicable to West Tennessee; use with discretion in Middle Tennessee, Consult TDEC-DWR Natural Resources Unit for use in East Tennessee.

Table 2. Metric to English conversion table with visual estimation sizes.

acres	ft^2	yd^2	ft on side	yd on side	ha	m^2	m on side
50	2,177,983	241,998	1476	492	20.2	202,000	449
25	1,088,992	120,999	1044	348	10.1	101,000	318
10	435,596	48,340	660	220	4.1	41,000	203
3	130,679	14,520	362	121	1.2	12,000	110
0.3	13,067	1,452	114	38	0.12	1,200	35
0.1	4,356	484	66	22	0.04	400	20

Metric 1 Total 1

Metric 2. Upland buffers and intensity of surrounding land uses (Max 14 points). Wetlands without upland "buffers", or that are located where human land use is more intensive, are often, but not always, more degraded and often have lower wildlife habitat resource value.

2a. Average Buffer Width (ABW). Calculate the average buffer width and select only one score. To calculate ABW, estimate buffer width on each side (max of 50m) and divide by the number of sides. Example: ABW of a wetland with buffers of 100m, 25m, 10m and 0m would be calculated as follows: ABW = (50m + 25m + 10m + 0m)/4 = 21.25m. Intensive land uses are not buffers, e.g. active row cropping, paved areas, housing developments, etc.			
7pts	WIDE. >50m (164ft) or more around perimeter.		
4pts	MEDIUM. 25m to <50m (82 to <164ft) around the perimeter.		
1pt	NARROW. 10m to <25m (32 to <82ft) around the perimeter.		
0pts	VERY NARROW. <10m (<32ft) around perimeter.	0	2a Avg.= 0.00
2b. Intensity of predominant surrounding land use(s) Select one, or choose up to two and average score, for the intensity of the predominant land use(s) outside the wetland's buffer zone.			
7pts	VERY LOW. 2nd growth or older forest, prairie, barren, wildlife area, etc.		
5pts	LOW. Old fallow field, shrub land, early successional young forest, etc.		
3pts	MODERATELY HIGH. Residential, pasture, orchard, park, conservation tillage, mowed field, etc.	3	
1pt	HIGH. urban, industrial, row cropping, mining, construction, etc.	1	2b Avg.= 2.00

KIF Retirement

PID#39170

W003

Metric 2 Total 2.00

Metric 3. Hydrology (Max 30 points). This metric evaluates the wetland's water budget, hydroperiod, the hydrologic connectivity of the wetland to other surface waters, and the degree to which the wetland's hydrology has been altered by human activity**. A wetland can receive no more than 30 points for Metric 3 even though it is possible to score more than 30 points.**

3a. Sources of Water. Select all that apply and sum the score. This question relates to a wetland's water budget. It also is reflective that wetlands with certain types of water sources, or multiple water sources, e.g. high pH groundwater or perennial surface water connections, can be very high quality wetlands or can have high functions and values.		
5pts	High pH groundwater (7.5-9.0)	
3pts	Other groundwater	
1pts	Precipitation	1
3pts	Seasonal surface water	
5pts	Perennial surface water (lake or stream)	
3b. Connectivity. Select all that apply and sum score		
1pt	**100 year floodplain.** "Floodplain" is defined as "...the relatively level land next to a stream or river channel that is periodically submerged by flood waters. It is composed of alluvium deposited by the present stream or river when it floods." Where they are available, flood insurance rate maps (FIRMs) and flood boundary and floodway maps may be used.	
1pt	**Between stream/lake and other human land use.** This question asks whether the wetland is located between a surface water and a different adjacent land use, such that run-off from the adjacent land use could flow through wetland before it discharges into the surface water buffering it. "Different adjacent land uses" include agricultural, commercial, industrial, mining, or residential uses.	
1pt	**Part of a larger wetland or upland complex.** This question asks whether the wetland is in physical proximity to, or a other nearby wetland or upland habitat areas.	
1pt	**Part of riparian corridor**.	
3c. Maximum water depth. Select only one and assign score. The evaluator *does not* need to actually observe the wetland when its water depth is greatest in order to award the maximum points for this question. The use of secondary indicators, as outlined in the 1987 Manual will be useful in answering this question.		
3 pts	>0.7m (27.6in)	
2pts	0.4 to 0.7m (15.7 to 27.6in)	
1pt	<0.4m (<15.7in)	1
3d. Duration of inundation/saturation. Select one or double check and average the scores if duration is uncertain. The use of ACOE 1987 Manual secondary indicators is necessary and expected in order to properly answer this question.		
4pts	Semi-permanently to permanently inundated or saturated	4
3pts	Regularly inundated or saturated	
2pts	Seasonally inundated	
1pt	Seasonally saturated in the upper 30cm (12in) of soil	

3d Avg.= 4.00

KIF Retirement

PID#39170

W003

3e. Modifications to natural hydrologic regime. Check all observable modifications from list below. Score by selecting the most appropriate description of the wetland. Scores may be double checked and averaged. This question asks the evaluator to assess the “intactness” of, or lack of disturbance to, the natural hydrologic regime of the type of wetland that is being evaluated.

Once the evaluator has listed all possible past and ongoing disturbances, the evaluator should check the most appropriate category to describe the present state of the wetland. In instances where the evaluator believes that a wetland falls between two categories, or where the evaluator is uncertain as to which category is appropriate, it is appropriate to choose more than one and average the score.

The evaluator may check one or several of these possible disturbances, yet still determine that the natural hydrologic regime is intact. However, see Metric 4 where these same disturbances may be habitat alterations.

Check all that are observed present in or near the wetland.

	ditch(es), in or near the wetland		point source discharges to the (non-stormwater)
	tile(s), in or near the wetland		filling/grading activities in or near the wetland
	dike(s), in or near the wetland		road beds/RR beds in or near the wetland
	weir(s), in or near the wetland		dredging activities in or near the wetland
	stormwater inputs (addition of water)		other (specify)

Have any of the disturbances identified above caused or appear to have caused more than trivial alterations to the wetland's natural hydrologic regime.	YES Assign a score 1, 3 or 7, or an intermediate score, depending on degree of recovery from the disturbance.	NO Assign a score of 12 since there are no or no apparent modifications.	NOT SURE Choose "recovered" and assign a score of 9.5.

Select one or double check adjoining numbers and average the score.		**score**
12pts	NONE OR NONE APPARENT. There are no modifications or no modifications that are apparent to the evaluator.	
7pts	RECOVERED. The wetland appears to have recovered from past modifications.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past modifications.	3
1pt	RECENT OR NO RECOVERY. The modifications have occurred recently occurred, and/or the wetland has not recovered from past modifications, and/or the modifications are ongoing.	

3e Avg= 3.00

KIF Retirement

Metric 3 Total 9.00

PID#39170

W003

Metric 4. Habitat Alteration and Development (Max 20 points). While hydrology may be the single most important determinant for the establishment and maintenance of specific types of wetlands and wetland processes, there is a range of other factors and activities which affect wetland quality and cause disturbances to wetlands that are unrelated to hydrology. These disturbances are termed "habitat alteration." In many instances, items checked as hydrologic disturbances in Question 3e will present as alterations to a wetland's habitat or disruptions in its development (successional state). In some instances, a disturbance may be appropriately considered under both Metric 3 and Metric 4. To determine the appropriate metric scores, the evaluator should carefully determine the actual cause of the disturbance to the wetland.

4a. Substrate/Soil Disturbance. Select one or double check and average. This question evaluates physical disturbances to the soil and surface substrates of the wetland. Note also that the labels on the scoring categories are intended to be descriptive but not controlling. In some instances, it may be more appropriate to consider the scoring categories as fixed locations on a disturbance continuum, from very high to very low or no disturbance.

Examples of substrate/soil disturbance include (circle all that apply):

____filling and grading

____plowing

____grazing (hooves)

____vehicle use (off-road vehicles, construction vehicles)

____sedimentation

____dredging, and other mechanical disturbances to the soil

Have any of soil or substrate disturbances caused or appear to have caused more than trivial alterations to the wetland's natural soils	YES Assign a score 1, 2 or 3, or an intermediate score, depending on degree of recovery from the disturbance.	NO Assign a score of 4 since there are no or no apparent modifications.	NOT SURE Choose "recovered" and assign a score of 3.5.

Select one or double check adjoining numbers and average the score.		
4pts	NONE OR NONE APPARENT. There are no disturbances or no disturbances apparent to the evaluator.	
3pts	RECOVERED. The wetland appears to have recovered from past disturbances.	
2pts	RECOVERING. The wetland appears to be in the process of recovering from past disturbances.	2.0
1pt	RECENT OR NO RECOVERY. The disturbances have occurred recently, and/or the wetland has not recovered from past disturbances, and/or the disturbances are ongoing.	

4a Avg.= 2.00

4b. Habitat development. Select only one and assign score. This question asks the evaluator to assign an overall qualitative rating of how well-developed the wetland is in comparison to other ecologically and/or hydrogeomorphically similar wetlands. This question presumes knowledge of the types of wetlands and the range in quality typical of the region or access to data from reference standard examples. If unsure, score as GOOD or MODERATELY GOOD.

7pts	EXCELLENT. Wetland appears to represent the best of its type or class.	
6pts	VERY GOOD. Wetland appears to be a very good example of its type or class but is lacking in characteristics which would make it excellent.	
5pts	GOOD. Wetland appears to be a good example of its type or class but because of past or present disturbances, successional state, or other reasons, is not excellent.	
4pts	MODERATELY GOOD. Wetland appears to be a fair to good example of its type or class.	4.0
3pts	FAIR. Wetland appears to be a moderately good example of its type or class but because of past or present disturbances, successional state, etc. is not good.	
2pts	POOR TO FAIR. Wetland appears to be a poor to fair example of its type or class.	
1pt	POOR. Wetland appears <u>not</u> to be a good example of its type or class because of past or present disturbances, successional state, etc.	

4b Avg.= 4.00

4c. Habitat alteration. This question evaluates the "intactness" the natural habitat of the type of wetland that is being evaluated. This question does not discriminate between wetlands with different types of habitat. Check all possible alterations that are observed. All available information, field visits, aerial photos, maps, etc. can be used to identify possible alterations. Evaluate whether the alteration is trivial in relation to the wetlands overall habitat. Select the most appropriate score that best describes the present state of the wetland. It is appropriate to "double check" and average scores. **The evaluator may check one or several of these possible disturbances, yet still determine that the natural habitat is intact.**

Check all that are observed present in or near the wetland

	Mowing		Herbaceous layer/aquatic bed removal
	Grazing (cattle, horses, etc.)		Sedimentation
	Clearcutting		Dredging
	Selective cutting		Row-crop or orchard farming
	Woody debris removal		Nutrient enrichment, e.g. nuisance algae
	Toxic pollutants	X	Other (specify): ROW Managed
	Shrub/sapling removal		Other (specify):

Have any of the disturbances identified above caused or appeared to cause more than trivial alterations to the wetland's natural habitat.	<u>YES</u> Assign a score 1, 3 or 6, or an intermediate score, depending on degree of recovery from the disturbance.	<u>NO</u> Assign a score of 9 since there are no or no apparent modifications.	<u>NOT SURE</u> Choose "recovered" and assign a score of 6.

Select one score or double check adjoining numbers and average the score.		Score
9pts	NONE OR NONE APPARENT. There are no past or current alterations that are apparent to the evaluator.	
6pts	RECOVERED. The wetland appears to have recovered from past alterations.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past alterations.	3.0
1pt	RECENT OR NO RECOVERY. The alterations have occurred recently, and/or the wetland has not recovered from past alterations, and/or the alterations are ongoing.	

4c Avg. = 3.00

Metric 4 Total 9

Metric 5. Special wetland communities. Assign points in left column if the wetland meets the associated criteria below. Refer to Narrative Rating for guidance. If wetland scores over 30 points within Metric 5 further determination needed to assess if the wetland exhibits outstanding ecological or recreational values as discussed in the Narrative Rating Section.

	5pts - >10m sq sphagnum or other moss or other vernal pools		5 pts - Superior fish, waterfowl, bat, or amphibian breeding habitat
	Ecological community with global rank (NatureServe): G1 (10pts), G2 (5pts), G2/G3 (3pts) or uncommon ecological resource in the ecoregion (habitat and/or species diversity, geology, wetland type, distribution/ occurrence) (10 pts)		5 pts - Wetland contains and is a buffer for a headwater stream or wetland contributes significantly to the water water quality of 303(d) listed stream and/or to surface or and/or to ground water
	10 pts - Older-aged mature forested wetland avg. DBH >= 30 inches		10 pts - Supports species Deemed in Need of Management by TWRA or TN Special Concern by TDEC

Metric 5 Total 0

Metric 6. Vegetation, Interspersion, and Microtopography (Max 20 points). **6a. Wetland Vegetation Communities** Check each community present <u>both vertically and horizontally</u> within the wetland with an area of at least 0.1 hectares or 1000m^2 (0.2471 acres). Assign a score of 0 to 3 using Table 3 for 1-4 or Table 5 for 5-6. Sum the scores for the classes present.	Score
1)Aquatic Bed Includes areas of wetlands dominated by plants that grow principally on or below the surface of the water for most of the growing season in most years. Floating aquatic species like duckweed (*Lemna* spp., *Spirodela* spp.) are excluded from definition of "aquatic bed." Aquatic beds often occur as a distinct zone as an "understory" below shrubs or trees.	
2)Emergent Includes areas of wetlands dominated by erect, rooted, herbaceous hydrophytes, excluding mosses and lichens. This vegetation is present for most of the growing season in most years. Common names for emergent communities include marsh, wet meadow, wet prairie, sedge meadow, and fens.	0.00
3)Shrub Includes areas of wetlands dominated by woody vegetation less than 1m (3ft.) - 6m (20 ft) tall with a dbh of <3in. The plant species include true shrubs, young trees, or trees or shrubs that are small or stunted because of environmental conditions. Shrub wetlands may represent a successional stage leading to a forested wetland or they may be relatively stable plant communities.	
4)Forested Includes wetlands or areas of wetlands characterized by woody vegetation greater than 6m (20ft) or taller. Forested wetlands have an overstory of trees and often contain an understory of young trees and shrubs and an herbaceous layer, although the young tree/shrub and herbaceous layers can be largely missing from some types of forested wetlands. Some forested wetlands are "vernal pools".	
5)Mudflats The "mudflat" class is equivalent to the "unconsolidated bottom/mud" class/subclass (PUB_3) described in Cowardin et al. (1979) and includes areas of wetlands characterized by exposed or shallowly inundated substrates with vegetative cover less than 30%.	
6)Open water The "open water" class is equivalent to the "open water - unknown bottom" class in Cowardin et al. (1979) and includes areas that are 1) inundated, 2) un-vegetated, and 3) and "open", i.e. there is no "canopy" of any type of vegetation.	

Table 3. Use this table to assign a cover score for Metric 6a to each of the vegetation communities identified on the preceding page. Refer to Table 4 for narrative description of "low," "moderate," and "high" quality.

Cover Scale	Description
0	The vegetation community is either 1) absent from wetland or 2) Comprises less than 0.1 ha (.2471 acres) of contiguous area within the wetland
1	Vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of low or moderate quality, or 2) if it comprises a significant part of the wetland's vegetation and is of low quality
2	Thee vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of moderate quality, or 2) the vegetation community comprises a small part of the wetland's vegetation but is of high quality
3	The vegetation community is of high quality and comprises a significant part, or more, of the wetland's vegetation

Table 4. Use this table in conjunction with Table 3 to determine what is a "low", "moderate," or " high" quality community.

Narrative	Description
Low	Low species richness and a predominance of invasive, non-native, or disturbance tolerant "weedy" species.
Moderate	Native species are the dominant component of the vegetation, although non-native or disturbance tolerant "weedy" species can also be present, and species richness is moderate to moderately high, but generally without the presence of rare, threatened, or endangered species.
High	A predominance of native species, with non-native species absent or virtually absent, and high species diversity and/or the presence of rare, threatened or endangered species.

Table 5. Mudflat and open water community cover scale.

0	Absent <0.1 ha (0.247 acres)
1	Low 0.1 to <1ha (0.247 to 2.47 acres)
2	Moderate 1 ha to < 4 ha (2.47 to 9.88 acres)
3	High 4 ha (9.88 acres) or more

6b. Horizontal (plan view) interspersion. Evaluate the wetland from a "plan view," i.e. as if the looking down upon it. See Figure 1.	Score
5pts HIGH Wetland has a high degree of interspersion	
4pts MODERATELY HIGH Wetland has a moderately high degree of interspersion	
3pts MODERATE Wetland has a moderate degree of interspersion	
2pts MODERATELY LOW Wetland has a moderately low degree of interspersion	2.0
1pt LOW Wetland has a low degree of interspersion.	
0pt NONE Wetland has no plan view interspersion	

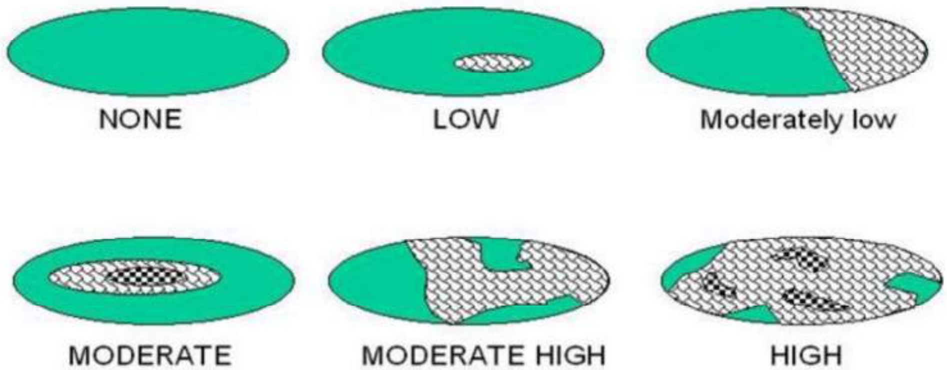

Figure 1. Hypothetical Wetlands for estimating degree of interspersion

6c. Coverage of Invasive Plant Species. Refer to Tennessee Exotic Pest Plant Council (http://www.tneppc.org/) for official list. Select only one and assign score.		Score
-5pts	Extensive >75% areal cover of invasive species	
-3pts	Moderate 25-75% areal cover of invasive species	
-1pts	Sparse 5-25% areal cover of invasive species	
0pt	Nearly absent. <5% areal cover of invasive species	0
1pt	Absent	

6d. Microtopography. Check each feature present in the wetland. Assign cover score of 0 to 3 using Table 6. Evaluate various microtopograhic habitat features often present in wetlands.	Score
Vegetated hummocks and tussocks	
Coarse woody debris >15cm (6in) in diameter	
Standing dead trees >25cm (10in) diameter at breast height	
Amphibian breeding habitat, e.g. vernal pools with standing water of sufficient duration and depth to support reproduction, or habitat for frog reproduction	

Table 6. Cover scale for microtopographic habitat features

Microtopographic habitat quality	**Narrative description**
0	Feature is absent or functionally absent from the wetland
1	Feature is present in the wetland in very small amounts or if more common, of low quality
2	Feature is present in moderate amounts, but not of highest quality or in small amounts of highest quality
3	Present in moderate or greater amounts and of the highest quality

Metric 6 Total 2

NON-HGM TRAM Summary Worksheet

Non-HGM Quantitative Rating	Metric 1: Size	1
	Metric 2: Buffers and surrounding land use	2
	Metric 3: Hydrology	9
	Metric 4: Habitat	9
	Metric 5: Special Wetland Communities	0
	Metric 6: Plant communities, interspersion, microtopography	2
	TOTAL SCORE	23

KIF Retirement

PID#39170

W003

Rank = Low

"Wetland Conditions with an overall score of 100-75 are considered Exceptional Tennessee Waters. Wetlands with a score of 74-45 are considered to have moderate resource value, and wetland with a score of 44 and below have a low resource value."
(TRAM 2015, pg 2)

Quantitative Rating
Tennessee Rapid Assessment Method

Metric 1. Wetland area (max 6 pts). Estimate the area of wetland and select the appropriate size class and assign score. Estimated areas should clearly place the wetland within the appropriate class.

6pts	>50 acres (west TN)	>25 acres (middle TN)	>10 acres (east TN *)	
5pts	25 - <50 acres (west TN)	10- 25 acres (middle TN)	7-<10 acres (east TN*)	
4pts	10 - <25 acres (west TN)	7-< 25acres (middle TN)	3-<7 acres (east TN*)	
3pts	3 - <10 acres(west TN)	3< 7 acres (middle TN)	1-<3 acres (east TN)	
2pts	0.3 - <3 acres (west TN)	0.5- <3 acres (middle TN)	0.5-<1 acres (east TN)	
1pt	0.1 - <0.3 acres(west TN)	<0.5 acres (middle TN)	<0.5 acres (east TN)	1

*More applicable to West Tennessee; use with discretion in Middle Tennessee, Consult TDEC-DWR Natural Resources Unit for use in East Tennessee.

Table 2. Metric to English conversion table with visual estimation sizes.

acres	ft^2	yd^2	ft on side	yd on side	ha	m^2	m on side
50	2,177,983	241,998	1476	492	20.2	202,000	449
25	1,088,992	120,999	1044	348	10.1	101,000	318
10	435,596	48,340	660	220	4.1	41,000	203
3	130,679	14,520	362	121	1.2	12,000	110
0.3	13,067	1,452	114	38	0.12	1,200	35
0.1	4,356	484	66	22	0.04	400	20

Metric 1 Total 1

Metric 2. Upland buffers and intensity of surrounding land uses (Max 14 points). Wetlands without upland “buffers", or that are located where human land use is more intensive, are often, but not always, more degraded and often have lower wildlife habitat resource value.

2a. Average Buffer Width (ABW). Calculate the average buffer width and select only one score. To calculate ABW, estimate buffer width on each side (max of 50m) and divide by the number of sides. Example: ABW of a wetland with buffers of 100m, 25m, 10m and 0m would be calculated as follows: ABW = (50m + 25m + 10m + 0m)/4 = 21.25m. Intensive land uses are not buffers, e.g. active row cropping, paved areas, housing developments, etc.			
7pts	WIDE. >50m (164ft) or more around perimeter.		
4pts	MEDIUM. 25m to <50m (82 to <164ft) around the perimeter.		
1pt	NARROW. 10m to <25m (32 to <82ft) around the perimeter.	1	
0pts	VERY NARROW. <10m (<32ft) around perimeter.	0	2a Avg.= 0.50
2b. Intensity of predominant surrounding land use(s) Select one, or choose up to two and average score, for the intensity of the predominant land use(s) outside the wetland's buffer zone.			
7pts	VERY LOW. 2nd growth or older forest, prairie, barren, wildlife area, etc.		
5pts	LOW. Old fallow field, shrub land, early successional young forest, etc.		
3pts	MODERATELY HIGH. Residential, pasture, orchard, park, conservation tillage, mowed field, etc.	3	
1pt	HIGH. urban, industrial, row cropping, mining, construction, etc.		2b Avg.= 3.00

KIF Retirement

PID#39170

W004

Metric 2 Total 3.50

Metric 3. Hydrology (Max 30 points). This metric evaluates the wetland's water budget, hydroperiod, the hydrologic connectivity of the wetland to other surface waters, and the degree to which the wetland's hydrology has been altered by human activity**. A wetland can receive no more than 30 points for Metric 3 even though it is possible to score more than 30 points.**

3a. Sources of Water. Select all that apply and sum the score. This question relates to a wetland's water budget. It also is reflective that wetlands with certain types of water sources, or multiple water sources, e.g. high pH groundwater or perennial surface water connections, can be very high quality wetlands or can have high functions and values.		
5pts	High pH groundwater (7.5-9.0)	
3pts	Other groundwater	
1pts	Precipitation	1
3pts	Seasonal surface water	
5pts	Perennial surface water (lake or stream)	
3b. Connectivity. Select all that apply and sum score		
1pt	**100 year floodplain.** "Floodplain" is defined as "...the relatively level land next to a stream or river channel that is periodically submerged by flood waters. It is composed of alluvium deposited by the present stream or river when it floods." Where they are available, flood insurance rate maps (FIRMs) and flood boundary and floodway maps may be used.	
1pt	**Between stream/lake and other human land use.** This question asks whether the wetland is located between a surface water and a different adjacent land use, such that run-off from the adjacent land use could flow through wetland before it discharges into the surface water buffering it. "Different adjacent land uses" include agricultural, commercial, industrial, mining, or residential uses.	
1pt	**Part of a larger wetland or upland complex.** This question asks whether the wetland is in physical proximity to, or a other nearby wetland or upland habitat areas.	
1pt	**Part of riparian corridor**.	
3c. Maximum water depth. Select only one and assign score. The evaluator *does not* need to actually observe the wetland when its water depth is greatest in order to award the maximum points for this question. The use of secondary indicators, as outlined in the 1987 Manual will be useful in answering this question.		
3 pts	>0.7m (27.6in)	
2pts	0.4 to 0.7m (15.7 to 27.6in)	
1pt	<0.4m (<15.7in)	1
3d. Duration of inundation/saturation. Select one or double check and average the scores if duration is uncertain. The use of ACOE 1987 Manual secondary indicators is necessary and expected in order to properly answer this question.		
4pts	Semi-permanently to permanently inundated or saturated	
3pts	Regularly inundated or saturated	
2pts	Seasonally inundated	
1pt	Seasonally saturated in the upper 30cm (12in) of soil	1

3d Avg.= 1.00

KIF Retirement

PID#39170

W004

3e. Modifications to natural hydrologic regime. Check all observable modifications from list below. Score by selecting the most appropriate description of the wetland. Scores may be double checked and averaged. This question asks the evaluator to assess the "intactness" of, or lack of disturbance to, the natural hydrologic regime of the type of wetland that is being evaluated.

Once the evaluator has listed all possible past and ongoing disturbances, the evaluator should check the most appropriate category to describe the present state of the wetland. In instances where the evaluator believes that a wetland falls between two categories, or where the evaluator is uncertain as to which category is appropriate, it is appropriate to choose more than one and average the score.

The evaluator may check one or several of these possible disturbances, yet still determine that the natural hydrologic regime is intact. However, see Metric 4 where these same disturbances may be habitat alterations.

Check all that are observed present in or near the wetland.

	ditch(es), in or near the wetland		point source discharges to the (non-stormwater)
	tile(s), in or near the wetland		filling/grading activities in or near the wetland
	dike(s), in or near the wetland		road beds/RR beds in or near the wetland
	weir(s), in or near the wetland		dredging activities in or near the wetland
	stormwater inputs (addition of water)		other (specify)

Have any of the disturbances identified above caused or appear to have caused more than trivial alterations to the wetland's natural hydrologic regime.	YES	NO	NOT SURE
	Assign a score 1, 3 or 7, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 12 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 9.5.

Select one or double check adjoining numbers and average the score.		**score**
12pts	NONE OR NONE APPARENT. There are no modifications or no modifications that are apparent to the evaluator.	
7pts	RECOVERED. The wetland appears to have recovered from past modifications.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past modifications.	3
1pt	RECENT OR NO RECOVERY. The modifications have occurred recently occurred, and/or the wetland has not recovered from past modifications, and/or the modifications are ongoing.	

3e Avg=
3.00

KIF Retirement

Metric 3 Total 6.00

PID#39170

W004

Metric 4. Habitat Alteration and Development (Max 20 points). While hydrology may be the single most important determinant for the establishment and maintenance of specific types of wetlands and wetland processes, there is a range of other factors and activities which affect wetland quality and cause disturbances to wetlands that are unrelated to hydrology. These disturbances are termed "habitat alteration." In many instances, items checked as hydrologic disturbances in Question 3e will present as alterations to a wetland's habitat or disruptions in its development (successional state). In some instances, a disturbance may be appropriately considered under both Metric 3 and Metric 4. To determine the appropriate metric scores, the evaluator should carefully determine the actual cause of the disturbance to the wetland.

4a. Substrate/Soil Disturbance. Select one or double check and average. This question evaluates physical disturbances to the soil and surface substrates of the wetland. Note also that the labels on the scoring categories are intended to be descriptive but not controlling. In some instances, it may be more appropriate to consider the scoring categories as fixed locations on a disturbance continuum, from very high to very low or no disturbance.	Examples of substrate/soil disturbance include (circle all that apply): ____filling and grading ____plowing ____grazing (hooves) ____vehicle use (off-road vehicles, construction vehicles) ____sedimentation ____dredging, and other mechanical disturbances to the soil

	YES	NO	NOT SURE
Have any of soil or substrate disturbances caused or appear to have caused more than trivial alterations to the wetland's natural soils	Assign a score 1, 2 or 3, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 4 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 3.5.

Select one or double check adjoining numbers and average the score.		
4pts	NONE OR NONE APPARENT. There are no disturbances or no disturbances apparent to the evaluator.	
3pts	RECOVERED. The wetland appears to have recovered from past disturbances.	3.0
2pts	RECOVERING. The wetland appears to be in the process of recovering from past disturbances.	
1pt	RECENT OR NO RECOVERY. The disturbances have occurred recently, and/or the wetland has not recovered from past disturbances, and/or the disturbances are ongoing.	

4a Avg.=
3.00

4b. Habitat development. Select only one and assign score. This question asks the evaluator to assign an overall qualitative rating of how well-developed the wetland is in comparison to other ecologically and/or hydrogeomorphically similar wetlands. This question presumes knowledge of the types of wetlands and the range in quality typical of the region or access to data from reference standard examples. If unsure, score as GOOD or MODERATELY GOOD.

7pts	EXCELLENT. Wetland appears to represent the best of its type or class.	
6pts	VERY GOOD. Wetland appears to be a very good example of its type or class but is lacking in characteristics which would make it excellent.	
5pts	GOOD. Wetland appears to be a good example of its type or class but because of past or present disturbances, successional state, or other reasons, is not excellent.	
4pts	MODERATELY GOOD. Wetland appears to be a fair to good example of its type or class.	4.0
3pts	FAIR. Wetland appears to be a moderately good example of its type or class but because of past or present disturbances, successional state, etc. is not good.	
2pts	POOR TO FAIR. Wetland appears to be a poor to fair example of its type or class.	
1pt	POOR. Wetland appears not to be a good example of its type or class because of past or present disturbances, successional state, etc.	

4b Avg.=
4.00

4c. Habitat alteration. This question evaluates the "intactness" the natural habitat of the type of wetland that is being evaluated. This question does not discriminate between wetlands with different types of habitat. Check all possible alterations that are observed. All available information, field visits, aerial photos, maps, etc. can be used to identify possible alterations. Evaluate whether the alteration is trivial in relation to the wetlands overall habitat. Select the most appropriate score that best describes the present state of the wetland. It is appropriate to "double check" and average scores. **The evaluator may check one or several of these possible disturbances, yet still determine that the natural habitat is intact.**

Check all that are observed present in or near the wetland

	Mowing		Herbaceous layer/aquatic bed removal
	Grazing (cattle, horses, etc.)		Sedimentation
	Clearcutting		Dredging
	Selective cutting		Row-crop or orchard farming
	Woody debris removal		Nutrient enrichment, e.g. nuisance algae
	Toxic pollutants	X	Other (specify): ROW Managed
	Shrub/sapling removal		Other (specify):

Have any of the disturbances identified above caused or appeared to cause more than trivial alterations to the wetland's natural habitat.	YES Assign a score 1, 3 or 6, or an intermediate score, depending on degree of recovery from the disturbance.	NO Assign a score of 9 since there are no or no apparent modifications.	NOT SURE Choose "recovered" and assign a score of 6.

Select one score or double check adjoining numbers and average the score.		Score
9pts	NONE OR NONE APPARENT. There are no past or current alterations that are apparent to the evaluator.	
6pts	RECOVERED. The wetland appears to have recovered from past alterations.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past alterations.	3.0
1pt	RECENT OR NO RECOVERY. The alterations have occurred recently, and/or the wetland has not recovered from past alterations, and/or the alterations are ongoing.	

4c Avg. = 3.00

Metric 4 Total 10

Metric 5. Special wetland communities. Assign points in left column if the wetland meets the associated criteria below. Refer to Narrative Rating for guidance. If wetland scores over 30 points within Metric 5 further determination needed to assess if the wetland exhibits outstanding ecological or recreational values as discussed in the Narrative Rating Section.

	5pts - >10m sq sphagnum or other moss or other vernal pools		5 pts - Superior fish, waterfowl, bat, or amphibian breeding habitat
	Ecological community with global rank (NatureServe): G1 (10pts), G2 (5pts), G2/G3 (3pts) or uncommon ecological resource in the ecoregion (habitat and/or species diversity, geology, wetland type, distribution/ occurrence) (10 pts)		5 pts - Wetland contains and is a buffer for a headwater stream or wetland contributes significantly to the water water quality of 303(d) listed stream and/or to surface or and/or to ground water
	10 pts - Older-aged mature forested wetland avg. DBH >= 30 inches		10 pts - Supports species Deemed in Need of Management by TWRA or TN Special Concern by TDEC

Metric 5 Total 0

Metric 6. Vegetation, Interspersion, and Microtopography (Max 20 points). **6a. Wetland Vegetation Communities** Check each community present both vertically and horizontally within the wetland with an area of at least 0.1 hectares or $1000m^2$ (0.2471 acres). Assign a score of 0 to 3 using Table 3 for 1-4 or Table 5 for 5-6. Sum the scores for the classes present.	Score
1)Aquatic Bed Includes areas of wetlands dominated by plants that grow principally on or below the surface of the water for most of the growing season in most years. Floating aquatic species like duckweed (*Lemna* spp., *Spirodela* spp.) are excluded from definition of “aquatic bed." Aquatic beds often occur as a distinct zone as an “understory” below shrubs or trees.	
2)Emergent Includes areas of wetlands dominated by erect, rooted, herbaceous hydrophytes, excluding mosses and lichens. This vegetation is present for most of the growing season in most years. Common names for emergent communities include marsh, wet meadow, wet prairie, sedge meadow, and fens.	0.00
3)Shrub Includes areas of wetlands dominated by woody vegetation less than 1m (3ft.) - 6m (20 ft) tall with a dbh of <3in. The plant species include true shrubs, young trees, or trees or shrubs that are small or stunted because of environmental conditions. Shrub wetlands may represent a successional stage leading to a forested wetland or they may be relatively stable plant communities.	
4)Forested Includes wetlands or areas of wetlands characterized by woody vegetation greater than 6m (20ft) or taller. Forested wetlands have an overstory of trees and often contain an understory of young trees and shrubs and an herbaceous layer, although the young tree/shrub and herbaceous layers can be largely missing from some types of forested wetlands. Some forested wetlands are “vernal pools”.	
5)Mudflats The “mudflat” class is equivalent to the “unconsolidated bottom/mud” class/subclass (PUB_3) described in Cowardin et al. (1979) and includes areas of wetlands characterized by exposed or shallowly inundated substrates with vegetative cover less than 30%.	
6)Open water The “open water” class is equivalent to the “open water - unknown bottom” class in Cowardin et al. (1979) and includes areas that are 1) inundated, 2) un-vegetated, and 3) and “open”, i.e. there is no “canopy” of any type of vegetation.	

Table 3. Use this table to assign a cover score for Metric 6a to each of the vegetation communities identified on the preceding page. Refer to Table 4 for narrative description of “low,” “moderate,” and “high” quality.

Cover Scale	Description
0	The vegetation community is either 1) absent from wetland or 2) Comprises less than 0.1 ha (.2471 acres) of contiguous area within the wetland
1	Vegetation community is present and either, 1) comprises a significant part of the wetland’s vegetation and is of low or moderate quality, or 2) if it comprises a significant part of the wetland’s vegetation and is of low quality
2	Thee vegetation community is present and either, 1) comprises a significant part of the wetland’s vegetation and is of moderate quality, or 2) the vegetation community comprises a small part of the wetland’s vegetation but is of high quality
3	The vegetation community is of high quality and comprises a significant part, or more, of the wetland’s vegetation

Table 4. Use this table in conjunction with Table 3 to determine what is a “low”, “moderate,” or “ high” quality community.

Narrative	Description
Low	Low species richness and a predominance of invasive, non-native, or disturbance tolerant “weedy” species.
Moderate	Native species are the dominant component of the vegetation, although non-native or disturbance tolerant “weedy” species can also be present, and species richness is moderate to moderately high, but generally without the presence of rare, threatened, or endangered species.
High	A predominance of native species, with non-native species absent or virtually absent, and high species diversity and/or the presence of rare, threatened or endangered species.

Table 5. Mudflat and open water community cover scale.

0	Absent <0.1 ha (0.247 acres)
1	Low 0.1 to <1ha (0.247 to 2.47 acres)
2	Moderate 1 ha to < 4 ha (2.47 to 9.88 acres)
3	High 4 ha (9.88 acres) or more

6b. Horizontal (plan view) interspersion. Evaluate the wetland from a "plan view," i.e. as if the looking down upon it. See Figure 1.	Score
5pts HIGH Wetland has a high degree of interspersion	
4pts MODERATELY HIGH Wetland has a moderately high degree of interspersion	
3pts MODERATE Wetland has a moderate degree of interspersion	
2pts MODERATELY LOW Wetland has a moderately low degree of interspersion	2.0
1pt LOW Wetland has a low degree of interspersion.	
0pt NONE Wetland has no plan view interspersion	

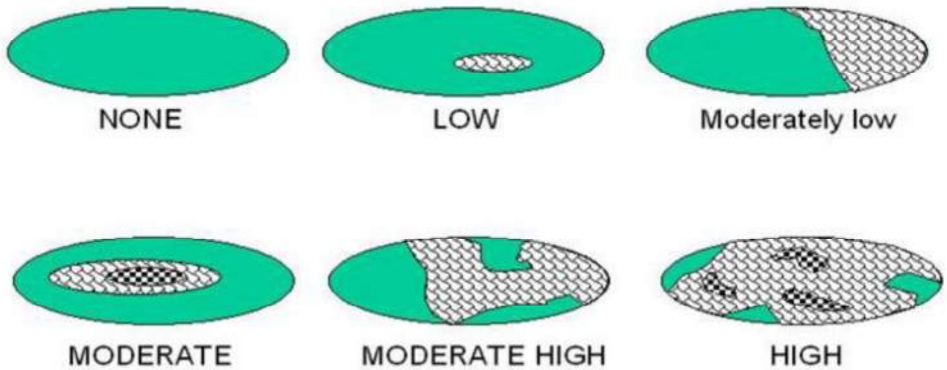

Figure 1. Hypothetical Wetlands for estimating degree of interspersion

6c. Coverage of Invasive Plant Species. Refer to Tennessee Exotic Pest Plant Council (http://www.tneppc.org/) for official list. Select only one and assign score.		Score
-5pts	Extensive >75% areal cover of invasive species	
-3pts	Moderate 25-75% areal cover of invasive species	
-1pts	Sparse 5-25% areal cover of invasive species	
0pt	Nearly absent. <5% areal cover of invasive species	0
1pt	Absent	

6d. Microtopography. Check each feature present in the wetland. Assign cover score of 0 to 3 using Table 6. Evaluate various microtopograhic habitat features often present in wetlands.	Score
Vegetated hummocks and tussocks	
Coarse woody debris >15cm (6in) in diameter	
Standing dead trees >25cm (10in) diameter at breast height	
Amphibian breeding habitat, e.g. vernal pools with standing water of sufficient duration and depth to support reproduction, or habitat for frog reproduction	

Table 6. Cover scale for microtopographic habitat features

Microtopographic habitat quality	**Narrative description**
0	Feature is absent or functionally absent from the wetland
1	Feature is present in the wetland in very small amounts or if more common, of low quality
2	Feature is present in moderate amounts, but not of highest quality or in small amounts of highest quality
3	Present in moderate or greater amounts and of the highest quality

Metric 6 Total 2

NON-HGM TRAM Summary Worksheet

Non-HGM Quantitative Rating	Metric 1: Size	1
	Metric 2: Buffers and surrounding land use	3.5
	Metric 3: Hydrology	6
	Metric 4: Habitat	10
	Metric 5: Special Wetland Communities	0
	Metric 6: Plant communities, interspersion, microtopography	2
	TOTAL SCORE	23

KIF Retirement

PID#39170

W004

Rank = Low

"Wetland Conditions with an overall score of 100-75 are considered Exceptional Tennessee Waters. Wetlands with a score of 74-45 are considered to have moderate resource value, and wetland with a score of 44 and below have a low resource value."
(TRAM 2015, pg 2)

Quantitative Rating
Tennessee Rapid Assessment Method

W005
3/30/2022
FPH

Metric 1. Wetland area (max 6 pts). Estimate the area of wetland and select the appropriate size class and assign score. Estimated areas should clearly place the wetland within the appropriate class.

6pts	>50 acres (west TN)	>25 acres (middle TN)	>10 acres (east TN *)	
5pts	25 - <50 acres (west TN)	10- 25 acres (middle TN)	7-<10 acres (east TN*)	
4pts	10 - <25 acres (west TN)	7-< 25acres (middle TN)	3-<7 acres (east TN*)	
3pts	3 - <10 acres(west TN)	3< 7 acres (middle TN)	1-<3 acres (east TN)	
2pts	0.3 - <3 acres (west TN)	0.5- <3 acres (middle TN)	0.5-<1 acres (east TN)	
1pt	0.1 - <0.3 acres(west TN)	<0.5 acres (middle TN)	<0.5 acres (east TN)	1

*More applicable to West Tennessee; use with discretion in Middle Tennessee, Consult TDEC-DWR Natural Resources Unit for use in East Tennessee.

Table 2. Metric to English conversion table with visual estimation sizes.

acres	ft^2	yd^2	ft on side	yd on side	ha	m^2	m on side
50	2,177,983	241,998	1476	492	20.2	202,000	449
25	1,088,992	120,999	1044	348	10.1	101,000	318
10	435,596	48,340	660	220	4.1	41,000	203
3	130,679	14,520	362	121	1.2	12,000	110
0.3	13,067	1,452	114	38	0.12	1,200	35
0.1	4,356	484	66	22	0.04	400	20

Metric 1 Total 1

Metric 2. Upland buffers and intensity of surrounding land uses (Max 14 points). Wetlands without upland "buffers", or that are located where human land use is more intensive, are often, but not always, more degraded and often have lower wildlife habitat resource value.

2a. Average Buffer Width (ABW). Calculate the average buffer width and select only one score. To calculate ABW, estimate buffer width on each side (max of 50m) and divide by the number of sides. Example: ABW of a wetland with buffers of 100m, 25m, 10m and 0m would be calculated as follows: ABW = (50m + 25m + 10m + 0m)/4 = 21.25m. Intensive land uses are not buffers, e.g. active row cropping, paved areas, housing developments, etc.			
7pts	WIDE. >50m (164ft) or more around perimeter.	7	
4pts	MEDIUM. 25m to <50m (82 to <164ft) around the perimeter.		
1pt	NARROW. 10m to <25m (32 to <82ft) around the perimeter.		
0pts	VERY NARROW. <10m (<32ft) around perimeter.		2a Avg.= 7.00
2b. Intensity of predominant surrounding land use(s) Select one, or choose up to two and average score, for the intensity of the predominant land use(s) outside the wetland's buffer zone.			
7pts	VERY LOW. 2nd growth or older forest, prairie, barren, wildlife area, etc.		
5pts	LOW. Old fallow field, shrub land, early successional young forest, etc.	5	
3pts	MODERATELY HIGH. Residential, pasture, orchard, park, conservation tillage, mowed field, etc.		
1pt	HIGH. urban, industrial, row cropping, mining, construction, etc.		2b Avg.= 5.00

KIF Retirement

PID#39170

W005

Metric 2 Total 12.00

Metric 3. Hydrology (Max 30 points). This metric evaluates the wetland's water budget, hydroperiod, the hydrologic connectivity of the wetland to other surface waters, and the degree to which the wetland's hydrology has been altered by human activity**. A wetland can receive no more than 30 points for Metric 3 even though it is possible to score more than 30 points.**

3a. Sources of Water. Select all that apply and sum the score. This question relates to a wetland's water budget. It also is reflective that wetlands with certain types of water sources, or multiple water sources, e.g. high pH groundwater or perennial surface water connections, can be very high quality wetlands or can have high functions and values.		
5pts	High pH groundwater (7.5-9.0)	
3pts	Other groundwater	
1pts	Precipitation	1
3pts	Seasonal surface water	
5pts	Perennial surface water (lake or stream)	
3b. Connectivity. Select all that apply and sum score		
1pt	**100 year floodplain.** "Floodplain" is defined as "...the relatively level land next to a stream or river channel that is periodically submerged by flood waters. It is composed of alluvium deposited by the present stream or river when it floods." Where they are available, flood insurance rate maps (FIRMs) and flood boundary and floodway maps may be used.	
1pt	**Between stream/lake and other human land use.** This question asks whether the wetland is located between a surface water and a different adjacent land use, such that run-off from the adjacent land use could flow through wetland before it discharges into the surface water buffering it. "Different adjacent land uses" include agricultural, commercial, industrial, mining, or residential uses.	1
1pt	**Part of a larger wetland or upland complex.** This question asks whether the wetland is in physical proximity to, or a other nearby wetland or upland habitat areas.	
1pt	**Part of riparian corridor**.	
3c. Maximum water depth. Select only one and assign score. The evaluator *does not* need to actually observe the wetland when its water depth is greatest in order to award the maximum points for this question. The use of secondary indicators, as outlined in the 1987 Manual will be useful in answering this question.		
3 pts	>0.7m (27.6in)	
2pts	0.4 to 0.7m (15.7 to 27.6in)	
1pt	<0.4m (<15.7in)	1
3d. Duration of inundation/saturation. Select one or double check and average the scores if duration is uncertain. The use of ACOE 1987 Manual secondary indicators is necessary and expected in order to properly answer this question.		
4pts	Semi-permanently to permanently inundated or saturated	
3pts	Regularly inundated or saturated	3
2pts	Seasonally inundated	
1pt	Seasonally saturated in the upper 30cm (12in) of soil	

3d Avg.= 3.00

KIF Retirement

PID#39170

W005

3e. Modifications to natural hydrologic regime. Check all observable modifications from list below. Score by selecting the most appropriate description of the wetland. Scores may be double checked and averaged. This question asks the evaluator to assess the “intactness” of, or lack of disturbance to, the natural hydrologic regime of the type of wetland that is being evaluated.

Once the evaluator has listed all possible past and ongoing disturbances, the evaluator should check the most appropriate category to describe the present state of the wetland. In instances where the evaluator believes that a wetland falls between two categories, or where the evaluator is uncertain as to which category is appropriate, it is appropriate to choose more than one and average the score.

The evaluator may check one or several of these possible disturbances, yet still determine that the natural hydrologic regime is intact. However, see Metric 4 where these same disturbances may be habitat alterations.

Check all that are observed present in or near the wetland.

	ditch(es), in or near the wetland		point source discharges to the (non-stormwater)
	tile(s), in or near the wetland		filling/grading activities in or near the wetland
	dike(s), in or near the wetland		road beds/RR beds in or near the wetland
	weir(s), in or near the wetland		dredging activities in or near the wetland
	stormwater inputs (addition of water)		other (specify)

	YES	NO	NOT SURE
Have any of the disturbances identified above caused or appear to have caused more than trivial alterations to the wetland's natural hydrologic regime.	Assign a score 1, 3 or 7, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 12 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 9.5.

Select one or double check adjoining numbers and average the score.		score
12pts	NONE OR NONE APPARENT. There are no modifications or no modifications that are apparent to the evaluator.	
7pts	RECOVERED. The wetland appears to have recovered from past modifications.	7.00
3pts	RECOVERING. The wetland appears to be in the process of recovering from past modifications.	
1pt	RECENT OR NO RECOVERY. The modifications have occurred recently occurred, and/or the wetland has not recovered from past modifications, and/or the modifications are ongoing.	

3e Avg=
7.00

KIF Retirement

Metric 3 Total 13.00

PID#39170

W005

Metric 4. Habitat Alteration and Development (Max 20 points). While hydrology may be the single most important determinant for the establishment and maintenance of specific types of wetlands and wetland processes, there is a range of other factors and activities which affect wetland quality and cause disturbances to wetlands that are unrelated to hydrology. These disturbances are termed "habitat alteration." In many instances, items checked as hydrologic disturbances in Question 3e will present as alterations to a wetland's habitat or disruptions in its development (successional state). In some instances, a disturbance may be appropriately considered under both Metric 3 and Metric 4. To determine the appropriate metric scores, the evaluator should carefully determine the actual cause of the disturbance to the wetland.

4a. Substrate/Soil Disturbance. Select one or double check and average. This question evaluates physical disturbances to the soil and surface substrates of the wetland. Note also that the labels on the scoring categories are intended to be descriptive but not controlling. In some instances, it may be more appropriate to consider the scoring categories as fixed locations on a disturbance continuum, from very high to very low or no disturbance.

Examples of substrate/soil disturbance include (circle all that apply):
____filling and grading
____plowing
____grazing (hooves)
____vehicle use (off-road vehicles, construction vehicles)
____sedimentation
____dredging, and other mechanical disturbances to the soil

Have any of soil or substrate disturbances caused or appear to have caused more than trivial alterations to the wetland's natural soils	YES	NO	NOT SURE
	Assign a score 1, 2 or 3, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 4 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 3.5.

Select one or double check adjoining numbers and average the score.		
4pts	NONE OR NONE APPARENT. There are no disturbances or no disturbances apparent to the evaluator.	
3pts	RECOVERED. The wetland appears to have recovered from past disturbances.	3.0
2pts	RECOVERING. The wetland appears to be in the process of recovering from past disturbances.	
1pt	RECENT OR NO RECOVERY. The disturbances have occurred recently, and/or the wetland has not recovered from past disturbances, and/or the disturbances are ongoing.	

4a Avg.= 3.00

4b. Habitat development. Select only one and assign score. This question asks the evaluator to assign an overall qualitative rating of how well-developed the wetland is in comparison to other ecologically and/or hydrogeomorphically similar wetlands. This question presumes knowledge of the types of wetlands and the range in quality typical of the region or access to data from reference standard examples. If unsure, score as GOOD or MODERATELY GOOD.

7pts	EXCELLENT. Wetland appears to represent the best of its type or class.	
6pts	VERY GOOD. Wetland appears to be a very good example of its type or class but is lacking in characteristics which would make it excellent.	
5pts	GOOD. Wetland appears to be a good example of its type or class but because of past or present disturbances, successional state, or other reasons, is not excellent.	5.0
4pts	MODERATELY GOOD. Wetland appears to be a fair to good example of its type or class.	
3pts	FAIR. Wetland appears to be a moderately good example of its type or class but because of past or present disturbances, successional state, etc. is not good.	
2pts	POOR TO FAIR. Wetland appears to be a poor to fair example of its type or class.	
1pt	POOR. Wetland appears not to be a good example of its type or class because of past or present disturbances, successional state, etc.	

4b Avg.= 5.00

4c. Habitat alteration. This question evaluates the "intactness" the natural habitat of the type of wetland that is being evaluated. This question does not discriminate between wetlands with different types of habitat. Check all possible alterations that are observed. All available information, field visits, aerial photos, maps, etc. can be used to identify possible alterations. Evaluate whether the alteration is trivial in relation to the wetlands overall habitat. Select the most appropriate score that best describes the present state of the wetland. It is appropriate to "double check" and average scores. **The evaluator may check one or several of these possible disturbances, yet still determine that the natural habitat is intact.**

Check all that are observed present in or near the wetland

	Mowing		Herbaceous layer/aquatic bed removal
	Grazing (cattle, horses, etc.)		Sedimentation
	Clearcutting		Dredging
	Selective cutting		Row-crop or orchard farming
	Woody debris removal		Nutrient enrichment, e.g. nuisance algae
	Toxic pollutants		Other (specify):
	Shrub/sapling removal		Other (specify):

Have any of the disturbances identified above caused or appeared to cause more than trivial alterations to the wetland's natural habitat.	YES Assign a score 1, 3 or 6, or an intermediate score, depending on degree of recovery from the disturbance.	NO Assign a score of 9 since there are no or no apparent modifications.	NOT SURE Choose "recovered" and assign a score of 6.

Select one score or double check adjoining numbers and average the score.		Score
9pts	NONE OR NONE APPARENT. There are no past or current alterations that are apparent to the evaluator.	
6pts	RECOVERED. The wetland appears to have recovered from past alterations.	6.00
3pts	RECOVERING. The wetland appears to be in the process of recovering from past alterations.	
1pt	RECENT OR NO RECOVERY. The alterations have occurred recently, and/or the wetland has not recovered from past alterations, and/or the alterations are ongoing.	

4c Avg. =
6.00

Metric 4 Total 14

Metric 5. Special wetland communities. Assign points in left column if the wetland meets the associated criteria below. Refer to Narrative Rating for guidance. If wetland scores over 30 points within Metric 5 further determination needed to assess if the wetland exhibits outstanding ecological or recreational values as discussed in the Narrative Rating Section.

	5pts - >10m sq sphagnum or other moss or other vernal pools		5 pts - Superior fish, waterfowl, bat, or amphibian breeding habitat
	Ecological community with global rank (NatureServe): G1 (10pts), G2 (5pts), G2/G3 (3pts) or uncommon ecological resource in the ecoregion (habitat and/or species diversity, geology, wetland type, distribution/ occurrence) (10 pts)		5 pts - Wetland contains and is a buffer for a headwater stream or wetland contributes significantly to the water water quality of 303(d) listed stream and/or to surface or and/or to ground water
	10 pts - Older-aged mature forested wetland avg. DBH >= 30 inches		10 pts - Supports species Deemed in Need of Management by TWRA or TN Special Concern by TDEC

Metric 5 Total 0

Metric 6. Vegetation, Interspersion, and Microtopography (Max 20 points). **6a. Wetland Vegetation Communities** Check each community present both vertically and horizontally within the wetland with an area of at least 0.1 hectares or 1000m^2 (0.2471 acres). Assign a score of 0 to 3 using Table 3 for 1-4 or Table 5 for 5-6. Sum the scores for the classes present.	Score
1)Aquatic Bed Includes areas of wetlands dominated by plants that grow principally on or below the surface of the water for most of the growing season in most years. Floating aquatic species like duckweed (*Lemna* spp., *Spirodela* spp.) are excluded from definition of "aquatic bed." Aquatic beds often occur as a distinct zone as an "understory" below shrubs or trees.	
2)Emergent Includes areas of wetlands dominated by erect, rooted, herbaceous hydrophytes, excluding mosses and lichens. This vegetation is present for most of the growing season in most years. Common names for emergent communities include marsh, wet meadow, wet prairie, sedge meadow, and fens.	
3)Shrub Includes areas of wetlands dominated by woody vegetation less than 1m (3ft.) - 6m (20 ft) tall with a dbh of <3in. The plant species include true shrubs, young trees, or trees or shrubs that are small or stunted because of environmental conditions. Shrub wetlands may represent a successional stage leading to a forested wetland or they may be relatively stable plant communities.	
4)Forested Includes wetlands or areas of wetlands characterized by woody vegetation greater than 6m (20ft) or taller. Forested wetlands have an overstory of trees and often contain an understory of young trees and shrubs and an herbaceous layer, although the young tree/shrub and herbaceous layers can be largely missing from some types of forested wetlands. Some forested wetlands are "vernal pools".	0.00
5)Mudflats The "mudflat" class is equivalent to the "unconsolidated bottom/mud" class/subclass (PUB_3) described in Cowardin et al. (1979) and includes areas of wetlands characterized by exposed or shallowly inundated substrates with vegetative cover less than 30%.	
6)Open water The "open water" class is equivalent to the "open water - unknown bottom" class in Cowardin et al. (1979) and includes areas that are 1) inundated, 2) un-vegetated, and 3) and "open", i.e. there is no "canopy" of any type of vegetation.	

Table 3. Use this table to assign a cover score for Metric 6a to each of the vegetation communities identified on the preceding page. Refer to Table 4 for narrative description of "low," "moderate," and "high" quality.

Cover Scale	Description
0	The vegetation community is either 1) absent from wetland or 2) Comprises less than 0.1 ha (.2471 acres) of contiguous area within the wetland
1	Vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of low or moderate quality, or 2) if it comprises a significant part of the wetland's vegetation and is of low quality
2	Thee vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of moderate quality, or 2) the vegetation community comprises a small part of the wetland's vegetation but is of high quality
3	The vegetation community is of high quality and comprises a significant part, or more, of the wetland's vegetation

Table 4. Use this table in conjunction with Table 3 to determine what is a "low", "moderate," or " high" quality community.

Narrative	Description
Low	Low species richness and a predominance of invasive, non-native, or disturbance tolerant "weedy" species.
Moderate	Native species are the dominant component of the vegetation, although non-native or disturbance tolerant "weedy" species can also be present, and species richness is moderate to moderately high, but generally without the presence of rare, threatened, or endangered species.
High	A predominance of native species, with non-native species absent or virtually absent, and high species diversity and/or the presence of rare, threatened or endangered species.

Table 5. Mudflat and open water community cover scale.

0	Absent <0.1 ha (0.247 acres)
1	Low 0.1 to <1ha (0.247 to 2.47 acres)
2	Moderate 1 ha to < 4 ha (2.47 to 9.88 acres)
3	High 4 ha (9.88 acres) or more

6b. Horizontal (plan view) interspersion. Evaluate the wetland from a "plan view," i.e. as if the looking down upon it. See Figure 1.	Score
5pts HIGH Wetland has a high degree of interspersion	
4pts MODERATELY HIGH Wetland has a moderately high degree of interspersion	
3pts MODERATE Wetland has a moderate degree of interspersion	3.0
2pts MODERATELY LOW Wetland has a moderately low degree of interspersion	
1pt LOW Wetland has a low degree of interspersion.	
0pt NONE Wetland has no plan view interspersion	

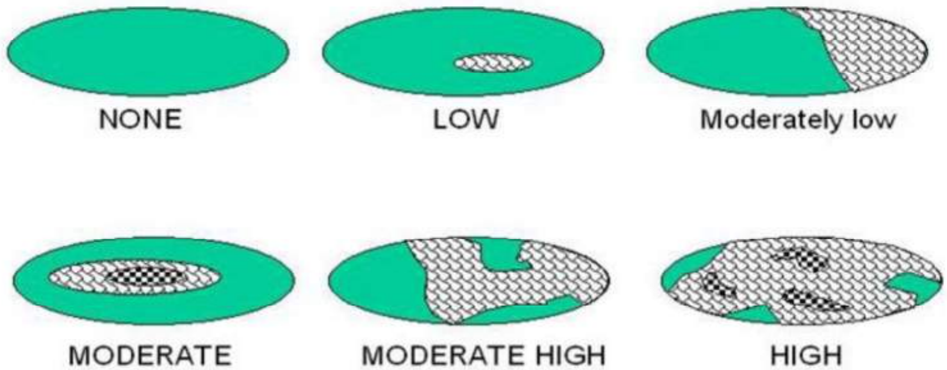

Figure 1. Hypothetical Wetlands for estimating degree of interspersion

6c. Coverage of Invasive Plant Species. Refer to Tennessee Exotic Pest Plant Council (http://www.tneppc.org/) for official list. Select only one and assign score.		Score
-5pts	Extensive >75% areal cover of invasive species	
-3pts	Moderate 25-75% areal cover of invasive species	
-1pts	Sparse 5-25% areal cover of invasive species	
0pt	Nearly absent. <5% areal cover of invasive species	0
1pt	Absent	

6d. Microtopography. Check each feature present in the wetland. Assign cover score of 0 to 3 using Table 6. Evaluate various microtopograhic habitat features often present in wetlands.	Score
Vegetated hummocks and tussocks	
Coarse woody debris >15cm (6in) in diameter	
Standing dead trees >25cm (10in) diameter at breast height	
Amphibian breeding habitat, e.g. vernal pools with standing water of sufficient duration and depth to support reproduction, or habitat for frog reproduction	

Table 6. Cover scale for microtopographic habitat features

Microtopographic habitat quality	**Narrative description**
0	Feature is absent or functionally absent from the wetland
1	Feature is present in the wetland in very small amounts or if more common, of low quality
2	Feature is present in moderate amounts, but not of highest quality or in small amounts of highest quality
3	Present in moderate or greater amounts and of the highest quality

Metric 6 Total 3

NON-HGM TRAM Summary Worksheet

Non-HGM Quantitative Rating	Metric 1: Size	1
	Metric 2: Buffers and surrounding land use	12
	Metric 3: Hydrology	13
	Metric 4: Habitat	14
	Metric 5: Special Wetland Communities	0
	Metric 6: Plant communities, interspersion, microtopography	3
	TOTAL SCORE	43

KIF Retirement

PID#39170

W005

Rank = Low

"Wetland Conditions with an overall score of 100-75 are considered Exceptional Tennessee Waters. Wetlands with a score of 74-45 are considered to have moderate resource value, and wetland with a score of 44 and below have a low resource value."
(TRAM 2015, pg 2)

Quantitative Rating
Tennessee Rapid Assessment Method

Metric 1. Wetland area (max 6 pts). Estimate the area of wetland and select the appropriate size class and assign score. Estimated areas should clearly place the wetland within the appropriate class.

6pts	>50 acres (west TN)	>25 acres (middle TN)	>10 acres (east TN *)	
5pts	25 - <50 acres (west TN)	10- 25 acres (middle TN)	7-<10 acres (east TN*)	
4pts	10 - <25 acres (west TN)	7-< 25acres (middle TN)	3-<7 acres (east TN*)	
3pts	3 - <10 acres(west TN)	3< 7 acres (middle TN)	1-<3 acres (east TN)	
2pts	0.3 - <3 acres (west TN)	0.5- <3 acres (middle TN)	0.5-<1 acres (east TN)	
1pt	0.1 - <0.3 acres(west TN)	<0.5 acres (middle TN)	<0.5 acres (east TN)	1

*More applicable to West Tennessee; use with discretion in Middle Tennessee, Consult TDEC-DWR Natural Resources Unit for use in East Tennessee.

Table 2. Metric to English conversion table with visual estimation sizes.

acres	ft^2	yd^2	ft on side	yd on side	ha	m^2	m on side
50	2,177,983	241,998	1476	492	20.2	202,000	449
25	1,088,992	120,999	1044	348	10.1	101,000	318
10	435,596	48,340	660	220	4.1	41,000	203
3	130,679	14,520	362	121	1.2	12,000	110
0.3	13,067	1,452	114	38	0.12	1,200	35
0.1	4,356	484	66	22	0.04	400	20

Metric 1 Total 1

Metric 2. Upland buffers and intensity of surrounding land uses (Max 14 points). Wetlands without upland “buffers", or that are located where human land use is more intensive, are often, but not always, more degraded and often have lower wildlife habitat resource value.

2a. Average Buffer Width (ABW). Calculate the average buffer width and select only one score. To calculate ABW, estimate buffer width on each side (max of 50m) and divide by the number of sides. Example: ABW of a wetland with buffers of 100m, 25m, 10m and 0m would be calculated as follows: ABW = (50m + 25m + 10m + 0m)/4 = 21.25m. Intensive land uses are not buffers, e.g. active row cropping, paved areas, housing developments, etc.			
7pts	WIDE. >50m (164ft) or more around perimeter.		
4pts	MEDIUM. 25m to <50m (82 to <164ft) around the perimeter.		
1pt	NARROW. 10m to <25m (32 to <82ft) around the perimeter.		
0pts	VERY NARROW. <10m (<32ft) around perimeter.	0	2a Avg.= 0.00
2b. Intensity of predominant surrounding land use(s) Select one, or choose up to two and average score, for the intensity of the predominant land use(s) outside the wetland's buffer zone.			
7pts	VERY LOW. 2nd growth or older forest, prairie, barren, wildlife area, etc.		
5pts	LOW. Old fallow field, shrub land, early successional young forest, etc.		
3pts	MODERATELY HIGH. Residential, pasture, orchard, park, conservation tillage, mowed field, etc.		
1pt	HIGH. urban, industrial, row cropping, mining, construction, etc.	1	2b Avg.= 1.00

KIF Retirement

PID#39170

W006

Metric 2 Total 1.00

Metric 3. Hydrology (Max 30 points). This metric evaluates the wetland's water budget, hydroperiod, the hydrologic connectivity of the wetland to other surface waters, and the degree to which the wetland's hydrology has been altered by human activity**. A wetland can receive no more than 30 points for Metric 3 even though it is possible to score more than 30 points.**

3a. Sources of Water. Select all that apply and sum the score. This question relates to a wetland's water budget. It also is reflective that wetlands with certain types of water sources, or multiple water sources, e.g. high pH groundwater or perennial surface water connections, can be very high quality wetlands or can have high functions and values.		
5pts	High pH groundwater (7.5-9.0)	
3pts	Other groundwater	
1pts	Precipitation	1
3pts	Seasonal surface water	3
5pts	Perennial surface water (lake or stream)	
3b. Connectivity. Select all that apply and sum score		
1pt	**100 year floodplain.** "Floodplain" is defined as "...the relatively level land next to a stream or river channel that is periodically submerged by flood waters. It is composed of alluvium deposited by the present stream or river when it floods." Where they are available, flood insurance rate maps (FIRMs) and flood boundary and floodway maps may be used.	
1pt	**Between stream/lake and other human land use.** This question asks whether the wetland is located between a surface water and a different adjacent land use, such that run-off from the adjacent land use could flow through wetland before it discharges into the surface water buffering it. "Different adjacent land uses" include agricultural, commercial, industrial, mining, or residential uses.	1
1pt	**Part of a larger wetland or upland complex.** This question asks whether the wetland is in physical proximity to, or a other nearby wetland or upland habitat areas.	
1pt	**Part of riparian corridor**.	
3c. Maximum water depth. Select only one and assign score. The evaluator *does not* need to actually observe the wetland when its water depth is greatest in order to award the maximum points for this question. The use of secondary indicators, as outlined in the 1987 Manual will be useful in answering this question.		
3 pts	>0.7m (27.6in)	
2pts	0.4 to 0.7m (15.7 to 27.6in)	
1pt	<0.4m (<15.7in)	1
3d. Duration of inundation/saturation. Select one or double check and average the scores if duration is uncertain. The use of ACOE 1987 Manual secondary indicators is necessary and expected in order to properly answer this question.		
4pts	Semi-permanently to permanently inundated or saturated	4
3pts	Regularly inundated or saturated	
2pts	Seasonally inundated	
1pt	Seasonally saturated in the upper 30cm (12in) of soil	

3d Avg.= 4.00

KIF Retirement

PID#39170

W006

3e. Modifications to natural hydrologic regime. Check all observable modifications from list below. Score by selecting the most appropriate description of the wetland. Scores may be double checked and averaged. This question asks the evaluator to assess the "intactness" of, or lack of disturbance to, the natural hydrologic regime of the type of wetland that is being evaluated.

Once the evaluator has listed all possible past and ongoing disturbances, the evaluator should check the most appropriate category to describe the present state of the wetland. In instances where the evaluator believes that a wetland falls between two categories, or where the evaluator is uncertain as to which category is appropriate, it is appropriate to choose more than one and average the score.

The evaluator may check one or several of these possible disturbances, yet still determine that the natural hydrologic regime is intact. However, see Metric 4 where these same disturbances may be habitat alterations.

Check all that are observed present in or near the wetland.

	ditch(es), in or near the wetland		point source discharges to the (non-stormwater)
	tile(s), in or near the wetland		filling/grading activities in or near the wetland
	dike(s), in or near the wetland		road beds/RR beds in or near the wetland
	weir(s), in or near the wetland		dredging activities in or near the wetland
	stormwater inputs (addition of water)		other (specify)

Have any of the disturbances identified above caused or appear to have caused more than trivial alterations to the wetland's natural hydrologic regime.	YES Assign a score 1, 3 or 7, or an intermediate score, depending on degree of recovery from the disturbance.	NO Assign a score of 12 since there are no or no apparent modifications.	NOT SURE Choose "recovered" and assign a score of 9.5.

Select one or double check adjoining numbers and average the score.		**score**
12pts	NONE OR NONE APPARENT. There are no modifications or no modifications that are apparent to the evaluator.	
7pts	RECOVERED. The wetland appears to have recovered from past modifications.	7.00
3pts	RECOVERING. The wetland appears to be in the process of recovering from past modifications.	
1pt	RECENT OR NO RECOVERY. The modifications have occurred recently occurred, and/or the wetland has not recovered from past modifications, and/or the modifications are ongoing.	

3e Avg=
7.00

KIF Retirement

Metric 3 Total 17.00

PID#39170

W006

Metric 4. Habitat Alteration and Development (Max 20 points). While hydrology may be the single most important determinant for the establishment and maintenance of specific types of wetlands and wetland processes, there is a range of other factors and activities which affect wetland quality and cause disturbances to wetlands that are unrelated to hydrology. These disturbances are termed "habitat alteration." In many instances, items checked as hydrologic disturbances in Question 3e will present as alterations to a wetland's habitat or disruptions in its development (successional state). In some instances, a disturbance may be appropriately considered under both Metric 3 and Metric 4. To determine the appropriate metric scores, the evaluator should carefully determine the actual cause of the disturbance to the wetland.

4a. Substrate/Soil Disturbance. Select one or double check and average. This question evaluates physical disturbances to the soil and surface substrates of the wetland. Note also that the labels on the scoring categories are intended to be descriptive but not controlling. In some instances, it may be more appropriate to consider the scoring categories as fixed locations on a disturbance continuum, from very high to very low or no disturbance.	Examples of substrate/soil disturbance include (circle all that apply): ____filling and grading ____plowing ____grazing (hooves) ____vehicle use (off-road vehicles, construction vehicles) ____sedimentation ____dredging, and other mechanical disturbances to the soil

	YES	NO	NOT SURE
Have any of soil or substrate disturbances caused or appear to have caused more than trivial alterations to the wetland's natural soils	Assign a score 1, 2 or 3, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 4 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 3.5.

Select one or double check adjoining numbers and average the score.		
4pts	NONE OR NONE APPARENT. There are no disturbances or no disturbances apparent to the evaluator.	
3pts	RECOVERED. The wetland appears to have recovered from past disturbances.	3.0
2pts	RECOVERING. The wetland appears to be in the process of recovering from past disturbances.	
1pt	RECENT OR NO RECOVERY. The disturbances have occurred recently, and/or the wetland has not recovered from past disturbances, and/or the disturbances are ongoing.	

4a Avg.= 3.00

4b. Habitat development. Select only one and assign score. This question asks the evaluator to assign an overall qualitative rating of how well-developed the wetland is in comparison to other ecologically and/or hydrogeomorphically similar wetlands. This question presumes knowledge of the types of wetlands and the range in quality typical of the region or access to data from reference standard examples. If unsure, score as GOOD or MODERATELY GOOD.

7pts	EXCELLENT. Wetland appears to represent the best of its type or class.	
6pts	VERY GOOD. Wetland appears to be a very good example of its type or class but is lacking in characteristics which would make it excellent.	
5pts	GOOD. Wetland appears to be a good example of its type or class but because of past or present disturbances, successional state, or other reasons, is not excellent.	5.0
4pts	MODERATELY GOOD. Wetland appears to be a fair to good example of its type or class.	
3pts	FAIR. Wetland appears to be a moderately good example of its type or class but because of past or present disturbances, successional state, etc. is not good.	
2pts	POOR TO FAIR. Wetland appears to be a poor to fair example of its type or class.	
1pt	POOR. Wetland appears not to be a good example of its type or class because of past or present disturbances, successional state, etc.	

4b Avg.= 5.00

4c. Habitat alteration. This question evaluates the "intactness" the natural habitat of the type of wetland that is being evaluated. This question does not discriminate between wetlands with different types of habitat. Check all possible alterations that are observed. All available information, field visits, aerial photos, maps, etc. can be used to identify possible alterations. Evaluate whether the alteration is trivial in relation to the wetlands overall habitat. Select the most appropriate score that best describes the present state of the wetland. It is appropriate to "double check" and average scores. **The evaluator may check one or several of these possible disturbances, yet still determine that the natural habitat is intact.**

Check all that are observed present in or near the wetland

	Mowing		Herbaceous layer/aquatic bed removal
	Grazing (cattle, horses, etc.)		Sedimentation
	Clearcutting		Dredging
	Selective cutting		Row-crop or orchard farming
	Woody debris removal		Nutrient enrichment, e.g. nuisance algae
	Toxic pollutants		Other (specify):
	Shrub/sapling removal		Other (specify):

Have any of the disturbances identified above caused or appeared to cause more than trivial alterations to the wetland's natural habitat.	YES Assign a score 1, 3 or 6, or an intermediate score, depending on degree of recovery from the disturbance.	NO Assign a score of 9 since there are no or no apparent modifications.	NOT SURE Choose "recovered" and assign a score of 6.

Select one score or double check adjoining numbers and average the score.		Score
9pts	NONE OR NONE APPARENT. There are no past or current alterations that are apparent to the evaluator.	
6pts	RECOVERED. The wetland appears to have recovered from past alterations.	6.00
3pts	RECOVERING. The wetland appears to be in the process of recovering from past alterations.	
1pt	RECENT OR NO RECOVERY. The alterations have occurred recently, and/or the wetland has not recovered from past alterations, and/or the alterations are ongoing.	

4c Avg. = 6.00

Metric 4 Total 14

Metric 5. Special wetland communities. Assign points in left column if the wetland meets the associated criteria below. Refer to Narrative Rating for guidance. If wetland scores over 30 points within Metric 5 further determination needed to assess if the wetland exhibits outstanding ecological or recreational values as discussed in the Narrative Rating Section.

	5pts - >10m sq sphagnum or other moss or other vernal pools		5 pts - Superior fish, waterfowl, bat, or amphibian breeding habitat
	Ecological community with global rank (NatureServe): G1 (10pts), G2 (5pts), G2/G3 (3pts) or uncommon ecological resource in the ecoregion (habitat and/or species diversity, geology, wetland type, distribution/ occurrence) (10 pts)		5 pts - Wetland contains and is a buffer for a headwater stream or wetland contributes significantly to the water water quality of 303(d) listed stream and/or to surface or and/or to ground water
	10 pts - Older-aged mature forested wetland avg. DBH >= 30 inches		10 pts - Supports species Deemed in Need of Management by TWRA or TN Special Concern by TDEC

Metric 5 Total 0

Metric 6. Vegetation, Interspersion, and Microtopography (Max 20 points). **6a. Wetland Vegetation Communities** Check each community present <u>both vertically and horizontally</u> within the wetland with an area of at least 0.1 hectares or 1000m^2 (0.2471 acres). Assign a score of 0 to 3 using Table 3 for 1-4 or Table 5 for 5-6. Sum the scores for the classes present.	Score
1)Aquatic Bed Includes areas of wetlands dominated by plants that grow principally on or below the surface of the water for most of the growing season in most years. Floating aquatic species like duckweed (*Lemna* spp., *Spirodela* spp.) are excluded from definition of "aquatic bed." Aquatic beds often occur as a distinct zone as an "understory" below shrubs or trees.	
2)Emergent Includes areas of wetlands dominated by erect, rooted, herbaceous hydrophytes, excluding mosses and lichens. This vegetation is present for most of the growing season in most years. Common names for emergent communities include marsh, wet meadow, wet prairie, sedge meadow, and fens.	0.00
3)Shrub Includes areas of wetlands dominated by woody vegetation less than 1m (3ft.) - 6m (20 ft) tall with a dbh of <3in. The plant species include true shrubs, young trees, or trees or shrubs that are small or stunted because of environmental conditions. Shrub wetlands may represent a successional stage leading to a forested wetland or they may be relatively stable plant communities.	
4)Forested Includes wetlands or areas of wetlands characterized by woody vegetation greater than 6m (20ft) or taller. Forested wetlands have an overstory of trees and often contain an understory of young trees and shrubs and an herbaceous layer, although the young tree/shrub and herbaceous layers can be largely missing from some types of forested wetlands. Some forested wetlands are "vernal pools".	
5)Mudflats The "mudflat" class is equivalent to the "unconsolidated bottom/mud" class/subclass (PUB_3) described in Cowardin et al. (1979) and includes areas of wetlands characterized by exposed or shallowly inundated substrates with vegetative cover less than 30%.	
6)Open water The "open water" class is equivalent to the "open water - unknown bottom" class in Cowardin et al. (1979) and includes areas that are 1) inundated, 2) un-vegetated, and 3) and "open", i.e. there is no "canopy" of any type of vegetation.	

Table 3. Use this table to assign a cover score for Metric 6a to each of the vegetation communities identified on the preceding page. Refer to Table 4 for narrative description of "low," "moderate," and "high" quality.

Cover Scale	Description
0	The vegetation community is either 1) absent from wetland or 2) Comprises less than 0.1 ha (.2471 acres) of contiguous area within the wetland
1	Vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of low or moderate quality, or 2) if it comprises a significant part of the wetland's vegetation and is of low quality
2	Thee vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of moderate quality, or 2) the vegetation community comprises a small part of the wetland's vegetation but is of high quality
3	The vegetation community is of high quality and comprises a significant part, or more, of the wetland's vegetation

Table 4. Use this table in conjunction with Table 3 to determine what is a "low", "moderate," or " high" quality community.

Narrative	Description
Low	Low species richness and a predominance of invasive, non-native, or disturbance tolerant "weedy" species.
Moderate	Native species are the dominant component of the vegetation, although non-native or disturbance tolerant "weedy" species can also be present, and species richness is moderate to moderately high, but generally without the presence of rare, threatened, or endangered species.
High	A predominance of native species, with non-native species absent or virtually absent, and high species diversity and/or the presence of rare, threatened or endangered species.

Table 5. Mudflat and open water community cover scale.

0	Absent <0.1 ha (0.247 acres)
1	Low 0.1 to <1ha (0.247 to 2.47 acres)
2	Moderate 1 ha to < 4 ha (2.47 to 9.88 acres)
3	High 4 ha (9.88 acres) or more

6b. Horizontal (plan view) interspersion. Evaluate the wetland from a "plan view," i.e. as if the looking down upon it. See Figure 1.	Score
5pts HIGH Wetland has a high degree of interspersion	
4pts MODERATELY HIGH Wetland has a moderately high degree of interspersion	
3pts MODERATE Wetland has a moderate degree of interspersion	3.0
2pts MODERATELY LOW Wetland has a moderately low degree of interspersion	
1pt LOW Wetland has a low degree of interspersion.	
0pt NONE Wetland has no plan view interspersion	

KIF Retirement

W006

PID#39170

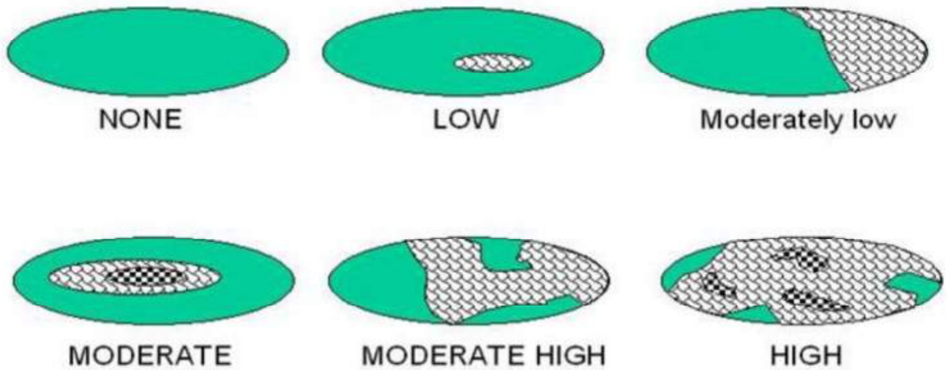

Figure 1. Hypothetical Wetlands for estimating degree of interspersion

6c. Coverage of Invasive Plant Species. Refer to Tennessee Exotic Pest Plant Council (http://www.tneppc.org/) for official list. Select only one and assign score.		Score
-5pts	Extensive >75% areal cover of invasive species	
-3pts	Moderate 25-75% areal cover of invasive species	
-1pts	Sparse 5-25% areal cover of invasive species	
0pt	Nearly absent. <5% areal cover of invasive species	0
1pt	Absent	

6d. Microtopography. Check each feature present in the wetland. Assign cover score of 0 to 3 using Table 6. Evaluate various microtopograhic habitat features often present in wetlands.	Score
Vegetated hummocks and tussocks	
Coarse woody debris >15cm (6in) in diameter	
Standing dead trees >25cm (10in) diameter at breast height	
Amphibian breeding habitat, e.g. vernal pools with standing water of sufficient duration and depth to support reproduction, or habitat for frog reproduction	

Table 6. Cover scale for microtopographic habitat features

Microtopographic habitat quality	**Narrative description**
0	Feature is absent or functionally absent from the wetland
1	Feature is present in the wetland in very small amounts or if more common, of low quality
2	Feature is present in moderate amounts, but not of highest quality or in small amounts of highest quality
3	Present in moderate or greater amounts and of the highest quality

Metric 6 Total 3

NON-HGM TRAM Summary Worksheet

Non-HGM Quantitative Rating	Metric 1: Size	1
	Metric 2: Buffers and surrounding land use	1
	Metric 3: Hydrology	17
	Metric 4: Habitat	14
	Metric 5: Special Wetland Communities	0
	Metric 6: Plant communities, interspersion, microtopography	3
	TOTAL SCORE	36

KIF Retirement

PID#39170

W006

Rank = Low

"Wetland Conditions with an overall score of 100-75 are considered Exceptional Tennessee Waters. Wetlands with a score of 74-45 are considered to have moderate resource value, and wetland with a score of 44 and below have a low resource value."
(TRAM 2015, pg 2)

Quantitative Rating
Tennessee Rapid Assessment Method

W007
3/30/2022
FPH

Metric 1. Wetland area (max 6 pts). Estimate the area of wetland and select the appropriate size class and assign score. Estimated areas should clearly place the wetland within the appropriate class.

6pts	>50 acres (west TN)	>25 acres (middle TN)	>10 acres (east TN *)	
5pts	25 - <50 acres (west TN)	10- 25 acres (middle TN)	7-<10 acres (east TN*)	
4pts	10 - <25 acres (west TN)	7-< 25acres (middle TN)	3-<7 acres (east TN*)	
3pts	3 - <10 acres(west TN)	3< 7 acres (middle TN)	1-<3 acres (east TN)	
2pts	0.3 - <3 acres (west TN)	0.5- <3 acres (middle TN)	0.5-<1 acres (east TN)	
1pt	0.1 - <0.3 acres(west TN)	<0.5 acres (middle TN)	<0.5 acres (east TN)	1

*More applicable to West Tennessee; use with discretion in Middle Tennessee, Consult TDEC-DWR Natural Resources Unit for use in East Tennessee.

Table 2. Metric to English conversion table with visual estimation sizes.

acres	ft^2	yd^2	ft on side	yd on side	ha	m^2	m on side
50	2,177,983	241,998	1476	492	20.2	202,000	449
25	1,088,992	120,999	1044	348	10.1	101,000	318
10	435,596	48,340	660	220	4.1	41,000	203
3	130,679	14,520	362	121	1.2	12,000	110
0.3	13,067	1,452	114	38	0.12	1,200	35
0.1	4,356	484	66	22	0.04	400	20

Metric 1 Total 1

Metric 2. Upland buffers and intensity of surrounding land uses (Max 14 points). Wetlands without upland "buffers", or that are located where human land use is more intensive, are often, but not always, more degraded and often have lower wildlife habitat resource value.

2a. Average Buffer Width (ABW). Calculate the average buffer width and select only one score. To calculate ABW, estimate buffer width on each side (max of 50m) and divide by the number of sides. Example: ABW of a wetland with buffers of 100m, 25m, 10m and 0m would be calculated as follows: ABW = (50m + 25m + 10m + 0m)/4 = 21.25m. Intensive land uses are not buffers, e.g. active row cropping, paved areas, housing developments, etc.			
7pts	WIDE. >50m (164ft) or more around perimeter.		
4pts	MEDIUM. 25m to <50m (82 to <164ft) around the perimeter.		
1pt	NARROW. 10m to <25m (32 to <82ft) around the perimeter.		
0pts	VERY NARROW. <10m (<32ft) around perimeter.	0	2a Avg.= 0.00
2b. Intensity of predominant surrounding land use(s) Select one, or choose up to two and average score, for the intensity of the predominant land use(s) outside the wetland's buffer zone.			
7pts	VERY LOW. 2nd growth or older forest, prairie, barren, wildlife area, etc.		
5pts	LOW. Old fallow field, shrub land, early successional young forest, etc.		
3pts	MODERATELY HIGH. Residential, pasture, orchard, park, conservation tillage, mowed field, etc.		
1pt	HIGH. urban, industrial, row cropping, mining, construction, etc.	1	2b Avg.= 1.00

KIF Retirement

PID#39170

W007

Metric 2 Total 1.00

Metric 3. Hydrology (Max 30 points). This metric evaluates the wetland's water budget, hydroperiod, the hydrologic connectivity of the wetland to other surface waters, and the degree to which the wetland's hydrology has been altered by human activity**. A wetland can receive no more than 30 points for Metric 3 even though it is possible to score more than 30 points.**

3a. Sources of Water. Select all that apply and sum the score. This question relates to a wetland's water budget. It also is reflective that wetlands with certain types of water sources, or multiple water sources, e.g. high pH groundwater or perennial surface water connections, can be very high quality wetlands or can have high functions and values.		
5pts	High pH groundwater (7.5-9.0)	
3pts	Other groundwater	
1pts	Precipitation	1
3pts	Seasonal surface water	
5pts	Perennial surface water (lake or stream)	
3b. Connectivity. Select all that apply and sum score		
1pt	**100 year floodplain.** "Floodplain" is defined as "...the relatively level land next to a stream or river channel that is periodically submerged by flood waters. It is composed of alluvium deposited by the present stream or river when it floods." Where they are available, flood insurance rate maps (FIRMs) and flood boundary and floodway maps may be used.	
1pt	**Between stream/lake and other human land use.** This question asks whether the wetland is located between a surface water and a different adjacent land use, such that run-off from the adjacent land use could flow through wetland before it discharges into the surface water buffering it. "Different adjacent land uses" include agricultural, commercial, industrial, mining, or residential uses.	
1pt	**Part of a larger wetland or upland complex.** This question asks whether the wetland is in physical proximity to, or a other nearby wetland or upland habitat areas.	
1pt	**Part of riparian corridor**.	
3c. Maximum water depth. Select only one and assign score. The evaluator *does not* need to actually observe the wetland when its water depth is greatest in order to award the maximum points for this question. The use of secondary indicators, as outlined in the 1987 Manual will be useful in answering this question.		
3 pts	>0.7m (27.6in)	
2pts	0.4 to 0.7m (15.7 to 27.6in)	
1pt	<0.4m (<15.7in)	1
3d. Duration of inundation/saturation. Select one or double check and average the scores if duration is uncertain. The use of ACOE 1987 Manual secondary indicators is necessary and expected in order to properly answer this question.		
4pts	Semi-permanently to permanently inundated or saturated	
3pts	Regularly inundated or saturated	3
2pts	Seasonally inundated	
1pt	Seasonally saturated in the upper 30cm (12in) of soil	

3d Avg.= 3.00

KIF Retirement

PID#39170

W007

3e. Modifications to natural hydrologic regime. Check all observable modifications from list below. Score by selecting the most appropriate description of the wetland. Scores may be double checked and averaged. This question asks the evaluator to assess the “intactness” of, or lack of disturbance to, the natural hydrologic regime of the type of wetland that is being evaluated.

Once the evaluator has listed all possible past and ongoing disturbances, the evaluator should check the most appropriate category to describe the present state of the wetland. In instances where the evaluator believes that a wetland falls between two categories, or where the evaluator is uncertain as to which category is appropriate, it is appropriate to choose more than one and average the score.

The evaluator may check one or several of these possible disturbances, yet still determine that the natural hydrologic regime is intact. However, see Metric 4 where these same disturbances may be habitat alterations.

Check all that are observed present in or near the wetland.

	ditch(es), in or near the wetland		point source discharges to the (non-stormwater)
	tile(s), in or near the wetland		filling/grading activities in or near the wetland
	dike(s), in or near the wetland		road beds/RR beds in or near the wetland
	weir(s), in or near the wetland		dredging activities in or near the wetland
	stormwater inputs (addition of water)		other (specify)

Have any of the disturbances identified above caused or appear to have caused more than trivial alterations to the wetland's natural hydrologic regime.	YES Assign a score 1, 3 or 7, or an intermediate score, depending on degree of recovery from the disturbance.	NO Assign a score of 12 since there are no or no apparent modifications.	NOT SURE Choose "recovered" and assign a score of 9.5.

Select one or double check adjoining numbers and average the score.		**score**
12pts	NONE OR NONE APPARENT. There are no modifications or no modifications that are apparent to the evaluator.	
7pts	RECOVERED. The wetland appears to have recovered from past modifications.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past modifications.	
1pt	RECENT OR NO RECOVERY. The modifications have occurred recently occurred, and/or the wetland has not recovered from past modifications, and/or the modifications are ongoing.	1

3e Avg=
1.00

KIF Retirement

Metric 3 Total 6.00

PID#39170

W007

Metric 4. Habitat Alteration and Development (Max 20 points). While hydrology may be the single most important determinant for the establishment and maintenance of specific types of wetlands and wetland processes, there is a range of other factors and activities which affect wetland quality and cause disturbances to wetlands that are unrelated to hydrology. These disturbances are termed "habitat alteration." In many instances, items checked as hydrologic disturbances in Question 3e will present as alterations to a wetland's habitat or disruptions in its development (successional state). In some instances, a disturbance may be appropriately considered under both Metric 3 and Metric 4. To determine the appropriate metric scores, the evaluator should carefully determine the actual cause of the disturbance to the wetland.

4a. Substrate/Soil Disturbance. Select one or double check and average. This question evaluates physical disturbances to the soil and surface substrates of the wetland. Note also that the labels on the scoring categories are intended to be descriptive but not controlling. In some instances, it may be more appropriate to consider the scoring categories as fixed locations on a disturbance continuum, from very high to very low or no disturbance.	Examples of substrate/soil disturbance include (circle all that apply): ____filling and grading ____plowing ____grazing (hooves) ____vehicle use (off-road vehicles, construction vehicles) ____sedimentation ____dredging, and other mechanical disturbances to the soil

Have any of soil or substrate disturbances caused or appear to have caused more than trivial alterations to the wetland's natural soils	YES	NO	NOT SURE
	Assign a score 1, 2 or 3, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 4 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 3.5.

Select one or double check adjoining numbers and average the score.		
4pts	NONE OR NONE APPARENT. There are no disturbances or no disturbances apparent to the evaluator.	
3pts	RECOVERED. The wetland appears to have recovered from past disturbances.	
2pts	RECOVERING. The wetland appears to be in the process of recovering from past disturbances.	2.0
1pt	RECENT OR NO RECOVERY. The disturbances have occurred recently, and/or the wetland has not recovered from past disturbances, and/or the disturbances are ongoing.	

4a Avg.=
2.00

4b. Habitat development. Select only one and assign score. This question asks the evaluator to assign an overall qualitative rating of how well-developed the wetland is in comparison to other ecologically and/or hydrogeomorphically similar wetlands. This question presumes knowledge of the types of wetlands and the range in quality typical of the region or access to data from reference standard examples. If unsure, score as GOOD or MODERATELY GOOD.

7pts	EXCELLENT. Wetland appears to represent the best of its type or class.	
6pts	VERY GOOD. Wetland appears to be a very good example of its type or class but is lacking in characteristics which would make it excellent.	
5pts	GOOD. Wetland appears to be a good example of its type or class but because of past or present disturbances, successional state, or other reasons, is not excellent.	
4pts	MODERATELY GOOD. Wetland appears to be a fair to good example of its type or class.	
3pts	FAIR. Wetland appears to be a moderately good example of its type or class but because of past or present disturbances, successional state, etc. is not good.	3.0
2pts	POOR TO FAIR. Wetland appears to be a poor to fair example of its type or class.	
1pt	POOR. Wetland appears not to be a good example of its type or class because of past or present disturbances, successional state, etc.	

4b Avg.=
3.00

4c. Habitat alteration. This question evaluates the "intactness" the natural habitat of the type of wetland that is being evaluated. This question does not discriminate between wetlands with different types of habitat. Check all possible alterations that are observed. All available information, field visits, aerial photos, maps, etc. can be used to identify possible alterations. Evaluate whether the alteration is trivial in relation to the wetlands overall habitat. Select the most appropriate score that best describes the present state of the wetland. It is appropriate to "double check" and average scores. **The evaluator may check one or several of these possible disturbances, yet still determine that the natural habitat is intact.**

Check all that are observed present in or near the wetland

X	Mowing		Herbaceous layer/aquatic bed removal
	Grazing (cattle, horses, etc.)		Sedimentation
	Clearcutting		Dredging
	Selective cutting		Row-crop or orchard farming
	Woody debris removal		Nutrient enrichment, e.g. nuisance algae
	Toxic pollutants		Other (specify):
	Shrub/sapling removal		Other (specify):

Have any of the disturbances identified above caused or appeared to cause more than trivial alterations to the wetland's natural habitat.	YES	NO	NOT SURE
	Assign a score 1, 3 or 6, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 9 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 6.

Select one score or double check adjoining numbers and average the score.		Score
9pts	NONE OR NONE APPARENT. There are no past or current alterations that are apparent to the evaluator.	
6pts	RECOVERED. The wetland appears to have recovered from past alterations.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past alterations.	
1pt	RECENT OR NO RECOVERY. The alterations have occurred recently, and/or the wetland has not recovered from past alterations, and/or the alterations are ongoing.	1.00

4c Avg. = 1.00

Metric 4 Total 6

Metric 5. Special wetland communities. Assign points in left column if the wetland meets the associated criteria below. Refer to Narrative Rating for guidance. If wetland scores over 30 points within Metric 5 further determination needed to assess if the wetland exhibits outstanding ecological or recreational values as discussed in the Narrative Rating Section.

	5pts - >10m sq sphagnum or other moss or other vernal pools		5 pts - Superior fish, waterfowl, bat, or amphibian breeding habitat
	Ecological community with global rank (NatureServe): G1 (10pts), G2 (5pts), G2/G3 (3pts) or uncommon ecological resource in the ecoregion (habitat and/or species diversity, geology, wetland type, distribution/ occurrence) (10 pts)		5 pts - Wetland contains and is a buffer for a headwater stream or wetland contributes significantly to the water water quality of 303(d) listed stream and/or to surface or and/or to ground water
	10 pts - Older-aged mature forested wetland avg. DBH >= 30 inches		10 pts - Supports species Deemed in Need of Management by TWRA or TN Special Concern by TDEC

Metric 5 Total 0

Metric 6. Vegetation, Interspersion, and Microtopography (Max 20 points). **6a. Wetland Vegetation Communities** Check each community present both vertically and horizontally within the wetland with an area of at least 0.1 hectares or 1000m^2 (0.2471 acres). Assign a score of 0 to 3 using Table 3 for 1-4 or Table 5 for 5-6. Sum the scores for the classes present.	Score
1)Aquatic Bed Includes areas of wetlands dominated by plants that grow principally on or below the surface of the water for most of the growing season in most years. Floating aquatic species like duckweed (*Lemna* spp., *Spirodela* spp.) are excluded from definition of "aquatic bed." Aquatic beds often occur as a distinct zone as an "understory" below shrubs or trees.	
2)Emergent Includes areas of wetlands dominated by erect, rooted, herbaceous hydrophytes, excluding mosses and lichens. This vegetation is present for most of the growing season in most years. Common names for emergent communities include marsh, wet meadow, wet prairie, sedge meadow, and fens.	0.00
3)Shrub Includes areas of wetlands dominated by woody vegetation less than 1m (3ft.) - 6m (20 ft) tall with a dbh of <3in. The plant species include true shrubs, young trees, or trees or shrubs that are small or stunted because of environmental conditions. Shrub wetlands may represent a successional stage leading to a forested wetland or they may be relatively stable plant communities.	
4)Forested Includes wetlands or areas of wetlands characterized by woody vegetation greater than 6m (20ft) or taller. Forested wetlands have an overstory of trees and often contain an understory of young trees and shrubs and an herbaceous layer, although the young tree/shrub and herbaceous layers can be largely missing from some types of forested wetlands. Some forested wetlands are "vernal pools".	
5)Mudflats The "mudflat" class is equivalent to the "unconsolidated bottom/mud" class/subclass (PUB_3) described in Cowardin et al. (1979) and includes areas of wetlands characterized by exposed or shallowly inundated substrates with vegetative cover less than 30%.	
6)Open water The "open water" class is equivalent to the "open water - unknown bottom" class in Cowardin et al. (1979) and includes areas that are 1) inundated, 2) un-vegetated, and 3) and "open", i.e. there is no "canopy" of any type of vegetation.	

Table 3. Use this table to assign a cover score for Metric 6a to each of the vegetation communities identified on the preceding page. Refer to Table 4 for narrative description of "low," "moderate," and "high" quality.

Cover Scale	Description
0	The vegetation community is either 1) absent from wetland or 2) Comprises less than 0.1 ha (.2471 acres) of contiguous area within the wetland
1	Vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of low or moderate quality, or 2) if it comprises a significant part of the wetland's vegetation and is of low quality
2	Thee vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of moderate quality, or 2) the vegetation community comprises a small part of the wetland's vegetation but is of high quality
3	The vegetation community is of high quality and comprises a significant part, or more, of the wetland's vegetation

Table 4. Use this table in conjunction with Table 3 to determine what is a "low", "moderate," or " high" quality community.

Narrative	Description
Low	Low species richness and a predominance of invasive, non-native, or disturbance tolerant "weedy" species.
Moderate	Native species are the dominant component of the vegetation, although non-native or disturbance tolerant "weedy" species can also be present, and species richness is moderate to moderately high, but generally without the presence of rare, threatened, or endangered species.
High	A predominance of native species, with non-native species absent or virtually absent, and high species diversity and/or the presence of rare, threatened or endangered species.

Table 5. Mudflat and open water community cover scale.

0	Absent <0.1 ha (0.247 acres)
1	Low 0.1 to <1ha (0.247 to 2.47 acres)
2	Moderate 1 ha to < 4 ha (2.47 to 9.88 acres)
3	High 4 ha (9.88 acres) or more

6b. Horizontal (plan view) interspersion. Evaluate the wetland from a "plan view," i.e. as if the looking down upon it. See Figure 1.		Score
5pts	HIGH Wetland has a high degree of interspersion	
4pts	MODERATELY HIGH Wetland has a moderately high degree of interspersion	
3pts	MODERATE Wetland has a moderate degree of interspersion	
2pts	MODERATELY LOW Wetland has a moderately low degree of interspersion	
1pt	LOW Wetland has a low degree of interspersion.	1.00
0pt	NONE Wetland has no plan view interspersion	

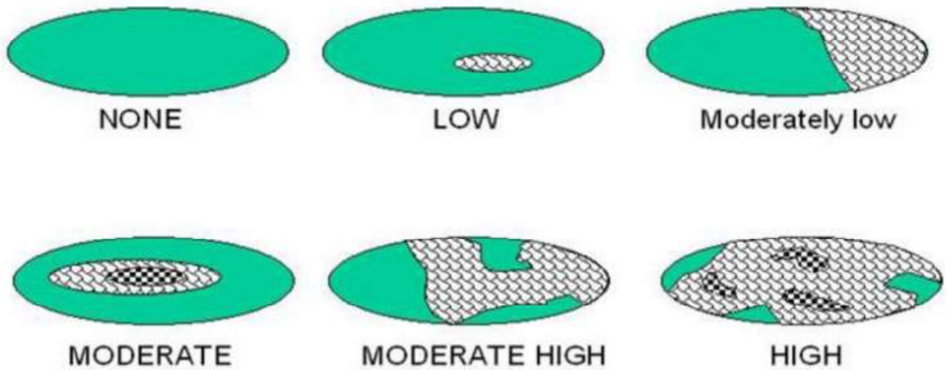

Figure 1. Hypothetical Wetlands for estimating degree of interspersion

6c. Coverage of Invasive Plant Species. Refer to Tennessee Exotic Pest Plant Council (http://www.tneppc.org/) for official list. Select only one and assign score.		Score
-5pts	Extensive >75% areal cover of invasive species	
-3pts	Moderate 25-75% areal cover of invasive species	
-1pts	Sparse 5-25% areal cover of invasive species	
0pt	Nearly absent. <5% areal cover of invasive species	0
1pt	Absent	

6d. Microtopography. Check each feature present in the wetland. Assign cover score of 0 to 3 using Table 6. Evaluate various microtopograhic habitat features often present in wetlands.	Score
Vegetated hummocks and tussocks	
Coarse woody debris >15cm (6in) in diameter	
Standing dead trees >25cm (10in) diameter at breast height	
Amphibian breeding habitat, e.g. vernal pools with standing water of sufficient duration and depth to support reproduction, or habitat for frog reproduction	

Table 6. Cover scale for microtopographic habitat features

Microtopographic habitat quality	**Narrative description**
0	Feature is absent or functionally absent from the wetland
1	Feature is present in the wetland in very small amounts or if more common, of low quality
2	Feature is present in moderate amounts, but not of highest quality or in small amounts of highest quality
3	Present in moderate or greater amounts and of the highest quality

Metric 6 Total 1

NON-HGM TRAM Summary Worksheet

Non-HGM Quantitative Rating	Metric 1: Size	1
	Metric 2: Buffers and surrounding land use	1
	Metric 3: Hydrology	6
	Metric 4: Habitat	6
	Metric 5: Special Wetland Communities	0
	Metric 6: Plant communities, interspersion, microtopography	1
	TOTAL SCORE	15

KIF Retirement

PID#39170

W007

Rank = Low

"Wetland Conditions with an overall score of 100-75 are considered Exceptional Tennessee Waters. Wetlands with a score of 74-45 are considered to have moderate resource value, and wetland with a score of 44 and below have a low resource value."
(TRAM 2015, pg 2)

Quantitative Rating
Tennessee Rapid Assessment Method

Metric 1. Wetland area (max 6 pts). Estimate the area of wetland and select the appropriate size class and assign score. Estimated areas should clearly place the wetland within the appropriate class.

6pts	>50 acres (west TN)	>25 acres (middle TN)	>10 acres (east TN *)	
5pts	25 - <50 acres (west TN)	10- 25 acres (middle TN)	7-<10 acres (east TN*)	
4pts	10 - <25 acres (west TN)	7-< 25acres (middle TN)	3-<7 acres (east TN*)	
3pts	3 - <10 acres(west TN)	3< 7 acres (middle TN)	1-<3 acres (east TN)	
2pts	0.3 - <3 acres (west TN)	0.5- <3 acres (middle TN)	0.5-<1 acres (east TN)	
1pt	0.1 - <0.3 acres(west TN)	<0.5 acres (middle TN)	<0.5 acres (east TN)	1

*More applicable to West Tennessee; use with discretion in Middle Tennessee, Consult TDEC-DWR Natural Resources Unit for use in East Tennessee.

Table 2. Metric to English conversion table with visual estimation sizes.

acres	ft^2	yd^2	ft on side	yd on side	ha	m^2	m on side
50	2,177,983	241,998	1476	492	20.2	202,000	449
25	1,088,992	120,999	1044	348	10.1	101,000	318
10	435,596	48,340	660	220	4.1	41,000	203
3	130,679	14,520	362	121	1.2	12,000	110
0.3	13,067	1,452	114	38	0.12	1,200	35
0.1	4,356	484	66	22	0.04	400	20

Metric 1 Total 1

Metric 2. Upland buffers and intensity of surrounding land uses (Max 14 points). Wetlands without upland "buffers", or that are located where human land use is more intensive, are often, but not always, more degraded and often have lower wildlife habitat resource value.

2a. Average Buffer Width (ABW). Calculate the average buffer width and select only one score. To calculate ABW, estimate buffer width on each side (max of 50m) and divide by the number of sides. Example: ABW of a wetland with buffers of 100m, 25m, 10m and 0m would be calculated as follows: ABW = (50m + 25m + 10m + 0m)/4 = 21.25m. Intensive land uses are not buffers, e.g. active row cropping, paved areas, housing developments, etc.			
7pts	WIDE. >50m (164ft) or more around perimeter.		
4pts	MEDIUM. 25m to <50m (82 to <164ft) around the perimeter.		
1pt	NARROW. 10m to <25m (32 to <82ft) around the perimeter.		
0pts	VERY NARROW. <10m (<32ft) around perimeter.	0	2a Avg.= 0.00
2b. Intensity of predominant surrounding land use(s) Select one, or choose up to two and average score, for the intensity of the predominant land use(s) outside the wetland's buffer zone.			
7pts	VERY LOW. 2^{nd} growth or older forest, prairie, barren, wildlife area, etc.		
5pts	LOW. Old fallow field, shrub land, early successional young forest, etc.		
3pts	MODERATELY HIGH. Residential, pasture, orchard, park, conservation tillage, mowed field, etc.		
1pt	HIGH. urban, industrial, row cropping, mining, construction, etc.	1	2b Avg.= 1.00

KIF D4 Area

PID#39170

W008

Metric 2 Total 1.00

Metric 3. Hydrology (Max 30 points). This metric evaluates the wetland's water budget, hydroperiod, the hydrologic connectivity of the wetland to other surface waters, and the degree to which the wetland's hydrology has been altered by human activity**. A wetland can receive no more than 30 points for Metric 3 even though it is possible to score more than 30 points.**

3a. Sources of Water. Select all that apply and sum the score. This question relates to a wetland's water budget. It also is reflective that wetlands with certain types of water sources, or multiple water sources, e.g. high pH groundwater or perennial surface water connections, can be very high quality wetlands or can have high functions and values.		
5pts	High pH groundwater (7.5-9.0)	
3pts	Other groundwater	
1pts	Precipitation	1
3pts	Seasonal surface water	
5pts	Perennial surface water (lake or stream)	
3b. Connectivity. Select all that apply and sum score		
1pt	**100 year floodplain.** "Floodplain" is defined as "...the relatively level land next to a stream or river channel that is periodically submerged by flood waters. It is composed of alluvium deposited by the present stream or river when it floods." Where they are available, flood insurance rate maps (FIRMs) and flood boundary and floodway maps may be used.	
1pt	**Between stream/lake and other human land use.** This question asks whether the wetland is located between a surface water and a different adjacent land use, such that run-off from the adjacent land use could flow through wetland before it discharges into the surface water buffering it. "Different adjacent land uses" include agricultural, commercial, industrial, mining, or residential uses.	
1pt	**Part of a larger wetland or upland complex.** This question asks whether the wetland is in physical proximity to, or a other nearby wetland or upland habitat areas.	
1pt	**Part of riparian corridor**.	
3c. Maximum water depth. Select only one and assign score. The evaluator *does not* need to actually observe the wetland when its water depth is greatest in order to award the maximum points for this question. The use of secondary indicators, as outlined in the 1987 Manual will be useful in answering this question.		
3 pts	>0.7m (27.6in)	
2pts	0.4 to 0.7m (15.7 to 27.6in)	
1pt	<0.4m (<15.7in)	1
3d. Duration of inundation/saturation. Select one or double check and average the scores if duration is uncertain. The use of ACOE 1987 Manual secondary indicators is necessary and expected in order to properly answer this question.		
4pts	Semi-permanently to permanently inundated or saturated	
3pts	Regularly inundated or saturated	3
2pts	Seasonally inundated	
1pt	Seasonally saturated in the upper 30cm (12in) of soil	

3d Avg.= 3.00

KIF D4 Area

PID#39170

W008

3e. Modifications to natural hydrologic regime. Check all observable modifications from list below. Score by selecting the most appropriate description of the wetland. Scores may be double checked and averaged. This question asks the evaluator to assess the "intactness" of, or lack of disturbance to, the natural hydrologic regime of the type of wetland that is being evaluated.

Once the evaluator has listed all possible past and ongoing disturbances, the evaluator should check the most appropriate category to describe the present state of the wetland. In instances where the evaluator believes that a wetland falls between two categories, or where the evaluator is uncertain as to which category is appropriate, it is appropriate to choose more than one and average the score.

The evaluator may check one or several of these possible disturbances, yet still determine that the natural hydrologic regime is intact. However, see Metric 4 where these same disturbances may be habitat alterations.

Check all that are observed present in or near the wetland.

X	ditch(es), in or near the wetland	X	point source discharges to the (non-stormwater)
	tile(s), in or near the wetland	X	filling/grading activities in or near the wetland
	dike(s), in or near the wetland	X	road beds/RR beds in or near the wetland
	weir(s), in or near the wetland		dredging activities in or near the wetland
X	stormwater inputs (addition of water)		other (specify)

Have any of the disturbances identified above caused or appear to have caused more than trivial alterations to the wetland's natural hydrologic regime.	YES	NO	NOT SURE
	Assign a score 1, 3 or 7, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 12 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 9.5.

Select one or double check adjoining numbers and average the score.		score
12pts	NONE OR NONE APPARENT. There are no modifications or no modifications that are apparent to the evaluator.	
7pts	RECOVERED. The wetland appears to have recovered from past modifications.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past modifications.	
1pt	RECENT OR NO RECOVERY. The modifications have occurred recently occurred, and/or the wetland has not recovered from past modifications, and/or the modifications are ongoing.	1

3e Avg= 1.00

KIF D4 Area

Metric 3 Total 6.00

PID#39170

W008

Metric 4. Habitat Alteration and Development (Max 20 points). While hydrology may be the single most important determinant for the establishment and maintenance of specific types of wetlands and wetland processes, there is a range of other factors and activities which affect wetland quality and cause disturbances to wetlands that are unrelated to hydrology. These disturbances are termed "habitat alteration." In many instances, items checked as hydrologic disturbances in Question 3e will present as alterations to a wetland's habitat or disruptions in its development (successional state). In some instances, a disturbance may be appropriately considered under both Metric 3 and Metric 4. To determine the appropriate metric scores, the evaluator should carefully determine the actual cause of the disturbance to the wetland.

4a. Substrate/Soil Disturbance. Select one or double check and average. This question evaluates physical disturbances to the soil and surface substrates of the wetland. Note also that the labels on the scoring categories are intended to be descriptive but not controlling. In some instances, it may be more appropriate to consider the scoring categories as fixed locations on a disturbance continuum, from very high to very low or no disturbance.	Examples of substrate/soil disturbance include (circle all that apply): ____filling and grading ____plowing ____grazing (hooves) ____vehicle use (off-road vehicles, construction vehicles) ____sedimentation ____dredging, and other mechanical disturbances to the soil

	YES	NO	NOT SURE
Have any of soil or substrate disturbances caused or appear to have caused more than trivial alterations to the wetland's natural soils	Assign a score 1, 2 or 3, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 4 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 3.5.

Select one or double check adjoining numbers and average the score.			
4pts	NONE OR NONE APPARENT. There are no disturbances or no disturbances apparent to the evaluator.		
3pts	RECOVERED. The wetland appears to have recovered from past disturbances.		
2pts	RECOVERING. The wetland appears to be in the process of recovering from past disturbances.		
1pt	RECENT OR NO RECOVERY. The disturbances have occurred recently, and/or the wetland has not recovered from past disturbances, and/or the disturbances are ongoing.	1.00	4a Avg.= 1.00

4b. Habitat development. Select only one and assign score. This question asks the evaluator to assign an overall qualitative rating of how well-developed the wetland is in comparison to other ecologically and/or hydrogeomorphically similar wetlands. This question presumes knowledge of the types of wetlands and the range in quality typical of the region or access to data from reference standard examples. If unsure, score as GOOD or MODERATELY GOOD.

7pts	EXCELLENT. Wetland appears to represent the best of its type or class.		
6pts	VERY GOOD. Wetland appears to be a very good example of its type or class but is lacking in characteristics which would make it excellent.		
5pts	GOOD. Wetland appears to be a good example of its type or class but because of past or present disturbances, successional state, or other reasons, is not excellent.		
4pts	MODERATELY GOOD. Wetland appears to be a fair to good example of its type or class.		
3pts	FAIR. Wetland appears to be a moderately good example of its type or class but because of past or present disturbances, successional state, etc. is not good.		
2pts	POOR TO FAIR. Wetland appears to be a poor to fair example of its type or class.		
1pt	POOR. Wetland appears not to be a good example of its type or class because of past or present disturbances, successional state, etc.	1.00	4b Avg.= 1.00

4c. Habitat alteration. This question evaluates the “intactness” the natural habitat of the type of wetland that is being evaluated. This question does not discriminate between wetlands with different types of habitat. Check all possible alterations that are observed. All available information, field visits, aerial photos, maps, etc. can be used to identify possible alterations. Evaluate whether the alteration is trivial in relation to the wetlands overall habitat. Select the most appropriate score that best describes the present state of the wetland. It is appropriate to “double check” and average scores. **The evaluator may check one or several of these possible disturbances, yet still determine that the natural habitat is intact.**

Check all that are observed present in or near the wetland

X	Mowing		Herbaceous layer/aquatic bed removal
	Grazing (cattle, horses, etc.)		Sedimentation
	Clearcutting		Dredging
	Selective cutting		Row-crop or orchard farming
	Woody debris removal		Nutrient enrichment, e.g. nuisance algae
	Toxic pollutants		Other (specify):
	Shrub/sapling removal		Other (specify):

Have any of the disturbances identified above caused or appeared to cause more than trivial alterations to the wetland's natural habitat.	YES	NO	NOT SURE
	Assign a score 1, 3 or 6, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 9 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 6.

Select one score or double check adjoining numbers and average the score.		Score
9pts	NONE OR NONE APPARENT. There are no past or current alterations that are apparent to the evaluator.	
6pts	RECOVERED. The wetland appears to have recovered from past alterations.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past alterations.	
1pt	RECENT OR NO RECOVERY. The alterations have occurred recently, and/or the wetland has not recovered from past alterations, and/or the alterations are ongoing.	1.00

4c Avg. = 1.00

Metric 4 Total 3

KIF D4 Area

W008

PID#39170

Metric 5. Special wetland communities. Assign points in left column if the wetland meets the associated criteria below. Refer to Narrative Rating for guidance. If wetland scores over 30 points within Metric 5 further determination needed to assess if the wetland exhibits outstanding ecological or recreational values as discussed in the Narrative Rating Section.

	5pts - >10m sq sphagnum or other moss or other vernal pools		5 pts - Superior fish, waterfowl, bat, or amphibian breeding habitat
	Ecological community with global rank (NatureServe): G1 (10pts), G2 (5pts), G2/G3 (3pts) or uncommon ecological resource in the ecoregion (habitat and/or species diversity, geology, wetland type, distribution/ occurrence) (10 pts)		5 pts - Wetland contains and is a buffer for a headwater stream or wetland contributes significantly to the water water quality of 303(d) listed stream and/or to surface or and/or to ground water
	10 pts - Older-aged mature forested wetland avg. DBH >= 30 inches		10 pts - Supports species Deemed in Need of Management by TWRA or TN Special Concern by TDEC

Metric 5 Total 0

Metric 6. Vegetation, Interspersion, and Microtopography (Max 20 points). **6a. Wetland Vegetation Communities** Check each community present both vertically and horizontally within the wetland with an area of at least 0.1 hectares or 1000m^2 (0.2471 acres). Assign a score of 0 to 3 using Table 3 for 1-4 or Table 5 for 5-6. Sum the scores for the classes present.	Score
1)Aquatic Bed Includes areas of wetlands dominated by plants that grow principally on or below the surface of the water for most of the growing season in most years. Floating aquatic species like duckweed (*Lemna* spp., *Spirodela* spp.) are excluded from definition of "aquatic bed." Aquatic beds often occur as a distinct zone as an "understory" below shrubs or trees.	
2)Emergent Includes areas of wetlands dominated by erect, rooted, herbaceous hydrophytes, excluding mosses and lichens. This vegetation is present for most of the growing season in most years. Common names for emergent communities include marsh, wet meadow, wet prairie, sedge meadow, and fens.	0.00
3)Shrub Includes areas of wetlands dominated by woody vegetation less than 1m (3ft.) - 6m (20 ft) tall with a dbh of <3in. The plant species include true shrubs, young trees, or trees or shrubs that are small or stunted because of environmental conditions. Shrub wetlands may represent a successional stage leading to a forested wetland or they may be relatively stable plant communities.	
4)Forested Includes wetlands or areas of wetlands characterized by woody vegetation greater than 6m (20ft) or taller. Forested wetlands have an overstory of trees and often contain an understory of young trees and shrubs and an herbaceous layer, although the young tree/shrub and herbaceous layers can be largely missing from some types of forested wetlands. Some forested wetlands are "vernal pools".	
5)Mudflats The "mudflat" class is equivalent to the "unconsolidated bottom/mud" class/subclass (PUB_3) described in Cowardin et al. (1979) and includes areas of wetlands characterized by exposed or shallowly inundated substrates with vegetative cover less than 30%.	
6)Open water The "open water" class is equivalent to the "open water - unknown bottom" class in Cowardin et al. (1979) and includes areas that are 1) inundated, 2) un-vegetated, and 3) and "open", i.e. there is no "canopy" of any type of vegetation.	

Table 3. Use this table to assign a cover score for Metric 6a to each of the vegetation communities identified on the preceding page. Refer to Table 4 for narrative description of "low," "moderate," and "high" quality.

Cover Scale	Description
0	The vegetation community is either 1) absent from wetland or 2) Comprises less than 0.1 ha (.2471 acres) of contiguous area within the wetland
1	Vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of low or moderate quality, or 2) if it comprises a significant part of the wetland's vegetation and is of low quality
2	Thee vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of moderate quality, or 2) the vegetation community comprises a small part of the wetland's vegetation but is of high quality
3	The vegetation community is of high quality and comprises a significant part, or more, of the wetland's vegetation

Table 4. Use this table in conjunction with Table 3 to determine what is a "low", "moderate," or " high" quality community.

Narrative	Description
Low	Low species richness and a predominance of invasive, non-native, or disturbance tolerant "weedy" species.
Moderate	Native species are the dominant component of the vegetation, although non-native or disturbance tolerant "weedy" species can also be present, and species richness is moderate to moderately high, but generally without the presence of rare, threatened, or endangered species.
High	A predominance of native species, with non-native species absent or virtually absent, and high species diversity and/or the presence of rare, threatened or endangered species.

Table 5. Mudflat and open water community cover scale.

0	Absent <0.1 ha (0.247 acres)
1	Low 0.1 to <1ha (0.247 to 2.47 acres)
2	Moderate 1 ha to < 4 ha (2.47 to 9.88 acres)
3	High 4 ha (9.88 acres) or more

6b. Horizontal (plan view) interspersion. Evaluate the wetland from a "plan view," i.e. as if the looking down upon it. See Figure 1.	Score
5pts HIGH Wetland has a high degree of interspersion	
4pts MODERATELY HIGH Wetland has a moderately high degree of interspersion	
3pts MODERATE Wetland has a moderate degree of interspersion	
2pts MODERATELY LOW Wetland has a moderately low degree of interspersion	
1pt LOW Wetland has a low degree of interspersion.	1.0
0pt NONE Wetland has no plan view interspersion	

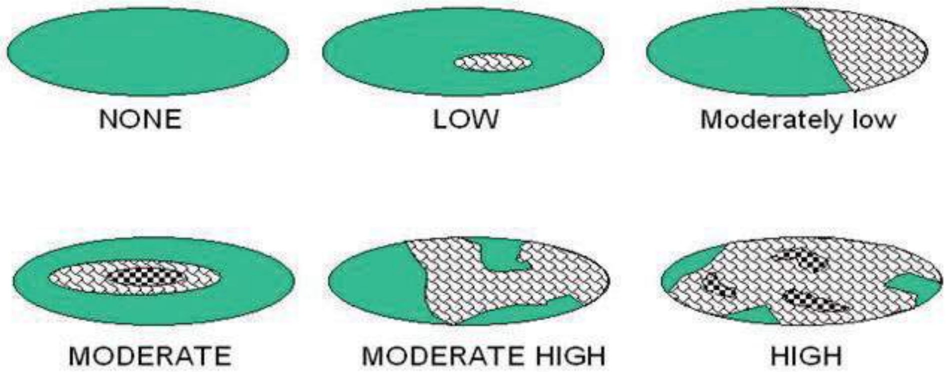

Figure 1. Hypothetical Wetlands for estimating degree of interspersion

6c. Coverage of Invasive Plant Species. Refer to Tennessee Exotic Pest Plant Council (http://www.tneppc.org/) for official list. Select only one and assign score.		Score
-5pts	Extensive >75% areal cover of invasive species	
-3pts	Moderate 25-75% areal cover of invasive species	
-1pts	Sparse 5-25% areal cover of invasive species	-1
0pt	Nearly absent. <5% areal cover of invasive species	
1pt	Absent	
6d. Microtopography. Check each feature present in the wetland. Assign cover score of 0 to 3 using Table 6. Evaluate various microtopograhic habitat features often present in wetlands.		Score
Vegetated hummocks and tussocks		
Coarse woody debris >15cm (6in) in diameter		
Standing dead trees >25cm (10in) diameter at breast height		
Amphibian breeding habitat, e.g. vernal pools with standing water of sufficient duration and depth to support reproduction, or habitat for frog reproduction		

Table 6. Cover scale for microtopographic habitat features

Microtopographic habitat quality	Narrative description
0	Feature is absent or functionally absent from the wetland
1	Feature is present in the wetland in very small amounts or if more common, of low quality
2	Feature is present in moderate amounts, but not of highest quality or in small amounts of highest quality
3	Present in moderate or greater amounts and of the highest quality

Metric 6 Total 0

NON-HGM TRAM Summary Worksheet

Non-HGM Quantitative Rating	Metric 1: Size	1
	Metric 2: Buffers and surrounding land use	1
	Metric 3: Hydrology	6
	Metric 4: Habitat	3
	Metric 5: Special Wetland Communities	0
	Metric 6: Plant communities, interspersion, microtopography	0
	TOTAL SCORE	11

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Rank = Low

"Wetland Conditions with an overall score of 100-75 are considered Exceptional Tennessee Waters. Wetlands with a score of 74-45 are considered to have moderate resource value, and wetland with a score of 44 and below have a low resource value."
TRAM 2015, pg 2)

W009
1/19/2023
FPH

Quantitative Rating
Tennessee Rapid Assessment Method

Metric 1. Wetland area (max 6 pts). Estimate the area of wetland and select the appropriate size class and assign score. Estimated areas should clearly place the wetland within the appropriate class.

6pts	>50 acres (west TN)	>25 acres (middle TN)	>10 acres (east TN *)	
5pts	25 - <50 acres (west TN)	10- 25 acres (middle TN)	7-<10 acres (east TN*)	
4pts	10 - <25 acres (west TN)	7-< 25acres (middle TN)	3-<7 acres (east TN*)	
3pts	3 - <10 acres(west TN)	3< 7 acres (middle TN)	1-<3 acres (east TN)	
2pts	0.3 - <3 acres (west TN)	0.5- <3 acres (middle TN)	0.5-<1 acres (east TN)	
1pt	0.1 - <0.3 acres(west TN)	<0.5 acres (middle TN)	<0.5 acres (east TN)	1

*More applicable to West Tennessee; use with discretion in Middle Tennessee, Consult TDEC-DWR Natural Resources Unit for use in East Tennessee.

Table 2. Metric to English conversion table with visual estimation sizes.

acres	ft^2	yd^2	ft on side	yd on side	ha	m^2	m on side
50	2,177,983	241,998	1476	492	20.2	202,000	449
25	1,088,992	120,999	1044	348	10.1	101,000	318
10	435,596	48,340	660	220	4.1	41,000	203
3	130,679	14,520	362	121	1.2	12,000	110
0.3	13,067	1,452	114	38	0.12	1,200	35
0.1	4,356	484	66	22	0.04	400	20

Metric 1 Total 1

Metric 2. Upland buffers and intensity of surrounding land uses (Max 14 points). Wetlands without upland "buffers", or that are located where human land use is more intensive, are often, but not always, more degraded and often have lower wildlife habitat resource value.

2a. Average Buffer Width (ABW). Calculate the average buffer width and select only one score. To calculate ABW, estimate buffer width on each side (max of 50m) and divide by the number of sides. Example: ABW of a wetland with buffers of 100m, 25m, 10m and 0m would be calculated as follows: ABW = (50m + 25m + 10m + 0m)/4 = 21.25m. Intensive land uses are not buffers, e.g. active row cropping, paved areas, housing developments, etc.

7pts	WIDE. >50m (164ft) or more around perimeter.		
4pts	MEDIUM. 25m to <50m (82 to <164ft) around the perimeter.		
1pt	NARROW. 10m to <25m (32 to <82ft) around the perimeter.		
0pts	VERY NARROW. <10m (<32ft) around perimeter.	0	2a Avg.= 0.00

2b. Intensity of predominant surrounding land use(s) Select one, or choose up to two and average score, for the intensity of the predominant land use(s) outside the wetland's buffer zone.

7pts	VERY LOW. 2^{nd} growth or older forest, prairie, barren, wildlife area, etc.		
5pts	LOW. Old fallow field, shrub land, early successional young forest, etc.		
3pts	MODERATELY HIGH. Residential, pasture, orchard, park, conservation tillage, mowed field, etc.		
1pt	HIGH. urban, industrial, row cropping, mining, construction, etc.	1	2b Avg.= 1.00

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Metric 2 Total 1.00

Metric 3. Hydrology (Max 30 points). This metric evaluates the wetland's water budget, hydroperiod, the hydrologic connectivity of the wetland to other surface waters, and the degree to which the wetland's hydrology has been altered by human activity**. A wetland can receive no more than 30 points for Metric 3 even though it is possible to score more than 30 points.**

3a. Sources of Water. Select all that apply and sum the score. This question relates to a wetland's water budget. It also is reflective that wetlands with certain types of water sources, or multiple water sources, e.g. high pH groundwater or perennial surface water connections, can be very high quality wetlands or can have high functions and values.		
5pts	High pH groundwater (7.5-9.0)	
3pts	Other groundwater	
1pts	Precipitation	1
3pts	Seasonal surface water	
5pts	Perennial surface water (lake or stream)	
3b. Connectivity. Select all that apply and sum score		
1pt	**100 year floodplain.** "Floodplain" is defined as "...the relatively level land next to a stream or river channel that is periodically submerged by flood waters. It is composed of alluvium deposited by the present stream or river when it floods." Where they are available, flood insurance rate maps (FIRMs) and flood boundary and floodway maps may be used.	
1pt	**Between stream/lake and other human land use.** This question asks whether the wetland is located between a surface water and a different adjacent land use, such that run-off from the adjacent land use could flow through wetland before it discharges into the surface water buffering it. "Different adjacent land uses" include agricultural, commercial, industrial, mining, or residential uses.	
1pt	**Part of a larger wetland or upland complex.** This question asks whether the wetland is in physical proximity to, or a other nearby wetland or upland habitat areas.	
1pt	**Part of riparian corridor**.	
3c. Maximum water depth. Select only one and assign score. The evaluator *does not* need to actually observe the wetland when its water depth is greatest in order to award the maximum points for this question. The use of secondary indicators, as outlined in the 1987 Manual will be useful in answering this question.		
3 pts	>0.7m (27.6in)	
2pts	0.4 to 0.7m (15.7 to 27.6in)	
1pt	<0.4m (<15.7in)	1
3d. Duration of inundation/saturation. Select one or double check and average the scores if duration is uncertain. The use of ACOE 1987 Manual secondary indicators is necessary and expected in order to properly answer this question.		
4pts	Semi-permanently to permanently inundated or saturated	
3pts	Regularly inundated or saturated	3
2pts	Seasonally inundated	
1pt	Seasonally saturated in the upper 30cm (12in) of soil	

3d Avg.= 3.00

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W009

3e. Modifications to natural hydrologic regime. Check all observable modifications from list below. Score by selecting the most appropriate description of the wetland. Scores may be double checked and averaged. This question asks the evaluator to assess the "intactness" of, or lack of disturbance to, the natural hydrologic regime of the type of wetland that is being evaluated.

Once the evaluator has listed all possible past and ongoing disturbances, the evaluator should check the most appropriate category to describe the present state of the wetland. In instances where the evaluator believes that a wetland falls between two categories, or where the evaluator is uncertain as to which category is appropriate, it is appropriate to choose more than one and average the score.

The evaluator may check one or several of these possible disturbances, yet still determine that the natural hydrologic regime is intact. However, see Metric 4 where these same disturbances may be habitat alterations.

Check all that are observed present in or near the wetland.

X	ditch(es), in or near the wetland	X	point source discharges to the (non-stormwater)
	tile(s), in or near the wetland	X	filling/grading activities in or near the wetland
	dike(s), in or near the wetland	X	road beds/RR beds in or near the wetland
	weir(s), in or near the wetland		dredging activities in or near the wetland
X	stormwater inputs (addition of water)		other (specify)

Have any of the disturbances identified above caused or appear to have caused more than trivial alterations to the wetland's natural hydrologic regime.	<u>YES</u> Assign a score 1, 3 or 7, or an intermediate score, depending on degree of recovery from the disturbance.	<u>NO</u> Assign a score of 12 since there are no or no apparent modifications.	<u>NOT SURE</u> Choose "recovered" and assign a score of 9.5.

Select one or double check adjoining numbers and average the score.		**score**
12pts	NONE OR NONE APPARENT. There are no modifications or no modifications that are apparent to the evaluator.	
7pts	RECOVERED. The wetland appears to have recovered from past modifications.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past modifications.	
1pt	RECENT OR NO RECOVERY. The modifications have occurred recently occurred, and/or the wetland has not recovered from past modifications, and/or the modifications are ongoing.	1

3e Avg=
1.00

KIF D4 Area

Metric 3 Total 6.00

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W009

Metric 4. Habitat Alteration and Development (Max 20 points). While hydrology may be the single most important determinant for the establishment and maintenance of specific types of wetlands and wetland processes, there is a range of other factors and activities which affect wetland quality and cause disturbances to wetlands that are unrelated to hydrology. These disturbances are termed “habitat alteration.” In many instances, items checked as hydrologic disturbances in Question 3e will present as alterations to a wetland’s habitat or disruptions in its development (successional state). In some instances, a disturbance may be appropriately considered under both Metric 3 and Metric 4. To determine the appropriate metric scores, the evaluator should carefully determine the actual cause of the disturbance to the wetland.

4a. Substrate/Soil Disturbance. Select one or double check and average. This question evaluates physical disturbances to the soil and surface substrates of the wetland. Note also that the labels on the scoring categories are intended to be descriptive but not controlling. In some instances, it may be more appropriate to consider the scoring categories as fixed locations on a disturbance continuum, from very high to very low or no disturbance.	Examples of substrate/soil disturbance include (circle all that apply): ____filling and grading ____plowing ____grazing (hooves) ____vehicle use (off-road vehicles, construction vehicles) ____sedimentation ____dredging, and other mechanical disturbances to the soil

	YES	NO	NOT SURE
Have any of soil or substrate disturbances caused or appear to have caused more than trivial alterations to the wetland's natural soils	Assign a score 1, 2 or 3, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 4 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 3.5.

Select one or double check adjoining numbers and average the score.			
4pts	NONE OR NONE APPARENT. There are no disturbances or no disturbances apparent to the evaluator.		
3pts	RECOVERED. The wetland appears to have recovered from past disturbances.		
2pts	RECOVERING. The wetland appears to be in the process of recovering from past disturbances.		
1pt	RECENT OR NO RECOVERY. The disturbances have occurred recently, and/or the wetland has not recovered from past disturbances, and/or the disturbances are ongoing.	1.00	4a Avg.= 1.00

4b. Habitat development. Select only one and assign score. This question asks the evaluator to assign an overall qualitative rating of how well-developed the wetland is in comparison to other ecologically and/or hydrogeomorphically similar wetlands. This question presumes knowledge of the types of wetlands and the range in quality typical of the region or access to data from reference standard examples. If unsure, score as GOOD or MODERATELY GOOD.

7pts	EXCELLENT. Wetland appears to represent the best of its type or class.		
6pts	VERY GOOD. Wetland appears to be a very good example of its type or class but is lacking in characteristics which would make it excellent.		
5pts	GOOD. Wetland appears to be a good example of its type or class but because of past or present disturbances, successional state, or other reasons, is not excellent.		
4pts	MODERATELY GOOD. Wetland appears to be a fair to good example of its type or class.		
3pts	FAIR. Wetland appears to be a moderately good example of its type or class but because of past or present disturbances, successional state, etc. is not good.		
2pts	POOR TO FAIR. Wetland appears to be a poor to fair example of its type or class.		
1pt	POOR. Wetland appears not to be a good example of its type or class because of past or present disturbances, successional state, etc.	1.00	4b Avg.= 1.00

4c. Habitat alteration. This question evaluates the "intactness" the natural habitat of the type of wetland that is being evaluated. This question does not discriminate between wetlands with different types of habitat. Check all possible alterations that are observed. All available information, field visits, aerial photos, maps, etc. can be used to identify possible alterations. Evaluate whether the alteration is trivial in relation to the wetlands overall habitat. Select the most appropriate score that best describes the present state of the wetland. It is appropriate to "double check" and average scores. **The evaluator may check one or several of these possible disturbances, yet still determine that the natural habitat is intact.**

Check all that are observed present in or near the wetland

X	Mowing		Herbaceous layer/aquatic bed removal
	Grazing (cattle, horses, etc.)		Sedimentation
	Clearcutting		Dredging
	Selective cutting		Row-crop or orchard farming
	Woody debris removal		Nutrient enrichment, e.g. nuisance algae
	Toxic pollutants		Other (specify):
	Shrub/sapling removal		Other (specify):

Have any of the disturbances identified above caused or appeared to cause more than trivial alterations to the wetland's natural habitat.	YES	NO	NOT SURE
	Assign a score 1, 3 or 6, or an intermediate score, depending on degree of recovery from the disturbance.	Assign a score of 9 since there are no or no apparent modifications.	Choose "recovered" and assign a score of 6.

Select one score or double check adjoining numbers and average the score.		Score
9pts	NONE OR NONE APPARENT. There are no past or current alterations that are apparent to the evaluator.	
6pts	RECOVERED. The wetland appears to have recovered from past alterations.	
3pts	RECOVERING. The wetland appears to be in the process of recovering from past alterations.	
1pt	RECENT OR NO RECOVERY. The alterations have occurred recently, and/or the wetland has not recovered from past alterations, and/or the alterations are ongoing.	1.00

4c Avg. = 1.00

Metric 4 Total 3

Metric 5. Special wetland communities. Assign points in left column if the wetland meets the associated criteria below. Refer to Narrative Rating for guidance. If wetland scores over 30 points within Metric 5 further determination needed to assess if the wetland exhibits outstanding ecological or recreational values as discussed in the Narrative Rating Section.

	5pts - >10m sq sphagnum or other moss or other vernal pools		5 pts - Superior fish, waterfowl, bat, or amphibian breeding habitat
	Ecological community with global rank (NatureServe): G1 (10pts), G2 (5pts), G2/G3 (3pts) or uncommon ecological resource in the ecoregion (habitat and/or species diversity, geology, wetland type, distribution/ occurrence) (10 pts)		5 pts - Wetland contains and is a buffer for a headwater stream or wetland contributes significantly to the water water quality of 303(d) listed stream and/or to surface or and/or to ground water
	10 pts - Older-aged mature forested wetland avg. DBH >= 30 inches		10 pts - Supports species Deemed in Need of Management by TWRA or TN Special Concern by TDEC

Metric 5 Total 0

Metric 6. Vegetation, Interspersion, and Microtopography (Max 20 points). **6a. Wetland Vegetation Communities** Check each community present both vertically and horizontally within the wetland with an area of at least 0.1 hectares or 1000m^2 (0.2471 acres). Assign a score of 0 to 3 using Table 3 for 1-4 or Table 5 for 5-6. Sum the scores for the classes present.	Score
1)Aquatic Bed Includes areas of wetlands dominated by plants that grow principally on or below the surface of the water for most of the growing season in most years. Floating aquatic species like duckweed (*Lemna* spp., *Spirodela* spp.) are excluded from definition of "aquatic bed." Aquatic beds often occur as a distinct zone as an "understory" below shrubs or trees.	
2)Emergent Includes areas of wetlands dominated by erect, rooted, herbaceous hydrophytes, excluding mosses and lichens. This vegetation is present for most of the growing season in most years. Common names for emergent communities include marsh, wet meadow, wet prairie, sedge meadow, and fens.	0.00
3)Shrub Includes areas of wetlands dominated by woody vegetation less than 1m (3ft.) - 6m (20 ft) tall with a dbh of <3in. The plant species include true shrubs, young trees, or trees or shrubs that are small or stunted because of environmental conditions. Shrub wetlands may represent a successional stage leading to a forested wetland or they may be relatively stable plant communities.	
4)Forested Includes wetlands or areas of wetlands characterized by woody vegetation greater than 6m (20ft) or taller. Forested wetlands have an overstory of trees and often contain an understory of young trees and shrubs and an herbaceous layer, although the young tree/shrub and herbaceous layers can be largely missing from some types of forested wetlands. Some forested wetlands are "vernal pools".	
5)Mudflats The "mudflat" class is equivalent to the "unconsolidated bottom/mud" class/subclass (PUB_3) described in Cowardin et al. (1979) and includes areas of wetlands characterized by exposed or shallowly inundated substrates with vegetative cover less than 30%.	
6)Open water The "open water" class is equivalent to the "open water - unknown bottom" class in Cowardin et al. (1979) and includes areas that are 1) inundated, 2) un-vegetated, and 3) and "open", i.e. there is no "canopy" of any type of vegetation.	

Table 3. Use this table to assign a cover score for Metric 6a to each of the vegetation communities identified on the preceding page. Refer to Table 4 for narrative description of "low," "moderate," and "high" quality.

Cover Scale	Description
0	The vegetation community is either 1) absent from wetland or 2) Comprises less than 0.1 ha (.2471 acres) of contiguous area within the wetland
1	Vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of low or moderate quality, or 2) if it comprises a significant part of the wetland's vegetation and is of low quality
2	Thee vegetation community is present and either, 1) comprises a significant part of the wetland's vegetation and is of moderate quality, or 2) the vegetation community comprises a small part of the wetland's vegetation but is of high quality
3	The vegetation community is of high quality and comprises a significant part, or more, of the wetland's vegetation

Table 4. Use this table in conjunction with Table 3 to determine what is a "low", "moderate," or " high" quality community.

Narrative	Description
Low	Low species richness and a predominance of invasive, non-native, or disturbance tolerant "weedy" species.
Moderate	Native species are the dominant component of the vegetation, although non-native or disturbance tolerant "weedy" species can also be present, and species richness is moderate to moderately high, but generally without the presence of rare, threatened, or endangered species.
High	A predominance of native species, with non-native species absent or virtually absent, and high species diversity and/or the presence of rare, threatened or endangered species.

Table 5. Mudflat and open water community cover scale.

0	Absent <0.1 ha (0.247 acres)
1	Low 0.1 to <1ha (0.247 to 2.47 acres)
2	Moderate 1 ha to < 4 ha (2.47 to 9.88 acres)
3	High 4 ha (9.88 acres) or more

6b. Horizontal (plan view) interspersion. Evaluate the wetland from a "plan view," i.e. as if the looking down upon it. See Figure 1.	Score
5pts HIGH Wetland has a high degree of interspersion	
4pts MODERATELY HIGH Wetland has a moderately high degree of interspersion	
3pts MODERATE Wetland has a moderate degree of interspersion	
2pts MODERATELY LOW Wetland has a moderately low degree of interspersion	
1pt LOW Wetland has a low degree of interspersion.	1.0
0pt NONE Wetland has no plan view interspersion	

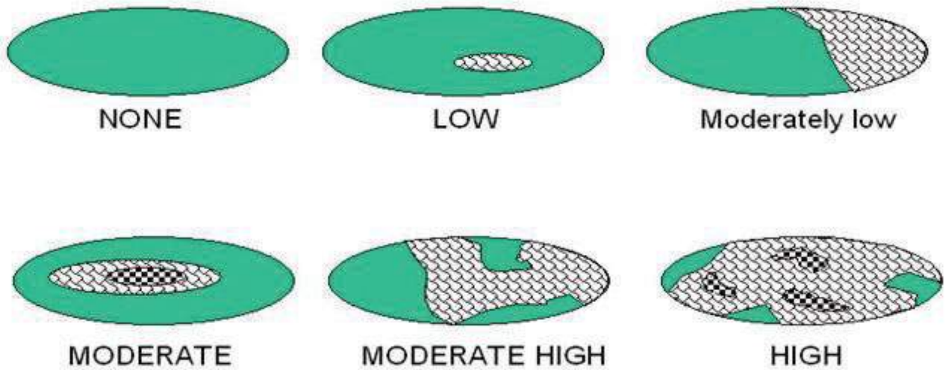

Figure 1. Hypothetical Wetlands for estimating degree of interspersion

6c. Coverage of Invasive Plant Species. Refer to Tennessee Exotic Pest Plant Council (http://www.tneppc.org/) for official list. Select only one and assign score.		Score
-5pts	Extensive >75% areal cover of invasive species	
-3pts	Moderate 25-75% areal cover of invasive species	
-1pts	Sparse 5-25% areal cover of invasive species	-1
0pt	Nearly absent. <5% areal cover of invasive species	
1pt	Absent	

6d. Microtopography. Check each feature present in the wetland. Assign cover score of 0 to 3 using Table 6. Evaluate various microtopograhic habitat features often present in wetlands.	Score
Vegetated hummocks and tussocks	
Coarse woody debris >15cm (6in) in diameter	
Standing dead trees >25cm (10in) diameter at breast height	
Amphibian breeding habitat, e.g. vernal pools with standing water of sufficient duration and depth to support reproduction, or habitat for frog reproduction	

Table 6. Cover scale for microtopographic habitat features

Microtopographic habitat quality	**Narrative description**
0	Feature is absent or functionally absent from the wetland
1	Feature is present in the wetland in very small amounts or if more common, of low quality
2	Feature is present in moderate amounts, but not of highest quality or in small amounts of highest quality
3	Present in moderate or greater amounts and of the highest quality

Metric 6 Total 0

NON-HGM TRAM Summary Worksheet

Non-HGM Quantitative Rating	Metric 1: Size	1
	Metric 2: Buffers and surrounding land use	1
	Metric 3: Hydrology	6
	Metric 4: Habitat	3
	Metric 5: Special Wetland Communities	0
	Metric 6: Plant communities, interspersion, microtopography	0
	TOTAL SCORE	11

KIF D4 Area

PID#39170

W009

Rank = Low

"Wetland Conditions with an overall score of 100-75 are considered Exceptional Tennessee Waters. Wetlands with a score of 74-45 are considered to have moderate resource value, and wetland with a score of 44 and below have a low resource value."
TRAM 2015, pg 2)

KIF (onsite) Fossil Retirement ESCS 39170

Wetland Photolog 2022

W001 – PFO1E; 0.13 acres. TRAM = (39) Low

KIF (onsite) Fossil Retirement ESCS 39170

Wetland Photolog 2022

W002 – PEM1E; 0.03 acres.

TRAM = (13) Low

KIF (onsite) Fossil Retirement ESCS 39170

Wetland Photolog 2022

W003 – PEM1Hr; 0.11 acres. TRAM = (23) Low

KIF (onsite) Fossil Retirement ESCS 39170

Wetland Photolog 2022

W004 – PEM1E; 0.43 acres.

TRAM = (23) Low

KIF (onsite) Fossil Retirement ESCS 39170

Wetland Photolog 2022

W005 – PFO1E; 0.10 acres.

TRAM = (43) Low

KIF (onsite) Fossil Retirement ESCS 39170

Wetland Photolog 2022

W006 – PEM1E; 0.11 acres. TRAM = (36) Low

KIF (onsite) Fossil Retirement ESCS 39170

Wetland Photolog 2022

W007 – PEM1E; 0.01 acres.

TRAM = (15) Low

KIF (onsite) Fossil Retirement ESCS 39170

Wetland Photolog 2023

W008 – PEM; <0.01 acres.

TRAM = (11) Low

KIF (onsite) Fossil Retirement ESCS 39170

Wetland Photolog 2023

W009 – PEM; 0.01 acres.

TRAM = (11) Low

Appendix E.3 – Wetlands and Waters Survey Memo for Proposed Transmission Line Upgrades (L5108, L5302, and L5383) Associated with the Kingston Retirement Project. December 2022 (Provided Under Separate Cover Due to File Size)

Appendix E.4 – Aquatic Resources Inventory Survey Report Kingston Fossil Plant Retirement Project: Offsite Transmission Line Upgrades (L5116, L5280, and L5381)
(Provided Under Separate Cover Due to File Size)

Appendix E.5 – USACE Jurisdictional Determination Documentation

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DEPARTMENT OF THE ARMY
NASHVILLE DISTRICT, CORPS OF ENGINEERS
REGULATORY DIVISION
3701 BELL ROAD
NASHVILLE, TENNESSEE 37214

December 12, 2023

SUBJECT: File No.LRN-2006-00597, Tennessee Valley Authority (TVA); Jurisdictional Determination; Kingston Fossil Plant, Harriman, Roane County, Tennessee

Tennessee Valley Authority
Attn: Mr. Paul Pearman
1101 Market Street, BR 2C
Chattanooga, TN 37402

Dear Mr. Pearman:

This letter is in regard to your jurisdictional determination request, which documented potential waters of the United States on a review area of approximately 500 acres. The JD Report in Harriman, Roane County, Tennessee, indicated your preference for potential waters of the U.S. on the review area to be reviewed as both a preliminary jurisdictional determination (PJD) and approved jurisdictional determination (AJD). This project has been assigned File No. LRN-2006-00597, please refer to this number in any future correspondence.

The U.S. Army Corps of Engineers (USACE) has regulatory responsibilities pursuant to Section 404 of the Clean Water Act (33 U.S.C. 1344) and Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. 403). Under Section 10, the USACE regulates any work in, or affecting, navigable waters of the U.S. It appears the review area does not include navigable waters of the U.S. and would not be subject to the provisions of Section 10. Under Section 404, the USACE regulates the discharge of dredged and/or fill material into waters of the U.S., including wetlands.

a. <u>Preliminary Jurisdictional Determination</u>: Based on a field review on September 19, 2022, three reaches of stream totaling 1,345 linear of intermittent and 0.43 acres of wetlands were documented within the review area. This office has determined these features **may** be jurisdictional waters of the U.S. in accordance with 33 C.F.R. 331.2 and a PJD has been prepared. The PJD is non-binding, cannot be appealed and only provides a written indication that waters of the U.S, including wetlands, may be present on-site. For purposes of computation of impacts, compensatory mitigation requirements and other resource protection measures, a permit decision made on the basis of a PJD will treat all waters that would be affected in any way by the permitted activity on the site as if they are jurisdictional waters of the

U.S. This determination is only valid for the review area shown on the attached map entitled “LRN-2006-00597, PJD/AJD Boundary Map”, attached to this letter.

Enclosed with this letter is a copy of the PJD. If you agree with the findings of this PJD and understand your options regarding the same, please sign and date the form and return it to this office within 30 days of receipt of this letter. You should submit the signed copy to the following address:

U.S. Army Corps of Engineers
Nashville District
501 Adesa Parkway, Suite 250
Lenoir City, TN 37771
Attn: Cara Beverly

b. Approved Jurisdictional Determination: Also enclosed is an approved jurisdictional determination for aquatic resources identified as Clinch River, Emory River, e001, e002, e003, e004, e005, e006, e007, e008, e009, e010, e011, e012, e013, e015, e016, Pond 1, Pond 2, Pond 3, Pond 4, Pond 5, Str-001, W003, W006, and W007. The rationale for this determination is provided in the attached Approved Jurisdictional Determination Memorandum For Record (MFR).

This MFR constitutes the basis of jurisdiction for a Corps AJD as defined in 33 CFR §331.2. The features addressed in this AJD were evaluated consistent with the definition of “waters of the United States” found in the pre-2015 regulatory regime and consistent with the Supreme Court’s decision in Sackett.

The approved jurisdictional determination expires five years from the date of this letter, unless new information warrants revision of the determination before the expiration date, or the District Engineer identifies specific geographic areas with rapidly changing environmental conditions that merit re-verification on a more frequent basis. This approved jurisdictional determination is only valid for the review of the waters listed in this paragraph as shown on the map labeled LRN-2006-00597, PJD/AJD Boundary Map”

If you object to this decision, you may request an administrative appeal under Corps regulations at 33 CFR Part 331. Enclosed you will find a Notification of Appeals Process (NAP) fact sheet and Request for Appeal (RFA) form. If you request to appeal this decision you must submit a completed RFA form to the Great Lakes and Ohio River Division, Division Office at the following address:

Regulatory Appeal Review Officer
ATTN: Ms. Katie McCafferty
Army Engineer Division
550 Main Street, Room 10-780
Cincinnati, OH 45202-3222
TEL (513) 684-2699

In order for an RFA to be accepted by the USACE, the USACE must determine that it is complete, that it meets the criteria for appeal under 33 CFR Part 331.5, and that it has been received by the Division Office within 60 days of the date listed on the RFA form. **It is not necessary to submit an RFA form to the Division Office if you do not object to the decision in this letter**.

The delineation included herein has been conducted to identify the location and extent of the aquatic resources for purposes of the Clean Water Act for the particular site identified in this request. This delineation may not be valid for the Wetland Conservation Provisions of the Food Security Act of 1985, as amended. If you or your tenant are USDA program participants, or anticipate participation in USDA programs, you should discuss the applicability of an NRCS Certified Wetland Determination with the local USDA service center, prior to starting work.

We appreciate your awareness of the USACE regulatory program. If you have any questions, you may contact me or Cara Beverly at (865) 304-1413 or by e-mail at cara.c.beverly@usace.army.mil.

Sincerely,

Casey H. Ehorn

Casey H. Ehorn
Deputy Chief
Regulatory Division

Enclosures

Electronic Copies Furnished:

Ms. Britta Lees (TVA)
Mr. Paul Pearman (TVA)

PRELIMINARY JURISDICTIONAL DETERMINATION (PJD) FORM

BACKGROUND INFORMATION

A. REPORT COMPLETION DATE FOR (PJD): December 12, 2023

B. NAME AND ADDRESS OF PERSON REQUESTING PRELIMINARY JD:
Tennessee Valley Authority
1101 Market Street, LP 5D-C
Chattanooga, TN 37402

C. DISTRICT OFFICE, FILE NAME, AND NUMBER:

Nashville District
TVA Kingston Fossil Plant
LRN-2006-00597

D. PROJECT LOCATION(S) AND BACKGROUND INFORMATION:
(USE THE ATTACHED TABLE TO DOCUMENT MULTIPLE AQUATIC RESOURCES AND/OR AQUATIC RESOURCES AT DIFFERENT SITES)

State: Tennessee County/parish/borough: Roane City: Harriman/Kingston
Center coordinates of site (lat/long in degree decimal format):
Lat. 35.895584 ° **N**, Long. -84.502191 ° **W**.

Universal Transverse Mercator:

Name of nearest waterbody: Clinch River and Emory River

Identify (estimate) amount of waters in the review area:

Non-wetland waters:
1,345 linear feet of Intermittent Stream

Wetlands: 0.43 acres

Open Waters acres

E. REVIEW PERFORMED FOR SITE EVALUATION (CHECK ALL THAT APPLY):
☒ Office (Desk) Determination. Date: December 8, 2023
☒ Field Determination. Date(s): September 19, 2022

TABLE OF AQUATIC RESOURCES IN REVIEW AREA WHICH “MAY BE” SUBJECT TO REGULATORY JURISDICTION.

Site number	**Latitude (decimal degrees)**	**Longitude (decimal degrees)**	**Estimated amount of aquatic resource in review area (acreage and linear feet, if applicable)**	**Type of aquatic resource (i.e., wetland vs. non-wetland waters)**	**Geographic authority to which the aquatic resource “may be” subject (i.e., Section 404 or Section 10/404)**
Intermittent-14	N 35.8652 °	W 84.50093°	354 linear ft.	Riverine, (Intermittent) R4	Section 404
Intermittent-17	N 35.89422°	W -84.49852°	164 linear ft.	Riverine, (Intermittent) R4	Section 404
Str-002	N 35.89515°	W 84.49773°	954 linear ft. 0.06 acre	Riverine, (Intermittent) R4	Section 404
W001	N 35.89429°	W 84. 50019°	0.13 acre	Palustrine, (Forested) PFO	Section 404
W002	N 35.89493°	W 84. 50027°	0.03 acre	Palustrine, (Emergent) PEM	Section 404
W004	N 35.89514°	W 84.49734°	0.17 acre	Palustrine, (Emergent) PEM	Section 404
W005	N 35.89423°	W 84.49884°	0.10 acre	Palustrine, (Forested) PFO	Section 404

1. The Corps of Engineers believes that there may be jurisdictional aquatic resources in the review area, and the requestor of this PJD is hereby advised of his or her option to request and obtain an approved JD (AJD) for that review area based on an informed decision after having discussed the various types of JDs and their characteristics and circumstances when they may be appropriate.

2. In any circumstance where a permit applicant obtains an individual permit, or a Nationwide General Permit (NWP) or other general permit verification requiring “pre-construction notification” (PCN), or requests verification for a non-reporting NWP or other general permit, and the permit applicant has not requested an AJD for the activity, the permit applicant is hereby made aware that: (1) the permit applicant has elected to seek a permit authorization based on a PJD, which does not make an official determination of jurisdictional aquatic resources; (2) the applicant has the option to request an AJD before accepting the terms and conditions of the permit authorization, and that basing a permit authorization on an AJD could possibly result in less compensatory mitigation being required or different special conditions; (3) the applicant

has the right to request an individual permit rather than accepting the terms and conditions of the NWP or other general permit authorization; (4) the applicant can accept a permit authorization and thereby agree to comply with all the terms and conditions of that permit, including whatever mitigation requirements the Corps has determined to be necessary; (5) undertaking any activity in reliance upon the subject permit authorization without requesting an AJD constitutes the applicant's acceptance of the use of the PJD; (6) accepting a permit authorization (e.g., signing a proffered individual permit) or undertaking any activity in reliance on any form of Corps permit authorization based on a PJD constitutes agreement that all aquatic resources in the review area affected in any way by that activity will be treated as jurisdictional, and waives any challenge to such jurisdiction in any administrative or judicial compliance or enforcement action, or in any administrative appeal or in any Federal court; and (7)whether the applicant elects to use either an AJD or a PJD, the JD will be processed as soon as practicable. Further, an AJD, a proffered individual permit (and all terms and conditions contained therein), or individual permit denial can be administratively appealed pursuant to 33 C.F.R. Part 331. If, during an administrative appeal, it becomes appropriate to make an official determination whether geographic jurisdiction exists over aquatic resources in the review area, or to provide an official delineation of jurisdictional aquatic resources in the review area, the Corps will provide an AJD to accomplish that result, as soon as is practicable. This PJD finds that there *"may be"* waters of the U.S. and/or that there *"may be"* navigable waters of the U.S. on the subject review area, and identifies all aquatic features in the review area that could be affected by the proposed activity, based on the following information:

SUPPORTING DATA. Data reviewed for preliminary JD (check all that apply - checked items should be included in case file and, where checked and requested, appropriately reference sources below):

☒ Maps, plans, plots or plat submitted by or on behalf of the applicant/consultant: Map: b. Information submitted by Tennessee Valley Authority in digital report titled "KIF-USACE-APJD-REQUEST" dated August 3, 2022, and updated map provided by TVA on October 31, 2022.

☐ Data sheets prepared/submitted by or on behalf of the applicant/consultant.

☐ Office concurs with data sheets/delineation report.

☐ Office does not concur with data sheets/delineation report. Rationale: .

☐ Data sheets prepared by the Corps: .

☐ Corps navigable waters' study: .

☒ U.S. Geological Survey Hydrologic Atlas: .

☒ USGS NHD data.

☒ USGS 8 and 12 digit HUC maps.

☒ U.S. Geological Survey map(s). Cite scale & quad name: Harriman and Elverton TN 24:000.

☒ Natural Resources Conservation Service Soil Survey. Citation: National Regulatory Viewer – Great Lakes and Ohio River Division, Accessed December 8, 2023

☒ National wetlands inventory map(s). Cite name: National Regulatory Viewer – Great Lakes and Ohio River Division, Accessed December 8, 2023.

☐ State/Local wetland inventory map(s): .

☐ FEMA/FIRM maps: .

☐ 100-year Floodplain Elevation is: (National Geodetic Vertical Datum of 1929)

☒ Photographs: ☐ Aerial (Name & Date): .
or ☒ Other (Name & Date): Submitted in Report dated May 13, 2019 and site visit photos from June 6, 2019 and September 19, 2022.

☒ Previous determination(s). File no. and date of response letter:LRN-2006-00597 dated August 16, 2019.

☐ Other information (please specify): .

IMPORTANT NOTE: The information recorded on this form has not necessarily been verified by the Corps and should not be relied upon for later jurisdictional determinations.

Cara Beverly

Signature and date of
Project Manager
(REQUIRED)

Signature and date of
person requesting preliminary JD
(REQUIRED, unless obtaining the signature is impracticable)[1]

[1] Districts may establish timeframes for requestor to return signed PJD forms. If the requestor does not respond within the established time frame, the district may presume concurrence and no additional follow up is necessary prior to finalizing an action. For the Nashville District, concurrence is presumed after 30 days.

DEPARTMENT OF THE ARMY
U.S. ARMY CORPS OF ENGINEERS, NASHVILLE DISTRICT
3701 BELL ROAD
NASHVILLE, TENNESSEE 37214

CELRN-RD 08 DEC 2023

MEMORANDUM FOR RECORD

SUBJECT: US Army Corps of Engineers (Corps) Pre-2015 Regulatory Regime Approved Jurisdictional Determination in Light of *Sackett v. EPA*, 143 S. Ct. 1322 (2023) ,[1] LRN-2006-0059[2]

BACKGROUND. An Approved Jurisdictional Determination (AJD) is a Corps document stating the presence or absence of waters of the United States on a parcel or a written statement and map identifying the limits of waters of the United States on a parcel. AJDs are clearly designated appealable actions and will include a basis of JD with the document.[3] AJDs are case-specific and are typically made in response to a request. AJDs are valid for a period of five years unless new information warrants revision of the determination before the expiration date or a District Engineer has identified, after public notice and comment, that specific geographic areas with rapidly changing environmental conditions merit re-verification on a more frequent basis.[4] For the purposes of this AJD, we have relied on section 10 of the Rivers and Harbors Act of 1899 (RHA),[5] the Clean Water Act (CWA) implementing regulations published by the Department of the Army in 1986 and amended in 1993 (references 2.a. and 2.b. respectively), the 2008 *Rapanos-Carabell* guidance (reference 2.c.), and other applicable guidance, relevant case law and longstanding practice, (collectively the pre-2015 regulatory regime), and the *Sackett* decision (reference 2.d.) in evaluating jurisdiction.

This Memorandum for Record (MFR) constitutes the basis of jurisdiction for a Corps AJD as defined in 33 CFR §331.2. The features addressed in this AJD were evaluated consistent with the definition of "waters of the United States" found in the pre-2015 regulatory regime and consistent with the Supreme Court's decision in *Sackett*. This AJD did not rely on the 2023 "Revised Definition of 'Waters of the United States,'" as

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[1] While the Supreme Court's decision in *Sackett* had no effect on some categories of waters covered under the CWA, and no effect on any waters covered under RHA, all categories are included in this Memorandum for Record for efficiency.
[2] When documenting aquatic resources within the review area that are jurisdictional under the Clean Water Act (CWA), use an additional MFR and group the aquatic resources on each MFR based on the TNW, interstate water, or territorial seas that they are connected to. Be sure to provide an identifier to indicate when there are multiple MFRs associated with a single AJD request (i.e., number them 1, 2, 3, etc.).
[3] 33 CFR 331.2.
[4] Regulatory Guidance Letter 05-02.
[5] USACE has authority under both Section 9 and Section 10 of the Rivers and Harbors Act of 1899 but for convenience, in this MFR, jurisdiction under RHA will be referred to as Section 10.

amended on 8 September 2023 (Amended 2023 Rule) because, as of the date of this decision, the Amended 2023 Rule is not applicable in this state due to litigation.

1. SUMMARY OF CONCLUSIONS.

   a. Provide a list of each individual feature within the review area and the jurisdictional status of each one (i.e., identify whether each feature is/is not a water of the United States and/or a navigable water of the United States).

Resource	Amount (Length/Area)	Jurisdictional Status	Applicable Authority(ies)
Clinch River	Varies	Jurisdictional	Section 10 & 404
Emory River	Varies	Jurisdictional	Section 10 & 404
e001	1910 linear feet	Non-jurisdictional	N/A
e002	182 linear feet	Non-jurisdictional	N/A
e003	244 linear feet	Non-jurisdictional	N/A
e004	172 linear feet	Non-jurisdictional	N/A
e005	1024 linear feet	Non-jurisdictional	N/A
e006	136 linear feet	Non-jurisdictional	N/A
e007	380 linear feet	Non-jurisdictional	N/A
e008	816 linear feet	Non-jurisdictional	N/A
e009	1466 linear feet	Non-jurisdictional	N/A
e010	57 linear feet	Non-jurisdictional	N/A
e011	320 linear feet	Non-jurisdictional	N/A
e012	546 linear feet	Non-jurisdictional	N/A
e013	398 linear feet	Non-jurisdictional	N/A
e015	2354 linear feet	Non-jurisdictional	N/A
e016	641 linear feet	Non-jurisdictional	N/A
Pond 1	0.04 acre	Non-jurisdictional	N/A
Pond 2	0.02 acre	Non-jurisdictional	N/A
Pond 3	0.02 acre	Non-jurisdictional	N/A
Pond 4	0.14 acre	Non-jurisdictional	N/A
Pond 5	0.12 acre	Non-jurisdictional	N/A
Str-001	606 linear feet	Non-jurisdictional	N/A
W003	0.11 acre	Non-jurisdictional	N/A
W006	0.11 acre	Non-jurisdictional	N/A
W007	0.11 are	Non-jurisdictional	N/A

2. REFERENCES.

   a. Final Rule for Regulatory Programs of the Corps of Engineers, 51 FR 41206 (November 13, 1986).

   b. Clean Water Act Regulatory Programs, 58 FR 45008 (August 25, 1993).

   c. U.S. EPA & U.S. Army Corps of Engineers, Clean Water Act Jurisdiction Following the U.S. Supreme Court's Decision in *Rapanos v. United States & Carabell v. United States* (December 2, 2008)

   d. *Sackett v. EPA*, 598 U.S. _, 143 S. Ct. 1322 (2023)

   e. 2008 Rapanos Guidance

3. REVIEW AREA. The Approved Jurisdictional Determination (AJD) review area includes approximately 550 acres of Tennessee Valley Authority Kingston Fossil Plant located at 714 Swan Pond Road, Harriman, Roane County, Tennessee (Latitude:35.8974° N, Longitude 84.5136° W). Features outside the AJD review area are not included in the AJD and were assessed under a Preliminary Jurisdictional Determination (PJD) simultaneously with the AJD.

4. NEAREST TRADITIONAL NAVIGABLE WATER (TNW), INTERSTATE WATER, OR THE TERRITORIAL SEAS TO WHICH THE AQUATIC RESOURCE IS CONNECTED. The nearest TNW's are Clinch and Emory Rivers as the site is a peninsula located between the confluence of the two river systems. Additionally, both the Clinch River and Emory River are listed on the Nashville District Traditional Navigable Water List.[6]

5. FLOWPATH FROM THE SUBJECT AQUATIC RESOURCES TO A TNW, INTERSTATE WATER, OR THE TERRITORIAL SEAS [Describe the flowpath from the subject aquatic resources within the review area to the TNW, interstate water, or the territorial seas (whether inside or outside the review area).]

[6] This MFR should not be used to complete a new stand-alone TNW determination. A stand-alone TNW determination for a water that is not subject to Section 9 or 10 of the Rivers and Harbors Act of 1899 (RHA) is completed independently of a request for an AJD. A stand-alone TNW determination is conducted for a specific segment of river or stream or other type of waterbody, such as a lake, where upstream or downstream limits or lake borders are established.

Resource	Amount (Length/Area)	Flowpath to TNW/Section 10
Clinch River	Varies	The Clinch River is a TNW
Emory River	Varies	The Emory River is a TNW
e001	1910 linear feet	Resource flows into Str-001 then through settling ponds 1,2 and 3 then discharged in Clinch River (TNW) via a constructed stormwater outfall.
e002	182 linear feet	Resource flows into e001 to Str-001 then through settling ponds 1,2 and 3 then discharges into Clinch River (TNW) via a constructed stormwater outfall.
e003	244 linear feet	Resource discharges into Clinch River (TNW).
e004	172 linear feet	Resource discharges into Clinch River (TNW) via constructed stormwater outfall.
e005	1024 linear feet	Resource discharges into Emory River (TNW) via a constructed stormwater outfall.
e006	136 linear feet	N/A; Resource does not have continuous downstream connection
e007	380 linear feet	Resource flows to e005 then discharges into Emory River (TNW) via a constructed stormwater outfall.
e008	816 linear feet	Resource flows to e007 to e005 then discharges into Emory River (TNW) via a constructed stormwater outfall.
e009	1466 linear feet	Resource flows to e004 then discharges into Clinch River (TNW) via constructed stormwater outfall.

e010	57 linear feet	Resource flows to e007 to e005 then discharges into Emory River (TNW) via a constructed stormwater outfall.
e011	320 linear feet	N/A; Resource does not have continuous downstream connection.
e012	546 linear feet	
e013	398 linear feet	
e015	2354 linear feet	
e016	641 linear feet	
Pond 1	0.04 acre	Ponds 1,2 and 3 are constructed settling ponds within Str-001 and discharge into Clinch River (TNW).
Pond 2	0.02 acre	
Pond 3	0.02 acre	
Pond 4	0.14 acre	N/A; Resource does not have continuous downstream connection.
Pond 5	0.12 acre	
Str-001	606 linear feet	Str-001 is a constructed wastewater feature that flows directly into Clinch River (TNW).
W003	0.11 acre	N/A; Resource does not have continuous downstream connection.
W006	0.11 acre	
W007	0.11 are	

6. SECTION 10 JURISDICTIONAL WATERS[7]: Describe aquatic resources or other features within the review area determined to be jurisdictional in accordance with Section 10 of the Rivers and Harbors Act of 1899. Include the size of each aquatic resource or other feature within the review area and how it was determined to be jurisdictional in accordance with Section 10.[8]

Section 10 Jurisdictional Waters:		
Clinch River	Varies	The Clinch River is a TNW
Emory River	Varies	The Emory River is a TNW

[7] 33 CFR 329.9(a) A waterbody which was navigable in its natural or improved state, or which was susceptible of reasonable improvement (as discussed in § 329.8(b) of this part) retains its character as "navigable in law" even though it is not presently used for commerce, or is presently incapable of such use because of changed conditions or the presence of obstructions.
[8] This MFR is not to be used to make a report of findings to support a determination that the water is a navigable water of the United States. The district must follow the procedures outlined in 33 CFR part 329.14 to make a determination that water is a navigable water of the United States subject to Section 10 of the RHA.

*Both these resources are listed on the Nashville District's Navigable waters list.

7. SECTION 404 JURISDICTIONAL WATERS: Describe the aquatic resources within the review area that were found to meet the definition of waters of the United States in accordance with the pre-2015 regulatory regime and consistent with the Supreme Court's decision in *Sackett*. List each aquatic resource separately, by name, consistent with the naming convention used in section 1, above. Include a rationale for each aquatic resource, supporting that the aquatic resource meets the relevant category of "waters of the United States" in the pre-2015 regulatory regime. The rationale should also include a written description of, or reference to a map in the administrative record that shows, the lateral limits of jurisdiction for each aquatic resource, including how that limit was determined, and incorporate relevant references used. Include the size of each aquatic resource in acres or linear feet and attach and reference related figures as needed.

   a. TNWs (a)(1):

Traditionally Navigable Waters:		
Clinch River	Varies	The Clinch River is a TNW
Emory River	Varies	The Emory River is a TNW

*Both these resources are listed on the Nashville District's Navigable waters list.

   b. Interstate Waters (a)(2): [N/A]

   c. Other Waters (a)(3): [N/A]

   d. Impoundments (a)(4): [N/A]

   e. Tributaries (a)(5): [N/A.]

   f. The territorial seas (a)(6): [N/A.]

   g. Adjacent wetlands (a)(7): [N/A]

8. NON-JURISDICTIONAL AQUATIC RESOURCES AND FEATURES

a. Describe aquatic resources and other features within the review area identified as "generally non-jurisdictional" in the preamble to the 1986 regulations (referred to as "preamble waters").[9] Include size of the aquatic resource or feature within the review area and describe how it was determined to be non-jurisdictional under the CWA as a preamble water.

Preamble Waters:			
Name	Amount (Length/Area)	Criteria	Rationale for Determination
Pond 4	0.14 acre	Preamble Water – Artificial lake/pond created by excavating/diking dry land, used exclusively for purposes such as stock watering, irrigation, settling basins, or rice growing.	Pond 4 was determined to be an upland man-made artificial pond, used exclusively as a settling pond during construction activities. Pond 4 was excavated in dry land, and does not have a relatively permanent or continuous surface water connection to an (a)(1) or other relatively permanent water. Additionally, the USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below.
Pond 5	0.12 acre	Preamble Water – Artificial lake/pond created by excavating/diking dry land, used exclusively for purposes such as stock watering, irrigation, settling basins, or rice growing.	Pond 5 was determined to be an upland man-made artificial pond, used exclusively as a settling pond during construction activities. Pond 5 was excavated in dry land, and does not have a relatively permanent or continuous surface water connection to an (a)(1) or other relatively permanent water. Additionally, the USACE completed an office review of a variety of available resources, as

[9] 51 FR 41217, November 13, 1986.

			described in Section 9. DATA SOURCES, below.

b. Describe aquatic resources and features within the review area identified as "generally not jurisdictional" in the *Rapanos* guidance. Include size of the aquatic resource or feature within the review area and describe how it was determined to be non-jurisdictional under the CWA based on the criteria listed in the guidance. [N/A.]

c. Describe aquatic resources and features identified within the review area as waste treatment systems, including treatment ponds or lagoons designed to meet the requirements of CWA. Include the size of the waste treatment system within the review area and describe how it was determined to be a waste treatment system. [N/A.]

Wastewater treatment systems:			
Name	Amount (Length/Area)	Criteria	Rationale for Determination
Str-001	1910 linear feet	NON-WOTUS: Waste treatment systems including treatment ponds or lagoons, designed to meet the requirements of the Clean Water Act	Str-001 is a channel with continuous flow from a leakage in the site's fire suppression system at the substation. The resource has three settling ponds constructed within it prior to discharging into Clinch River.
Pond 1	0.04 acre	NON-WOTUS: Waste treatment systems including treatment ponds or lagoons, designed to meet the requirements of the Clean Water Act.	Pond 1 is a constructed settling pond within the Str-001 which has continuous flow from documented leakage in the site's fire suppression system. Pond 1 is one of three constructed settling basins within the wastewater system.

Pond 2	0.02 acre	NON-WOTUS: Waste treatment systems including treatment ponds or lagoons, designed to meet the requirements of the Clean Water Act	Pond 2 is a constructed settling pond within the Str-001 which has continuous flow from documented leakage in the site's fire suppression system. Pond 1 is one of three constructed settling basins within the wastewater system.
Pond 3	0.02 acre	NON-WOTUS: Waste treatment systems including treatment ponds or lagoons, designed to meet the requirements of the Clean Water Act	Pond 3 is a constructed settling pond within the Str-001 which has continuous flow from documented leakage in the site's fire suppression system. Pond 1 is one of three constructed settling basins within the wastewater system.

d. Describe aquatic resources and features within the review area determined to be prior converted cropland in accordance with the 1993 regulations (reference 2.b.). Include the size of the aquatic resource or feature within the review area and describe how it was determined to be prior converted cropland. [N/A.]

e. Describe aquatic resources (i.e. lakes and ponds) within the review area, which do not have a nexus to interstate or foreign commerce, and prior to the January 2001 Supreme Court decision in "*SWANCC*," would have been jurisdictional based solely on the "Migratory Bird Rule." Include the size of the aquatic resource or feature, and how it was determined to be an "isolated water" in accordance with *SWANCC*. [N/A.]

f. Describe aquatic resources and features within the review area that were determined to be non-jurisdictional because they do not meet one or more categories of waters of the United States under the pre-2015 regulatory regime consistent with the Supreme Court's decision in *Sackett* (e.g., tributaries that are non-relatively permanent waters; non-tidal wetlands that do not have a continuous surface connection to a jurisdictional water).
[N/A or enter rationale/discussion here.]

Pre-2015 Regulatory Regime Guidance:			
Name	Amount (Length/Area)	Criteria	Rationale for Determination
e001	1910 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e001 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a non-relatively permanent tributary.
e002	182 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e002 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This

			feature was previously determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a non-relatively permanent tributary.
e003	244 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e003 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a

			non-relatively permanent tributary.
e004	172 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e004 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a non-relatively permanent tributary.
e005	1024 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e005 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously

			determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a non-relatively permanent tributary.
e006	136 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e006 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a

			non-relatively permanent tributary.
e007	380 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e007 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a non-relatively permanent tributary.
e008	816 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e008 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously

			determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a non-relatively permanent tributary.
e009	1466 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e009 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a

			non-relatively permanent tributary.
e010	57 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e010 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a non-relatively permanent tributary.
e011	320 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e011 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously

			determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a non-relatively permanent tributary.
e012	546 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e012 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a

			non-relatively permanent tributary.
e013	398 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e013 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a non-relatively permanent tributary.
e014	2354 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e014 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously

			determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a non-relatively permanent tributary.
e015	641 linear feet	NON-WOTUS: Tributary to a water identified in paragraphs (a)(1) through (4), where the tributary is not a relatively permanent, standing or continuously flowing body of water.	e015 was characterized by having a non-relatively permanent flow regime (only flowing in direct response to rain) based on an evaluation of the submitted field data sheets and hydrologic determination forms submitted by TVA, and site visit conducted by USACE on September 19, 2022. This feature was previously determined to have non-relatively permanent flow in previous jurisdictional determinations that were conducted at this location. USACE completed an office review of a variety of available resources, as described in Section 9. DATA SOURCES, below. The available data and information support a determination that this is a

			non-relatively permanent tributary.
W003	0.11 acre	NON-WOTUS: Wetland that is not adjacent to a water identified in paragraph (a)(1) through (6).	W003 was determined to be a wetland based on the presence of wetland indicators including soil, hydrology, and vegetation. W003 is fringe wetland surrounding Pond 4. W003 is located approximately 500 linear feet from the nearest jurisdictional tributary (Str-002) and there is no direct surface connection between the resources.
W006	0.11 acre	NON-WOTUS: Wetland that is not adjacent to a water identified in paragraph (a)(1) through (6).	W006 was determined to be a wetland based on the presence of wetland indicators including soil, hydrology, and vegetation. W006 is approximately 850 linear feet from the nearest jurisdictional tributary (Intermittent 014) and there is no direct surface connection between the resources.
W007	0.01 acre	NON-WOTUS: Wetland that is not adjacent to a water identified in paragraph (a)(1) through (6).	W007 was determined to be a wetland based on the presence of wetland indicators including soil, hydrology, and vegetation. W006 is approximately 1000 linear feet from the nearest jurisdictional tributary (Intermittent 014) and there is no direct surface connection between the resources.

9. DATA SOURCES. List sources of data/information used in making determination. Include titles and dates of sources used and ensure that information referenced is available in the administrative record.

a. Site visit conducted September 19, 2022, and USACE office review conducted December 8, 2023.

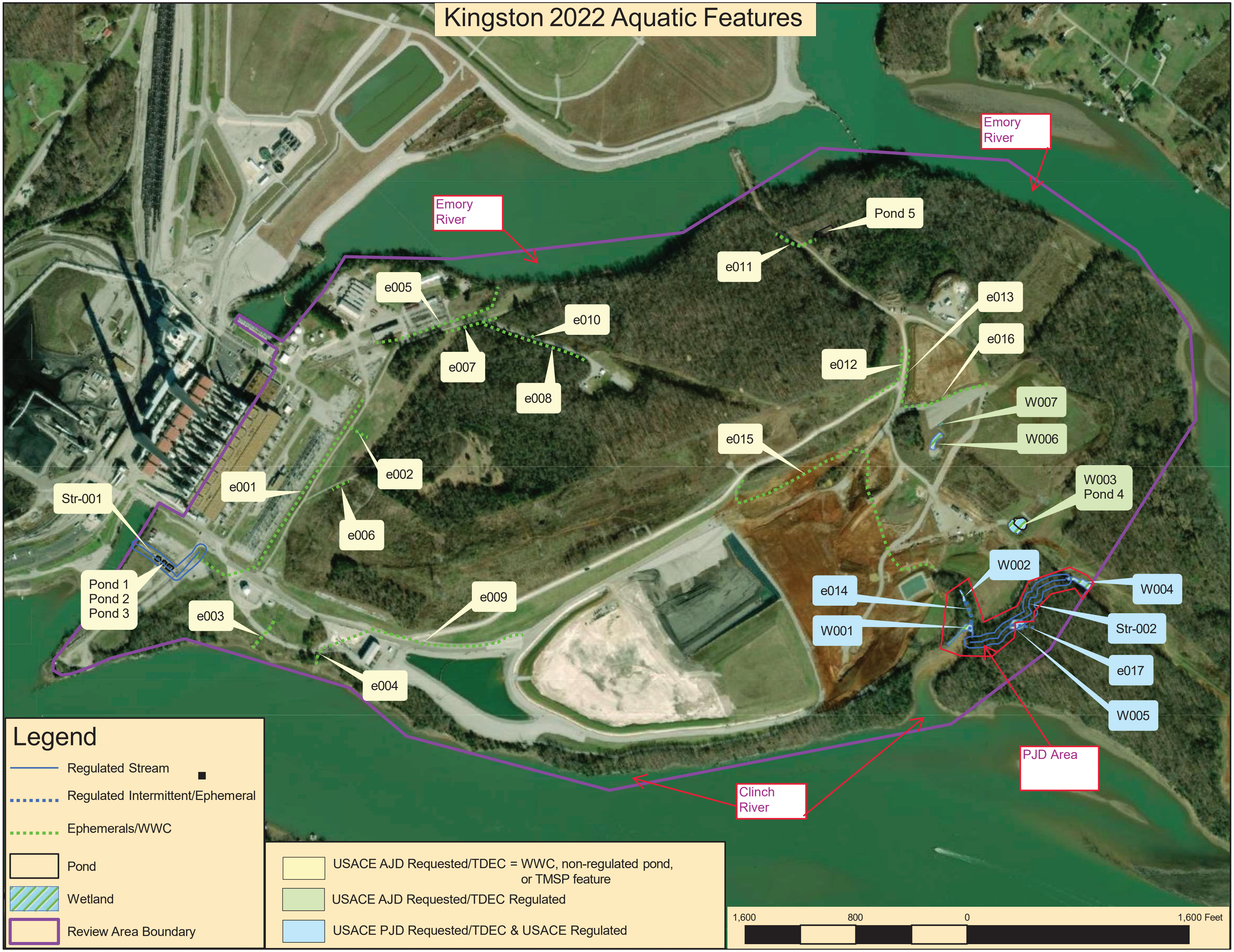
b. Information submitted by Tennessee Valley Authority in digital report titled "KIF-USACE-APJD-REQUEST" dated August 3, 2022, and updated map provided by TVA on October 31, 2022.

e. National Regulatory Viewer – Great Lakes and Ohio River Division, Accessed December 8, 2023:
    a. USFWS National Wetland Inventory (NWI) Maps
    b. National Hydrography Dataset (NHD)
    c. USDA NRCS Soil Survey Map Units
    d. USGS Topographic Map
    e. 3DEP Digital Elevation Model (DEM)
    f. 3DEP Hill Shade
    g. Elevation Modeling Tool
    h. Aerial Imagery

10. OTHER SUPPORTING INFORMATION. USCAE also reviewed previous AJD/PJD documentation dated August 16, 2019.

11. NOTE: The structure and format of this MFR were developed in coordination with the EPA and Department of the Army. The MFR's structure and format may be subject to future modification or may be rescinded as needed to implement additional guidance from the agencies; however, the approved jurisdictional determination described herein is a final agency action.

Kingston 2022 Aquatic Features



NOTIFICATION OF ADMINISTRATIVE APPEAL OPTIONS AND PROCESS AND REQUEST FOR APPEAL

Applicant: Tennessee Valley Authority		File Number: LRN-2006-00597	Date: December 12, 2023
Attached is:			See Section below
	INITIAL PROFFERED PERMIT (Standard Permit or Letter of permission)		A
	PROFFERED PERMIT (Standard Permit or Letter of permission)		B
	PERMIT DENIAL WITHOUT PREJUDICE		C
	PERMIT DENIAL WITH PREJUDICE		D
X	APPROVED JURISDICTIONAL DETERMINATION		E
X	PRELIMINARY JURISDICTIONAL DETERMINATION		F

SECTION I

The following identifies your rights and options regarding an administrative appeal of the above decision. Additional information may be found at https://www.usace.army.mil/Missions/Civil-Works/Regulatory-Program-and-Permits/appeals/ or Corps regulations at 33 CFR Part 331.

A: INITIAL PROFFERED PERMIT: You may accept or object to the permit

- ACCEPT: If you received a Standard Permit, you may sign the permit document and return it to the district engineer for final authorization. If you received a Letter of Permission (LOP), you may accept the LOP and your work is authorized. Your signature on the Standard Permit or acceptance of the LOP means that you accept the permit in its entirety, and waive all rights to appeal the permit, including its terms and conditions, and approved jurisdictional determinations associated with the permit.

- OBJECT: If you object to the permit (Standard or LOP) because of certain terms and conditions therein, you may request that the permit be modified accordingly. You must complete Section II of this form and return the form to the district engineer. Upon receipt of your letter, the district engineer will evaluate your objections and may: (a) modify the permit to address all of your concerns, (b) modify the permit to address some of your objections, or (c) not modify the permit having determined that the permit should be issued as previously written. After evaluating your objections, the district engineer will send you a proffered permit for your reconsideration, as indicated in Section B below.

B: PROFFERED PERMIT: You may accept or appeal the permit

- ACCEPT: If you received a Standard Permit, you may sign the permit document and return it to the district engineer for final authorization. If you received a Letter of Permission (LOP), you may accept the LOP and your work is authorized. Your signature on the Standard Permit or acceptance of the LOP means that you accept the permit in its entirety, and waive all rights to appeal the permit, including its terms and conditions, and approved jurisdictional determinations associated with the permit.

- APPEAL: If you choose to decline the proffered permit (Standard or LOP) because of certain terms and conditions therein, you may appeal the declined permit under the Corps of Engineers Administrative Appeal Process by completing Section II of this form and sending the form to the division engineer. This form must be received by the division engineer within 60 days of the date of this notice.

C. PERMIT DENIAL WITHOUT PREJUDICE: Not appealable
You received a permit denial without prejudice because a required Federal, state, and/or local authorization and/or certification has been denied for activities which also require a Department of the Army permit before final action has been taken on the Army permit application. The permit denial without prejudice is not appealable. There is no prejudice to the right of the applicant to reinstate processing of the Army permit application if subsequent approval is received from the appropriate Federal, state, and/or local agency on a previously denied authorization and/or certification.

D: PERMIT DENIAL WITH PREJUDICE: You may appeal the permit denial
You may appeal the denial of a permit under the Corps of Engineers Administrative Appeal Process by completing Section II of this form and sending the form to the division engineer. This form must be received by the division engineer within 60 days of the date of this notice.

E: APPROVED JURISDICTIONAL DETERMINATION: You may accept or appeal the approved JD or provide new information for reconsideration

- ACCEPT: You do not need to notify the Corps to accept an approved JD. Failure to notify the Corps within 60 days of the date of this notice means that you accept the approved JD in its entirety and waive all rights to appeal the approved JD.

- APPEAL: If you disagree with the approved JD, you may appeal the approved JD under the Corps of Engineers Administrative Appeal Process by completing Section II of this form and sending the form to the division engineer. This form must be received by the division engineer within 60 days of the date of this notice.

- RECONSIDERATION: You may request that the district engineer reconsider the approved JD by submitting new information or data to the district engineer within 60 days of the date of this notice. The district will determine whether the information submitted qualifies as new information or data that justifies reconsideration of the approved JD. A reconsideration request does not initiate the appeal process. You may submit a request for appeal to the division engineer to preserve your appeal rights while the district is determining whether the submitted information qualifies for a reconsideration.

F: PRELIMINARY JURISDICTIONAL DETERMINATION: Not appealable
You do not need to respond to the Corps regarding the preliminary JD. The Preliminary JD is not appealable. If you wish, you may request an approved JD (which may be appealed), by contacting the Corps district for further instruction. Also, you may provide new information for further consideration by the Corps to reevaluate the JD.

POINT OF CONTACT FOR QUESTIONS OR INFORMATION:

If you have questions regarding this decision you may contact:	If you have questions regarding the appeal process, or to submit your request for appeal, you may contact:
Cara Beverly Nashville District, U.S. Army Corps of Engineers Regulatory Branch 3701 Bell Road Nashville, Tennessee, 37214 (865) 304-1413; cara.c.beverly@usace.army.mil	Regulatory Appeals Review Officer ATTN: Ms. Katie McCafferty Army Engineers Division 550 Main Street, Room 10-780 Cincinnati, Ohio 45202-3222 Phone: (513) 684-2699

SECTION II – REQUEST FOR APPEAL or OBJECTIONS TO AN INITIAL PROFFERED PERMIT

REASONS FOR APPEAL OR OBJECTIONS: (Describe your reasons for appealing the decision or your objections to an initial proffered permit in clear concise statements. Use additional pages as necessary. You may attach additional information to this form to clarify where your reasons or objections are addressed in the administrative record.)

ADDITIONAL INFORMATION: The appeal is limited to a review of the administrative record, the Corps memorandum for the record of the appeal conference or meeting, and any supplemental information that the review officer has determined is needed to clarify the administrative record. Neither the appellant nor the Corps may add new information or analyses to the record. However, you may provide additional information to clarify the location of information that is already in the administrative record.

RIGHT OF ENTRY: Your signature below grants the right of entry to Corps of Engineers personnel, and any government consultants, to conduct investigations of the project site during the course of the appeal process. You will be provided a 15-day notice of any site investigation and will have the opportunity to participate in all site investigations.

______________________________ Signature of appellant or agent.	Date:
Email address of appellant and/or agent:	Telephone number:

Appendix F – Biological Resources
(Provided Under Separate Cover Due to File Size)

Appendix F.1 – USFWS Consultation Documentation
(Provided Under Separate Cover Due to File Size)

Appendix F.2 – TVA’s Kingston Fossil Plant Natural Resources Survey
(Provided Under Separate Cover Due to File Size)

Appendix F.3 – Wildlife and Vegetation Assessment Kingston Transmission Line. Kingston Fossil Plant. December 2022 (Provided Under Separate Cover Due to File Size)

Appendix F.4 – Wildlife and Vegetation Assessment Technical Report. Kingston Fossil Plant Retirement Project: Offsite Transmission Line Upgrades (L5116, L5280, and L5280)
(Provided Under Separate Cover Due to File Size)

Appendix G – Preliminary Sound Study, Tennessee Valley Authority's Kingston Fossil Plant, Kingston, Tennessee

Preliminary Sound Study

Tennessee Valley Authority

Kingston Fossil Plant
Project No. 142943

Revision 1
8/18/2022

Preliminary Sound Study

prepared for

Tennessee Valley Authority
Kingston Fossil Plant
Kingston, Tennessee

Project No. 142943

Revision 1
8/18/2022

prepared by

Burns & McDonnell
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
ACC	Air-Cooled Condenser
ANSI	American National Standards Institute
CadnaA	Computer Aided Noise Abatement
dB	decibels
dBA	A-weighted decibels
Existing Facility	Kingston Fossil Plant
Hz	hertz
ISO	International Organization of Standardization
L_{eq}	equivalent sound level
MP	measurement point
Project	Kingston Combustion Turbine Plant
TVA	Tennessee Valley Authority

1.0 INTRODUCTION

Burns & McDonnell conducted a preliminary sound study for the proposed Kingston Combustion Turbine Plant (Project). The proposed Project consists of one (1) J-Class 1x1 combined-cycle combustion turbine and 16 aeroderivative simple-cycle combustion turbines to be located to the southeast of the existing Tennessee Valley Authority (TVA) Kingston Fossil Plant (Existing Facility) in Kingston, Tennessee. This preliminary study consists of sound monitoring of the existing environment and predictive sound modeling of the Project to analyze potential offsite sound impacts from operation of the Project.

The objectives of this study are as follows:

- Identify the appropriate standards applicable to the proposed Project;
- Conduct an ambient sound survey in the surrounding community to quantify existing sound levels; and
- Develop a sound model to estimate future sound levels emitted by the proposed Project.

The following chapters describe the study in further detail.

2.0 ACOUSTICAL TERMINOLOGY

The terms “noise level” and “sound level” are often used interchangeably to describe two different sound characteristics called sound power and sound pressure. Every source that produces sound has a sound power level. The sound power level is the acoustical energy emitted by a sound source and is an absolute number that is not affected by the environment. The acoustical energy produced by a source propagates through the air as air pressure fluctuations. These pressure fluctuations, also called sound pressure, are what human ears hear and microphones measure.

Sound energy is physically characterized by amplitude and frequency. Sound amplitude is measured in decibels (dB) as the logarithmic ratio of a sound pressure to a reference sound pressure (20 microPascals). The reference sound pressure corresponds to the typical threshold of human hearing. A 3-dB change in a continuous broadband sound level is generally considered “just barely perceptible” to the average listener. A 5-dB change is generally considered “clearly noticeable,” and a 10-dB change is generally considered a doubling (or halving, if the sound is decreasing) of the apparent loudness.

Frequency is measured in Hertz (Hz), which is the number of cycles per second. The typical human ear can hear frequencies ranging from approximately 20 to 20,000 Hz. Normally, the human ear is most sensitive to sounds in the middle frequencies (1,000 to 8,000 Hz) and is less sensitive to sounds in the low and high frequencies. As such, the A-weighted scale was developed to simulate the frequency response of the human ear to sounds at typical environmental levels. The A-weighted scale emphasizes sounds in the middle frequencies and de-emphasizes sounds in the low and high frequencies. Any sound level to which the A-weighted scale has been applied is expressed in dBA. For reference, the sound pressure level and subjective loudness associated with some common sound sources are listed in Table 2-1.

Sound in the environment is constantly fluctuating, for example, when a car drives by, a dog barks, or a plane passes overhead. Although an instantaneous sound level measured in dBA may indicate the level of noise experienced by an observer at that point in time, environmental noise levels vary continuously. Most ambient environmental noise includes a mixture of noise from some identifiable sources plus a relatively steady background noise where no particular source is identifiable. A single descriptor called the equivalent sound level (L_{eq}) is used to describe sound that is constant or changing in level. The L_{eq} is the average sound level for a specific time period.

Table 2-1: Typical Sound Pressure Levels Associated with Common Sound Sources

Sound Pressure Level (dBA)	Subjective Evaluation	Environment	
		Outdoor	Indoor
140	Deafening	Jet aircraft at 75 ft.	--
130	Threshold of pain	Jet aircraft during takeoff at a distance of 300 ft.	--
120	Threshold of feeling	Elevated train	Hard rock band
110	--	Jet flyover at 1,000 ft.	Inside propeller plane
100	Very loud	Power mower, motorcycle at 25 ft., auto horn at 10 ft., crowd noise at football game	--
90	--	Propeller plane flyover at 1,000 ft., noisy urban street	Full symphony or band, food blender, noisy factory
80	Moderately loud	Diesel truck (40 mph) at 50 ft.	Inside auto at high speed, garbage disposal
70	Loud	B-757 cabin during flight	Close conversation, vacuum cleaner
60	Moderate	Air-conditioner condenser at 15 ft., near highway traffic	General office
50	Quiet	--	Private office
40	--	Farm field with light breeze, birdcalls	Soft stereo music in residence
30	Very quiet	Quiet residential neighborhood	Bedroom, average residence (without TV and stereo)
20	--	Rustling leaves	Quiet theater, whisper
10	Just audible	--	Human breathing
0	Threshold of hearing	--	--

Sources:
(1) Adapted from *Architectural Acoustics*, M. David Egan, 1988
(2) *Architectural Graphic Standards*, Ramsey and Sleeper, 1994

3.0 APPLICABLE REGULATIONS

There were no identified federal, state, or local noise regulations applicable to the Project.

4.0 NOISE MONITORING

Noise measurements for the existing ambient and baseline environment were collected using American National Standards Institute (ANSI) S1.4 Type 1 sound level meters (Larson Davis Model LXT). The sound level meters were calibrated at the beginning and end of each set of measurements. Five continuous long-term sound level meters were set up at the measurement locations, labeled MP01 through MP05, shown in Figure A-1 of Appendix A. During the measurements, the microphone cable associated with MP01 was chewed through by an animal, and data was only collected from 4:00 p.m. to 10:00 p.m. Measurements at MP01 should be excluded from the analysis, as the meter could not be calibrated at the end of the measurement. The data associated with MP01 is provided below for informational purposes only. The coordinates and measurement periods for each sound monitor are shown below in Table 4-1.

Table 4-1: Sound Meter Summary

Meter	Coordinates UTM Meters Zone 16		Start Time	Stop Time
	Easting (m)	Northing (m)		
MP01	725,628	3,975,847	June 15 – 4:42 p.m.	June 15 – 10:07 p.m.
MP02	726,338	3,974,887	June 15 – 4:57 p.m.	June 16 – 3:09 p.m.
MP03	724,659	3,974,830	June 15 – 5:14 p.m.	June 16 – 3:25 p.m.
MP04	726,391	3,974,106	June 15 – 5:41 p.m.	June 16 – 3:46 p.m.
MP05	726,053	3,976,250	June 15 – 5:52 p.m.	June 16 – 3:59 p.m.

The measured sound levels varied at each monitor location mostly due to variations in traffic noise and other background sounds that influenced each location. Sound metrics, inclusive of L_{eq}, were collected throughout the monitoring periods. The daytime and nighttime average L_{eq} and lowest 1-hour average L_{eq} measured values for each measurement location are provided in Table 4-2.

Table 4-2: Average Sound Levels

Location	Daytime Average[a] (L_{eq} dBA)	Nighttime Average[a] (L_{eq} dBA)	Lowest 1-Hour (L_{eq} dBA)
MP01[b]	44	--	32
MP02	47	44	37
MP03	47	45	41
MP04	53	46	38
MP05	52	48	42

(a) Daytime is from 7 AM to 10 PM. Nighttime is from 10 PM to 7 AM.
(b) MP01 could not be calibrated at the end of the measurement

The existing Kingston Fossil Plant coal-fired units were operating at base load throughout the monitoring period. Local roadway traffic and naturally occurring sounds were the largest contributors to measured sound levels at the monitoring locations. The Existing Facility was faintly audible at MP03 and not audible at the other measurement locations during daytime hours when the equipment was being set up and torn down.

5.0 PREDICTIVE SOUND MODELING

Burns & McDonnell performed predictive sound modeling for the Project using Computer Aided Noise Abatement (CadnaA), Version 2022, published by DataKustik, Ltd., Munich, Germany. Air absorption, ground absorption, and reflections and shielding for each piece of sound-emitting equipment were considered for predicting downwind sound pressure levels per International Organization for Standardization (ISO) 9613-2, Acoustics – Sound Attenuation during Propagation Outdoors (ISO, 1996).

The ISO standard considers sound propagation and directivity. The sound-modeling software calculates omnidirectional, downwind sound propagation using worst-case directivity factors, in tandem with user-specified directivities and propagation properties. Empirical studies accepted within the industry have demonstrated that modeling may over-predict sound levels in certain directions, and as a result, modeling results generally are considered a conservative measure of the Project's actual sound level.

5.1 Model Inputs

The Project general arrangement is included as Figure A-2 of Appendix A. The modeled equipment octave-band sound levels assumed for each piece of equipment are included as Appendix B.

Average ground absorption was assumed to be 0.5 for the Project and the land surrounding the Project due to the mix of gravel and soft vegetative surface types. Large water bodies were assumed to have a ground absorption of 0.0. The default meteorological conditions were applied in the model. Each piece of noise-emitting equipment associated with the proposed Project was modeled with the expected sound power levels applied to them. Each piece of proposed Project equipment was assumed to be continuously operating at maximum sound levels, propagating in all directions. None of the Exiting Facilities' sound contributions are included in the model.

5.2 Model Results

The Project will operate at fairly constant sound levels when operational. Therefore, steady-state sound level predictions were completed. The predicted overall steady-state operational sound levels, which do not include contributions from ambient sound sources or the Existing Facility, are shown with 5-dB contours in Figure A-3 of Appendix A.

The Project sound levels were calculated for MP01 through MP05, and the most impacted residential area to the south. The predicted Project sound levels were logarithmically added to the lowest measured existing condition sound levels at each respective location to estimate the future sound levels near the

Project. The lowest hourly sound level at each MP, the predicted Project sound level, and the logarithmic sum are provided in Table 5-1.

Table 5-1: Modeled Sound Levels at Measurement Points

Location	Lowest Measured Hourly Sound Level[a] (dBA)	Model Predicted Project Sound Level[b] (dBA)	Predicted Future Total Sound Level[c] (dBA)
MP01[d]	32	54	54
MP02	37	53	53
MP03	41	54	54
MP04	38	50	50
MP05	42	51	51
RES[e]	38	55	55

(a) Lowest measured hourly sound level
(b) Model predicted Project sound level
(c) Log addition of lowest measured hourly sound level plus the Project's contribution
(d) MP01 could not be calibrated at the end of the measurement
(e) RES is in a similar location to MP04. The ambient sound levels measured at MP04 are assumed to be similar to those at RES.

The Project is expected to contribute a maximum absolute sound level of approximately 55 dBA in the vicinity of the nearest residential noise sensitive receptors, RES, which are located south of the Project site. Project sound levels are primarily influenced by the Air-Cooled Condenser (ACC), simple- and combined-cycle stack exits, and combustion turbine air inlets.

6.0 CONCLUSION

Burns & McDonnell conducted a preliminary sound study for the proposed Project. This preliminary study consists of sound monitoring of the existing environment and predictive sound modeling of the Project to analyze potential offsite sound impacts from operation of the Project.

The Project is expected to contribute a maximum absolute sound level of approximately 55 dBA at the nearest residential noise sensitive receptors, south of the Project site. Sound impacts would increase the existing sound levels in the area. If necessary, additional mitigation measures could be applied to Project noise sources that would result in reductions to offsite sound level impacts from the Project.

APPENDIX A - FIGURES

Path: Z:\Clients\ENS\TVA\142943_CCandAeroNoise\Studies\Modeling\Kingston\GIS\Kingston_Figures.aprx gweger 6/30/2022
Service Layer Credits: World Boundaries and Places: Esri, HERE, Garmin, GeoTechnologies, Inc.

Residential Receptor

Measurement Point

Project Layout

NORTH

1,500 750 0 1,500

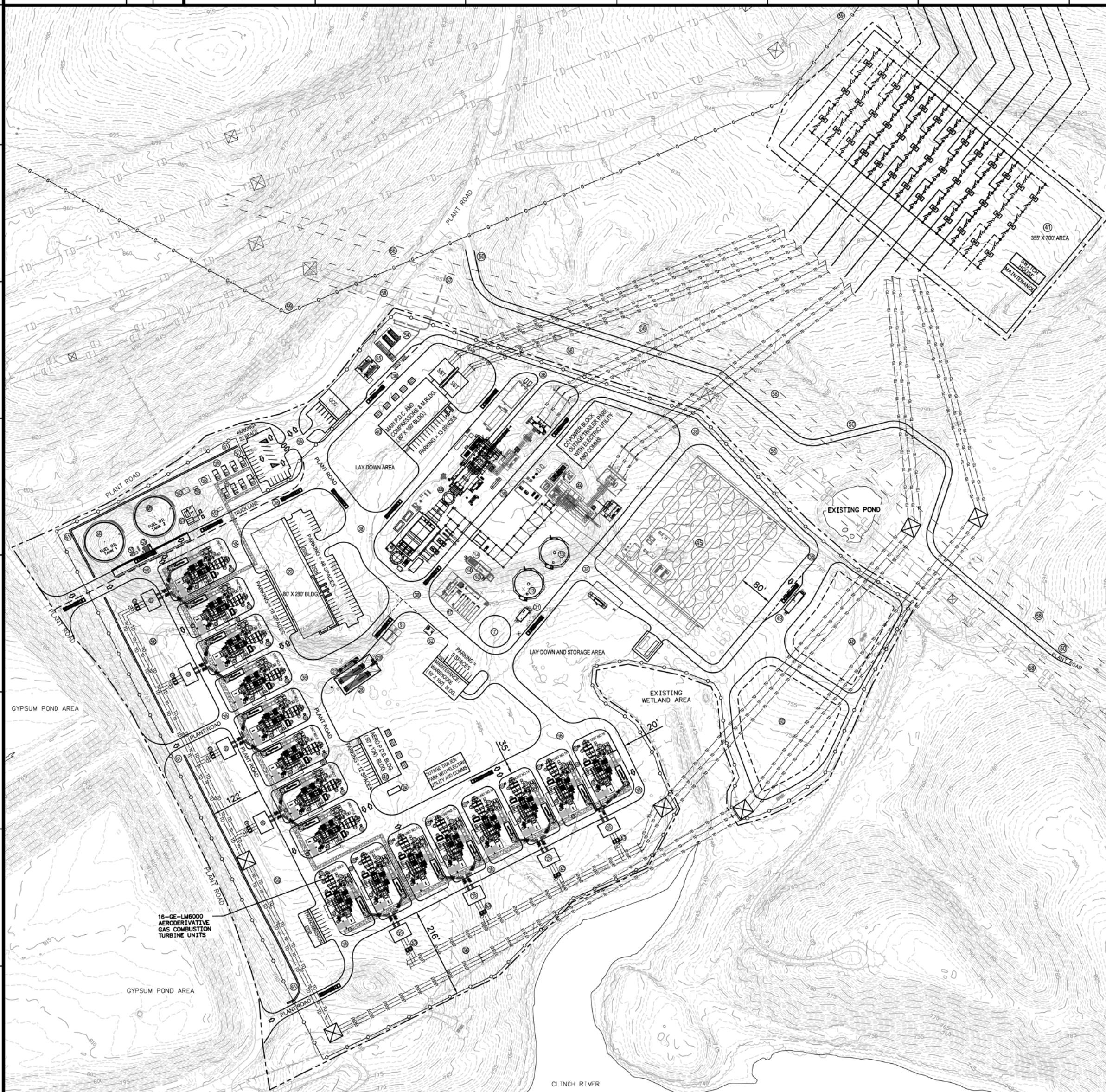
Scale in Feet

BURNS McDONNELL

Figure A-1
TVA
Kingston
Monitoring Locations

Source: ESRI, Burns & McDonnell

Issued: 6/30/2022



VICINITY MAP
NOT TO SCALE

TOPOGRAPHIC MAPPING SOURCE NOTES:

1. DRAWINGS WERE PREPARED USING TOPOGRAPHIC INFORMATION PROVIDED BY TVA. THE PROJECT BASEMAP WAS DEVELOPED FROM LIDAR SURVEY FLOWN IN MARCH 2017, FEATURES DIGITIZED FROM TVA DRAWINGS OF RECORD AND PULLED FROM GE POWER GAS POWER SYSTEMS PROVIDED BY TVA. ACTUAL CONDITIONS MAY VARY FROM THOSE SHOWN ON THESE PLANS AND SHOULD BE VERIFIED.
2. SURVEY COORDINATES ARE REFERENCED TO TENNESSEE STATE PLANE COORDINATE SYSTEM NAD83 (CORS 96). ELEVATIONS ARE BASED ON NGVD29.

EQUIPMENT LIST:

TAG No	Q.No	DESCRIPTION (SIMPLE CYCLE)
1	16	GAS TURBINE – GE LM6000 AERODERIVATIVE
2	16	GENERATOR
3	16	STACK WITH SCR / CO CATALYST – HORIZONTAL
4	16	TURBINE AUXILIARY SKID
5	16	MINERAL LUBE OIL SKID
6	16	GT AIR FILTER
7	1	SERVICE WATER STORAGE TANK
8	16	SIMPLEX FINAL FILTER
9	16	GT AREA DRAIN TANK
10	1	GENERAL SERVICE PUMP ELECTRICAL ENCLOSURE
11	16	MLO / TLO FIN FAN COOLER
12	1	FUEL GAS ANALYSER (2x100%)
13	2	DEMINERLISED WATER TANK
14	1	DEMINERALIZED WATER AND SERVICE WATER PUMPS
15	16	CEMS – CONTINUOUS EMISSIONS MONITORING SYSTEMS
16	2	MV SKID FOR GAS COMPRESSORS
17	1	AIR COMPRESSOR (2x100%)
18	3	GAS COMPRESSOR COOLER
19	–	PIPING / CABLE CORRIDOR (CONCRETE TRENCH & LID)
20	16	DOUBLE BLOCK AND BLEED VALVE
21	2	AMMONIA UNLOADING AND CONTAINMENT AREA
22	1	ADMINISTRATION BLDG./CONTROL ROOM/WAREHOUSE
23	5	GTG PCM – GAS TURBINE GEN. POWER CONTROL MODULE
24	1	BSNGG–BLACK START NATURAL GAS GENERATOR
25	5	GSUT–GENERATOR STEP–UP TRANSFORMER
26	8	FUEL GAS INLET MODULE (SHUT OFF & FLOW METER)
27	3	FUEL GAS COMPRESSOR
28	2	AMMONIA TANKS (AQUEOUS AMMONIA)
29	2	AMMONIA TRANSFER PUMP
30	8	GCB – GENERATOR CIRCUIT BREAKERS
31	1	FIRE PUMP ENCLOSURE
32	1	FINAL WASTE DRAIN PIT
33	1	OIL WATER SEPARATOR
34	1	OIL WATER RETENTION PIT
35	1	OIL DRUM
36	16	NOT USED – AUXILIARY TRANSFORMER
37	1	GAS COMPRESSOR SHED AND FUEL GAS YARD
38	1	NEW ACCESS ROAD
39	16	MAINTENANCE DRIVEWAY
40	1	POWER DISTRIBUTION CENTER / BUILDING
41	1	COLLECTOR YARD AND SWITCHYARD (BY OWNER)
42	16	AMMONIA BLOWERS
43	7	LINE BREAKERS
44	1	1x1 GAS AND STEAM TURBINE COMBINED CYCLE
45	1	AIR CONDENSER COOLING
46	2	FUEL OIL TANKS
47	1	DEMIN WATER TREATMENT AREA WITH CONTAINMENT
48	1	BLOWDOWN POND
49	1	BLOWDOWN POND MONITORING BUILDING
50	1	REROUTED EXISTING PLANT ROAD (1,958 LF)
51	1	HYDROGEN STORAGE SYSTEM
52	1	CO2 STORAGE TANKS
53	1	FUEL OIL UNLOADING AND STORAGE AREA
54	1	FUEL GAS FILTRATION AND REGULATION
55	1	DEW POINT HEATERS
56	1	TRANSMISSION LINE YARD
57	1	FUTURE CT PLANT GAS PIPELINE CONNECTION POINT
58	1	EXISTING TRANSMISSION 69/161KV LINE EASEMENT
59	1	NEW GAS PIPELINE ROUTE
60	1	STORMWATER POND
61	1	RETAINING WALLS

LEGEND:

- EXISTING RAILROAD
- EXISTING STORM SEWER
- EXISTING SANITARY SEWER
- 409 EXISTING CONTOUR (MINOR)
- 410 EXISTING CONTOUR W/ELEVATION (MAJOR)
- EXISTING FENCE
- TD EXISTING TRANSMISSION LINES
- EXISTING VEGETATION/BRUSH LINE
- TD EXISTING TRANSMISSION LINES
- EXISTING VEGETATION/BRUSH LINE
- TD NEW TRANSMISSION DISTRIBUTION LINES
- PROPOSED TRAFFIC FLOW ARROWS
- NEW COMBUSTION TURBINE / COMBINED CYCLE PLANT SITE AREA = 48 ACRES
  NEW COLLECTOR YARD AND SWITCHYARD AREA = 7 ACRES
- NEW CONCRETE RETAINING WALL
- GT BLADE–OFF ZONE
- MAINTENANCE ACCESS AREA
- PIPING / CABLE CORRIDOR
- PIPE AND CABLE TRAY RACK(OVERHEAD)
- SF NEW SWITCHYARD AREA/FENCE
- NEW PLANT FENCE
- RSD = ROLLUP SIDE DOOR

50 0 100 200 FEET
GRAPHIC SCALE: 1" = 100'
CONTOUR INTERVAL = 1 FEET

PRELIMINARY

REV. NO.	DATE	DSGN	DRWN	CHKD	SUPV	RVWD	APPD	ISSD	PROJECT ID	AS CONST	REV CD
R –	–	–	–	–	–	–	–	–	–	–	–
R 0	12/8/2021								7064115	–	J

ISSUED FOR REVIEW

DISCIPLINE INTERFACE 1 2 3 4

SCALE: 1"=100' EXCEPT AS NOTED

GENERAL YARD
16–LM6000 AERODERIVATIVE GAS COMBUSTION TURBINES

GENERAL ARRANGEMENT LAYOUT PLAN (OPTION 1B) EAST AREA

DESIGNED BY:	DRAWN BY:	CHECKED BY:	SUPERVISED BY:	REVIEWED BY:	APPROVED BY:	ISSUED BY:
BDC	BDC	TFY	SRW	RW / JC	JC / SE	

KINGSTON COMBUSTION TURBINE PLANT
TENNESSEE VALLEY AUTHORITY
FOSSIL AND HYDRO ENGINEERING

HDR
HDR Engineering, Inc.
1201 Market Street
Suite C
Chattanooga, TN 37402-2714
423.414.3546

PROJECT NUMBER–10329097

AUTOCAD R | DATE 10/28/21 | 36 | C | SK–KIF–GA–02 | R 0

HDR | 0
TASK COMPLETED BY: | REV NO.

Figure A-2

PLOT FACTOR:1
W_TVA

C.A.D. DRAWING
DO NOT ALTER MANUALLY

Path: Z:\Clients\ENS\TVA\142943_CCandAeroNoise\Studies\Modeling\Kingston\GIS\Kingston_Figures.aprx gweger 8/19/2022
Service Layer Credits: World Boundaries and Places: Esri, HERE, Garmin, GeoTechnologies, Inc.

Residential Receptor
Measurement Point
Project Layout

45 dBA
50 dBA
55 dBA
60 dBA
65 dBA
70 dBA
75 dBA
80 dBA

NORTH

1,500 750 0 1,500
Scale in Feet

BURNS McDONNELL

Figure A-3
TVA
Kingston
Sound Level Contours

Source: ESRI, Burns & McDonnell

Issued: 8/19/2022

APPENDIX B - MODELED SOUND POWER LEVELS

Equipment Description	Number of Sources	Model Inputs - Source Sound Power Levels (dBA)										Source / BMCD Comments
		Octave Band Center Frequency (Hz)									Overall dBA	
		31.5	63	125	250	500	1000	2000	4000	8000		
J-Class Combined-Cycle Combustion Turbine												
Exhaust Diffuser	1	107	114	98	94	88	85	87	89	76	95	BMCD Estimate - J Class Turbine
GT	1	106	103	101	95	96	97	100	106	94	109	BMCD Estimate - J Class Turbine
GT Inlet Duct	1	107	99	93	85	84	85	101	100	77	104	BMCD Estimate - J Class Turbine
GT Inlet Face	1	112	105	101	94	90	91	96	104	95	106	BMCD Estimate - J Class Turbine
GT Inlet Plenum	1	102	99	98	93	94	97	97	94	89	102	BMCD Estimate - J Class Turbine
GT Inlet Walls	1	102	90	83	70	61	57	60	74	61	77	BMCD Estimate - J Class Turbine
GTG	1	99	105	107	96	102	100	100	94	84	106	BMCD Estimate - J Class Turbine
HRSG Body	1	121	114	110	95	93	91	89	88	70	99	BMCD Estimate - J Class Turbine
HRSG Inlet	1	120	115	114	106	96	96	94	93	75	104	BMCD Estimate - J Class Turbine
HRSG Stack Casing	1	118	114	104	89	73	64	52	39	12	92	BMCD Estimate - J Class Turbine
HRSG BDVT	1	85	93	101	105	102	99	95	91	69	104	BMCD Estimate
HRSG Vent	2	80	88	96	100	97	94	90	86	64	99	BMCD Estimate - J Class Turbine
HRSG Stack	1	131	123	111	97	87	82	80	76	56	100	BMCD Estimate - J Class Turbine
HRSG Steam Piping	1	101	98	91	86	82	79	95	76	65	107	BMCD Estimate
LP Fuel Gas Skid	1	104	100	89	81	80	86	88	91	89	96	BMCD Estimate - J Class Turbine
Lube Oil Skid	1	101	102	99	98	97	96	96	97	88	103	BMCD Estimate - J Class Turbine
Steam Jet Air Injectors	2	87	93	91	90	89	88	87	86	82	94	BMCD Estimate - J Class Turbine
Turbine Compartment Vent Fans	4	102	102	110	101	98	95	94	98	95	104	BMCD Estimate - J Class Turbine
Vacuum Pump	2	94	100	98	97	96	95	94	93	89	101	BMCD Estimate - J Class Turbine
Lube Oil Skid	1	101	102	99	98	97	96	96	97	88	103	BMCD Estimate
Steam Turbine	1	123	123	115	108	107	104	103	102	95	111	BMCD Estimate - J Class Turbine
Steam Turbine Generator	1	102	107	110	99	105	102	103	97	87	108	BMCD Estimate - J Class Turbine
Boiler Feed Pump	2	92	98	96	90	91	100	98	94	84	103	BMCD Estimate
Aux Transformer	2	99	99	103	103	103	87	82	75	70	101	BMCD Estimate
GSU Transformer	2	105	105	109	109	109	93	88	81	76	107	BMCD Estimate
Control Oil Skid	1	101	102	99	98	97	96	96	97	88	103	BMCD Estimate (85 dBA at 3 feet)
LM6000 Simple-Cycle Combustion Turbine												
SC Filter Seperator	16	0	78	83	88	88	84	83	79	73	90	BMCD Estimate - LM6000 Turbine
SC Generator Vent	48	0	106	94	83	72	72	71	68	62	84	BMCD Estimate - LM6000 Turbine
PDC HVAC	48	79	69	73	73	70	68	63	60	57	73	BMCD Estimate
SC TA Fan	32	0	105	107	98	97	91	89	83	84	99	BMCD Estimate - LM6000 Turbine
SC Turbine Vent	48	103	105	97	94	79	77	76	70	60	89	BMCD Estimate - LM6000 Turbine
SC Stack Exit	16	135	133	126	121	112	98	93	95	87	116	BMCD Estimate - LM6000 Turbine
SC Air Inlet Filter Face	32	107	109	102	99	97	93	90	86	79	99	BMCD Estimate - LM6000 Turbine
SC Ammonia Flow Skid	16	82	90	92	84	86	86	84	78	72	90	BMCD Estimate - LM6000 Turbine
SC Aux Skid	16	82	90	92	84	86	86	84	78	72	90	BMCD Estimate - LM6000 Turbine
SC Generator Compartment	16	100	97	100	102	90	91	84	75	65	96	BMCD Estimate - LM6000 Turbine
SC Generator Vent	16	0	102	102	91	78	73	71	68	65	88	BMCD Estimate - LM6000 Turbine
SC GSU Transformer	8	93	105	105	102	101	99	95	87	78	103	BMCD Estimate - LM6000 Turbine
SC Lube Oil Fin Fan Cooler	16	108	109	102	99	97	93	90	86	79	99	BMCD Estimate - LM6000 Turbine
SC Lube Oil Skid	16	101	102	99	98	97	96	96	97	88	103	BMCD Estimate - LM6000 Turbine
SC SCR	16	113	110	107	103	97	89	86	82	53	99	BMCD Estimate - LM6000 Turbine
SC SCR Transition	16	113	110	107	103	97	89	86	82	53	99	BMCD Estimate - LM6000 Turbine
SC TA Fan Casing	16	0	105	107	98	97	91	89	83	84	99	BMCD Estimate - LM6000 Turbine
SC Turbine Compartment	16	101	97	101	100	97	89	87	87	83	98	BMCD Estimate - LM6000 Turbine
SC Turbine Vent	48	100	93	97	98	92	92	94	92	86	100	BMCD Estimate - LM6000 Turbine
BOP Equipment												
ACC	1	120	123	123	119	116	113	106	102	98	118	62 dBA at 400 ft
ACC Steam Trunk	1	101	98	91	86	82	79	95	76	65	107	BMCD Estimate
Air Compressor	2	90	89	91	91	91	91	91	88	81	97	BMCD Estimate (85 dBA at 3 feet)
Air Dryer	2	90	89	91	91	91	91	91	88	81	97	BMCD Estimate (85 dBA at 3 feet)
Ammonia Skid	1	91	98	94	91	92	92	90	87	82	97	BMCD Estimate (85 dBA at 3 feet)
Condensate Recir Pumps	2	85	99	94	92	92	91	91	86	84	97	BMCD Estimate (85 dBA at 3 feet)
Fuel Gas Heater	1	104	100	89	81	80	86	88	91	89	96	BMCD Estimate (85 dBA at 3 feet)
Fuel Gas Meter	8	0	0	56	64	67	65	60	54	48	69	BMCD Estimate
Fuel Gas Skid	3	104	100	89	81	80	86	88	91	89	96	BMCD Estimate (85 dBA at 3 feet)
HP Fuel Gas Skid	1	104	100	89	81	80	86	88	91	89	96	BMCD Estimate (85 dBA at 3 feet)
HVAC	2	89	79	83	83	80	78	73	70	67	83	BMCD Estimate
Gas Compressor Building	1	3	115	118	114	106	105	89	83	66	110	BMCD Estimate - IMP Walls
Compressor Transformer	2	105	105	109	109	109	93	88	81	76	107	BMCD Estimate

BURNS & McDONNELL

CREATE AMAZING.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
O 816-333-9400
F 816-333-3690
www.burnsmcd.com

Appendix H - Resource Figures H1-H4 and H5-H9 for East Tennessee Natural Gas' Ridgeline Expansion Project under Alternative A (Provided Under Separate Cover Due to File Size)

Appendix I – Estimated Direct Operational Emissions and Associated Social Cost of Greenhouse Gas for Alternatives

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TVA-Wide Emissions – 2018

Pollutant	(Abbrev.)	ACC	ACK	ALF	BCT	BRF	CCC	CCT	CUF	GAF	GCC	JCC	JCT	KCT	KIF	LCC	LCT	MCT	MCC	PAF	SCC	SHF	Total
Particulate Matter	PM	100	56.3	67.8	10.9	74.3	136	3.59	343	183	15.8	80.3	20.6	18.4	182	22.9	35.2	20.1	140	772	151	651	3,084
Total PM<10 microns	TPM10	102	96.5	44.9	37.7	102	120	5.9	1520	259	29.9	83.1	28.8	30.3	380	26.2	58.1	29.1	203	992	159	641	4,949
Total PM<2.5 microns	TPM2.5	102	96	26.4	37.7	79.6	119	5.9	1410	197	29.9	83.1	28.8	30.3	319	26.1	58.1	29.1	198	819	152	401	4,248
Sulfur Dioxide	SO2	6.66	6.88	902	2.01	199	8.33	0.284	7410	1830	1.8	11	2.51	1.73	1330	116	3.6	1.12	12.5	2550	8.54	15100	29,504
Nitrogen Oxides	NOX	224	141	277	244	794	154	352	4300	1300	216	176	245	83	1160	14.6	167	54.9	243	4960	171	8230	23,507
Carbon Monoxide	CO	33.6	419	63.5	191	171	71.2	10.4	1140	826	46.8	54.2	101	115	430	22.4	271	41	96	504	226	1010	5,843
Volatile Organic Compnds	VOC	34.8	11.3	14.1	16.2	20.2	29.3	0.843	135	99.4	9.04	52.9	19.8	17.4	51.5	5.64	9.19	3.55	25.4	144	16.4	121	837
Sulfuric Acid	H2SO4	0.195	0.993	0.00376	0.151	30	0.0274	0.0229	1100	0.024	0.139	0.0466	0.0474	0.15	192	0.0305	0.262	0.105	1.88	357	0.0168	1.27	1,684
Ammonia	NH3	13.5	24.6	4.93		1.55	220		4.77	65.5		17.9	4.81		15.7	10.6			24.3	4.94	15.6	18.6	447
Carbon Dioxide	CO2	1320000	1360000	457000	399000	1600000	1650000	59700	11100000	6060000	357000	2070000	501000	299000	3850000	1120000	577000	222000	2480000	7190000	1690000	7990000	52,351,700
Methane	CH4	24.5	24.9	5.06	7.18	17.3	30.6	1.1	122	64	6.61	39	9.19	5.66	38.5	21.9	10.8	4.27	49.6	91.5	32.3	78.7	685
Nitrous Oxide	N2O	2.45	2.49	7.58	0.718	26.7	3.06	0.113	192	101	0.661	3.98	0.932	0.575	61.2	2.19	1.09	0.435	4.96	79.1	3.23	125	619
CO2 equivalent (GHGs)	CO2e	1330000	1360000	459000	399000	1600000	1650000	59700	11200000	6100000	357000	2070000	503000	299000	3870000	1120000	578000	222000	2480000	7220000	1690000	8030000	52,596,700
Mercury	Hg	1.7E-05	9.7E-06	6.0E-04	2.8E-06	2.6E-03	1.6E-05	6.4E-06	1.6E-02	2.1E-02	3.1E-06	1.7E-04	2.5E-04	2.1E-05	9.1E-03	8.3E-06	2.5E-05	1.7E-05	1.9E-05	1.0E-02	1.7E-05	1.6E-02	7.6E-02
Lead	Pb								1.13E-01														

TVA-Wide Emissions – 2019

Pollutant	(Abbrev.)	ACC	ACK	ACT	BCT	BRF	CCC	CCT	CUF	GAF	GCC	JCC	JCT	KCT	KIF	LCC	LCT	MCT	MCC	PAF	SCC	SHF	Totals
Particulate Matter	PM	137	55.5	0.227	9.31	75.5	59.4	0.185	278	163	13.2	82	17.3	10.9	264	23.8	19	5.07	91.7	406	121	540	2,372
Total PM<10 microns	TPM10	140	94.9	0.328	32.4	115	123	0.296	1310	224	25	84.8	22.1	18	469	27.4	31.3	7.3	129	629	131	538	4,152
Total PM<2.5 microns	TPM2.5	140	94.3	0.328	32.4	91.3	117	0.296	1230	170	25	84.8	22.1	18	377	27.2	31.3	7.3	126	572	125	342	3,633
Sulfur Dioxide	SO2	11.4	6.73	0.0145	1.73	308	8.34	0.0136	7210	1730	1.5	10.6	3.25	1.01	1920	6.16	2.31	0.47	8.57	2130	7.21	16300	29,667
Nitrogen Oxides	NOX	223	144	7.51	203	741	156	11.2	3930	1350	179	174	65.8	48.5	1260	108	84.2	15	174	4410	143	8030	21,457
Carbon Monoxide	CO	19.5	176	0.393	164	161	59	0.502	1030	698	56.7	46.9	62.8	40.7	493	24.7	146	8.07	101	372	192	996	4,848
Volatile Organic Compnds	VOC	49.9	11.1	0.417	13.8	19.1	29	0.0422	122	85.3	7.52	54	16.2	10.3	58.9	24.6	4.97	0.975	26.5	117	11.9	119	783
Sulfuric Acid	H2SO4	0.162	0.972	0.00117	0.129	43.2	0.0213	0.0011	966	0.417	0.116	0.0532	0.0375	0.0862	215	0.0488	0.158	0.0379	1.19	253	0.0252	1.54	1,482
Ammonia	NH3	2.62	32.8			1.32	91.4		4.1	49.4		2.3	1.02		16.3	15.6			36	3.12	48.5	15.5	320
Carbon Dioxide	CO2	2260000	1330000	2530	342000	1510000	1650000	3150	10000000	4990000	297000	2110000	412000	177000	4350000	1220000	306000	55500	1700000	5750000	1430000	7650000	47,545,180
Methane	CH4	41.6	24.4	0.0722	6.12	16.7	30.4	0.055	108	52.9	5.51	39.6	7.65	3.35	44.8	22.9	5.84	1.09	31.5	80.4	27.8	77.9	629
Nitrous Oxide	N2O	4.16	2.44	0.0122	0.612	25.9	3.04	0.00602	169	81.6	0.551	3.96	0.788	0.34	71	2.29	0.595	0.117	3.15	55.1	2.78	124	551
CO2 equivalent (GHGs)	CO2e	2270000	1330000	2530	342000	1520000	1650000	3160	10100000	5020000	298000	2120000	415000	177000	4370000	1220000	306000	55500	1700000	5780000	1430000	7690000	47,799,190
Mercury	Hg	2.2E-05	9.4E-06	9.1E-06	2.5E-06	2.2E-03	1.6E-05	9.6E-07	7.4E-03	2.4E-07	2.4E-06	2.6E-05	1.7E-04	1.0E-05	1.0E-02	8.6E-06	2.3E-05	1.5E-05	1.3E-05	9.6E-03	1.4E-05	1.1E-02	4.1E-02
Lead	Pb								8.76E-02														

TVA-Wide Emissions – 2020

Pollutant	(Abbrev.)	ACC	ACK	ACT	BCT	BRF	CCC	CCT	CUF	GAF	GCC	JCC	JCT	KCT	KIF	LCC	LCT	MCT	MCC	PAF	SCC	SHF	Totals
Particulate Matter	PM	88.6	54.8	0.00328	8.62	56.6	66	0.253	335	130	12.9	83.9	23.3	10.4	109	25.6	9.11	1.94	128	223	167	264	1,798
Total PM<10 microns	TPM10	90.4	92.3	0.00553	29.9	69.3	139	0.41	1410	157	24.4	86.8	29.1	17.2	137	29.4	15	2.74	182	370	179	257	3,318
Total PM<2.5 microns	TPM2.5	90.4	91.7	0.00553	23.9	52	132	0.41	1300	116	24.4	86.8	29.1	17.2	103	29.3	15	2.74	176	358	172	167	2,987
Sulfur Dioxide	SO2	7.4	6.59	0.000381	1.15	229	9.43	0.0197	7180	1040	1.47	10.8	2.56	0.918	873	6.86	1.17	0.418	12	395	9.75	9020	18,808
Nitrogen Oxides	NOX	230	141	0.197	132	436	181	11.3	3920	946	171	169	94.5	40.3	696	121	36.1	6.62	237	1530	193	4600	13,892
Carbon Monoxide	CO	41.7	170	0.0119	110	82.1	52.8	0.705	1080	402	77.5	22.1	62.3	35.3	222	11	69.8	2.29	68	114	220	630	3,474
Volatile Organic Compnds	VOC	30.5	10.8	0.367	20.8	9.54	33.2	0.0584	129	50.3	7.36	54.3	18.5	9.88	26.6	25.1	2.39	0.432	26.8	66.9	18.3	75.3	616
Sulfuric Acid	H2SO4	0.0418	0.944	3.07E-05	0.086	22.1	0.0202	0.00158	1010	0.537	0.114	0.041	0.0517	0.0744	35	0.0226	0.0815	0.0336	1.67	111	0.00686	0.778	1,183
Ammonia	NH3	2.05	23.5			0.778	84.4		3.16	22.7		0.875	1.13		6.36	27.8			48.5	0.67	29.8	11.2	263
Carbon Dioxide	CO2	1470000	1300000	48.2	228000	755000	1870000	3300	10400000	2860000	291000	2140000	515000	169000	1960000	1360000	147000	19700	2370000	3320000	1930000	4710000	37,818,048
Methane	CH4	27.2	23.7	0.00202	4.09	9.11	34.8	0.0763	112	30.4	5.4	40.5	9.39	3.18	20.3	26.3	2.81	0.432	44.1	59.8	37.3	49.3	540
Nitrous Oxide	N2O	2.72	2.37	0.000404	0.409	13.6	3.48	0.00814	177	44.8	0.54	4.05	0.948	0.32	32.1	2.63	0.286	0.0545	4.41	14.4	3.73	78.2	386
CO2 equivalent (GHGs)	CO2e	1470000	1310000	48.4	229000	759000	1870000	3310	10400000	2870000	292000	2140000	516000	169000	1970000	1360000	147000	19800	2390000	3330000	1930000	4730000	37,905,158
Mercury	Hg	1.7E-05	8.6E-06	3.7E-07	2.6E-06	9.7E-04	1.8E-05	9.5E-07	1.0E-04	3.5E-03	2.3E-06	2.6E-05	5.5E-05	4.6E-06	4.8E-03	9.6E-06	1.2E-05	2.0E-05	1.6E-05	1.6E-03	1.9E-05	4.2E-03	1.5E-02
Lead	Pb								1.01E-01														

Table 3.7-3 - KIF Coal Retirement/Replacement EIS - Operational Air Emissions Comparisons - Only Direct Impact TVA Facilities

Pollutant	(Abbrev.)	KIF 3-Year Avg. Annual Operational Emissions (2018-2020) (tons/yr)	Proposed CC Plant at KIF - Alternative A Operational Emissions (tons/yr)	Proposed CTs at KIF - Alternative A Operational Emissions (tons/yr)	Total Alternative A Proposed Operational Emissions (tons/yr)	Change in KIF Operational Emissions - Alternative A (tons/yr) [2]	Change in KIF Operational Emissions - Alternative B - Solar/Battery Storage (tons/yr)
Particulate Matter/Total Suspended Particulate (Filterable only)	PM/TSP	185.0	52.3	10.8	63.1	-121.9	-185.0
Total PM<10 microns (Filterable+Condensible)	PM_{10}	328.7	63.9	18.5	82.4	-246.3	-328.7
Total PM<2.5 microns (Filterable+Condensible)	$PM_{2.5}$	266.3	63.9	18.5	82.4	-183.9	-266.3
Sulfur Dioxide	SO_2	1,374.3	7.2	1.0	8.2	-1,366.1	-1,374.3
Nitrogen Oxides	NOx	1,038.7	94.6	84.2	178.8	-859.9	-1,038.7
Carbon Monoxide	CO	381.7	67.2	98.3	165.5	-216.2	-381.7
Volatile Organic Compounds	VOC	45.7	24.0	8.1	32.1	-13.6	-45.7
Sulfuric Acid	H_2SO_4	147.3	0.0	0.0	0.0	-147.3	-147.3
Ammonia	NH_3	12.8	80.5	10.6	91.1	78.3	-12.8
Carbon Dioxide	CO_2	3,386,666.7	1,438,066.3	230,672.2	1,668,738.5	-1,717,928.2	-3,386,666.7
Methane	CH_4	34.5	102.0	15.9	117.8	83.3	-34.5
Nitrous Oxide	N_2O	54.8	35.5	5.4	40.9	-13.9	-54.8
CO_2 equivalent (GHGs)	CO_2-e	3,403,333.3	1,451,207.9	232,678.1	1,683,886.0	-1,719,447.3	-3,403,333.3
Mercury [1]	Hg	8.0E-03	No Data	No Data	No Data	No Data	-8.0E-03
Lead [1]	Pb	No Data	No Data	No Data	No Data	No Data	No Data
Formaldehyde [2]	CH2O	2.8E-02	2.6	1.4	4.0	4.0	-2.8E-02

[1] = Additional hazardous air pollutants are emitted from fossil fuel combustion but in negligible quantities, except for hydrogen fluoride (HF) and hydrogen chloride (HCl) from coal combustion. HF and HCl emissions from coal burning would be eliminated with the switch to natural gas combustion turbines. Current lead emissions data is not available but based on historical data is expected to be insignificant.

[2] = KIF 3-year formaldehyde emissions values for 2018-2020 are 0.0219, 0.0411, and 0.0201 tons/year, respectively.

NA = Not Applicable

Table 3.7-4 - KIF Coal Retirement/Replacement EIS - Net Social Benefit from Operational Emissions Reductions for Alternatives A and B - Only Direct Impact TVA Facilities (2027) - Biden Administration SCC Rates

GHG Pollutant	(Abbrev.)	Nominal SCC Rate (\$/mt) (2028)	Nominal SCC Rate (\$/ton) (2028)			SCC Benefit - Alternative A (2028, Dollars)	SCC Benefit - Alternative B (2028, Dollars)
Carbon Dioxide	CO_2	\$ 70	\$ 64			**\$ (109,591,288)**	**\$ (216,044,636)**

Notes: 2028 SCC is presented as this is the first full year that Alternatives A and B are planned to begin operation. 3% discount rate used. Costs based on global impacts.

Social cost of Methane and Nitrous Oxide values are not presented because they are each insignificant, <1%, with regard to direct combustion emissions from all alternatives, when compared to the social cost of carbon, i.e., CO_2. However, they are calculated and presented in the GHG Life Cycle Analysis.

\$ = U.S. Dollars; mt = metric tons; SCC = Social Cost of Carbon

Table 3.7-5 - KIF Coal Retirement/Replacement EIS - Net Social Benefit of GHG Operational Emissions Reductions for Alternatives A and B - Only Direct Impact TVA Facilities (2027) - Prior Administration SCC Rates

GHG Pollutant	(Abbrev.)	Nominal SCC Rate (\$/mt) (2028)	Nominal SCC Rate (\$/ton) (2028)			SCC Benefit - Alternative A (2028, Dollars)	SCC Benefit - Alternative B (2028, Dollars)
Carbon Dioxide	CO2	\$ 8	\$ 7			**\$ (12,025,497)**	**\$ (23,706,667)**

Notes: 2028 SCC is presented as this is the first full year that Alternatives A and B are planned to begin operation. 3% discount rate used. Costs based on U.S. impacts only.

Social cost of Methane and Nitrous Oxide values are not presented because they are each insignificant, <1%, with regard to direct combustion emissions from all alternatives, when compared to the social cost of carbon, i.e., CO_2. However, they are calculated and presented in the GHG Life Cycle Analysis.

\$ = U.S. Dollars; mt = metric tons; SCC = Social Cost of Carbon

Biden Administration Communication - Technical Support Document: Social Cost of Carbon, Methane, Nitrous Oxide - Interim Estimates under Executive Order 13990 - Feb. 2021 (Appendix A Tables, 3% Discount Rate)
Converted to Nominal Dollars using 2% inflation annual rate approximation; then converted those rates to $/short ton (ton)

	2% Inflation Adjustor	Real SCC ($/mt)	Nominal SCC ($/mt)	**Nominal SCC ($/ton)**
2020	1.00	$ 51	$ 51	$ 46
2021	1.02	$ 52	$ 53	$ 48
2022	1.04	$ 53	$ 55	$ 50
2023	1.06	$ 54	$ 57	$ 52
2024	1.08	$ 55	$ 60	$ 54
2025	1.10	$ 56	$ 62	$ 56
2026	1.13	$ 57	$ 64	$ 58
2027	1.15	$ 59	$ 68	$ 61
2028	1.17	$ 60	$ 70	$ 64
2029	1.20	$ 61	$ 73	$ 66
2030	1.22	$ 62	$ 76	$ 69
2031	1.24	$ 63	$ 78	$ 71
2032	1.27	$ 64	$ 81	$ 74
2033	1.29	$ 65	$ 84	$ 76
2034	1.32	$ 66	$ 87	$ 79
2035	1.35	$ 67	$ 90	$ 82
2036	1.37	$ 69	$ 95	$ 86
2037	1.40	$ 70	$ 98	$ 89
2038	1.43	$ 71	$ 101	$ 92
2039	1.46	$ 72	$ 105	$ 95
2040	1.49	$ 73	$ 108	$ 98
2041	1.52	$ 74	$ 112	$ 102
2042	1.55	$ 75	$ 116	$ 105
2043	1.58	$ 77	$ 121	$ 110
2044	1.61	$ 78	$ 125	$ 114
2045	1.64	$ 79	$ 130	$ 118
2046	1.67	$ 80	$ 134	$ 121
2047	1.71	$ 81	$ 138	$ 125
2048	1.74	$ 82	$ 143	$ 130
2049	1.78	$ 84	$ 149	$ 135
2050	1.81	$ 85	$ 154	$ 140

Federal Government's Social Cost of Carbon - Estimates Used in Conducting Regulatory Impact Analyses under prior EPA Administration, 2020 (3% Discount Rate)

	Nominal SCC ($/mt) [1]	**Nominal SCC ($/ton)**
2020	$ 7.0	$ 6
2021	$ 7.1	$ 6
2022	$ 7.2	$ 7
2023	$ 7.3	$ 7
2024	$ 7.4	$ 7
2025	$ 7.5	$ 7
2026	$ 7.6	$ 7
2027	$ 7.7	$ 7
2028	$ 7.8	$ 7
2029	$ 7.9	$ 7
2030	$ 8.0	$ 7
2031	$ 8.1	$ 7
2032	$ 8.2	$ 7
2033	$ 8.3	$ 8
2034	$ 8.4	$ 8
2035	$ 8.5	$ 8
2036	$ 8.6	$ 8
2037	$ 8.7	$ 8
2038	$ 8.8	$ 8
2039	$ 8.9	$ 8
2040	$ 9.0	$ 8
2041	$ 9.2	$ 8
2042	$ 9.4	$ 9
2043	$ 9.6	$ 9
2044	$ 9.8	$ 9
2045	$ 10.0	$ 9
2046	$ 10.2	$ 9
2047	$ 10.4	$ 9
2048	$ 10.6	$ 10
2049	$ 10.8	$ 10
2050	$ 11.0	$ 10

[1] Under the prior Administration, federal estimates of the social cost of carbon dioxide were originally reported in 2016 U.S. dollars in EPA's regulatory impact analysis for the 2019 Affordable Clean Energy Rule. The Government Accountability Office (GAO) adjusted the values for inflation and expressed them in 2018 U.S. dollars using the United States Gross Domestic Product Price Index from the U.S. Department of Commerce, Bureau of Economic Analysis. The GAO source document is cited as: U.S. Government Accountability Office, Report to Congressional Requesters, Social Cost of Carbon, Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis (GAO-20-254), June 2020.

CO_2 rates for years between 2020 and 2030, between 2030 and 2040, and between 2040 and 2050 were prorated as only 2020, 2030, 2040, and 2050 rates were provided in the reference.

KIF Coal Retirement/Replacement EIS - GHG Geographic Comparison Analysis

	KIF - Alternative A	Solar/Battery Storage - Alternative B
KIF EIS Alternatives Net Change in CO_2 emissions (2027) (tons/yr)	-1,717,928	-3,386,667
KIF EIS Alternatives Net Change in CO_2 emissions (2027) (metric tons/yr)	-1,558,479	-3,072,333
KIF EIS Alternatives Net Change in CO_2 emissions (2027) (Million metric tons/yr)	-1.6	-3.1
2018 Tennessee CO_2 emissions from Energy Consumption (Million metric tons)	94.7	94.7
2020 U.S. CO_2 emissions from Energy Consumption (Million metric tons)	4,576.3	4,576.3
2020 Global CO_2 emissions from Energy Consumption (Million metric tons)	31,500.0	31,500.0
% of Tennessee CO_2 emissions from Energy Consumption	-1.65	-3.24
% of U.S. CO_2 emissions from Energy Consumption	-0.03	-0.07
% of Global CO_2 emissions from Energy Consumption	-0.005	-0.01

Combined Cycle (CC) Gas Turbines at TVA Kingston: One CC Generation Train

Table 1. Operational Data

Parameter	Value	Units	Comment
Total Generation	714	MW	Total generation for one CC train (summer capacity) consisting of one combustion turbine and one steam turbine (i.e., 1x1 configuration).
Design Max. Natural Gas Amount	115	MMscf/day	where "MM" denotes "10^6"; amount includes duct firing operations
Annual Average Capacity Factor	55	%	Energy Information Agency (EIA) CC industry average over the last 10 years; from EIA website: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a
Natural Gas Heat Content	1,020	Btu/scf	AP-42, Section 3.1 - Stationary Gas Turbines, Table 3.1-2a, footnote c, average natural gas heating value (HHV) of 1,020 Btu/scf at 60 degrees F.
Annual Avg. Natural Gas Usage	23,622,654	MMBtu/yr	Average annual natural gas usage over the life of the CC train

Table 2. Expected Emission Limits/Factors

Constituent		Value	Units	Comment
Nitrogen Oxides (as NO2)	NO2	2.0	ppmvd [1]	Manufacturer's guarantee, includes Selective Catalytic Reduction (SCR) system for NOx reduction.
Carbon Monoxide	CO	2.0	ppmvd [1]	Manufacturer's guarantee
Volatile Organic Compounds	VOC	1.5	ppmvd [1]	Manufacturer's guarantee
Filterable PM/TSP	FPM	4.40E-03	lb/MMBtu	Manufacturer's data
Total PM10/2.5	TPM2.5	5.30E-03	lb/MMBtu	Manufacturer's data
Sulfur Dioxide	SO2	6.00E-04	lb/MMBtu	40 CFR Part 75, Appendix D, 2.3.1.1.1, default SO2 emission rate for firing pipeline natural gas
Ammonia Slip	NH3	5.0	ppmvd [1]	Engineering estimate of unreacted SCR ammonia (ammonia slip)
Carbon Dioxide	CO2	120	lb/MMBtu	40 CFR Part 60, Subpart TTTT
Methane	CH4	8.60E-03	lb/MMBtu	EPA AP-42, Vol. I, 5th Ed., Section 3.1 - Stationary Gas Turbines - Supp. F, 4/00, Table 3.1-2a
Nitrous Oxide	N2O	3.00E-03	lb/MMBtu	EPA AP-42, Vol. I, 5th Ed., Section 3.1 - Stationary Gas Turbines - Supp. F, 4/00, Table 3.1-2a
Formaldehyde	CH2O	0.091	ppmvd [1]	Although this rule doesn't apply, the emission rate was conservatively based on the 40 CFR 63, Subpart YYYY Table 1 formaldehyde limit for Combustion Turbines.

Tbl 2 [1] Concentration in parts-per-million (ppm) by volume, dry-basis (ppmvd), at 15% O2; concentration is converted to an emission factor (lb/MMBtu) via the following:

EF (lb/MMBtu) = ppmvd * Fd * 20.9 / (20.9 - %O2d) * MW / 385.3

where... "ppmvd" denotes constituent concentration;

"Fd" is the 40 CFR 60, App. A, Ref. Method 19, Table 19-2, dry-basis "F-Factor": 8710 dscf/MMBtu;

"%O2d" is the (ref. method) percent oxygen, dry-basis: 15 %;

"MW" is molecular weight (lb/lbmol): NO2 = 46.01 CO = 28.01 VOC* = 16.04 NH3 = 17.03 CH2O = 30.03

*VOC as methane, which is representative of the highest stack-exit concentration guaranteed by the manufacturer

The molar volume of any ideal gas at standard temp. and pressure is 385.3 lbmol/scf

Table 3. Emission Estimates [1,3]

Constituent		Value	Units	Note
Nitrogen Oxides (as NO2)	NO2	87	tons/yr	
Carbon Monoxide	CO	53	tons/yr	
VOC as CH4	VOC	23	tons/yr	
Filterable PM/TSP	FPM	52	tons/yr	
Total PM10/2.5	TPM2.5	63	tons/yr	
Sulfur Dioxide	SO2	7	tons/yr	
Ammonia Slip	NH3	81	tons/yr	
Carbon Dioxide	CO2	1,417,359	tons/yr	
Methane	CH4	102	tons/yr	
Nitrous Oxide	N2O	35	tons/yr	
CO2 equivalent	CO2e	1,430,458	tons/yr	2
Formaldehyde	CH2O	3	tons/yr	

Tbl 3 [1] Estimates based on the following: E (tons/year) = EF * Annual Avg Natrl Gas Usage / 2000

Tbl 3 [2] CO2e based on US EPA, Code of Federal Regulations, Title 40, Part 98, Subpart A, Table A-1, as amended 11-29-13 (78 FR 71904), 100-Year Horizon Global Warming Potentials (GWP) of 25 for CH4 and 298 for N2O.

Tbl 3 [3] Emissions include operation of the Duct Burner (nominal rating 1,054 MMBtu/hr) whose emissions would be controlled simultaneosuly as the combined cycle combustion turbine.

Natural Gas-Fired Auxiliary Boiler

Table 1. Operational Data

Parameter	Value	Units	Comment
Number of Units	1		
Maximum Heat Input (each)	75	MMBtu/hr	
Annual Average Capacity Factor	45	%	The auxilary boiler services the CC train and would only operate as needed; conservatively assumed inverse of the CC capacity factor (100% - 55% = 45%).
Natural Gas Heat Content	1,020	Btu/scf	EPA AP-42, Vol. I, 5th Ed., Section 1.4 - Natural Gas Combustion - Supplement D, 4/98
Design Max. Natural Gas Amount (each)	295,650	MMBtu/yr	Annual average natural gas usage over the life of the plant

Table 2. Expected Emission Limits/Factors

Constituent		Value	Units	Comment
Nitrogen Oxides (as NO2)	NO2	50	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-1 (Low-NOX Burner)
Carbon Monoxide	CO	84	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-1
Volatile Organic Compounds	VOC	5.5	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Filterable PM/TSP	FPM	1.9	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Total PM10/2.5	TPM2.5	7.6	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Sulfur Dioxide	SO2	0.6	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Carbon Dioxide	CO2	120,000	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Methane	CH4	2.30E+00	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Nitrous Oxide	N2O	6.40E-01	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Formaldehyde	CH2O	7.50E-02	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-3

Table 3. Emission Estimates [1]

Constituent		Value	Units	Note
Nitrogen Oxides (as NO2)	NO2	7	tons/yr	
Carbon Monoxide	CO	12	tons/yr	
VOC as CH4	VOC	1	tons/yr	
Filterable PM/TSP	FPM	0	tons/yr	
Total PM10/2.5	TPM2.5	1	tons/yr	
Sulfur Dioxide	SO2	0.1	tons/yr	
Carbon Dioxide	CO2	17,391	tons/yr	
Methane	CH4	0	tons/yr	
Nitrous Oxide	N2O	0	tons/yr	
CO2 equivalent	CO2e	17,427	tons/yr	2
Formaldehyde	CH2O	0.01	tons/yr	

Tbl 3 [1] Estimates based on the following: E (tons/year) = EF / Natrl Gas Heat Content * Annual Avg Natrl Gas Usage / 2000 * No. of Units

Tbl 3 [2] CO2e based on US EPA, Code of Federal Regulations, Title 40, Part 98, Subpart A, Table A-1, as amended 11-29-13 (78 FR 71904), 100-Year Horizon Global Warming Potentials (GWP) of 25 for CH4 and 298 for N2O.

The CC plant would have one diesel fire water pump emergency engine rated at 275 horsepower; however, emissions would be negligible.

Natural Gas-Fired Dewpoint Gas Heaters

Table 1. Operational Data

Parameter	Value	Units	Comment
Number of Units	5		Two dewpoint gas heaters would service the CC train but one would be redundant and the other would operate at 100% capacity. The other three heaters would service the Aeroderivative CT units but one of those would be redundant and the other two would operate at 50% capacity.
Maximum Heat Input (each)	9.9	MMBtu/hr	
Annual Average Capacity Factor (CC heaters)	55	%	The CC dewpoint gas heaters would follow CC train lifetime operations, i.e., 55% capacity factor
Annual Average Capacity Factor (Aero. CT heaters)	10	%	The Aeroderivative CT heaters would follow the CT lifetime operations, i.e., capacity factor of 10%.
Natural Gas Heat Content	1,020	Btu/scf	EPA AP-42, Vol. I, 5th Ed., Section 1.4 - Natural Gas Combustion - Supplement D, 4/98
Design Max. Natural Gas Amount (each CC heater)	47,698	MMBtu/yr	Annual average natural gas usage over the life of the plant (per CC heater)
Design Max. Natural Gas Amount (each CT heater)	4,336	MMBtu/yr	Annual average natural gas usage over the life of the plant (per CT heater); *0.5 term is for operating at 50% of max. capacity.

Table 2. Expected Emission Limits/Factors

Constituent		Value	Units	Comment
Nitrogen Oxides (as NO2)	NO2	11.1	lb/MMscf	Manufacturer's data for similarly sized gas heaters with low-NOX burners in TVA's system.
Carbon Monoxide	CO	75.4	lb/MMscf	Manufacturer's data for similarly sized gas heaters in TVA's system.
Volatile Organic Compounds	VOC	15.1	lb/MMscf	Manufacturer's data for similarly sized gas heaters in TVA's system.
Filterable PM/TSP	FPM	1.9	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Total PM10/2.5	TPM2.5	7.6	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Sulfur Dioxide	SO2	0.6	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Carbon Dioxide	CO2	120,000	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Methane	CH4	2.30E+00	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Nitrous Oxide	N2O	6.40E-01	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-2
Formaldehyde	CH2O	7.50E-02	lb/MMscf	EPA AP-42, Vol. I, 5th Ed., Sec. 1.4 - Natural Gas Combustion - Supp. D, 4/98, Table 1.4-3

Table 3. Emission Estimates [1]

Constituent		Value	Units	Note
Nitrogen Oxides (as NO2)	NO2	0.3	tons/yr	3
Carbon Monoxide	CO	2.1	tons/yr	3
VOC as CH4	VOC	0.4	tons/yr	3
Filterable PM/TSP	FPM	0.1	tons/yr	3
Total PM10/2.5	TPM2.5	0.2	tons/yr	3
Sulfur Dioxide	SO2	0.0	tons/yr	3
Carbon Dioxide	CO2	3,315.9	tons/yr	3
Methane	CH4	0.1	tons/yr	3
Nitrous Oxide	N2O	0.0	tons/yr	3
CO2 equivalent	CO2e	3,323	tons/yr	2
Formaldehyde	CH2O	2.07E-03	tons/yr	3

Tbl 3 [1] Estimates based on the following: E (tons/year) = EF / Natrl Gas Heat Content * Annual Avg Natrl Gas Usage / 2000 * No. of Operating Units * Unit Capacity

Tbl 3 [2] CO2e based on US EPA, Code of Federal Regulations, Title 40, Part 98, Subpart A, Table A-1, as amended 11-29-13 (78 FR 71904), 100-Year Horizon Global Warming Potentials (GWP) of 25 for CH4 and 298 for N2O.

Tbl 3 [3] One CC dewpoint heater that operates and two CT heaters that operate explains the term *1 for the first term and *2 for the second term.

The CC plant would have one diesel fire water pump emergency engine rated at 275 horsepower; however, emissions would be negligible.

Aeroderivative Simple Cycle (CTs) Gas Turbines at TVA Kingston: 16 CT Units
Natural-Gas Fired with Ultra-Low Sulfur Diesel as Backup Fuel

Table 1. Operational Data

Parameter	Value	Units	Comment
Total Generation	848	MW	Approximated total generation for 16 Aeroderivative CT units; 53 MW/CT
Number of CTs	16		
Estimated Max. Heat Input (each CT)	517	MMBtu/CT-hr	Manufacturer's data; peformance at 59 deg. F; where "MM" denotes "10^6"
Annual Average Capacity Factor	10	%	Energy Information Agency (EIA) CT industry average over the last 10 years; from EIA website: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a
Natural Gas Heat Content	1,020	Btu/scf	AP-42, Section 3.1 - Stationary Gas Turbines, Table 3.1-2a, footnote c, average natural gas heating value (HHV) of 1,020 Btu/scf at 60 degrees F.
Annual Avg. Natural Gas Usage (each CT)	175,444	MMBtu/CT-yr	Average annual natural gas usage over the life of a CT. Accounts for time on ULSD and start/stop cycle time and NSPS Subpart TTTT equivalent hours of operation; ~3,600/CT).
Annual Start/Stop Cycles	250	cycles/CT-yr	Estimate from design data provider.
Time per Start Cycle	0.50	hours/cycle	Per manufacturer design data indicating time for catalysts to achieve operating temperatures; time to achieve normal emissions rates.
Time per Stop Cycle	0.15	hours/cycle	Per manufacturer design data
Backup Fuel Use Limit (ULSD)	125,000	gal/CT-yr	Approximation based on ULSD storage of two million gallon and 16 CT units operating.
Heating Value of ULSD	137,000	Btu/gal	AP-42, Appendix A, Typical Parameters of Various Fuels, Diesel

Table 2. Expected Emission Limits/Factors - Primary Fuel (Natural Gas), Continuous Operation

Constituent		Value	Units	Comment
Nitrogen Oxides (as NO2)	NO2	5.0	ppmvd [1]	Manufacturer's guarantee, includes Selective Catalytic Reduction (SCR) system for NOx reduction.
Carbon Monoxide	CO	5.0	ppmvd [1]	Manufacturer's guarantee
Volatile Organic Compounds	VOC	1.9	ppmvd [1]	USEPA RBLC Database, 2016-2021, avg. after leaving out lowest and highest
Filterable PM/TSP	FPM	4.60E-03	lb/MMBtu	Manufacturer's data
Total PM10/2.5	TPM2.5	6.90E-03	lb/MMBtu	Manufacturer's guarantee
Sulfur Dioxide	SO2	6.00E-04	lb/MMBtu	40 CFR Part 75, Appendix D, 2.3.1.1.1, default SO2 emission rate for firing pipeline natural gas
Ammonia Slip	NH3	5.0	ppmvd [1]	Engineering estimate of unreacted SCR ammonia (ammonia slip)
Carbon Dioxide	CO2	120	lb/MMBtu	40 CFR Part 60, Subpart TTTT
Methane	CH4	8.60E-03	lb/MMBtu	EPA AP-42, Vol. I, 5th Ed., Section 3.1 - Stationary Gas Turbines - Supp. F, 4/00, Table 3.1-2a
Nitrous Oxide	N2O	3.00E-03	lb/MMBtu	EPA AP-42, Vol. I, 5th Ed., Section 3.1 - Stationary Gas Turbines - Supp. F, 4/00, Table 3.1-2a
Formaldehyde	CH2O	0.091	ppmvd [1]	Although this rule doesn't apply, the emission rate was conservatively based on the 40 CFR 63, Subpart YYYY Table 1 formaldehyde limit for Combustion Turbines

Tbl 2 [1] Concentration in parts-per-million (ppm) by volume, dry-basis (ppmvd), at 15% O2; concentration is converted to an emission factor (lb/MMBtu) via the following:

EF (lb/MMBtu) = ppmvd * Fd * 20.9 / (20.9 - %O2d) * MW / 385.3

where... "ppmvd" denotes constituent concentration;

"Fd" is the 40 CFR 60, App. A, Ref. Method 19, Table 19-2, dry-basis "F-Factor": 8710 dscf/MMBtu;

"%O2d" is the (ref. method) percent oxygen, dry-basis: 15 %;

"MW" is molecular weight (lb/lbmol): NO2 = 46.01 CO = 28.01 VOC* = 16.04 NH3 = 17.03 CH2O = 30.03

*VOC as methane, which is representative of the highest stack-exit concentration guaranteed by the manufacturer

The molar volume of any ideal gas at standard temp. and pressure is 385.3 lbmol/scf

Table 3. Expected Emission Limits/Factors - Primary Fuel (Natural Gas) - Start/Stop Cycles

Constituent		Start	Stop	Units	Comment
Nitrogen Oxides (as NO2)	NO2	44	30	lbs/hr	Manufacturer's data; start emissions accrued until SCR catalytic bed is at operating temperature.
Carbon Monoxide	CO	50	102	lbs/hr	Manufacturer's data; start emissions accrued until oxidation catalyst is at operating temperature.
Volatile Organic Compounds	VOC	2	4	lbs/hr	Manufacturer's data; start emissions accrued until oxidation catalyst is at operating temperature.
Filterable PM/TSP	FPM	1.7	1.35	lbs/hr	Manufacturer's data; emissions accrued until post-combustion catalytic beds are at operating temperatures.
Total PM10/2.5	TPM2.5	3.4	2.7	lbs/hr	Manufacturer's data; emissions accrued until post-combustion catalytic beds are at operating temperatures.
Sulfur Dioxide	SO2	0	0	---	Assumed SO2 Start/Stop emisisons are negligible
Carbon Dioxide	CO2	120	120	lb/MMBtu	40 CFR Part 60, Subpart TTTT
Methane	CH4	8.60E-03	8.60E-03	lb/MMBtu	EPA AP-42, Vol. I, 5th Ed., Section 3.1 - Stationary Gas Turbines - Supp. F, 4/00, Table 3.1-2a
Nitrous Oxide	N2O	3.00E-03	3.00E-03	lb/MMBtu	EPA AP-42, Vol. I, 5th Ed., Section 3.1 - Stationary Gas Turbines - Supp. F, 4/00, Table 3.1-2a
Formaldehyde	CH2O	6.76E-01	1.35	lbs/hr	Assumed formaldehyde emission rates are 33.8% of VOC emissions rates based on ratio of Formaldehyde to VOC EPA AP-42 emission factors for NG CTs.

Table 4. Expected Emission Limits/Factors - Backup Fuel (ULSD)

Constituent		Value	Units	Comment
Nitrogen Oxides (as NO2)	NO2	10.0	ppmvd [1]	Manufacturer's guarantee, includes Selective Catalytic Reduction (SCR) system for NOx reduction.
Carbon Monoxide	CO	6.0	ppmvd [1]	Manufacturer's data
Volatile Organic Compounds	VOC	8.0	ppmvd [1]	Manufacturer's data
Filterable PM/TSP	FPM	1.67E-02	lb/MMBtu	Manufacturer's data
Total PM10/2.5	TPM2.5	3.34E-02	lb/MMBtu	Manufacturer's data
Sulfur Dioxide	SO2	1.52E-03	lb/MMBtu	EPA AP-42, Vol. I, 5th Ed., Section 3.1 - Stationary Gas Turbines - Supp. F, 4/00, Table 3.1-2a
Ammonia Slip	NH3	5.0	ppmvd [1]	Engineering estimate of unreacted SCR ammonia (ammonia slip)
Carbon Dioxide	CO2	160	lb/MMBtu	40 CFR Part 60, Subpart TTTT
Methane	CH4	6.61E-03	lb/MMBtu	US EPA, Code of Federal Regulations, Title 40, Part 98, Subpart C, Tables C-1 & C-2, as amended 11-29-13 (78 FR 71904)
Nitrous Oxide	N2O	1.32E-03	lb/MMBtu	US EPA, Code of Federal Regulations, Title 40, Part 98, Subpart C, Tables C-1 & C-2, as amended 11-29-13 (78 FR 71904)
Formaldehyde	CH2O	2.30E-04	lb/MMBtu	Based on 40 CFR 63, Subpart YYYY formaldehyde limit for Combustion Turbines; 91 ppbvd (91 ppmvd)

Tbl 4 [1] Concentration in parts-per-million (ppm) by volume, dry-basis (ppmvd), at 15% O2; concentration is converted to an emission factor (lb/MMBtu) via the following:

EF (lb/MMBtu) = ppmvd * Fd * 20.9 / (20.9 - %O2d) * MW / 385.3

where... "ppmvd" denotes constituent concentration;

"Fd" is the 40 CFR 60, App. A, Ref. Method 19, Table 19-2, dry-basis "F-Factor", Oil: 9190 dscf/MMBtu;

"%O2d" is the (ref. method) percent oxygen, dry-basis: 15 %;

"MW" is molecular weight (lb/lbmol): NO2 = 46.01 CO = 28.01 VOC* = 16.04 NH3 = 17.03 CH2O = 30.03

*VOC as methane, which is representative of the highest stack-exit concentration guaranteed by the manufacturer

The molar volume of any ideal gas at standard temp. and pressure is 385.3 lbmol/scf

Table 5. Emission Estimates [1] - Both Fuels and Start/Stop Cycles

Constituent		Primary Fuel (NG)	Units	Note	Start/Stop Cycles	Units	Note	Backup Fuel (ULSD)	Units	Note	**TOTAL Emissions**	Units
Nitrogen Oxides (as NO2)	NO2	26	tons/yr	[1]	53	tons/yr	[4]	5	tons/yr	[6]	84	tons/yr
Carbon Monoxide	CO	16	tons/yr	[1]	81	tons/yr	[4]	2	tons/yr	[6]	98	tons/yr
VOC as CH4	VOC	3	tons/yr	[1]	3	tons/yr	[4]	1	tons/yr	[6]	8	tons/yr
Filterable PM/TSP	FPM	6	tons/yr	[1]	2	tons/yr	[4]	2	tons/yr	[6]	11	tons/yr
Total PM10/2.5	TPM2.5	10	tons/yr	[1]	4	tons/yr	[4]	5	tons/yr	[6]	18	tons/yr
Sulfur Dioxide	SO2	1	tons/yr	[1]	0	tons/yr	[4]	0	tons/yr	[6]	1	tons/yr
Ammonia Slip	NH3	10	tons/yr	[1]	0	tons/yr	[5]	1	tons/yr	[6]	11	tons/yr
Carbon Dioxide	CO2	168,426	tons/yr	[1]	40,326	tons/yr	[2], [4]	21,920	tons/yr	[6]	230,672	tons/yr
Methane	CH4	12	tons/yr	[1]	3	tons/yr	[2], [4]	1	tons/yr	[6]	16	tons/yr
Nitrous Oxide	N2O	4	tons/yr	[1]	1	tons/yr	[2], [4]	0	tons/yr	[6]	5	tons/yr
CO2 equivalent	CO2e	169,983	tons/yr	[3]	40,699	tons/yr	[3]	21,997	tons/yr	[3]	232,678	tons/yr
Formaldehyde	CH2O	3.07E-01	tons/yr	[1]	1	tons/yr	[4]	3.2E-02	tons/yr	[6]	1	tons/yr

Tbl 5 [1] Estimates based on the following: E (tons/year) = EF * Annual Avg Natrl Gas Usage / 2000 * No. of Units

Tbl 5 [2] For GHG emissions from start/stop cycles, the max. heat input capacity was divided by 2 to estimate the average heat input during a ramp up and ramp down during the cycles.

Tbl 5 [3] CO2e based on US EPA, Code of Federal Regulations, Title 40, Part 98, Subpart A, Table A-1, as amended 11-29-13 (78 FR 71904), 100-Year Horizon Global Warming Potentials (GWP) of 28 for CH4 and 298 for N2O.

Tbl 5 [4] Estimates based on the following: E (tons/year) = EF * Hours/Cycle * Cycles/Year/Turbine * No. of Units / 2000

Tbl 5 [5] Considered neglible

Tbl 5 [6] Estimates based on the following: E (tons/year) = EF * Gal./Year * Btu/Gal. / 1,000,000 / 2,000

The aeroderivatives would utilize a 3,000 horsepower diesel-engine generator to provide electical service in the unlikely event of a transmission emergency (e.g., black start). The black-start generator (BSG) would only operate to energize the switchyard and would be transient. Emissions for the BSG are not included because they would be negligible.

Appendix J – Life Cycle Analyses of Greenhouse Gas Emissions Estimated for Alternatives Evaluated in the Kingston EIS

APPENDIX J
GREENHOUSE GAS EMISSIONS LIFE CYCLE ANALYSES OF KINGSTON RETIREMENT ALTERNATIVES

Contents

Tables

J.1. Introduction

This Appendix explains the methodology and provides the emissions calculations and results of the Life Cycle Analyses (LCAs) of greenhouse gases (GHGs) emissions for each of the three alternative actions, on both an individual replacement resource by alternative basis (henceforth "individual") and a TVA system-wide portfolio basis with simulated generation dispatch (henceforth "system-wide"). The GHGs included in this analysis are carbon dioxide (CO_2), methane (CH_4), and nitrous dioxide (N_2O) as these GHGs of concern are specifically emphasized in the January 2021 Executive Order 13990 on capturing the social costs of GHGs. The life cycle GHG emissions results were used to calculate the social cost of carbon (SCC), social cost of methane (SCM), and social cost of nitrous oxide (SCN) values for each alternative, as well as the total social cost of the three GHGs for each alternative (SC-GHG). Social costs were calculated and presented in nominal dollars and in terms of Net Present Value (NPV) in 2023 dollars.

The life cycle and SC-GHG emissions for each alternative have been calculated for both the individual replacement resource by alternative basis and the TVA system-wide portfolio basis and are summarized in Section 3.7.2 of this EIS.

All tables referenced below are provided in Section J.6 of this Appendix, except for four summary tables provided in Section J.4 for the total SC-GHGs for each alternative for both the individual basis LCA and TVA system-wide basis LCA.

J.2. Methodology/Basis

The LCAs are based on National Renewable Energy Laboratory (NREL) publications that provide harmonized CO_2-equivalent (CO_2-e) life cycle emission factors for each of the different life cycle segments of the generating technologies being considered (Nicholson and Heath 2021). The NREL references include Hsu et al. 2012, Kim et al. 2012, Whitaker et al. 2012, O'Donoughue et al. 2014, Beatty et al. 2017, and Nicholson and Heath 2021. The NREL's LCA harmonization process included reviews of approximately 3,000 published LCA studies on a variety of utility-scale electrical generation and storage technologies and included three rounds of screening by multiple subject matter experts to select references that met strict criteria for quality, relevance, and transparency (Nicholson and Heath 2021). The six aforementioned NREL references provided a range of life cycle emission factors for each technology; the median published life cycle emission factors were used in the calculations described in this section. These six references were considered the most applicable and complete references currently available for calculating emissions from all life cycle segments for the electricity generation technologies in this EIS.

The following life cycle segments were included in the NREL references:

- <u>One-Time Upstream</u> includes GHG emissions from resource extraction/production, processing/conversion, material manufacturing, component manufacturing, delivery to site, and construction for plant/technology components. Although these activities may occur in multiple locations and over multiple years, for simplicity of the analysis, this LCA assumes One-Time Upstream GHG emissions and associated social costs are all for the year 2027.

- Ongoing Annual Combustion includes GHG emissions from combustion of fuels at the proposed facilities over the entire operational life cycle of the technology[1].
- Ongoing Annual Non-Combustion includes GHG emissions from plant operations activities other than fuel combustion, plant maintenance activities, and the fuel cycle GHG emissions, i.e., fuel extraction/processing/distribution/transport (including pipelines) and coal bed methane.
- One-Time Downstream includes dismantling, decommissioning, disposal, and recycling of the plant/technology. Although these activities may occur in multiple locations and over multiple years, for simplicity of the analysis, this LCA assumes One-Time Downstream GHG emissions and associated costs are all in 2058 for Alternative A and Alternative B.

Although data on methane leaks from natural gas technologies is provided in the NREL references, this parameter was not harmonized by NREL in the LCA Harmonization (Nicholson and Heath 2021). However, the natural gas LCAs reviewed by NREL that passed their strict criteria included methane leakage in terms of a percent of total natural gas production and use. These values for LCAs conducted in the U.S. were averaged to obtain a representative cumulative methane leakage rate of 1.6 percent over the life cycle of the proposed CC and CT plants. This 1.6 percent of total natural gas flow leakage rate was used to calculate methane emissions from the natural gas technologies in Alternative A. A separate line item for methane leak emissions from natural gas technologies is provided in this LCA because it is not included in the Ongoing Annual Non-Combustion emission factor per interpretation of the natural gas NREL LCA Harmonization (Nicholson and Heath 2021).

The life cycle emission factors in the NREL references were only provided in terms of CO_2-equivalent emissions (in grams) per kilowatt-hour of electricity production. To disaggregate the CO_2-e emission factors into emission factors for each of the three individual GHGs, the individual GWP-weighted contributions of CO_2, CH_4, and N_2O to their total CO_2-e emission factors are prorated based on their relative contribution from the *USEPA Emission Factors for GHG Inventories, Table 6 - Electricity under Total Output Emission Factors for the eGRID Subregion of SERC Tennessee Valley (*USEPA 2021b). These emission factors are 834.2 lb/MW-hr for CO_2, 0.075 lb/MW-hr for CH_4, and 0.011 lb/MW-hr for N_2O. Using these values, the percent contribution of CO_2, CH_4, and N_2O to the CO_2-e emission factor is 99.99 percent, 0.009 percent, and 0.001 percent, respectively. For coal technology, this prorating was not necessary as the NREL coal LCA publication provided the mean GWP-weighted contribution of CH_4 and N_2O to CO_2-e as approximately 5 percent and <1 percent (assumed 0.9 percent), respectively, so that the CO_2 contribution is 94.1 percent. The emission factors used for the LCAs are provided in Tables J.6.1 through J.6.4 for CO_2-e, CO_2, CH_4 and N_2O emissions, respectively.

None of the emission factors in the references include transmission and distribution (T&D) electricity losses as they were outside the scope of the NREL studies and are not considered appreciably different for each EIS alternative.

[1] The Ongoing Annual Combustion emission factors in the NREL references (Hsu et al. 2012, Kim et al. 2012, Whitaker et al. 2012, O'Donoughue et al. 2014, Beatty et al. 2017, and Nicholson and Heath 2021) were not used because those combustion emissions were calculated using alternative-specific design, operational, and regulatory information. These emission factors were instead based on the specifications of the proposed CC and CT plants.

J.2.1. Assumptions and Conditions Defining Generation Rates for LCAs of Alternatives

The assumptions and conditions defining the electricity generation rates for supporting each alternative's life cycle emissions calculations for the individual LCA are provided below. These generation rates are based on the projected average annual lifetime electricity generation. Table J.6.5 provides the assumptions, conditions, and projected average annual electricity generation lifetime rates in kw-hours per year. The maximum capacity annual electricity generation rates are provided for coal and natural gas technologies only to show the basis for calculating the average annual lifetime rates.

- No Action Alternative – Coal Technology
    - Plant size – 1,298 Megawatts (MW)
    - Projected average annual lifetime generation – assumed approximately 55 percent capacity factor based on U.S. Energy Information Administration (USEIA) industry averages over the last 10 years (USEIA 2023).

- Alternative A – Natural Gas Combined Cycle Combustion Turbine Technology
    - Plant size – 714 MW (Summer capacity)
    - Projected average annual lifetime generation – assumed approximately 55 percent capacity factor based on USEIA industry averages over the last 10 years (USEIA 2023). Based on TVA's experience and industry knowledge, actual CC capacity factors for any given plant in any given year may vary between about 35 percent and about 90 percent depending on factors such as load growth, natural gas prices, composition of the balance of TVA's generating fleet in any given year, outages, or other unforeseen circumstances.

- Alternative A – Natural Gas Simple Cycle Aeroderivative Combustion Turbine Technology
    - Plant size – 848 MW
    - Projected average annual lifetime generation – assumed approximately 10 percent capacity factor based on USEIA industry averages over the last 10 years (USEIA 2023). Based on TVA's experience and industry knowledge, actual Aeroderivative CT capacity factors for any given plant in any given year may vary between about 1 percent and about 40 percent depending on factors such as load growth, natural gas prices, composition of the balance of TVA's generating fleet in any given year, outages, or other unforeseen circumstances.

- Alternative A – On-Site Solar Panel/Battery Storage Technology
    - Facility sizes – 4 MW solar; 100 MW battery storage
    - See assumptions below for Alternative B solar/battery storage technology
    - Projected average annual lifetime generation and battery storage/discharge – assumed 25 percent capacity factor for solar and 16.7 percent capacity factor for battery storage. Solar basis is based on typical responses to recent TVA RFPs for utility-scale, single axis tracking solar facilities. Battery basis is from an NREL publication on 4-hour duration utility scale battery energy storage systems (NREL 2023a).
    - Additional assumptions – battery storage calculations assume one full cycle/day (5 hours to charge from the grid and 4 hours to discharge to grid = 9

hours/cycle). Battery efficiency is assumed to be 85 percent based on typical responses to recent TVA RFPs for utility-scale battery storage systems[2].

- Alternative B – Solar Panel/Battey Storage Technology
    - Plant sizes – 1,500 MW Solar; 2,200 MW battery storage.
    - Projected average annual lifetime generation and battery storage/discharge – same as described above for Alternative A - On-Site Solar Panel/Battery Storage Technology.
    - Additional assumptions – same as described above for Alternative A - On-Site Solar Panel/Battery Storage Technology.

Life cycle operational time for CC and CT turbines under Alternative A is 30 years (NREL 2023b). TVA typically models solar and battery storage as 20-year Power Purchase Agreements and assumes operational time for solar panels/battery storage under Alternative B is 20 years. However, to provide a consistent life cycle comparison across all alternatives, the solar/battery storage alternative was prorated to 30 years by scaling up 20-year emissions by a factor of 1.5; 20 x 1.5 = 30. The life cycle operational time for the No Action Alternative was extended to the same 30-year period as the other alternatives but only for obtaining an equivalent comparison. Under Alternatives A and B evaluated in this EIS, the coal plant would be retired by the end of 2027, which includes all nine boiler units.

The individual GHG LCA provides one comparison of GHG effects for each alternative; however, the TVA system-wide LCA provides a more thorough and accurate view of overall GHG effects when comparing each alternative. The system-wide view provides critical context into how the specific resource retirements and replacements, underpinning the assumptions of each of the Proposed Action Alternatives, integrates into the system overall. Developing a TVA system-wide LCA reflects TVA's broader asset strategy and target power supply mix set by the 2019 IRP. A TVA system-wide comparison of emissions is the most effective way to accurately identify incremental emission differences between the alternatives because it illustrates how the entire TVA system is expected to operate with each alternative.

The system-wide LCA builds off the assumptions presented above for the individual LCA, while also considering net changes in generation supplied by the remaining TVA fleet on an ongoing basis as compared to the No Action Alternative for 20 years. Carbon dioxide emissions are pulled directly from TVA models, while nitrous oxide and methane emissions use factors that are based on annual electricity generation by resource type. One-time upstream emissions are assumed to occur in 2027, while one-time downstream emissions occur in 2058 (the first year following the 30-year asset life) and are discounted to the year 2042, which is the end of the 20-year study period. Ongoing annual combustion and non-combustion emissions are accounted for in the year emitted.

J.3. GHG Life Cycle Emissions for Each Alternative

On an individual basis, the estimated life cycle CO_2 emissions for each alternative are provided in Table J.6.6. The estimated life cycle CH_4 emissions for each alternative are provided in

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[2] It is almost impossible to accurately determine what grid charging sources will be used over the lifespan of the battery storage system. As the system evolves (coal retirements, solar/gas additions), the charging power will come from increasingly lower emitting sources. The system wide LCA will account for forecasted charging generation and associated emissions.

[3] The social cost values in the Technical Support Document were converted to nominal values using a 2 percent per year inflation rate.

Tables J.6.7. The estimated methane leakage emissions for Alternative A are provided in Table J.6.8 and J.6.9, respectively. The estimated life cycle N_2O emissions for each alternative are provided in Table J.6.10. Tables J.6.6, J.6.7, and J.6.10 also show the emissions for each life cycle segment.

On a system-wide basis, as a delta (i.e. change) compared to the No Action Alternative, the estimated change in life cycle CO_2 emissions for each alternative are provided in Table J.6.25. The estimated change in life cycle CH_4 emissions, including methane leakage, for each alternative are provided in Tables J.6.26. The estimated life cycle N_2O emissions for each alternative are provided in Table J.6.27.

J.4. Life Cycle Social Costs of GHGs for Each Alternative

The GHG life cycle emissions described above were multiplied by social cost values[3], in dollars per short ton (converted from dollars per metric ton), under the following Biden Administration Interagency Working Group on Social Cost of GHGs document (IWG 2021): Technical Support Document, Social Cost of Carbon - Interim Estimates under Biden Administration Executive Order 13990, February 2021 (Appendix A, Table A-1, 3 percent discount rates). The social costs for each of the three GHGs were calculated in this manner using their individual values for the years covering the life cycle period. The social costs for each GHG were summed to obtain a total GHG life cycle social cost. For each alternative, on an individual basis, Table J.6.11 provides the estimated life cycle social costs of CO_2 emissions, including for each life cycle segment. Tables J.6.13 and J.6.15 provide the same information for CH_4 and N_2O, respectively and on an individual basis. Table J.6.17 provides the summary of life cycle GHG social costs (based on IWG 2021 social cost values) for each of the alternatives, on an individual basis. Tables J.6.12, J.6.14, and J.6.16 provide the Biden Administration social cost value tables by year for CO_2, CH_4, and N_2O respectively, on an individual basis. The main information in Table J.6.17 is summarized below in Table J.4.1.

Table J.4-1 – Individual Basis Total Life Cycle Social Cost of GHG Emissions under Biden Administration SC-GHG Values

Electricity Power Technology	Total Life Cycle Social Cost of GHG Emissions, Nominal $	NPV of Total Life Cycle Social Costs of GHG Emissions, 2023 $
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency in comparing alternatives	**$11,790,149,438**	**$3,134,936,802**
Alternative A - Natural Gas – CC (30-year Life Cycle)	$6,520,857,456	$1,730,503,536
Alternative A - Natural Gas (ULSD backup) – Aero. CTs (30-year Life Cycle)	$1,236,860,789	$327,064,559
Alternative A – On-Site Solar (on-site service only)	$1,093,054	$490,952

[3] The social cost values in the Technical Support Document were converted to nominal values using a 2 percent per year inflation rate.

Electricity Power Technology	Total Life Cycle Social Cost of GHG Emissions, Nominal $	NPV of Total Life Cycle Social Costs of GHG Emissions, 2023 $
Alternative A – On-Site Li-Ion Battery Storage (on-site service only)	$12,293,660	$7,411,057
Alternative A - Total Life Cycle Social Cost of GHG Emissions	**$7,771,104,958**	**$2,065,470,104**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years for consistency in comparing alternatives)	$402,443,040	$184,106,908
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years for consistency in comparing alternatives)	$270,460,530	$163,052,290
Alternative B - Total Life Cycle Social Cost of GHG Emissions, $	**$672,903,570**	**$347,159,198**

TVA has decided to provide a range for GHG life cycle social costs using the current and previous presidential administration's social cost values for GHGs. Presenting social costs as a range of values, as estimated and published under two different federal government administrations (prior Administration under President Trump and current Administration under President Biden), provides decision makers and the public with a complete set of information to support making an informed decision. Under the prior Administration, federal estimates of the SCC were originally reported in 2016 U.S. dollars in the USEPA's regulatory impact analysis for the 2019 Affordable Clean Energy Rule. The U.S. Government Accountability Office (GAO) adjusted the values for inflation and expressed them in 2018 U.S. dollars at a 3 percent discount rate using the United States Gross Domestic Product Price Index from the U.S. Department of Commerce, Bureau of Economic Analysis (GAO 2020). In a similar manner, federal estimates of the SCM were originally reported in 2016 U.S. dollars in the Bureau of Land Management's (BLM's) regulatory impact analysis for the 2018 Final Rule to Rescind or Revise Certain Requirements of the 2016 Waste Prevention Rule. The GAO adjusted the values for inflation and expressed them in 2018 U.S. dollars at a 3 percent discount rate in the same manner as for CO_2; however, the estimates were only provided to 2030. These values were then interpolated through the life cycle period, which is to 2058. The GAO did not find a recent rulemaking that used monetary estimates for N_2O that were based directly on the SCC approach. Instead, GAO used a National Highway Traffic Safety Administration (NHTSA) rulemaking where the N_2O Global Warming Potential factor of 298 was used to convert USEPA's SCC value estimates to monetary value estimates for N_2O.

Using the prior Administration (under President Trump) values, the social costs for each of the three GHGs were calculated using their individual values for the years covering the life cycle period. The social costs for each GHG were summed to obtain a total GHG life cycle social cost. For each alternative, Table J.6.18 provides the estimated life cycle SCC emissions, on an individual basis. Tables J.6.20 and J.6.22 provide the same information but for SCM and SCN, respectively, and on an individual basis. Tables J.6.18, J.6.20, and J.6.22 also show the SCC, SCM, and SCN, respectively, for each life cycle segment, on an individual basis. Table J.6.24 provides the summary of SC-GHG (based on prior Administration cost values) for each of the alternatives on an individual basis. The main information in Table J.6.24 is summarized below in Table J.4.2. Tables J.6.19, J.6.21, and J.6.23 provide the prior Administration social cost value tables by year for CO_2, CH_4, and N_2O, respectively. The one-time upstream SC-GHGs conservatively assumed they were all incurred in the year 2027. The one-time downstream SC-GHGs assumed they were all incurred in the year 2058 for all alternatives.

Using the prior Administration values, the social costs of the system-wide delta compared to the No Action Alternative for each of the three GHGs were calculated for the years covering the 20-year life cycle period. The social costs for each GHG were summed to obtain a total GHG life cycle social cost. For each alternative, Table J.6.31 provides the estimated life cycle SCC emissions on a system-wide delta compared to the No Action Alternative basis. Tables J.6.32 and J.6.33 provide the same information but for SCM and SCN, respectively, and on a system-wide delta compared to No Action Alternative basis. Table J.4.4 provides the summary of life cycle GHG social costs (based on prior Administration estimates) for each of the alternatives.

As stated in Section 3.7, a system-wide view provides critical context into how the specific resource retirements and replacements, underpinning the assumptions of each proposed action alternative, integrates to the system overall, and completes the overall characterization of total system impact and performance. Developing a system-wide life cycle analysis reflects TVA's broader asset strategy and target power supply mix set by the 2019 IRP (TVA 2019a). The system-wide LCA was conducted to assess the implementation of each alternative's impacts on the power generation mix throughout TVA's system. For example, Alternative A is estimated to indirectly reduce GHG emissions from other TVA coal plants as their load factors will likely decrease due to increased efficiency of the new CC/Aero CT Plant compared to the existing KIF coal plant. Therefore, the system-wide LCA estimates the cumulative effects of TVA's forecasted GHG emissions across all of TVA's operations

Using the current Administration (under President Biden), costs described previously for each emission type, the social costs for each of the three GHGs were calculated using their individual values for the years covering the 20-year life cycle period modeled. The social costs for each GHG were summed to obtain a total GHG life cycle social cost. For each alternative, Table J.6.28 provides the estimated life cycle SCC emissions, including for each life cycle segment. Tables J.6.29 and J.6.30 provide the same information for SCM and SCN, respectively. Table J.4.3 below provides the summary of life cycle SC-GHG (based on IWG 2021 social cost values) for each of the alternatives.

Table J.4-2 – Individual Basis Total Life Cycle Social Cost of GHG Emissions under Prior Administration SC-GHG Values

Electricity Power Technology	Total Life Cycle Social Cost of GHG Emissions, Nominal $	NPV of Total Life Cycle Social Costs of CHG Emissions, 2023 $
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency in comparing alternatives	**$937,489,373**	**$272,952,177**
Alternative A - Natural Gas - CC (30-year Life Cycle)	$512,878,575	$149,955,920

Electricity Power Technology	Total Life Cycle Social Cost of GHG Emissions, Nominal $	NPV of Total Life Cycle Social Costs of CHG Emissions, 2023 $
Alternative A - Natural Gas (ULSD backup) – Aero. CTs (30-year Life Cycle)	$96,579,913	$27,988,817
Alternative A – On-Site Solar (on-site service only)	$99,944	$52,425
Alternative A – On-Site Li-Ion Battery Storage (on-site service only)	$1,261,607	$830,641
Alternative A - Total Life Cycle Social Cost of GHG Emissions	**$610,820,039**	**$177,827,802**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years for consistency in comparing alternatives)	$37,478,956	$19,659,363
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years for consistency in comparing alternatives)	$27,755,351	$18,274,102
Alternative B - Total Life Cycle Social Cost of GHG Emissions	**$65,234,307**	**$37,933,466**

ULSD = ultra-low sulfur diesel

Table J.4-3 – TVA System-Wide Estimated Social Cost of Life Cycle GHG Emissions for Action Alternatives Compared to the No Action Alternative, by Life Cycle Phase (Current Administration)

Proposed Action Alternatives	One-Time Upstream (Nominal $)	Ongoing Combustion (Nominal $)	Ongoing Non-Combustion (Nominal $)	Methane Leakage (Nominal $)	One-Time Downstream (Nominal $)	Total (Nominal $)	NPV (2023 $)
Alternative A							
CO_2	5,486,517	(4,624,055,776)	364,123,337	NA	385,283	(4,254,060,640)	(1,818,580,699)
CH_4	603	4	(16,030)	108	51	(15,264)	(6,315)
N_2O	66	0	(102,907,889)	NA	5	(102,907,818)	(43,844,156)
Alternative A Total	**5,487,185**	**(4,624,055,772)**	**261,199,417**	**108**	**385,339**	**(4,356,983,722)**	**(1,862,431,170)**
Alternative B							
CO_2	521,945,210	(5,881,551,155)	94,122,420	NA	162,573,650	(5,102,909,875)	(2,120,668,569)
CH_4	57,331	1	(49,851,272)	88	101,738	(49,692,113)	(20,860,102)
N_2O	6,235	0	(101,118,255)	NA	2,135	(101,109,885)	(42,598,672)
Alternative B Total	**522,008,776**	**(5,881,551,153)**	**(56,847,107)**	**88**	**162,677,523**	**(5,253,711,873)**	**(2,184,127,343)**

Table J.4-4 – TVA System-Wide Estimated Social Cost of Life Cycle GHG Emissions for Action Alternatives Compared to the No Action Alternative, by Life Cycle Phase (Prior Administration)

Proposed Action Alternatives	One-Time Upstream (Nominal $)	Ongoing Combustion (Nominal $)	Ongoing Non-Combustion (Nominal $)	Methane Leakage (Nominal $)	One-Time Downstream (Nominal $)	Total (Nominal $)	NPV (2023 $)
Alternative A							
CO_2	624,487	(426,150,142)	33,531,434	NA	26,616	(391,967,605)	(171,800,839)
CH_4	65	0	(1,410)	9	3	(1,332)	(563)
N2O	6	0	(7,499,582)	NA	0	(7,499,575)	(3,300,739)
Alternative A Total	**624,558**	**(426,150,141)**	**26,030,441**	**9**	**26,619**	**(399,468,513)**	**(175,102,141)**
Alternative B							
CO_2	59,408,876	(544,551,635)	7,953,199	NA	11,231,010	(465,958,550)	(195,329,834)
CH_4	43,901	0	(4,365,940)	7	5,732	(4,316,299)	(1,846,142)
N2O	4,752	0	(7,338,103)	NA	109	(7,333,242)	(3,187,470)
Alternative B Total	**59,457,530**	**(544,551,635)**	**(3,750,845)**	**7**	**11,236,851**	**(477,608,091)**	**(200,363,446)**

J.5. LCA References

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J.6. Tables with Estimated LCA GHG Emission Factors, GHG Emissions, and Social Cost of GHG Emissions for Individual and System-Wide Analyses

Table J.6-1. Median Published Life Cycle CO_2 Equivalent Emission Factors for Electricity Generation Technologies by Life Cycle Phase

Electric Power Technology	One-Time Upstream GHG (CO_2 equivalent), g/kW-hr	Ongoing Annual Combustion GHG (CO_2 equivalent), g/kW-hr	Ongoing Annual Non-Combustion GHG (CO_2 equivalent), g/kW-hr	One-Time Downstream GHG (CO_2 equivalent), g/kW-hr	Total Life Cycle (CO_2 equivalent), g/kW-hr
Coal (Supercritical pulverized)(1)	4.9	NU	4.9	4.9	NA1
Natural Gas - CC	0.8	NU	62	0.02	NA1
Natural Gas - CTs	0.14	NU	70	0.003	NA1
Solar Panels (2)	28	NA2	10	5	43
Li-Ion Battery Storage	31.5	NA2	NR	3.4	34.9

Sources: Kim et al. 2012, Hsu et al. 2012, Whitaker et al. 2012, O'Donoghue et al. 2014, Nicholson and Heath 2021. Includes sub technology emissions factors augmenting Table 1: https://data.nrel.gov/submissions/171.

Acronyms:
g = grams; kW = kilowatts; hr = hours
CC = Combined Cycle Gas Turbine Plant
CT = Simple-Cycle Aeroderivative Gas Turbine Plant
NU = Emission factors in NREL references were not used; GHG emissions from ongoing annual combustion were calculated separately using proposed action alternatives and existing coal plant specific design/operating information.
NA1 = Not Applicable; emission factors/rates for each applicable life cycle segment were used instead of the total life cycle emission factor in the NREL reference.
NA2 = Not Applicable; no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations.
NR = Not Reported in the NREL references.

NOTES:
None of the emission factors in the NREL LCA harmonization reference documents include Transmission and Distribution (T&D) electricity losses as they were outside the scope of the NREL studies and are not considered appreciably different for each Alternative.
(1) = Assumed <5 g/kW-hr values in the source document table are 4.9 g/kW-hr
(2) = Utilized the approximate values for each individual segment provided in the reference document that are a combination of thin-film and crystalline silicon technology.

Table J.6-2. Estimated Life Cycle CO_2 Emission Factors for Electricity Generation Technologies by Life Cycle Phase

Electric Power Technology	One-Time Upstream CO_2, g/kW-hr	Ongoing Annual Combustion CO_2, g/kW-hr	Ongoing Annual Non-Combustion CO_2, g/kW-hr	One-Time Downstream CO_2, g/kW-hr	Total Life Cycle CO_2, g/kW-hr
Coal (Supercritical pulverized)	4.61	NU	4.61	4.61	NA1
Natural Gas - CC	7.999E-01	NU	6.199E+01	1.9998E-02	NA1
Natural Gas - CTs	1.3999E-01	NU	6.9993E+01	2.9997E-03	NA1
Solar	28	NA2	10	5	43.00
Li-Ion Battery Storage	31.4969	NA2	NR	3.3997	34.8965

Source: Calculated based on sources footnoted in Table J6-1

Acronyms:
g = grams; kW = kilowatts; hr = hours
CC = Combined Cycle Gas Turbine Plant
CT = Simple-Cycle Aeroderivative Gas Turbine Plant
NU = Emission factors in NREL references were not used; GHG emissions from ongoing annual combustion were calculated separately using proposed action alternatives and existing coal plant specific design/operating information.
NA1 = Not Applicable; emission factors/rates for each applicable life cycle segment were used instead of the total life cycle emission factor in the NREL reference.
NA2 = Not Applicable; no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations.
NR = Not Reported in the NREL references.

NOTES:
See text (Appendix I, Section J.2) for assumptions on GSP-weighted contributions of CO_2, CH_4, and N_2O to CO_2-e.

Table J.6-3. Estimated Life Cycle CH_4 Emission Factors for Electricity Generation Technologies, by Life Cycle Phase

Electric Power Technology	One-Time Upstream CH_4, g/kW-hr (GWP-weighted)	Ongoing Annual Combustion CH_4, g/kW-hr (GWP-weighted)	Ongoing Annual Non-Combustion CH_4, g/kW-hr (GWP-weighted)	One-Time Downstream CH_4, g/kW-hr (GWP-weighted)	Total Life Cycle CH_4, g/kW-hr (GWP-weighted)	Methane Leakage (% of NG Production)
Coal (Supercritical pulverized)	0.25	NU	0.25	0.25	NA1	NA3
Natural Gas - CC	7.200E-05	NU	5.580E-03	1.800E-06	NA1	1.6
Natural Gas - CTs	1.260E-05	NU	6.300E-03	2.700E-07	NA1	1.6
Solar	2.52E-03	NA2	9.00E-04	4.50E-04	3.87E-03	NA3
Li-Ion Battery Storage	2.84E-03	NA2	NR	3.06E-04	3.14E-03	NA3

Source: Calculated based on sources footnoted in Table J.6-1

NA3 = Not Applicable: methane leakage due to direct natural gas use is not applicable to coal, solar, and battery storage; coal bed methane releases is accounted for under the ongoing annual non-combustion emission factor.

The Natural Gas NREL reference (O'Donoghue et al. 2014) lists Methane Leakage rates in percent of natural gas production for various Life Cycle Analyses (LCAs) in the U.S. and their average value, based on 21 LCAs, is rounded to 1.6 based on data in Table 1 of O'Donoghue et al. 2014. Assumed this leakage is not included in the Ongoing Annual Non-Combustion emission factor per interpretation of the Natural Gas NREL LCA harmonization O'Donoghue et al. 2014.

Table J.6-4. Estimated Life Cycle N_2O Emission Factors for Electricity Generation Technologies, by Life Cycle Phase

Electric Power Technology	One-Time Upstream N_2O, g/kW-hr (GWP-weighted)	Ongoing Annual Combustion N_2O, g/kW-hr (GWP-weighted)	Ongoing Annual Non-Combustion N_2O, g/kW-hr (GWP-weighted)	One-Time Downstream N_2O, g/kW-hr (GWP-weighted)	Total Life Cycle N_2O, g/kW-hr (GWP-weighted)
Coal (Supercritical pulverized)	0.04	NU	0.04	0.04	NA1
Natural Gas - CC	8.000E-06	NU	6.200E-04	2.000E-07	NA1
Natural Gas - CTs	1.400E-06	NU	7.000E-04	3.000E-08	NA1
Solar	2.80E-04	NA2	1.00E-04	5.00E-05	4.30E-04
Li-Ion Battery Storage	3.15E-04	NA2	NR	3.40E-05	3.49E-04

Source: Calculated based on sources footnoted in Table J6-1

Table J.6-5. Electricity Generation Assumptions for Each Alternative

Electricity Generation Technology	Electricity Generation Annual Rate (kW-hr/year)	Plant Size (MW)	Alternative
Coal kW-hr/year (max. capacity generation)	11,370,480,000	1298	No Action
Coal kW-hr/year (projected average annual lifetime generation)	6,253,764,000		
CC kW-hr/year (max. capacity generation)	6,254,640,000	714	A
CC kW-hr/year (projected average annual lifetime generation)	3,440,052,000		
16x Aeroderivative CT kW-hr/year (max. capacity generation)	2,971,392,000	848	A
16x Aeroderivative CT kW-hr/year (projected average annual lifetime generation)	742,848,000		
On-site Solar kW-hr/year (projected average annual lifetime generation)	8,760,000	4	A
On-site Battery Storage kW-hr/year (projected average annual lifetime generation discharged)	146,000,000	100	A
Solar kW-hr/year (projected average annual lifetime generation)	3,285,000,000	1500	B
Li-Ion Battery Storage kW-hr/year (projected average annual lifetime generation discharged)	3,212,000,000	2200	B

Supporting Information: Conversion, Acronyms, Capacity Factors

grams to lbs conversion: 0.00220462

CC = Natural Gas Turbine Combined Cycle

CF = Capacity Factor

CT = Natural Gas Turbine Simple Cycle Aeroderivative

Max. Generation for CC/Coal @ 100% CF, CTs @ 38% CF, Solar/Battery @ 30% CF

Projected Average Annual Lifetime Generation CC/Coal @ 55% CF, CTs @ 10% CF, Solar @ 25% CF, Battery @ 16.7% CF [based on USEIA industry/technology actual averages over the last eight years of published data (USEIA 2021, 2022a, 2022b)].

Batteries assume max. of 2 full cycles/day (5 hours to charge from the grid and 4 hours to discharge to grid = 9 hours/cycle). 1 cycle/day is assumed to be the predicted actual operation. Battery efficiency is assumed to be 85% based on TVA historical model data.

Table J.6-6. Estimated Life Cycle CO_2 Emissions for Electricity Generation Technologies, by Life Cycle Phase - Based on Projected Average Annual Lifetime Electricity Production

Electricity Generation Technology	One-Time Upstream CO_2 Emissions, tons	Ongoing Annual Combustion CO_2 Emissions, tons/yr	Ongoing Annual Non-Combustion CO_2 Emissions, tons/yr	One-Time Downstream CO_2 Emissions, tons	Total Life Cycle CO_2 Emissions, tons
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency	953,569	3,386,667	31,786	953,569	**104,460,708**
Alternative A - Natural Gas - CC (30-year Life Cycle)	90,999	1,438,066	235,081	2,275	50,287,686
Alternative A - Natural Gas – Aero. CTs (30-year Life Cycle)	3,439	230,672	57,314	74	8,643,089
Alternative A - On-site Solar (20-year Life Cycle, prorated to 30 years)	8,110	NA2	97	1,448	12,455
Alternative A - On-site Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	152,071	NA2	NC	16,414	168,484
Alternative A - Total Life Cycle CO_2 Emissions, tons					**59,111,714**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years)	3,041,410	NA2	36,207	543,109	4,670,737
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	3,345,551	NA2	NC	361,107	3,706,658
Alternative B - Total Life Cycle CO_2 Emissions, tons					**8,377,395**

NA2 = Not Applicable; no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations.
NC = Not calculated separately; incorporated in the total life cycle emissions.
See text (Appendix I, Section J.2) for assumptions on GSP-weighted contributions of CO_2, CH_4, and N_2O to CO_2-e.

Table J.6-7. Estimated Life Cycle CH_4 Emissions for Electricity Generation Technologies, by Life Cycle Phase - Based on Projected Average Annual Lifetime Electricity Production

Electricity Generation Technology	One-Time Upstream CH_4 Emissions, tons	Ongoing Annual Combustion CH_4 Emissions, tons/yr	Ongoing Annual Non-Combustion CH_4 Emissions, tons/yr	One-Time Downstream CH_4 Emissions, tons	Methane Life Cycle Leakage, tons	Total Life Cycle CH_4 Emissions, tons
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency	2,026.7	35	67.6	2,026.7	NA3	**7,115**
Alternative A - Natural Gas - CCs (30-year Life Cycle)	0.3	102	0.8	0.01	216,456	219,541
Alternative A - Natural Gas – Aero CTs (30-year Life Cycle)	0.01	16	0.2	2.65E-04	66,909	67,391
Alternative A - On-site Solar (20-year Life Cycle, prorated to 30 years)	0.03	NA2	3.48E-04	0.01	NA3	0.04
Alternative A - On-site Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	1	NA2	NC	0.1	NC2	1
Alternative A - Total Life Cycle CH_4 Emissions, tons					283,365	**286,933**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years)	11	NA2	0.1	2.0	NA3	17
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	12	NA2	NC	1.3	NC2	13
Alternative B - Total Life Cycle CH_4 Emissions, tons						**30**

NA2 = Not Applicable; no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations.

NA3 = Not Applicable: methane leakage due to natural gas use is not applicable to coal and solar; coal bed methane releases are accounted for under the ongoing annual non-combustion emissions.

NC = Not calculated separately; incorporated in the total life cycle emissions.

NC2 = Not calculated separately; Methane leak emissions due to grid power generation from natural gas plants for charging the batteries is incorporated into TVA system wide GHG emissions analysis.

See text (Appendix I, Section J.2) for assumptions on GSP-weighted contributions of CO_2, CH_4, and N_2O to CO_2-e.

Table J.6-8. Estimated Methane Leak Emissions, Average Annual Lifetime - Alternative A, CC Plant

64,225,176	NG scf/day use at Kingston CC
94	Estimated Methane portion of NG (percent)
60,371,666	Methane scf/day use at Kingston CC
0.657	Methane density (kg/m^3)
0.0283168	conversion, 1 cubic foot = 0.0283168 cubic meters
14,430,395	Methane Release Emissions (lbs/yr) from NG use at Kingston CC
7,215	**Methane Release Emissions (tons/yr) from NG use at Kingston CC**

NG = natural gas
Scf/day = standard cubic feet per day

Table J.6-9. Estimated Methane Leak Emissions, Average Annual Lifetime - Alternative A, Aero. CTs

827	NG MMBtu/hr at Kingston Aero CTs
19,852,800	NG scf/day use for Kingston Aero. CTs
94	Estimated Methane portion of NG (percent)
18,661,632	Methane scf/day use for Kingston Aero CTs
0.657	Methane density (kg/m^3)
0.0283168	conversion, 1 cubic foot = 0.0283168 cubic meters
4,460,615	Methane Release Emissions (lbs/yr) from NG use at Kingston Aero. CTs
2,230	**Methane Release Emissions (tons/yr) from NG use at** Kingston **Aero. CTs**

NG = natural gas
Scf/day = standard cubic feet per day
MMBtu/hr = Millions of British Thermal Units per hour

Table J.6-10. Estimated Life Cycle N_2O Emissions for Electricity Generation Technologies, by Life Cycle Phase - Based on Projected Average Annual Lifetime Electricity Production

Electricity Generation Technology	One-Time Upstream N_2O Emissions, tons	Ongoing Annual Combustion N_2O Emissions, tons/yr	Ongoing Annual Non-Combustion N_2O Emissions, tons/yr	One-Time Downstream N_2O Emissions, tons	Total Life Cycle N_2O Emissions, tons
No Action Alternative -Coal(Supercritical pulverized); assumed 30-years remaining life for consistency	30.60	55	1.02	31	**1,736**
Alternative A - Natural Gas - CCs (30-year Life Cycle)	3.05E-03	36	0.01	7.63E-05	1,067
Alternative A - Natural Gas – Aero. CTs (30-year Life Cycle)	1.15E-04	5	1.92E-03	2.47E-06	162
Alternative A - On-site Solar (20-year Life Cycle, prorated to 30 years)	2.72E-04	NA2	3.24E-06	4.86E-05	4.20E-04
Alternative A - On-site Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	0.0	NA2	NC	0.00	0
Alternative A - Total Life Cycle N_2O Emissions, tons					**1,229**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years)	0.1	NA2	1.22E-03	0.02	0.2
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	0.1	NA2	NC	0.01	0.1
Alternative B - Total Life Cycle N_2O Emissions, tons					**0.3**

NA2 = Not Applicable; no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations.

NC = Not calculated separately; incorporated in the total life cycle emissions.

See text (Appendix I, Section J.2) for assumptions on GSP-weighted contributions of CO_2, CH_4, and N_2O to CO_2-e.

Table J.6-11. Estimated Social Cost of Life Cycle CO_2 Emissions for Electricity Generation Technologies, by Life Cycle Phase - Based on Projected Average Annual Lifetime Electricity Production (Biden Administration EO 13990 Interim Rates, 3% Discount Rates)

Electricity Generation Technology	One-Time Upstream Social Cost of CO_2 Emissions, $	Ongoing Combustion Social Cost of CO_2 Emissions, $/LC	Ongoing Non-Combustion Social Cost of CO_2 Emissions, $/LC	One-Time Downstream Social Cost of CO_2 Emissions, $	Total Life Cycle Social Cost of CO_2 Emissions, $
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency	$58,644,031	$11,350,263,656	$106,528,161	$170,789,070	**$11,686,224,919**
Alternative A - Natural Gas - CCs (30-year Life Cycle)	$5,596,393	$4,819,615,715	$787,862,636	$407,460	$5,613,482,203
Alternative A - Natural Gas – Aero CTs (30-year Life Cycle)	$211,486	$773,087,649	$192,084,272	$13,198	$965,396,605
Alternative A - On-site Solar (20-year Life Cycle, prorated to 30 years)	$498,787	NA2	$334,726	$259,396	$1,092,909
Alternative A - On-site Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$9,352,261	NA2	NC	$2,939,823	$12,292,084
Alternative A Total Life Cycle Social Cost of CO_2 Emissions, $					**$6,592,263,801**
Alternative B- Solar (20-year Life Cycle, prorated to 30-years)	$187,045,212	NA2	$118,070,095	$97,273,564	$402,388,872
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$205,749,733	NA2	NC	$64,676,112	$270,425,845
Alternative B Total Life Cycle Social Cost of CO_2 Emissions, $					**$672,814,717**

LC = Life Cycle period
NA2 = Not Applicable; no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations.
NC = Not calculated separately; incorporated in the total life cycle emissions.
NPV = Net Present Value
Assumed One-Time Upstream costs are all in 2027.
Assumed One-Time Downstream costs are all in 2058 for all Alternatives.

Table J.6-12. Technical Support Document: Social Cost of Carbon - Interim Estimates under Biden Administration Executive Order 13990 - Feb. 2021 (Appendix A, Table A-1, 3% Discount Rate)

Year	2% Inflation Adjustor	Real SC-CO_2 ($/mt)	Nominal SC-CO_2 ($/mt)	Nominal SC-CO_2 ($/ton)
2020	1.00	$ 51	$ 51	$ 46
2021	1.02	$ 52	$ 53	$ 48
2022	1.04	$ 53	$ 55	$ 50
2023	1.06	$ 54	$ 57	$ 52
2024	1.08	$ 55	$ 60	$ 54
2025	1.10	$ 56	$ 62	$ 56
2026	1.13	$ 57	$ 64	$ 58
2027	1.15	$ 59	$ 68	$ 61
2028	1.17	$ 60	$ 70	$ 64
2029	1.20	$ 61	$ 73	$ 66
2030	1.22	$ 62	$ 76	$ 69
2031	1.24	$ 63	$ 78	$ 71
2032	1.27	$ 64	$ 81	$ 74
2033	1.29	$ 65	$ 84	$ 76
2034	1.32	$ 66	$ 87	$ 79
2035	1.35	$ 67	$ 90	$ 82
2036	1.37	$ 69	$ 95	$ 86
2037	1.40	$ 70	$ 98	$ 89
2038	1.43	$ 71	$ 101	$ 92
2039	1.46	$ 72	$ 105	$ 95
2040	1.49	$ 73	$ 108	$ 98
2041	1.52	$ 74	$ 112	$ 102
2042	1.55	$ 75	$ 116	$ 105
2043	1.58	$ 77	$ 121	$ 110
2044	1.61	$ 78	$ 125	$ 114
2045	1.64	$ 79	$ 130	$ 118
2046	1.67	$ 80	$ 134	$ 121

Year	2% Inflation Adjustor	Real SC-CO_2 ($/mt)	Nominal SC-CO_2 ($/mt)	Nominal SC-CO_2 ($/ton)
2047	1.71	$ 81	$ 138	$ 125
2048	1.74	$ 82	$ 143	$ 130
2049	1.78	$ 84	$ 149	$ 135
2050	1.81	$ 85	$ 154	$ 140
2051	1.85	$ 86	$ 159	$ 144
2052	1.88	$ 87	$ 164	$ 149
2053	1.92	$ 88	$ 169	$ 153
2054	1.96	$ 89	$ 175	$ 158
2055	2.00	$ 90	$ 180	$ 163
2056	2.04	$ 91	$ 186	$ 168
2057	2.08	$ 92	$ 191	$ 174
2058	2.12	$ 92	$ 191	$ 174

Converted to Nominal Dollars using 2% inflation annual rate approximation; then converted those values to $/short ton (ton)

$ = U.S. Dollars; mt = metric tons; SC-CO_2 = Social Cost of Carbon Dioxide; SC-CH_4 = Social Cost of Methane; SC-N_2O = Social Cost of Nitrous Oxide

Real CO_2 values for years 2051 through 2058 were assumed to increase $1/mt per year based on a similar rate of increase in previous years.

Table J.6-13. Estimated Social Cost of Life Cycle CH_4 Emissions for Electricity Generation Technologies, by Life Cycle Phase - Based on Projected Average Annual Lifetime Electricity Production (Biden Administration EO 13990 Interim Values, 3% Discount Rates)

Electricity Power Technology	One-Time Upstream Social Cost of CH_4 Emissions, $	Ongoing Combustion Social Cost of CH_4 Emissions, $/LC	Ongoing Non-Combustion Social Cost of CH_4 Emissions, $/LC	One-Time Downstream Social Cost of CH_4 Emissions, $	Methane Leakage Social Cost of CH_4, $	Total Life Cycle Social Cost of CH_4 Emissions, $
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency	$3,802,635	$4,062,755	$7,955,597	$13,661,096	NA3	**$29,482,083**
Alternative A - Natural Gas - CCs (30-year Life Cycle)	$615	$12,008,595	$99,670	$55	$849,668,907	$861,777,843
Alternative A- Natural Gas – Aero. CTs (30-year Life Cycle)	$23	$1,868,413	$24,300	$2	$262,643,216	$264,535,954
Alternative A - On-site Solar (20-year Life Cycle, prorated to 30 years)	$55	NA2	$41	$35	NA3	$131
Alternative A - On-site Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$1,027	NA2	NC	$398	NC2	$1,426
Alternative A Total Life Cycle Social Cost of CH_4 Emissions, $						**$1,126,315,353**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years)	$20,545	NA2	$15,351	$13,180	NA3	$49,077
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$22,600	NA2	NC	$8.763	NC2	$31,363
Alternative B Total Life Cycle Social Cost of CH_4 Emissions, $						**$80,440**

LC = Life Cycle period
NA2 = Not Applicable; no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations.
NA3 = Not Applicable: methane leakage due to natural gas use is not applicable to coal and solar; coal bed methane releases are accounted for under the ongoing annual non-combustion emissions.
NC = Not calculated separately; incorporated in the total life cycle emissions.
NC2 = Not calculated separately; Methane leak emissions due to grid power generation from natural gas plants for charging the batteries is incorporated into TVA system wide GHG emissions analysis.
Assumed One-Time Upstream costs are all in 2027.
Assumed One-Time Downstream costs are all in 2058 for all Alternatives.

Table J.6-14. Technical Support Document: Social Cost of Methane - Interim Estimates under Biden Administration Executive Order 13990 - Feb. 2021 (Appendix A, Table A-2, 3% Discount Rate)

Year	2% Inflation Adjustor	Real SC-CH_4 ($/mt)	Nominal SC-CH_4 ($/mt)	Nominal SC-CH_4 ($/ton)
2020	1.00	$1,500	$ 1,500	$ 1,361
2021	1.02	$1,500	$ 1,530	$ 1,388
2022	1.04	$1,600	$ 1,665	$ 1,511
2023	1.06	$1,600	$ 1,698	$ 1,541
2024	1.08	$1,700	$ 1,840	$ 1,670
2025	1.10	$1,700	$ 1,877	$ 1,703
2026	1.13	$1,800	$ 2,027	$ 1,839
2027	1.15	$1,800	$ 2,068	$ 1,876
2028	1.17	$1,900	$ 2,226	$ 2,020
2029	1.20	$1,900	$ 2,271	$ 2,061
2030	1.22	$2,000	$ 2,438	$ 2,212
2031	1.24	$2,000	$ 2,487	$ 2,257
2032	1.27	$2,100	$ 2,663	$ 2,417
2033	1.29	$2,100	$ 2,717	$ 2,465
2034	1.32	$2,200	$ 2,903	$ 2,634
2035	1.35	$2,200	$ 2,961	$ 2,687
2036	1.37	$2,300	$ 3,157	$ 2,865
2037	1.40	$2,300	$ 3,221	$ 2,922
2038	1.43	$2,400	$ 3,428	$ 3,111
2039	1.46	$2,500	$ 3,642	$ 3,305
2040	1.49	$2,500	$ 3,715	$ 3,371
2041	1.52	$2,600	$ 3,941	$ 3,576
2042	1.55	$2,600	$ 4,020	$ 3,648
2043	1.58	$2,700	$ 4,258	$ 3,864
2044	1.61	$2,700	$ 4,343	$ 3,941
2045	1.64	$2,800	$ 4,594	$ 4,169
2046	1.67	$2,800	$ 4,686	$ 4,252

Year	2% Inflation Adjustor	Real SC-CH_4 ($/mt)	Nominal SC-CH_4 ($/mt)	Nominal SC-CH_4 ($/ton)
2047	1.71	$2,900	$ 4,950	$ 4,492
2048	1.74	$3,000	$ 5,223	$ 4,740
2049	1.78	$3,000	$ 5,328	$ 4,834
2050	1.81	$3,100	$ 5,615	$ 5,095
2051	1.85	$3,100	$ 5,728	$ 5,197
2052	1.88	$3,200	$ 6,031	$ 5,472
2053	1.92	$3,200	$ 6,151	$ 5,582
2054	1.96	$3,300	$ 6,470	$ 5,871
2055	2.00	$3,300	$ 6,600	$ 5,989
2056	2.04	$3,400	$ 6,936	$ 6,294
2057	2.08	$3,400	$ 7,074	$ 6,420
2058	2.12	$3,500	$ 7,428	$ 6,741

Converted to Nominal Dollars using 2% inflation annual rate approximation; then converted those values to $/short ton (ton)

$ = U.S. Dollars; mt = metric tons; SC-CO_2 = Social Cost of Carbon Dioxide; SC-CH_4 = Social Cost of Methane; SC-N_2O = Social Cost of Nitrous Oxide

Real CH_4 values for years 2051 through 2058 were assumed to increase by $100/mt every two years based on a similar rate of increase in previous years.

Table J.6-15. Estimated Social Cost of Life Cycle N_2O Emissions for Electricity Generation Technologies, by Life Cycle Phase - Based on Projected Average Annual Lifetime Electricity Production (Biden Administration EO 13990 Interim Values, 3% Discount Rates)

Electricity Power Technology	One-Time Upstream Social Cost of N_2O Emissions, $/LC	Ongoing Combustion Social Cost of N_2O Emissions, $/LC	Ongoing Non-Combustion Social Cost of N_2O Emissions, $/LC	One-Time Downstream Social Cost of N_2O Emissions, $/LC	Total Life Cycle Social Cost of N_2O Emissions, $
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency	$669,927	$70,283,315	$1,308,396	$2,180,798	**$74,442,437**
Alternative A - Natural Gas - CCs (30-year Life Cycle)	$67	$45,587,219	$10,118	$5	$45,597,409
Alternative B - Natural Gas - CTs (30-year Life Cycle)	$3	$6,925,760	$2,467	$0	$6,928,230
Alternative A - On-site Solar (20-year Life Cycle, prorated to 30 years)	$6	NA2	$4	$3	$14
Alternative A - On-site Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$112	NA2	NC	$39	$151
Alternative B Total Life Cycle Social Cost of N_2O Emissions, $					**$52,525,803**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years)	$2,234	NA2	$1,558	$1,229	$5,092
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$2,458	NA2	NC	$864	$3,321
Alternative B Total Life Cycle Social Cost of N_2O Emissions, $					**$8,413**

LC = Life Cycle period

NA2 = Not Applicable; no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations.

NC = Not calculated separately; incorporated in the total life cycle emissions.

Assumed One-Time Upstream costs are all in 2027.

Assumed One-Time Downstream costs are all in 2058 for all Alternatives.

Table J.6-16. Technical Support Document: Social Cost of Nitrous Oxide - Interim Estimates under Biden Administration Executive Order 13990 - Feb. 2021 (Appendix A, Table A-3, 3% Discount Rate)

Year	2% Inflation Adjustor	Real SC-N_2O ($/mt)	Nominal SC-N_2O ($/mt)	Nominal SC-N_2O ($/ton)
2020	1.00	$18,000	$18,000	$16,334
2021	1.02	$19,000	$19,380	$17,586
2022	1.04	$19,000	$19,768	$17,938
2023	1.06	$20,000	$21,224	$19,260
2024	1.08	$20,000	$21,649	$19,645
2025	1.10	$21,000	$23,186	$21,040
2026	1.13	$21,000	$23,649	$21,460
2027	1.15	$21,000	$24,122	$21,890
2028	1.17	$22,000	$25,777	$23,391
2029	1.20	$22,000	$26,292	$23,858
2030	1.22	$23,000	$28,037	$25,442
2031	1.24	$23,000	$28,598	$25,951
2032	1.27	$24,000	$30,438	$27,621
2033	1.29	$24,000	$31,047	$28,173
2034	1.32	$25,000	$32,987	$29,934
2035	1.35	$25,000	$33,647	$30,532
2036	1.37	$26,000	$35,692	$32,389
2037	1.40	$26,000	$36,406	$33,037
2038	1.43	$27,000	$38,563	$34,993
2039	1.46	$27,000	$39,334	$35,693
2040	1.49	$28,000	$41,607	$37,755
2041	1.52	$28,000	$42,439	$38,511
2042	1.55	$29,000	$44,833	$40,684
2043	1.58	$29,000	$45,730	$41,497
2044	1.61	$30,000	$48,253	$43,787
2045	1.64	$30,000	$49,218	$44,663
2046	1.67	$31,000	$51,876	$47,074

Year	2% Inflation Adjustor	Real SC-N_2O ($/mt)	Nominal SC-N_2O ($/mt)	Nominal SC-N_2O ($/ton)
2047	1.71	$31,000	$52,913	$48,016
2048	1.74	$32,000	$55,713	$50,556
2049	1.78	$32,000	$56,827	$51,567
2050	1.81	$33,000	$59,775	$54,242
2051	1.85	$33,000	$60,970	$55,327
2052	1.88	$34,000	$64,074	$58,144
2053	1.92	$34,000	$65,356	$59,307
2054	1.96	$35,000	$68,624	$62,272
2055	2.00	$35,000	$69,996	$63,517
2056	2.04	$36,000	$73,436	$66,639
2057	2.08	$36,000	$74,905	$67,972
2058	2.12	$37,000	$78,525	$71,257

Converted to Nominal Dollars using 2% inflation annual rate approximation; then converted those values to $/short ton (ton)

$ = U.S. Dollars; mt = metric tons; SC-CO_2 = Social Cost of Carbon Dioxide; SC-CH_4 = Social Cost of Methane; SC-N_2O = Social Cost of Nitrous Oxide

Real N_2O values for years 2051 through 2058 were assumed to increase by $1,000/mt every two years based on a similar rate of increase in previous years.

Table J.6-17. Estimated Social Cost of Life Cycle GHG Emissions for Electricity Generation Technologies, by Life Cycle Phase - Based on Projected Average Annual Lifetime Electricity Production (Biden Administration EO 13990 Interim Values, 3% Discount Rates)

Electricity Power Technology	Total Life Cycle Social Cost of CO_2 Emissions, $	Total Life Cycle Social Cost of CH_4 Emissions, $	Total Life Cycle Social Cost of N_2O Emissions, $	Total Life Cycle Social Cost of GHG Emissions, $
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency	**$11,686,224,919**	**$29,482,083**	**$74,442,437**	**$11,790,149,438**
Alternative A - Natural Gas - CC (30-year Life Cycle)	$5,613,482,203	$861,777,843	$45,597,409	$6,520,857,456
Alternative A - Natural Gas – Aero CTs (30-year Life Cycle)	$965,396,605	$264,535,954	$6,928,230	$1,236,860,789
Alternative A - On-site Solar (20-year Life Cycle, prorated to 30 years)	$1,092,909	$131	$14	$1,093,054
Alternative A - On-site Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$12,292,084	$1,426	$151	$12,293,660
Alternative A Total Life Cycle Social Cost of GHG Emissions, $	**$6,592,263,801**	**$1,126,315,353**	**$52,525,803**	**$7,771,104,958**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years)	$402,388,872	$49,077	$5,092	$402,443,040
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$270,425,845	$31,363	$3,321	$270,460,530
Alternative B Total Life Cycle Social Cost of GHG Emissions, $	**$672,814,717**	**$80,440**	**$8,413**	**$672,903,570**

Table J.6-18. Estimated Social Cost of Life Cycle CO_2 Emissions for Electricity Generation Technologies, by Life Cycle Phase - Based on Projected Average Annual Lifetime Electricity Production (Prior Administration Values, 2020, 3% Discount Rates)

Electricity Power Technology	One-Time Upstream Social Cost of CO_2 Emissions, $	Ongoing Combustion Social Cost of CO_2 Emissions, $/LC	Ongoing Non-Combustion Social Cost of CO_2 Emissions, $/LC	One-Time Downstream Social Cost of CO_2 Emissions, $	Total Life Cycle Social Cost of CO_2 Emissions, $
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency	$6,674,984	$904,240,009	$8,486,765	$11,442,830	**$930,844,588**
Alternative A - Natural Gas - CCs (30-year Life Cycle)	$636,993	$383,963,711	$62,766,552	$27,300	$447,394,556
Alternative A - Natural Gas – Aero. CTs (30-year Life Cycle)	$24,072	$61,589,475	$15,302,753	$884	$76,917,185
Alternative A - On-site Solar (20-year Life Cycle, prorated to 30 years)	$56,773	NA2	$25,780	$17,379	$99,932
Alternative A - On-site Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$1,064,494	NA2	NC	$196,968	$1,261,461
Alternative A Total Life Cycle Social Cost of CO_2 Emissions, $					**$525,673,134**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years)	$21,289,870	NA2	$9,667,339	$6,517,307	$37,474,517
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$23,418,857	NA2	NC	$4,333,285	$27,752,142
Alternative B Total Life Cycle Social Cost of CO_2 Emissions, $					**$65,226,659**

LC = Life Cycle period

NA2 = Not Applicable; no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations.

NC = Not calculated separately; incorporated in the total life cycle emissions.

Assumed One-Time Upstream costs are all in 2027.

Assumed One-Time Downstream costs are all in 2058 for all Alternatives.

Table J.6-19. Federal Government's Social Cost of Carbon - Estimates Used in Conducting Regulatory Impact Analyses under Prior EPA Administration, 2020 (3% Discount Rate)

Year	Nominal SC-CO_2 [1] ($/mt)	Nominal SC-CO_2 ($/ton)	
2020	$7.0	$	6
2021	$7.1	$	6
2022	$7.2	$	7
2023	$7.3	$	7
2024	$7.4	$	7
2025	$7.5	$	7
2026	$7.6	$	7
2027	$7.7	$	7
2028	$7.8	$	7
2029	$7.9	$	7
2030	$8.0	$	7
2031	$8.1	$	7
2032	$8.2	$	7
2033	$8.3	$	8
2034	$8.4	$	8
2035	$8.5	$	8
2036	$8.6	$	8
2037	$8.7	$	8
2038	$8.8	$	8
2039	$8.9	$	8
2040	$9.0	$	8
2041	$9.2	$	8
2042	$9.4	$	9
2043	$9.6	$	9
2044	$9.8	$	9
2045	$10.0	$	9
2046	$10.2	$	9

Year	Nominal SC-CO_2 [1] ($/mt)	Nominal SC-CO_2 ($/ton)	
2047	$10.4	$	9
2048	$10.6	$	10
2049	$10.8	$	10
2050	$11.0	$	10
2051	$11.2	$	10
2052	$11.5	$	10
2053	$11.7	$	11
2054	$12.0	$	11
2055	$12.3	$	11
2056	$12.5	$	11
2057	$12.8	$	12
2058	$13.1	$	12

$ = U.S. Dollars; mt = metric tons; SC-CO_2 = Social Cost of Carbon Dioxide

1 Under the prior Administration, federal estimates of the social cost of carbon dioxide were originally reported in 2016 U.S. dollars in EPA's regulatory impact analysis for the 2019 Affordable Clean Energy Rule. The GAO adjusted the values for inflation and expressed them in 2018 U.S. dollars using the United States Gross Domestic Product Price Index from the U.S. Department of Commerce, Bureau of Economic Analysis. The GAO source document is cited as: U.S. Government Accountability Office, Report to Congressional Requesters, Social Cost of Carbon, Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis (GAO-20-254), June 2020 (GAO 2020).

CO_2 values for years between 2020 and 2030, between 2030 and 2040, and between 2040 and 2050 were interpolated as only 2020, 2030, 2040, and 2050 values were provided in the reference.

Table J.6-20. Estimated Social Cost of Life Cycle CH_4 Emissions for Electricity Generation Technologies, by Life Cycle Phase - Based on Projected Average Annual Lifetime Electricity Production (Prior Administration Values, 2020, 3% Discount Rates)

Electricity Power Technology	One-Time Upstream Social Cost of CH_4 Emissions, $	Ongoing Combustion Social Cost of CH_4 Emissions, $/LC	Ongoing Non-Combustion Social Cost of CH_4 Emissions, $/LC	One-Time Downstream Social Cost of CH_4 Emissions, $	Methane Leakage Social Cost of CH_4, $	Total Life Cycle Social Cost of CH_4 Emissions, $
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency	$413,067	$295,379	$578,404	$743,742	NA3	**$2,030,592**
Alternative A - Natural Gas - CCs (30-year Life Cycle)	$67	$873,074	$7,246	$3	$61,774,401	$62,654,791
Alternative A - Natural Gas – Aero CTs (30-year Life Cycle)	$3	$135,841	$1,767	$0	$19,095,235	$19,232,846
Alternative A – On-Site Solar (20-year Life Cycle, prorated to 30 years)	$6	NA2	$3	$2	NA3	$11
Alternative A – On-Site Li-ion Battery Storge (20-year Life Cycle, prorated to 30 years)	$112	NA2	NC	$22	NC2	$133
Alternative A Total Life Cycle Social Cost of CH_4 Emissions, $						**$81,887,781**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years)	$2,232	NA2	$1,116	$718	NA3	$4,065
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$2,455	NA2	NC	$477	NC2	$2,932
Alternative B Total Life Cycle Social Cost of CH_4 Emissions, $						**$6,997**

LC = Life Cycle period

NA2 = Not Applicable; no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations.

NA3 = Not Applicable: methane leakage due to natural gas use is not applicable to coal and solar; coal bed methane releases are accounted for under the ongoing annual non-combustion emissions.

NC = Not calculated separately; incorporated in the total life cycle emissions.

NC2 = Not calculated separately; Methane leak emissions due to grid power generation from natural gas plants for charging the batteries is incorporated into TVA system wide GHG emissions analysis.

Assumed One-Time Upstream costs are all in 2027.

Assumed One-Time Downstream costs are all in 2058 for all Alternatives.

Table J.6-21. Federal Government's Social Cost of Methane - Estimates Used in Conducting Regulatory Impact Analyses under Prior EPA Administration, 2020 (3% Discount Rate)

Year	Nominal SC-CH4 [1] ($/mt)	Nominal SC-CH4 ($/ton)
2020	$ 184	$ 167
2021	$ 190	$ 172
2022	$ 196	$ 177
2023	$ 201	$ 183
2024	$ 207	$ 188
2025	$ 213	$ 193
2026	$ 219	$ 199
2027	$ 225	$ 204
2028	$ 230	$ 209
2029	$ 236	$ 214
2030	$ 242	$ 220
2031	$ 248	$ 225
2032	$ 254	$ 230
2033	$ 259	$ 235
2034	$ 265	$ 241
2035	$ 271	$ 246
2036	$ 277	$ 251
2037	$ 283	$ 256
2038	$ 288	$ 262
2039	$ 294	$ 267
2040	$ 300	$ 272
2041	$ 306	$ 277
2042	$ 312	$ 283
2043	$ 317	$ 288
2044	$ 323	$ 293
2045	$ 329	$ 299
2046	$ 335	$ 304

Year	Nominal SC-CH4 [1] ($/mt)		Nominal SC-CH4 ($/ton)	
2047	$	341	$	309
2048	$	346	$	314
2049	$	352	$	320
2050	$	358	$	325
2051	$	364	$	330
2052	$	370	$	335
2053	$	375	$	341
2054	$	381	$	346
2055	$	387	$	351
2056	$	393	$	356
2057	$	399	$	362
2058	$	404	$	367

1 Under the prior Administration, federal estimates of the social cost of methane were originally reported in 2016 U.S. dollars in BLM's regulatory impact analysis for the 2018 Final Rule to Rescind or Revise Certain Requirements of the 2016 Waste Prevention Rule. The GAO adjusted the values for inflation and expressed them in 2018 U.S. dollars using the United States Gross Domestic Product Price Index from the U.S. Department of Commerce, Bureau of Economic Analysis. Unlike EPA, BLM included estimates only to 2030. The GAO source document is cited as: U.S. Government Accountability Office, Report to Congressional Requesters, Social Cost of Carbon, Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis (GAO-20-254), June 2020 (GAO 2020).

$ = U.S. Dollars; mt = metric tons; SC-CH_4 = Social Cost of Methane

CH_4 values for years between 2020 and 2030 and thereafter were interpolated based on the change in rates between the 2020 and 2030 rates provided.

Table J.6-22. Estimated Social Cost of Life Cycle N_2O Emissions for Electricity Generation Technologies, by Life Cycle Phase - Based on Projected Average Annual Lifetime Electricity Production (Prior Administration Values, 2020, 3% Discount Rates)

Electricity Power Technology	One-Time Upstream Social Cost of N_2O Emissions, $/LC	Ongoing Combustion Social Cost of N_2O Emissions, $/LC	Ongoing Non-Combustion Social Cost of N_2O Emissions, $/LC	One-Time Downstream Social Cost of N_2O Emissions, $/LC	Total Life Cycle Social Cost of N_2O Emissions, $
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency	$63,726	$4,360,935	$81,183	$108,349	**$4,614,193**
Alternative A - Natural Gas - CCs (30-year Life Cycle)	$6	$2,829,568	$628	$0	$2,829,228
Alternative A - Natural Gas – Aero CTs (30-year Life Cycle)	$0	$429,729	$153	$0	$429,882
Alternative A - On-site Solar (20-year Life Cycle, prorated to 30 years)	$1	NA2	$0	$0	$1
Alternative A - On-site Solar (20-year Life Cycle, prorated to 30 years)	$11	NA2	NC	$2	$13
Alternative A Total Life Cycle Social Cost of N_2O Emissions, $					**$3,259,124**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years)	$213	NA2	$97	$65	$374
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$234	NA2	NC	$43	$277
Alternative B Total Life Cycle Social Cost of N_2O Emissions, $					**$650**

LC = Life Cycle period

NA2 = Not Applicable; no direct ongoing annual combustion emissions are generated directly from Alternative B solar and battery operations.

NC = Not calculated separately; incorporated in the total life cycle emissions.

Assumed One-Time Upstream costs are all in 2027.

Assumed One-Time Downstream costs are all in 2058 for all Alternatives.

Table J.6-23. Federal Government's Social Cost of Nitrous Oxide - Estimates Used in Conducting Regulatory Impact Analyses under Prior EPA Administration, 2020 (3% Discount Rate)

Year	Nominal SC-N_2O [1] ($/mt)		Nominal SC-N_2O ($/ton)	
2020	$	2,086	$	1,893
2021	$	2,116	$	1,920
2022	$	2,146	$	1,947
2023	$	2,175	$	1,974
2024	$	2,205	$	2,001
2025	$	2,235	$	2,028
2026	$	2,265	$	2,055
2027	$	2,295	$	2,082
2028	$	2,324	$	2,109
2029	$	2,354	$	2,136
2030	$	2,384	$	2,163
2031	$	2,414	$	2,190
2032	$	2,444	$	2,217
2033	$	2,473	$	2,244
2034	$	2,503	$	2,272
2035	$	2,533	$	2,299
2036	$	2,563	$	2,326
2037	$	2,593	$	2,353
2038	$	2,622	$	2,380
2039	$	2,652	$	2,407
2040	$	2,682	$	2,434
2041	$	2,742	$	2,488
2042	$	2,801	$	2,542
2043	$	2,861	$	2,596
2044	$	2,920	$	2,650
2045	$	2,980	$	2,704
2046	$	3,040	$	2,758

Year	Nominal SC-N_2O [1] ($/mt)		Nominal SC-N_2O ($/ton)	
2047	$	3,099	$	2,812
2048	$	3,159	$	2,866
2049	$	3,218	$	2,921
2050	$	3,278	$	2,975
2051	$	3,350	$	3,040
2052	$	3,424	$	3,107
2053	$	3,499	$	3,175
2054	$	3,576	$	3,245
2055	$	3,655	$	3,317
2056	$	3,735	$	3,389
2057	$	3,817	$	3,464
2058	$	3,901	$	3,540

1 Under the prior Administration, the GAO did not find a recent rulemaking that used monetary estimates for nitrous oxide that were based on the social cost of carbon approach. Instead, the NHTSA used a Global Warming Potential factor to convert EPA's social cost carbon dioxide estimates to monetary estimates for nitrous oxide. Monetary estimates the agency used in sensitivity analyses involving nitrous oxide were estimated by applying the 100-year Global Warming Potential factor for nitrous oxide (which is 298) to the central estimates of the social cost of carbon dioxide for each future year. The source document for this information is: U.S. Government Accountability Office, Report to Congressional Requesters, Social Cost of Carbon, Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis (GAO-20-254), June 2020 (GAO 2020).

$ = U.S. Dollars; mt = metric tons; SC-N_2O = Social Cost of Nitrous Oxide

Table J.6-24. Estimated Social Cost of Life Cycle GHG Emissions for Electricity Generation Technologies, by Life Cycle Phase - Based on Projected Average Annual Lifetime Electricity Production (Prior Administration Values, 2020, 3% Discount Rates)

Electricity Power Technology	Total Life Cycle Social Cost of CO_2 Emissions, $	Total Life Cycle Social Cost of CH_4 Emissions, $	Total Life Cycle Social Cost of N_2O Emissions, $	Total Life Cycle Social Cost of GHG Emissions, $
No Action Alternative - Coal (Supercritical pulverized); assumed 30-years remaining life for consistency	**$930,844,588**	**$2,030,592**	**$4,614,193**	**$937,489,373**
Alternative A - Natural Gas - CCs (30-year Life Cycle)	$447,394,556	$62,654,791	$2,829,228	$512,878,575
Alternative A - Natural Gas - CTs (30-year Life Cycle)	$76,917,185	$19,232,846	$429,882	$96,579,913
Alternative A - On-site Solar (20-year Life Cycle, prorated to 30 years)	$99,932	$11	$1	$99,944
Alternative A - On-site Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$1,261,461	$133	$13	$1,261,607
Alternative B Total Life Cycle Social Cost of GHG Emissions, $	**$525,673,134**	**$81,887,781**	**$3,259,124**	**$610,820,039**
Alternative B - Solar (20-year Life Cycle, prorated to 30-years)	$37,474,517	$4,065	$374	$37,478,956
Alternative B - Li-Ion Battery Storage (20-year Life Cycle, prorated to 30-years)	$27,752,142	$2,932	$277	$27,755,351
Alternative B Total Life Cycle Social Cost of GHG Emissions, $	**$65,226,659**	**$6,997**	**$650**	**$65,234,307**

Table J.6-25. TVA System-Wide Estimated 20-Year Life Cycle CO_2 Emissions Compared to the No Action Alternative, by Life Cycle Phase

Electric Power Technology	One-Time Upstream CO_2 Emissions, tons	Cumulative Combustion CO_2 Emissions, tons	Cumulative Non-Combustion CO_2 Emissions, tons	One-Time Downstream CO_2 Emissions, tons	Life Cycle CO_2 Emissions, tons	Total CO_2 Emissions, tons
Alternative A Total						**-50,111,425**
Coal		-79,326,356	-342,055			**-79,668,411**
Natural Gas - Combined Cycle	85,774	24,612,288	4,338,697	2,144		**29,038,903**
Natural Gas - Simple Cycle	3,439	377,764	306,054	74		**687,330**
Hydroelectric		0	0			**0**
Nuclear		0	0			**0**
Wind & Solar		0	NR			**0**
Battery Storage (Generation)		0	NR			**0**
Pumped Hydro (Generation)		0	1,745			**1,745**
Market Purchases		-154,401	-16,591			**-170,992**
Alternative B Total						**-61,966,464**
Coal		-77,046,850	-331,417			**-77,378,267**
Natural Gas - Combined Cycle		1,701,580	350,685			**2,052,264**
Natural Gas - Simple Cycle		5,108,205	868,446			**5,976,651**
Hydroelectric		0	-2			**-2**
Nuclear		0	0			**0**
Wind & Solar		0	NR		4,634,530	**4,634,530**
Battery Storage (Generation)	2,230,367	0	NR	240,738		**2,471,105**
Pumped Hydro (Generation)		0	-12,119			**-12,119**
Market Purchases		164,176	125,198			**289,374**

Table J.6-26. TVA System-Wide Estimated 20-Year Life Cycle CH_4 Emissions Compared to the No Action Alternative, by Life Cycle Phase

Electric Power Technology	One-Time Upstream CH_4 Emissions, tons	Cumulative Combustion CH_4 Emissions, tons	Cumulative Non-Combustion CH_4 Emissions, tons	One-Time Downstream CH_4 Emissions, tons	Life Cycle CH_4 Emissions, tons	Natural Gas Related Methane Life Cycle Leakage, tons	Total CH_4 Emissions, tons
Alternative A Total							**-3,226**
Coal		-0.0004	-3,272				**-3,272**
Natural Gas - Combined Cycle	0.3	0.0016	43	0.01		-	**44**
Natural Gas - Simple Cycle	0.0	0.0002	3.1	0		-	**3**
Hydroelectric		0	0				**0**
Nuclear		0	0				**0**
Wind & Solar		0	NR				**0**
Battery Storage (Generation)		0	NR				**0**
Pumped Hydro (Generation)		0	1.57E-01				**0**
Market Purchases		0	-1.49			-	**-1**
Alternative B Total							**-3,122**
Coal		-0.0004	-3,170				**-3,170**
Natural Gas - Combined Cycle		0.0001	4			-	**4**
Natural Gas - Simple Cycle		0.0005	8.7			-	**9**
Hydroelectric		0	0				**0**
Nuclear		0	0				**0**
Wind & Solar		0	NR		17		**17**
Battery Storage (Generation)	8	0	NR	0.9			**9**
Pumped Hydro (Generation)		0	-1.09E+00				**-1**
Market Purchases		0	11.27			-	**11**

Table J.6-27. TVA System-Wide Estimated 20-Year Life Cycle N_2O Emissions Compared to the No Action Alternative, by Life Cycle Phase

Electric Power Technology	One-Time Upstream N_2O Emissions, tons	Cumulative Combustion N_2O Emissions, tons	Cumulative Non-Combustion N_2O Emissions, tons	One-Time Downstream N_2O Emissions, tons	Life Cycle N_2O Emissions, tons	Total N_2O Emissions, tons
Alternative A Total						**-3,225**
Coal		-0.0006	-3,272			**-3,272**
Natural Gas - Combined Cycle	0.003	0.00	43.4	0.0001		**43**
Natural Gas - Simple Cycle	0.000	0.00	3.06	0.0000		**3**
Hydroelectric		0	-2.51E-06			**0**
Nuclear		0	0			**0**
Wind & Solar		0	NR			**0**
Battery Storage (Generation)		0	NR			**0**
Pumped Hydro (Generation)		0	1.75E-02			**0**
Market Purchases		0	-0.166			**0**
Alternative B Total						**-3,156**
Coal		-0.0006	-3,170			**-3,170**
Natural Gas - Combined Cycle		0.00	3.5			**4**
Natural Gas - Simple Cycle		0.00	8.69			**9**
Hydroelectric		0	-2.51E-06			**0**
Nuclear		0	0			**0**
Wind & Solar		0	NR		0.2	**0**
Battery Storage (Generation)	0.1	0	NR	0.008		**0**
Pumped Hydro (Generation)		0	-1.21E-01			**0**
Market Purchases		0	1.252			**1**

Table J.6-28. TVA System-Wide Estimated 20-Year Life Cycle CO_2 Costs, Biden Administration, Compared to the No Action Alternative, by Life Cycle Phase (Biden Administration EO 13990 Interim Rates, 3% Discount Rates)

Electric Power Technology	One-Time Upstream CO_2 Cost	Yearly Ongoing Combustion and Non-Combustion CO2 Cost										
Alternative A	5,486,517	0	0	0	0	3,328,433	-168,063,761	-182,992,614	-195,884,349	-203,500,314	-226,867,680	-253,009,377
Alternative B	521,945,210	0	0	0	-12,145,696	-77,555,951	-249,597,769	-263,092,053	-277,176,716	-284,869,433	-304,491,062	-330,198,449

Electric Power Technology	Yearly Ongoing Combustion and Non-Combustion CO2 Cost (cont'd)									Downstream CO_2 Cost	Total Cost (Nominal $)	NPV (2023 $)
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2057		
Alternative A	-285,962,884	-292,777,312	-312,183,577	-320,496,100	-341,966,954	-338,219,572	-361,628,021	-378,810,695	-400,897,660	385,283	**-4,254,060,640**	**-1,818,580,699**
Alternative B	-380,657,913	-382,205,787	-406,714,192	-421,067,593	-445,469,927	-452,467,291	-481,649,907	-495,169,327	-522,899,671	162,573,650	**-5,102,909,875**	**-2,120,668,569**

Table J.6-29. TVA System-Wide Estimated 20-Year Life Cycle CH4 Costs, Biden Administration, Compared to the No Action Alternative, by Life Cycle Phase (Biden Administration EO 13990 Interim Rates, 3% Discount Rates)

Electric Power Technology	One-Time Upstream CH4 Cost	Yearly Combined Ongoing Combustion and Non-Combustion CH4 Cost and Leakage Cost										
Alternative A	603	0	0	0	0	-8	-578	-635	-721	-743	-862	-930
Alternative B	57,331	0	0	0	177,149	-66,714	-1,741,893	-1,881,608	-2,071,265	-2,107,234	-2,405,068	-2,627,070

Electric Power Technology	Yearly Combined Ongoing Combustion and Non-Combustion CH4 Cost and Leakage Cost (cont'd)									One-Time Downstream CH_4 Cost	Total Cost (Nominal $)	NPV (2023 $)
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2057		
Alternative A	-1,036	-1,045	-1,186	-1,187	-1,274	-1,284	-1,406	-1,499	-1,522	51	**-15,264**	**-6,315**
Alternative B	-3,406,875	-3,478,509	-3,723,952	-3,765,206	-4,103,430	-4,299,354	-4,486,284	-4,760,015	-5,103,856	101,738	**-49,692,113**	**-20,860,102**

Table J.6-30. TVA System-Wide Estimated 20-Year Life Cycle N_2O Costs, Biden Administration, Compared to the No Action Alternative, by Life Cycle Phase (Biden Administration EO 13990 Interim Rates, 3% Discount Rates)

Electric Power Technology	One-Time Upstream N_2O Cost	Yearly Ongoing Combustion and Non-Combustion N_2O Cost										
	2027	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Alternative A	66	0	0	0	0	135,664	-3,926,004	-4,204,918	-4,647,214	-4,796,485	-5,325,442	-5,953,746
Alternative B	6,235	0	0	0	383,419	-120,658	-3,631,411	-3,925,133	-4,292,029	-4,366,534	-4,955,520	-5,415,637

Electric Power Technology	Yearly Ongoing Combustion and Non-Combustion N_2O Cost (cont'd)									Downstream N_2O Cost	Total Cost (Nominal $)	NPV (2023 $)
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2057		
Alternative A	-6,933,199	-7,080,958	-7,542,041	-7,625,543	-8,273,926	-8,320,574	-9,008,964	-9,191,264	-10,213,274	5	**-102,907,818**	**-43,844,156**
Alternative B	-6,993,352	-7,141,138	-7,605,239	-7,689,499	-8,341,347	-8,389,582	-9,080,275	-9,263,820	-10,290,500	2,135	**-101,109,885**	**-42,598,672**

Table J.6-31. TVA System-Wide Estimated 20-Year Life Cycle CO_2 Costs, Prior Administration, Compared to the No Action Alternative, by Life Cycle Phase (Estimates Used in Conducting Regulatory Impact Analyses under Prior EPA Administration, 2020 (3% Discount Rate))

Electric Power Technology	One-Time Upstream CO_2 Cost	Yearly Ongoing Combustion and Non-Combustion CO2 Cost									
Alternative A	624,487	0	0	0	0	378,849	-18,441,706	-19,363,409	-19,993,368	-20,040,211	-21,561,066	-26,527,273
Alternative B	59,408,876	0	0	0	-1,459,574	-8,827,578	-27,388,466	-27,839,151	-28,290,653	-28,053,241	-28,938,242	-34,620,315

Electric Power Technology	Yearly Ongoing Combustion and Non-Combustion CO2 Cost (cont'd)									Downstream CO_2 Cost	Total Cost (Nominal $)	NPV (2023 $)
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2057		
Alternative A	-28,949,090	-28,624,086	-29,055,596	-28,826,597	-29,729,957	-28,427,231	-29,390,526	-29,775,461	-34,291,982	26,616	**-391,967,605**	**-171,800,839**
Alternative B	-38,535,421	-37,367,278	-37,853,764	-37,872,366	-38,728,309	-38,029,710	-39,145,042	-38,921,538	-44,727,789	11,231,010	**-465,958,550**	**-195,329,834**

Table J.6-32. TVA System-Wide Estimated 20-Year Life Cycle CH_4 Costs, Prior Administration, Compared to the No Action Alternative, by Life Cycle Phase (Estimates Used in Conducting Regulatory Impact Analyses under Prior EPA Administration, 2020 (3% Discount Rate))

Electric Power Technology	One-Time Upstream CH4 Cost	Yearly Combined Ongoing Combustion and Non-Combustion CH4 Cost and Leakage Cost										
Alternative A	65	0	0	0	0	-1	-60	-66	-72	-74	-82	-89
Alternative B	43,901	0	0	0	19,121	-7,247	-180,281	-195,728	-205,598	-209,982	-229,010	-250,853

Electric Power Technology	Yearly Combined Ongoing Combustion and Non-Combustion CH4 Cost and Leakage Cost (cont'd)									One-Time Downstream CH_4 Cost	Total Cost (Nominal $)	NPV (2023 $)
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2057		
Alternative A	-95	-96	-104	-104	-107	-104	-114	-116	-118	3	**-1,332**	**-563**
Alternative B	-311,247	-318,374	-326,467	-330,393	-345,245	-347,298	-362,297	-369,376	-395,657	5,732	**-4,316,299**	**-1,846,142**

Table J.6-33. TVA System-Wide Estimated 20-Year Life Cycle N_2O Costs, Prior Administration, Compared to the No Action Alternative, by Life Cycle Phase (Estimates Used in Conducting Regulatory Impact Analyses under Prior EPA Administration, 2020 (3% Discount Rate))

Electric Power Technology	One-Time Upstream N_2O Cost	Yearly Ongoing Combustion and Non-Combustion N_2O Cost										
	2027	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Alternative A	6	0	0	0	0	12,905	-354,028	-376,510	-395,157	-404,850	-427,536	-474,320
Alternative B	4,752	0	0	0	36,718	-11,477	-327,463	-351,458	-364,955	-368,560	-397,838	-431,450

Electric Power Technology	Yearly Ongoing Combustion and Non-Combustion N_2O Cost (cont'd)									Downstream N_2O Cost	Total Cost (Nominal $)	NPV (2023 $)
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2057		
Alternative A	-526,122	-533,070	-541,536	-543,038	-562,657	-561,038	-580,727	-593,769	-638,127	0	**-7,499,575**	**-3,300,739**
Alternative B	-530,687	-537,601	-546,074	-547,592	-567,242	-565,691	-585,324	-598,456	-642,952	109	**-7,333,242**	**-3,187,470**

Appendix K – Cultural Resource Consultation Documentation and Cultural Resource Reports (Protected Sensitive Information Provided Under Separate Cover)

Subject: FW: Retirement of Kingston Fossil Plant and Construction of Replacement Generation, (35.8980, -84.5200), CID 81491 - Project # SHPO0001212

TENNESSEE HISTORICAL COMMISSION
STATE HISTORIC PRESERVATION OFFICE
2941 LEBANON PIKE
NASHVILLE, TENNESSEE 37243-0442
OFFICE: (615) 532-1550
www.tnhistoricalcommission.org

2023-05-04 10:17:50 CDT

James Osborne
Tennessee Valley Authority
jwosborn@tva.gov

RE: Tennessee Valley Authority (TVA), Retirement of Kingston Fossil Plant and Construction of Replacement Generation, (35.8980, -84.5200), CID 81491, Project#: SHPO0001212, Kingston, Roane, Anderson, Cumberland, Sumner, and Wilson County, TN

Dear Mr. Osborne:

Pursuant to your request, this office has reviewed documentation concerning the above-referenced undertaking. Our review of and comment on your proposed undertaking are among the requirements of Section 106 of the National Historic Preservation Act. This Act requires federal agencies or applicants for federal assistance to consult with the appropriate State Historic Preservation Office before they carry out their proposed undertakings. The Advisory Council on Historic Preservation has codified procedures for carrying out Section 106 review in 36 CFR 800 (Federal Register, December 12, 2000, 77698-77739).

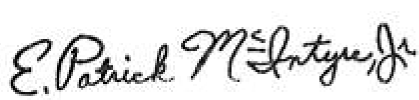
Based on the architectural survey results, we could not determine National Register eligibility for the Green Cemetery but due to the planned avoidance of the site described in your letter we concur that if it were to be determined eligible the proposed undertaking would be unlikely to adversely affect it. We would require additional information to determine whether Fredonia Baptist Church and Cemetery is eligible for listing in the National Register but based on the changed scope of the project, this property appears to be outside of the area of potential affect. The remaining properties in the architectural survey report did not appear to be eligible.

See the comments below regarding archaeological resources:

1. Concur with eligibility determinations for archaeology. No adverse effect to site 40RE45.
2. The 40RE45 testing report includes digital editorial notes from TVA to the author. The revised report should address these comments and delete them from the text.
3. The consultation letter erroneously lists site 40CU691 in two places. The correct site number is 40CU91.
4. Remove all references to sites 40RE44A, 40RE44C, and 40RE44D in both consultation letters and reports. The official site number for each of these areas is 40RE44. Additionally, the area designated as 40RE44A is not recorded as a site or within the boundary of 40RE44.
5. The testing report and your letter state that the boundary of 40RE45 was reduced. The recorded site boundary has not been reduced. The results of the testing simply defined the portions of the site that retain integrity. The letter and reports should be revised accordingly. As a portion of 40RE45 lies within the area of potential effects, our office finds that the site will be affected, but the affect will not be adverse.
6. Site record updates for previously recorded sites 40RE224, 40RE228, 40RE572, and 40RE620 must be filed with, and accepted by, the Tennessee Division of Archaeology.

This office has no objection to the implementation of this project as currently planned. If project plans are changed or previously unevaluated archaeological resources are discovered during project construction, please contact this office to determine what further action, if any, will be necessary to comply with Section 106 of the National Historic Preservation Act. Include the Project # if you need to submit any additional information regarding this undertaking. Questions and comments may be directed to Kelley Reid, who drafted this response, at Kelley.Reid@tn.gov, +16157701099. We appreciate your cooperation.

Sincerely,



E. Patrick McIntyre, Jr.
Executive Director and
State Historic Preservation Officer

Ref:MSG8192430_KHcXCZJBxAfna1AFT0NM

TVA TENNESSEE VALLEY AUTHORITY

400 West Summit Hill Drive, Knoxville, Tennessee 37902

June 15, 2023

Mr. E. Patrick McIntyre, Jr.
Executive Director
and State Historic Preservation Officer
Tennessee Historical Commission
2941 Lebanon Road
Nashville, Tennessee 37243-0442

Dear Mr. McIntyre:

TENNESSEE VALLEY AUTHORITY (TVA), RETIREMENT OF KINGSTON FOSSIL PLANT (KIF) AND CONSTRUCTION OF REPLACEMENT GENERATION, HUMPHREYS AND ROANE COUNTIES, TENNESSEE (35.8980, -84.5200) – PHASE I CULTURAL RESOURCES SURVEY AND PHASE II TESTING OF SITE 40RE45 (TVA TRACKING NUMBER – CID 81491) (SHPO0001212)

We received your May 4, 2023, response to our most recent consultation regarding the above-cited project. We thank you for your comments. These indicate the following findings:

- The National Register eligibility of the Green Cemetery cannot be determined based on available information, but you agree that the project is unlikely to adversely affect the cemetery.
- Additional information would be required to determine the National Register eligibility of Fredonia Baptist Church and Cemetery, but the resource is outside the undertaking's area of potential effects (APE).
- No additional historical architectural properties in the APE are eligible for listing in the National Register.
- Site 40RE45 is eligible for the National Register but would not be adversely affected.

After additional consideration we agree with your comments.

You also noted four problems in the phase II testing report:

- Inadvertent inclusion of digital notes from TVA to the report authors
- Erroneous listing of site 40CU691; should be 40CU91.
- Listing of sites 40RE44A, 40RE44C, and 40RE44D. You indicate these are all part of a single site, 40RE44, and that the area indicated as 40RE44A is not part of the site.
- You indicate a preference to maintain the existing site boundary for site 40RE45, despite an absence of archaeological material in the site's western area, and to find that the site would not be adversely affected by the undertaking (our letter had stated a finding of no effect to the site).

We forwarded your comments to the report authors, and they have provided a revised phase II testing report in which the errors have been corrected and the finding of No Adverse Effects to Site 40RE45 is stated. The report, prepared by HDR, is titled, *Phase II Archaeological Testing and Site Evaluation of 40RE45 for Proposed Kingston CC/Aero CT Plant Project*. A digital copy of the report is uploaded as part of this consultation package.

Please contact Steve Cole by email, sccole0@tva.gov with any additional comments.

Sincerely,

James W. Osborne, Jr.

James W. Osborne, Jr.
Manager
Cultural Compliance

SCC:ERB
Enclosures
Cc (Enclosures):

Ms. Jennifer Barnett
Tennessee Division of Archaeology
1216 Foster Avenue, Cole Bldg. #3
Nashville, Tennessee 37210

TVA TENNESSEE VALLEY AUTHORITY

400 West Summit Hill Drive, Knoxville, Tennessee 37902

November 21, 2023

Mr. E. Patrick McIntyre, Jr.
Executive Director
and State Historic Preservation Officer
Tennessee Historical Commission
2941 Lebanon Road
Nashville, Tennessee 37243-0442

Dear Mr. McIntyre:

TENNESSEE VALLEY AUTHORITY (TVA), RETIREMENT OF KINGSTON FOSSIL PLANT (KIF) AND CONSTRUCTION OF REPLACEMENT GENERATION, ANDERSON AND ROANE COUNTIES, TENNESSEE (35.8980, -84.5200 TO 35.9355, -84.2789) – ADDITIONAL PHASE I CULTURAL RESOURCES SURVEY (TVA TRACKING NUMBER – CID 81491) (SHPO PROJECT#: SHPO0001212)

We initiated consultation with your office regarding the above-cited undertaking in a letter dated November 9, 2021. In April 2023 we consulted regarding our re-determined area of potential effects (APE) and a phase I survey of areas affected by associated transmission line upgrades. More recently, we consulted with you regarding phase II testing at site 40RE45. To date our offices have agreed that no resources listed in or eligible for listing in the National Register of Historic Places (NRHP) would be adversely affected by the undertaking.

Earlier this year TVA identified additional activities, not noted in our prior correspondence, that would need to be completed as part of the undertaking. These include: 1) updates to three additional transmission line segments to facilitate connection of the proposed Combined Cycle/Aeroderivative Combustion Turbine (CC/Aero CT) power generation plant; 2) construction of a gas metering station and connecting it to an off-site gas pipeline; and 3) designation of areas on the Kingston Reservation for construction parking and laydown. Therefore, TVA is reopening consultation to propose an enlargement of the APE and discuss our identification efforts in the new APE portions.

<u>Newly proposed activities and re-determined APE</u>

1. *Transmission Line Modifications*

Three additional 161-kilovolt (kV) transmission lines (TLs) totaling 22.1 miles (Table 1) would be modified. Line L5116 is made up of two segments (01 and 02); lines L5381 and L5280 both consist of single segments.

Table 1. Affected TLs

Line No.	Line Name	Length (miles)
L5116	Kingston FP – Bethel Valley No. 2	15.95
L5381	Bethel Valley-ORNL	2.82
L5280	ORNL-Spallation Neutron Source	3.34

For all three lines TVA's work would include structure inspections, reconductoring (replacing the cables that carry power with new cable) and replacing all porcelain insulators with standard glass insulators. In addition, the work at each line or line segment would include the following activities:

L5116, Kingston FP-Bethel Valley No. 2

- Adding tower extensions and new grillage surcharge (gravel that stabilizes the tower foundations) on 12 structures
- Replacing guy wires and guy wire anchors on six structures
- Installing new guy wires and anchors on three structures
- Replacing 34 wood poles and 13 steel poles with new steel pole structures
- Installing new fiber (optical ground wire) between Structures 1 and 104

L5381, Bethel Valley-ORNL

- Replacing guy wires and guy wire anchors on two structures
- Replacing 12 existing steel poles with new steel pole structures

L5280, ORNL-Spallation Neutron Source

- Replacing all existing wood poles with steel poles -- 17 total structures to be replaced
- Installing two new intermediate structures.

The specific heights needed for the replacement poles has not yet been determined. Some would be taller than the existing poles because the purpose of some of the pole replacements is to achieve sufficient ground clearance for operation at higher temperatures, which increases line sag. Two exclusions in TVA's Section 106 Programmatic Agreement (PA) pertain to increases in the heights of transmission structures: item E.7 in Appendix A specifies replacement of wood poles that do not require "additional height greater than seven to 10 feet", and item D.2 in Appendix B specifies tower extensions "when the size of the increase is no more than 20 percent of the height of the existing structure". For purposes of this review, TVA assumed that none of the pole replacements would be consistent with these thresholds.

Line L5116, Segment 01 and L5280 were both installed more than fifty years ago (Table 2). All the structures in L5280 were replaced between 1997 and 2018 as part of TVA's regular maintenance, and the line no longer has integrity as a historic resource. Line 5116, segment 01 retains all of the original steel towers. TVA would add extensions to twelve of those.

Table 2. Dates of Construction and Composition of Each TL Segment

Line No.-Segment	Length	Structure Type(s)	Construction Date	No. of Structures	Per cent original
L5116-01	8.6	Towers	1953	41	100%
L5116-02	7.3	Wood and steel poles	2008	67	100%
L5381-01	2.8	Steel poles	2014	28	100%
L5280-01	3.3	Steel poles	1944	34	0%

Some of the upgrade work would be accomplished using light-duty equipment. The following proposed activities would be consistent with items excluded by Appendix A of TVA's Section 106 PA:

- structure inspections (E-1)
- replacing porcelain insulators with glass insulators (E-2)
- adding new grillage surcharge (E-13)
- replacing existing guy wires and anchors (E-13)

The remaining proposed activities are either types of activities that are not excluded by TVA's Section 106 PA, or would not be completed using the conditions in Appendix A. Potential effects could include both physical effects from ground disturbance and visual effects on resources outside the TL right-of-way (ROW) resulting from tower extensions. Therefore, TVA proposes that the undertaking's APE be enlarged to include the entire length of 100-foot-wide TL ROW within which the work would take place, along with the access routes that would be used to move equipment to the work structures. Portions of Lines L5280 and L5381 overlap in a 0.33-mile section of ROW. The proposed new APE portion is illustrated in Figure 1.

2. *Gas Pipeline and Metering Station*

In addition to the TL work, TVA would also connect a natural gas trunk line to the new CC/Aero CT units. This would require a directional bore underneath the Emory River and a metering station on the Kingston Reservation. The depth of the pipeline would be 3-4 feet on the dryland areas and 80 feet below the river bottom. The directional bore would result in limited ground disturbance at the insertion point, which is located in a TVA TL corridor north of the Emory River (Figure 2). This area is in the additional APE portion, which TVA included in a phase I archaeological survey (described below). Archaeological surveys on the Kingston Reservation have not identified potential for deep alluvial deposits in this part of the APE, which is an upland. The metering station would be built within an area that we previously identified as one of the alternate locations for a battery energy storage system on the Kingston Reservation. TVA has completed archaeological surveys of all areas on the Kingston Reservation, identified four archaeological sites that are eligible for the NRHP, and completed consultation under Section 106 with your office and federally recognized Indian tribes. There are no archaeological sites in or adjacent to the proposed gas metering station.

3. Construction Parking and Laydown Area

TVA has identified 14 areas on the Kingston Reservation that may be used for parking and/or laydown during construction (Figure 3). All of these areas were included in prior archaeological surveys. One parking/laydown could affect ineligible site 40RE612, and another could affect a small unnumbered site that is no longer extant. None of the parking/laydown areas would affect any of the four sites on the Kingston Reservation that our offices have agreed are eligible or potentially eligible: 40RE44, 40RE45, 40RE622, and 40RE626 (please see our letter to you dated April 4, 2023 and your response dated May 4, 2023).

Surveys

TVA contracted with HDR, Inc. for a phase I cultural resources survey to identify historic properties in this portion of the APE. The investigation included an archaeological survey (based on systematic shovel testing and pedestrian survey) in the ROW and access routes. The draft archaeological survey report, titled, *Archaeological Survey of Additional Transmission Line Upgrades, TVA's Kingston Fossil Plant Retirement Project*, has been uploaded as part of this consultation package. The investigation also included a survey of historic architectural resources within the one-half mile radius of the structures. The draft report of that survey, titled, *Historical and Architectural Survey for the Additional Transmission Line Upgrades, TVA's Kingston Fossil Plant Retirement Project* also has been uploaded.

Archaeological Resources

Three previously-recorded archaeological sites (40RE567, 40RE575, and 40RE619) are located in the new APE portion and were revisited. Site 40RE567 was recorded as a mid 20th-century house site associated with a standing structure in 2004. Since then, a gravel road has been constructed through the site boundary, which is on U.S. Department of Energy land. The current survey noted the structure is no longer present and no artifacts were identified at this location. Although the site boundary extended slightly outside the current survey area, HDR recommends the site is ineligible. Given the extent of the disturbance from road construction, there appears to be little potential for intact deposits. Therefore, TVA agrees with HDR's recommendation.

Site 40RE575 was identified in 2006 as a rural domestic site dating from 1866 to 1932, associated with a standing structure. HDR's survey established the house is no longer extant and identified no remnants of the structure or any artifacts. HDR recommends the site is ineligible. TVA finds that because more than half the site boundary is outside the current survey area, the site's NRHP eligibility status should be considered "undetermined". However, TVA also finds the project would not adversely affect the site since the portion of the site within the project footprint lacks artifacts and features and does not contribute to the site's NRHP eligibility.

Site 40RE619 was identified in 2019 as a rural domestic house site associated with a stone foundation. HDR did not identify any artifacts associated with the site in the survey area, but did observe a stone foundation outside the TVA ROW. HDR suggests that the site was slightly mis-mapped and is located outside the ROW. They recommend the site's NRHP eligibility status is undetermined, and the site would not be affected by TVA's undertaking. TVA agrees with this recommendation.

The survey also identified a previously-unrecorded archaeological site, 40RE647. This site consists of a low-density pre-contact lithic scatter unattributed to any specific time period. HDR recommends that the site is of undetermined NRHP eligibility status, but that the portion within the TVA ROW does not contribute to the site's NRHP eligibility and that therefore the proposed undertaking would not result in any adverse effects on the site. TVA agrees with this recommendation.

The survey results indicate no potential for deeply buried deposits in the portion of the APE that would be affected by the directional bore for the gas pipeline connection. As stated above, archaeological surveys on the Kingston Reservation have not identified potential for deep alluvial deposits in this part of the APE and the area where the pipeline would be buried is an upland area with relatively shallow soils. On the north side of the Emory River, where the pipeline would be within an existing transmission line corridor, soils are in one of two units: Dewey silt loam, 6 to 15 percent slopes or Dewey silt loam, 15 to 25 percent slopes. Both soil units have a typical profile with a silt loam A horizon from 0 to 9 inches and a clay Bt horizon from 9 to 72 inches (U.S. Department of Agriculture, Natural Resources Conservation Service, Web Soil Survey). Therefore, there is no potential for archaeological sites at the depths where the planned pipeline would be installed.

Table 3. Summary of Eligibility Determinations and Effect Findings for the Investigated Archaeological Sites

Site	TVA Eligibility Determination	TVA Effect Finding
40RE567	Ineligible	N/A
40RE575	Undetermined	No adverse effect
40RE619	Undetermined	No effect
40RE647	Undetermined	No adverse effect

<u>Historic Architectural Properties</u>

Segment 01 of L5116 (Kingston FP – Bethel Valley No. 2 161-kV TL) is 70 years old and physically intact. Therefore, the line meets the minimum age threshold for consideration as a potential historic property. However, this TL is not associated with any important historical persons, and so is not eligible under Criterion B. Although it is associated with the construction of KIF, KIF is ineligible for the NRHP due to loss of integrity, which in turn diminishes any integrity of association that the TL might have. Therefore, the line is not significant under Criterion A. The TL does not embody the distinctive characteristic of a type, period, or method of construction. Although the line is a good example of lattice tower type construction (Figures 4 and 5), the design and materials are those commonly used by TVA and other power companies throughout the southeastern US, from the 1940s to the present day. The materials and design lack historic significance, and TVA finds that the line is not eligible under Criterion C. Therefore, TVA has determined that L5116 is ineligible for inclusion in the NRHP.

The historic architectural survey identified and documented 47 historic-age resources in the APE, including ten that were previously inventoried. HDR recommends that 43 of these resources are ineligible for the NRHP due to a lack of historic significance and/or a loss of integrity. TVA agrees with these recommendations.

Tow of the resources are listed in the NRHP: X-10 Graphite Reactor and New Bethel Baptist Church and Cemetery. The only work with potential for visual effects in the vicinity of the X-10 Graphite Reactor would be tower extensions and adding additional gravel surcharge in L5116. HDR recommends that the undertaking would not adversely affect either of these resources. The affected structures are all at least 0.45 miles from this property, and are surrounded by other existing transmission tower structures. In addition, buildings surrounding the X-10 Graphite reactor, topography, and forest cover would also partially obscure views of the modified towers. No tower extensions would take place within 0.5 miles of the New Bethel Baptist Church and Cemetery, but four steel pole structures of the S1G type (Figure 6) in L5381, located between 0.35 and 0.49 miles to the north, would be replaced with new, somewhat taller S1G steel pole structures. HDR's field study documented that the existing steel pole structures are not visible from this property. The new poles could possibly, due to the height increase, be visible from the property, but if so visibility would be mostly obscured by the thick stand of trees growing on the adjacent hillside. In addition, the viewshed of the New Bethel Baptist Church and Cemetery has previously been diminished to some degree by a local power line supported on wood poles that passes directly behind the church and modern development along Bear Creek Road. Any visual effects on the property from TVA's undertaking would be small, especially in comparison to the effects the property has experienced from prior modern development. Therefore, TVA finds that the undertaking would not adversely any NRHP-listed resources.

HDR also recommends that two resources they were unable to access (RE-1695, ca. 1918 dwelling, and RE-1698, a cemetery originally on the same property as RE-1695) be assumed to be eligible. Both of these properties were inaccessible and could not be fully documented. TVA does not agree with this recommendation. While these properties are of sufficient age to be considered as historic properties, there is not enough information available about significance or condition to complete a NRHP assessment of either property. Therefore, TVA finds that RE-1695 and RE-1698 should be considered to be of undetermined NRHP eligibility. HDR also recommends that the proposed project would not cause adverse effects on either property, were they to be determined eligible for the NRHP. TVA agrees with this recommendation.

Conclusion
Taking into consideration the results of this identification survey for the new portions of the APE and our assessment of effects for the two NRHP-listed resources and the two resources of undetermined NRHP eligibility, TVA continues to find that the undertaking would not adversely affect any historic properties.

Should TVA modify any aspect of the undertaking's design in a manner that would require us to redetermine the APE, carry out additional identification efforts, or revise our findings of effect, we will consult further with your office.

Pursuant to 36 CFR Part 800.3(f)(2), TVA is consulting with federally recognized Indian tribes regarding historic properties within the proposed project's APE that may be of religious and cultural significance and are eligible for the NRHP.

Pursuant to 36 CFR Part 800.5(c) we are notifying you of TVA's re-determination of APE and finding of no adverse effect for the undertaking as currently described, providing the documentation specified in § 800.11, and inviting you to review the finding. Also, we are seeking your agreement with TVA's eligibility determinations and finding that the undertaking as currently planned will have no adverse effects on historic properties.

We would appreciate receiving any comments within 30 days. Please contact Steve Cole by email, sccole0@tva.gov with your comments.

Sincerely,

James W. Osborne, Jr.
Manager
Cultural Compliance

SCC:ERB
Enclosures:
Cc (Enclosures):
Ms. Jennifer Barnett
Tennessee Division of Archaeology
1216 Foster Avenue, Cole Bldg. #3
Nashville, Tennessee 37210

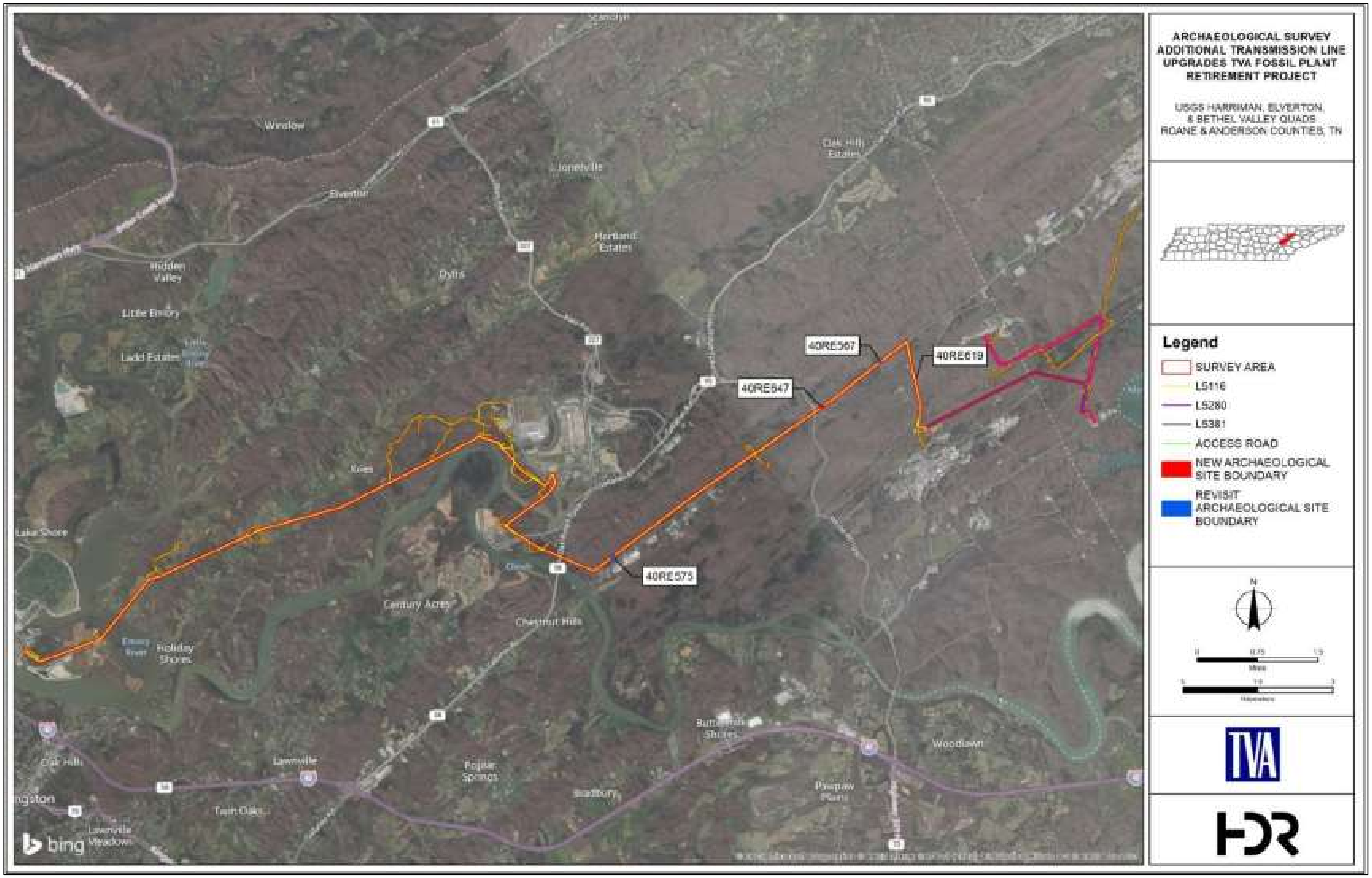


Figure 1. Location of the new portion of the APE, with archaeological sites investigated in the survey. Map prepared by HDR. The Kingston Reservation is at the far western end of this portion of the APE.

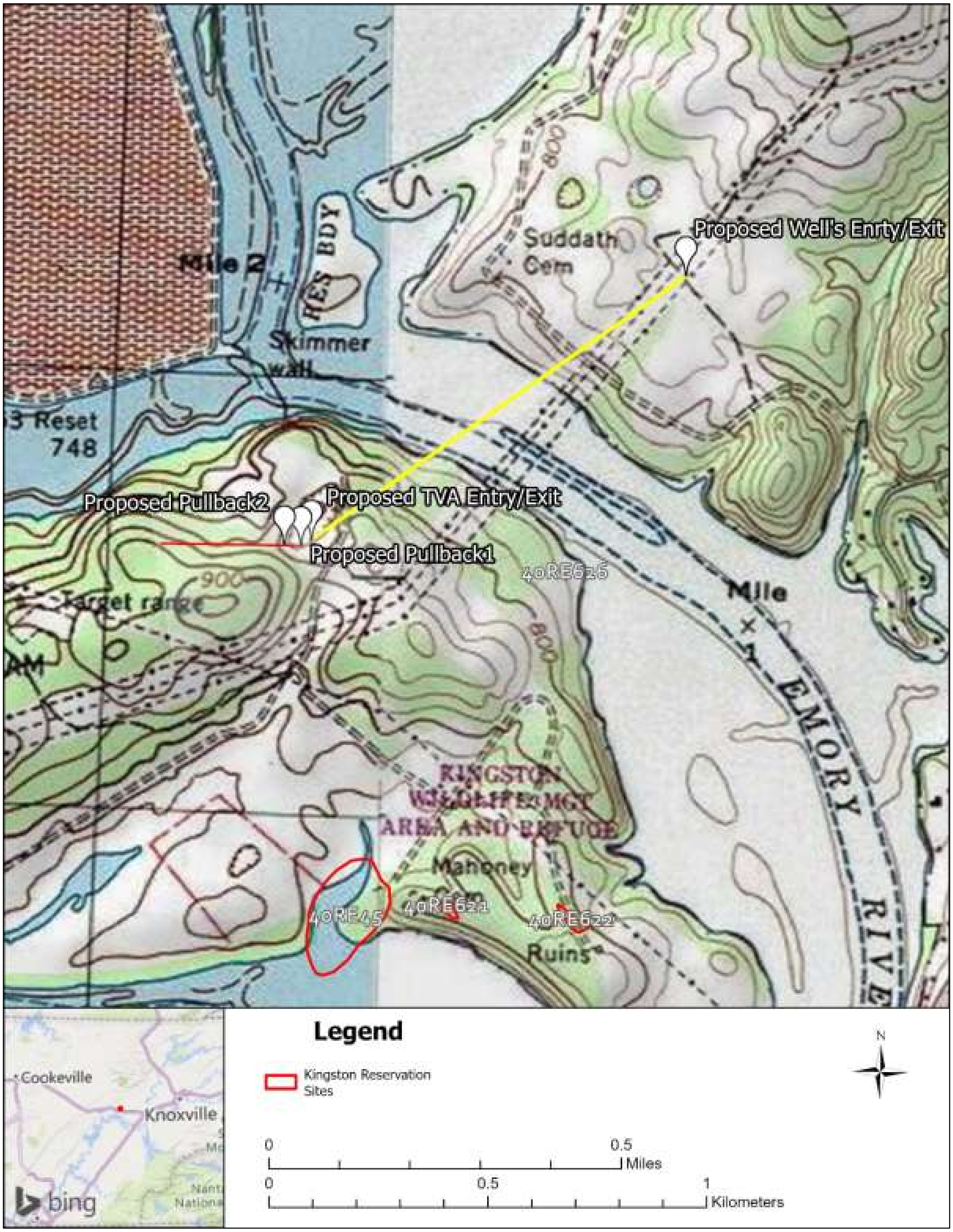


Figure 2. Proposed location for gas pipeline connection (yellow line) and metering station (at "Proposed TVA Entry/Exit"), with eligible and potentially eligible archaeological sites and the Green/Mahoney Cemetery (40RE621).

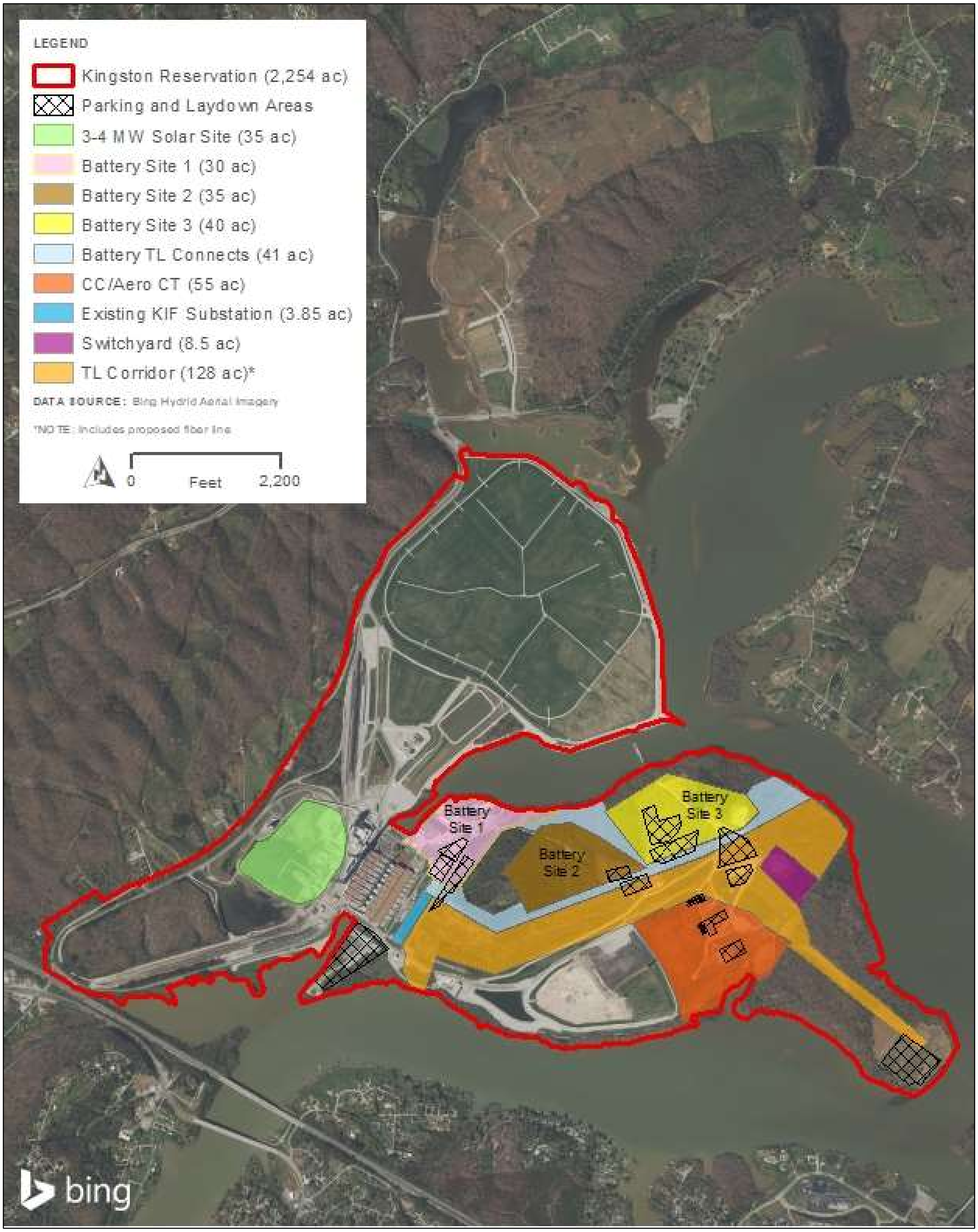


Figure 3. Proposed parking and/or laydown areas (hatching).

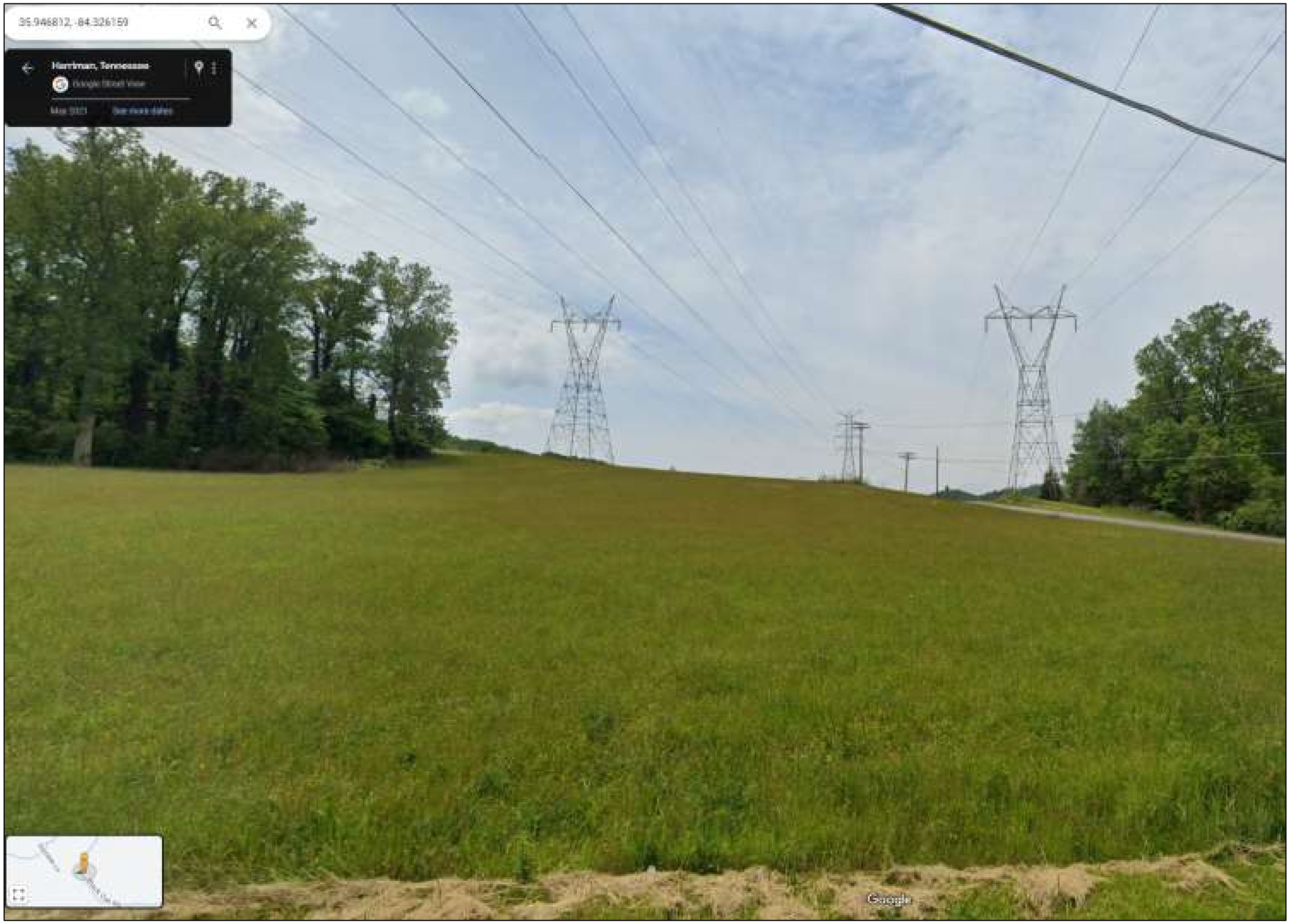


Figure 4. View east along the TVA ROW that contains three existing 161-kV transmission lines, from Google Street View (vantage point from Black Oak Road, between Kingston and Oak Ridge). The lines are, from right to left: L5108, built 1953; L5786, built 1955 (tall structure in far distance); and L5116, built 1953. Of these three lines only L5116 would be affected by the undertaking.

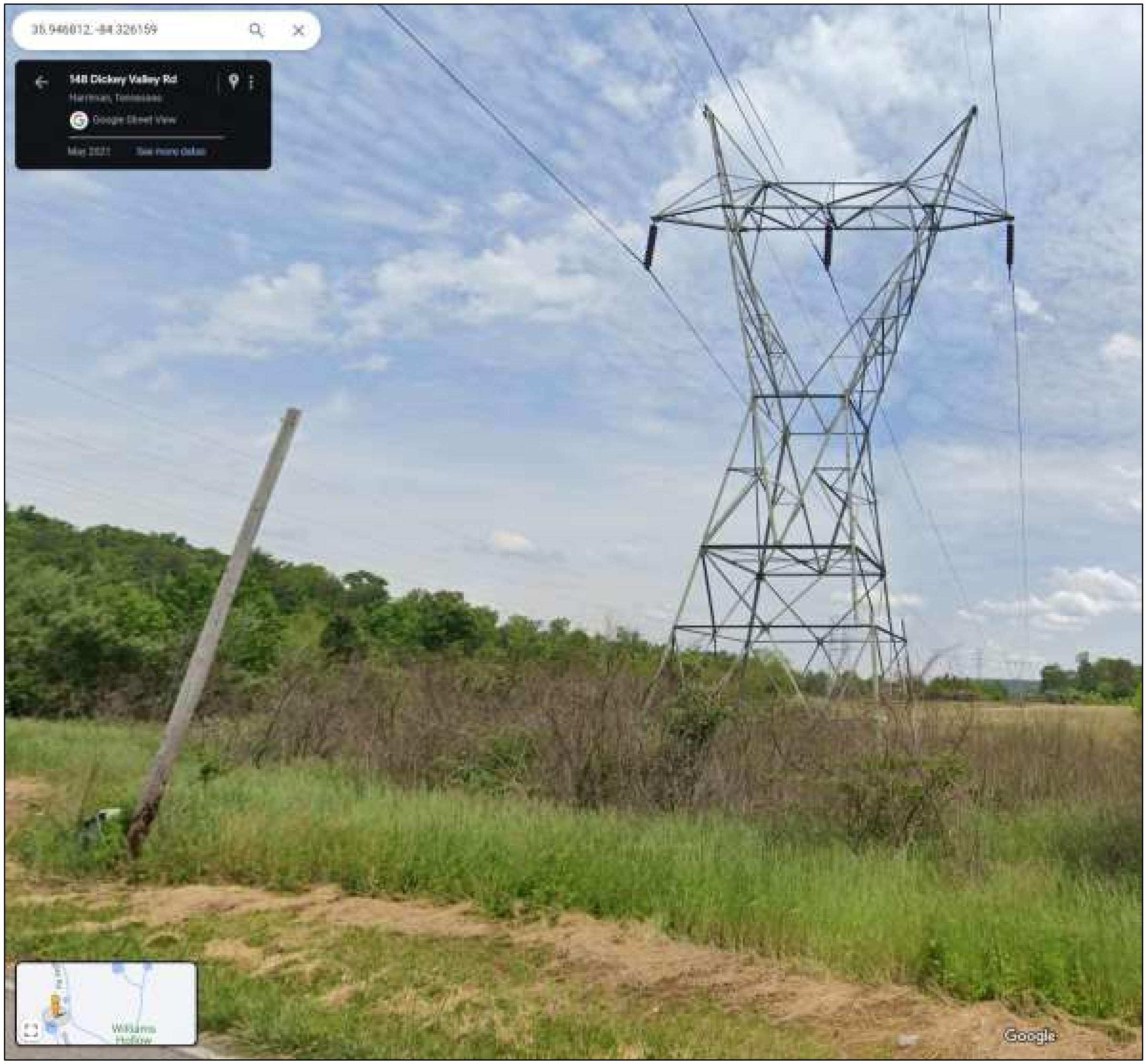


Figure 5. View of a structure in L5116 from a vantage point along Dickey Valley Road; from Google Street View.

Figure 6. A typical example of the S1G type of steel pole structure (not from the current APE).

Huddleston, Misty

From: TN Help <tnhelp@service-now.com>
Sent: Tuesday, November 28, 2023 2:22 PM
To: Beliles, Emily
Cc: Osborne, James W Jr; Cole, Steve C
Subject: Retirement of Kingston Fossil Plant and Construction of Replacement Generation, (35.8980, -84.5200), CID 81491 - Project # SHPO0001212

TENNESSEE HISTORICAL COMMISSION
STATE HISTORIC PRESERVATION OFFICE
2941 LEBANON PIKE
NASHVILLE, TENNESSEE 37243-0442
OFFICE: (615) 532-1550
www.tnhistoricalcommission.org

11-28-2023 13:19:00 CST

James Osborne
TVA

RE: Tennessee Valley Authority (TVA), Retirement of Kingston Fossil Plant and Construction of Replacement Generation, (35.8980, -84.5200), CID 81491, Project#: SHPO0001212, , Roane County, TN

Dear James Osborne:

Pursuant to your request, this office has reviewed documentation concerning the above-referenced undertaking. Our review of and comment on your proposed undertaking are among the requirements of Section 106 of the National Historic Preservation Act. This Act requires federal agencies or applicants for federal assistance to consult with the appropriate State Historic Preservation Office before they carry out their proposed undertakings. The Advisory Council on Historic Preservation has codified procedures for carrying out Section 106 review in 36 CFR 800 (Federal Register, December 12, 2000, 77698-77739).

Based on the information provided, we concur that the project area contains cultural resources eligible for listing in the National Register of Historic Places. We further concur that the project as currently proposed will not adversely affect these historic properties.

This office has no objection to the implementation of this project as currently planned. If project plans are changed or previously unevaluated archaeological resources are discovered during project construction, please contact this office to determine what further action, if any, will be necessary to comply with Section 106 of the National Historic Preservation Act. Include the Project # if you need to submit any additional information regarding this undertaking. Questions and comments may be directed to Jennifer Barnett, who drafted this response, at Jennifer.Barnett@tn.gov, +16156874780. We appreciate your cooperation.

Sincerely,

E. Patrick McIntyre, Jr.
Executive Director and
State Historic Preservation Officer

Ref:MSG11085793_yJHAvt3MbSXFcaI2dqG

TVA TENNESSEE VALLEY AUTHORITY

400 West Summit Hill Drive, Knoxville, Tennessee 37902

November 21, 2023

Mr. E. Patrick McIntyre, Jr.
Executive Director
and State Historic Preservation Officer
Tennessee Historical Commission
2941 Lebanon Road
Nashville, Tennessee 37243-0442

Dear Mr. McIntyre:

TENNESSEE VALLEY AUTHORITY (TVA), RETIREMENT OF KINGSTON FOSSIL PLANT (KIF) AND CONSTRUCTION OF REPLACEMENT GENERATION, ANDERSON AND ROANE COUNTIES, TENNESSEE (35.8980, -84.5200 TO 35.9355, -84.2789) – ADDITIONAL PHASE I CULTURAL RESOURCES SURVEY (TVA TRACKING NUMBER – CID 81491) (SHPO PROJECT#: SHPO0001212)

We initiated consultation with your office regarding the above-cited undertaking in a letter dated November 9, 2021. In April 2023 we consulted regarding our re-determined area of potential effects (APE) and a phase I survey of areas affected by associated transmission line upgrades. More recently, we consulted with you regarding phase II testing at site 40RE45. To date our offices have agreed that no resources listed in or eligible for listing in the National Register of Historic Places (NRHP) would be adversely affected by the undertaking.

Earlier this year TVA identified additional activities, not noted in our prior correspondence, that would need to be completed as part of the undertaking. These include: 1) updates to three additional transmission line segments to facilitate connection of the proposed Combined Cycle/Aeroderivative Combustion Turbine (CC/Aero CT) power generation plant; 2) construction of a gas metering station and connecting it to an off-site gas pipeline; and 3) designation of areas on the Kingston Reservation for construction parking and laydown. Therefore, TVA is reopening consultation to propose an enlargement of the APE and discuss our identification efforts in the new APE portions.

Newly proposed activities and re-determined APE

1. *Transmission Line Modifications*

Three additional 161-kilovolt (kV) transmission lines (TLs) totaling 22.1 miles (Table 1) would be modified. Line L5116 is made up of two segments (01 and 02); lines L5381 and L5280 both consist of single segments.

Table 1. Affected TLs

Line No.	Line Name	Length (miles)
L5116	Kingston FP – Bethel Valley No. 2	15.95
L5381	Bethel Valley-ORNL	2.82
L5280	ORNL-Spallation Neutron Source	3.34

For all three lines TVA's work would include structure inspections, reconductoring (replacing the cables that carry power with new cable) and replacing all porcelain insulators with standard glass insulators. In addition, the work at each line or line segment would include the following activities:

L5116, Kingston FP-Bethel Valley No. 2

- Adding tower extensions and new grillage surcharge (gravel that stabilizes the tower foundations) on 12 structures
- Replacing guy wires and guy wire anchors on six structures
- Installing new guy wires and anchors on three structures
- Replacing 34 wood poles and 13 steel poles with new steel pole structures
- Installing new fiber (optical ground wire) between Structures 1 and 104

L5381, Bethel Valley-ORNL

- Replacing guy wires and guy wire anchors on two structures
- Replacing 12 existing steel poles with new steel pole structures

L5280, ORNL-Spallation Neutron Source

- Replacing all existing wood poles with steel poles -- 17 total structures to be replaced
- Installing two new intermediate structures.

The specific heights needed for the replacement poles has not yet been determined. Some would be taller than the existing poles because the purpose of some of the pole replacements is to achieve sufficient ground clearance for operation at higher temperatures, which increases line sag. Two exclusions in TVA's Section 106 Programmatic Agreement (PA) pertain to increases in the heights of transmission structures: item E.7 in Appendix A specifies replacement of wood poles that do not require "additional height greater than seven to 10 feet", and item D.2 in Appendix B specifies tower extensions "when the size of the increase is no more than 20 percent of the height of the existing structure". For purposes of this review, TVA assumed that none of the pole replacements would be consistent with these thresholds.

Line L5116, Segment 01 and L5280 were both installed more than fifty years ago (Table 2). All the structures in L5280 were replaced between 1997 and 2018 as part of TVA's regular maintenance, and the line no longer has integrity as a historic resource. Line 5116, segment 01 retains all of the original steel towers. TVA would add extensions to twelve of those.

Table 2. Dates of Construction and Composition of Each TL Segment

Line No.-Segment	Length	Structure Type(s)	Construction Date	No. of Structures	Per cent original
L5116-01	8.6	Towers	1953	41	100%
L5116-02	7.3	Wood and steel poles	2008	67	100%
L5381-01	2.8	Steel poles	2014	28	100%
L5280-01	3.3	Steel poles	1944	34	0%

Some of the upgrade work would be accomplished using light-duty equipment. The following proposed activities would be consistent with items excluded by Appendix A of TVA's Section 106 PA:

- structure inspections (E-1)
- replacing porcelain insulators with glass insulators (E-2)
- adding new grillage surcharge (E-13)
- replacing existing guy wires and anchors (E-13)

The remaining proposed activities are either types of activities that are not excluded by TVA's Section 106 PA, or would not be completed using the conditions in Appendix A. Potential effects could include both physical effects from ground disturbance and visual effects on resources outside the TL right-of-way (ROW) resulting from tower extensions. Therefore, TVA proposes that the undertaking's APE be enlarged to include the entire length of 100-foot-wide TL ROW within which the work would take place, along with the access routes that would be used to move equipment to the work structures. Portions of Lines L5280 and L5381 overlap in a 0.33-mile section of ROW. The proposed new APE portion is illustrated in Figure 1.

2. *Gas Pipeline and Metering Station*

In addition to the TL work, TVA would also connect a natural gas trunk line to the new CC/Aero CT units. This would require a directional bore underneath the Emory River and a metering station on the Kingston Reservation. The depth of the pipeline would be 3-4 feet on the dryland areas and 80 feet below the river bottom. The directional bore would result in limited ground disturbance at the insertion point, which is located in a TVA TL corridor north of the Emory River (Figure 2). This area is in the additional APE portion, which TVA included in a phase I archaeological survey (described below). Archaeological surveys on the Kingston Reservation have not identified potential for deep alluvial deposits in this part of the APE, which is an upland. The metering station would be built within an area that we previously identified as one of the alternate locations for a battery energy storage system on the Kingston Reservation. TVA has completed archaeological surveys of all areas on the Kingston Reservation, identified four archaeological sites that are eligible for the NRHP, and completed consultation under Section 106 with your office and federally recognized Indian tribes. There are no archaeological sites in or adjacent to the proposed gas metering station.

3. Construction Parking and Laydown Area

TVA has identified 14 areas on the Kingston Reservation that may be used for parking and/or laydown during construction (Figure 3). All of these areas were included in prior archaeological surveys. One parking/laydown could affect ineligible site 40RE612, and another could affect a small unnumbered site that is no longer extant. None of the parking/laydown areas would affect any of the four sites on the Kingston Reservation that our offices have agreed are eligible or potentially eligible: 40RE44, 40RE45, 40RE622, and 40RE626 (please see our letter to you dated April 4, 2023 and your response dated May 4, 2023).

Surveys

TVA contracted with HDR, Inc. for a phase I cultural resources survey to identify historic properties in this portion of the APE. The investigation included an archaeological survey (based on systematic shovel testing and pedestrian survey) in the ROW and access routes. The draft archaeological survey report, titled, *Archaeological Survey of Additional Transmission Line Upgrades, TVA's Kingston Fossil Plant Retirement Project*, has been uploaded as part of this consultation package. The investigation also included a survey of historic architectural resources within the one-half mile radius of the structures. The draft report of that survey, titled, *Historical and Architectural Survey for the Additional Transmission Line Upgrades, TVA's Kingston Fossil Plant Retirement Project* also has been uploaded.

Archaeological Resources

Three previously-recorded archaeological sites (40RE567, 40RE575, and 40RE619) are located in the new APE portion and were revisited. Site 40RE567 was recorded as a mid 20th-century house site associated with a standing structure in 2004. Since then, a gravel road has been constructed through the site boundary, which is on U.S. Department of Energy land. The current survey noted the structure is no longer present and no artifacts were identified at this location. Although the site boundary extended slightly outside the current survey area, HDR recommends the site is ineligible. Given the extent of the disturbance from road construction, there appears to be little potential for intact deposits. Therefore, TVA agrees with HDR's recommendation.

Site 40RE575 was identified in 2006 as a rural domestic site dating from 1866 to 1932, associated with a standing structure. HDR's survey established the house is no longer extant and identified no remnants of the structure or any artifacts. HDR recommends the site is ineligible. TVA finds that because more than half the site boundary is outside the current survey area, the site's NRHP eligibility status should be considered "undetermined". However, TVA also finds the project would not adversely affect the site since the portion of the site within the project footprint lacks artifacts and features and does not contribute to the site's NRHP eligibility.

Site 40RE619 was identified in 2019 as a rural domestic house site associated with a stone foundation. HDR did not identify any artifacts associated with the site in the survey area, but did observe a stone foundation outside the TVA ROW. HDR suggests that the site was slightly mis-mapped and is located outside the ROW. They recommend the site's NRHP eligibility status is undetermined, and the site would not be affected by TVA's undertaking. TVA agrees with this recommendation.

The survey also identified a previously-unrecorded archaeological site, 40RE647. This site consists of a low-density pre-contact lithic scatter unattributed to any specific time period. HDR recommends that the site is of undetermined NRHP eligibility status, but that the portion within the TVA ROW does not contribute to the site's NRHP eligibility and that therefore the proposed undertaking would not result in any adverse effects on the site. TVA agrees with this recommendation.

The survey results indicate no potential for deeply buried deposits in the portion of the APE that would be affected by the directional bore for the gas pipeline connection. As stated above, archaeological surveys on the Kingston Reservation have not identified potential for deep alluvial deposits in this part of the APE and the area where the pipeline would be buried is an upland area with relatively shallow soils. On the north side of the Emory River, where the pipeline would be within an existing transmission line corridor, soils are in one of two units: Dewey silt loam, 6 to 15 percent slopes or Dewey silt loam, 15 to 25 percent slopes. Both soil units have a typical profile with a silt loam A horizon from 0 to 9 inches and a clay Bt horizon from 9 to 72 inches (U.S. Department of Agriculture, Natural Resources Conservation Service, Web Soil Survey). Therefore, there is no potential for archaeological sites at the depths where the planned pipeline would be installed.

Table 3. Summary of Eligibility Determinations and Effect Findings for the Investigated Archaeological Sites

Site	TVA Eligibility Determination	TVA Effect Finding
40RE567	Ineligible	N/A
40RE575	Undetermined	No adverse effect
40RE619	Undetermined	No effect
40RE647	Undetermined	No adverse effect

Historic Architectural Properties

Segment 01 of L5116 (Kingston FP – Bethel Valley No. 2 161-kV TL) is 70 years old and physically intact. Therefore, the line meets the minimum age threshold for consideration as a potential historic property. However, this TL is not associated with any important historical persons, and so is not eligible under Criterion B. Although it is associated with the construction of KIF, KIF is ineligible for the NRHP due to loss of integrity, which in turn diminishes any integrity of association that the TL might have. Therefore, the line is not significant under Criterion A. The TL does not embody the distinctive characteristic of a type, period, or method of construction. Although the line is a good example of lattice tower type construction (Figures 4 and 5), the design and materials are those commonly used by TVA and other power companies throughout the southeastern US, from the 1940s to the present day. The materials and design lack historic significance, and TVA finds that the line is not eligible under Criterion C. Therefore, TVA has determined that L5116 is ineligible for inclusion in the NRHP.

The historic architectural survey identified and documented 47 historic-age resources in the APE, including ten that were previously inventoried. HDR recommends that 43 of these resources are ineligible for the NRHP due to a lack of historic significance and/or a loss of integrity. TVA agrees with these recommendations.

Tow of the resources are listed in the NRHP: X-10 Graphite Reactor and New Bethel Baptist Church and Cemetery. The only work with potential for visual effects in the vicinity of the X-10 Graphite Reactor would be tower extensions and adding additional gravel surcharge in L5116. HDR recommends that the undertaking would not adversely affect either of these resources. The affected structures are all at least 0.45 miles from this property, and are surrounded by other existing transmission tower structures. In addition, buildings surrounding the X-10 Graphite reactor, topography, and forest cover would also partially obscure views of the modified towers. No tower extensions would take place within 0.5 miles of the New Bethel Baptist Church and Cemetery, but four steel pole structures of the S1G type (Figure 6) in L5381, located between 0.35 and 0.49 miles to the north, would be replaced with new, somewhat taller S1G steel pole structures. HDR's field study documented that the existing steel pole structures are not visible from this property. The new poles could possibly, due to the height increase, be visible from the property, but if so visibility would be mostly obscured by the thick stand of trees growing on the adjacent hillside. In addition, the viewshed of the New Bethel Baptist Church and Cemetery has previously been diminished to some degree by a local power line supported on wood poles that passes directly behind the church and modern development along Bear Creek Road. Any visual effects on the property from TVA's undertaking would be small, especially in comparison to the effects the property has experienced from prior modern development. Therefore, TVA finds that the undertaking would not adversely any NRHP-listed resources.

HDR also recommends that two resources they were unable to access (RE-1695, ca. 1918 dwelling, and RE-1698, a cemetery originally on the same property as RE-1695) be assumed to be eligible. Both of these properties were inaccessible and could not be fully documented. TVA does not agree with this recommendation. While these properties are of sufficient age to be considered as historic properties, there is not enough information available about significance or condition to complete a NRHP assessment of either property. Therefore, TVA finds that RE-1695 and RE-1698 should be considered to be of undetermined NRHP eligibility. HDR also recommends that the proposed project would not cause adverse effects on either property, were they to be determined eligible for the NRHP. TVA agrees with this recommendation.

Conclusion

Taking into consideration the results of this identification survey for the new portions of the APE and our assessment of effects for the two NRHP-listed resources and the two resources of undetermined NRHP eligibility, TVA continues to find that the undertaking would not adversely affect any historic properties.

Should TVA modify any aspect of the undertaking's design in a manner that would require us to redetermine the APE, carry out additional identification efforts, or revise our findings of effect, we will consult further with your office.

Pursuant to 36 CFR Part 800.3(f)(2), TVA is consulting with federally recognized Indian tribes regarding historic properties within the proposed project's APE that may be of religious and cultural significance and are eligible for the NRHP.

Pursuant to 36 CFR Part 800.5(c) we are notifying you of TVA's re-determination of APE and finding of no adverse effect for the undertaking as currently described, providing the documentation specified in § 800.11, and inviting you to review the finding. Also, we are seeking your agreement with TVA's eligibility determinations and finding that the undertaking as currently planned will have no adverse effects on historic properties.

We would appreciate receiving any comments within 30 days. Please contact Steve Cole by email, sccole0@tva.gov with your comments.

Sincerely,

James W. Osborne, Jr.
Manager
Cultural Compliance

SCC:ERB
Enclosures:
Cc (Enclosures):

Ms. Jennifer Barnett
Tennessee Division of Archaeology
1216 Foster Avenue, Cole Bldg. #3
Nashville, Tennessee 37210

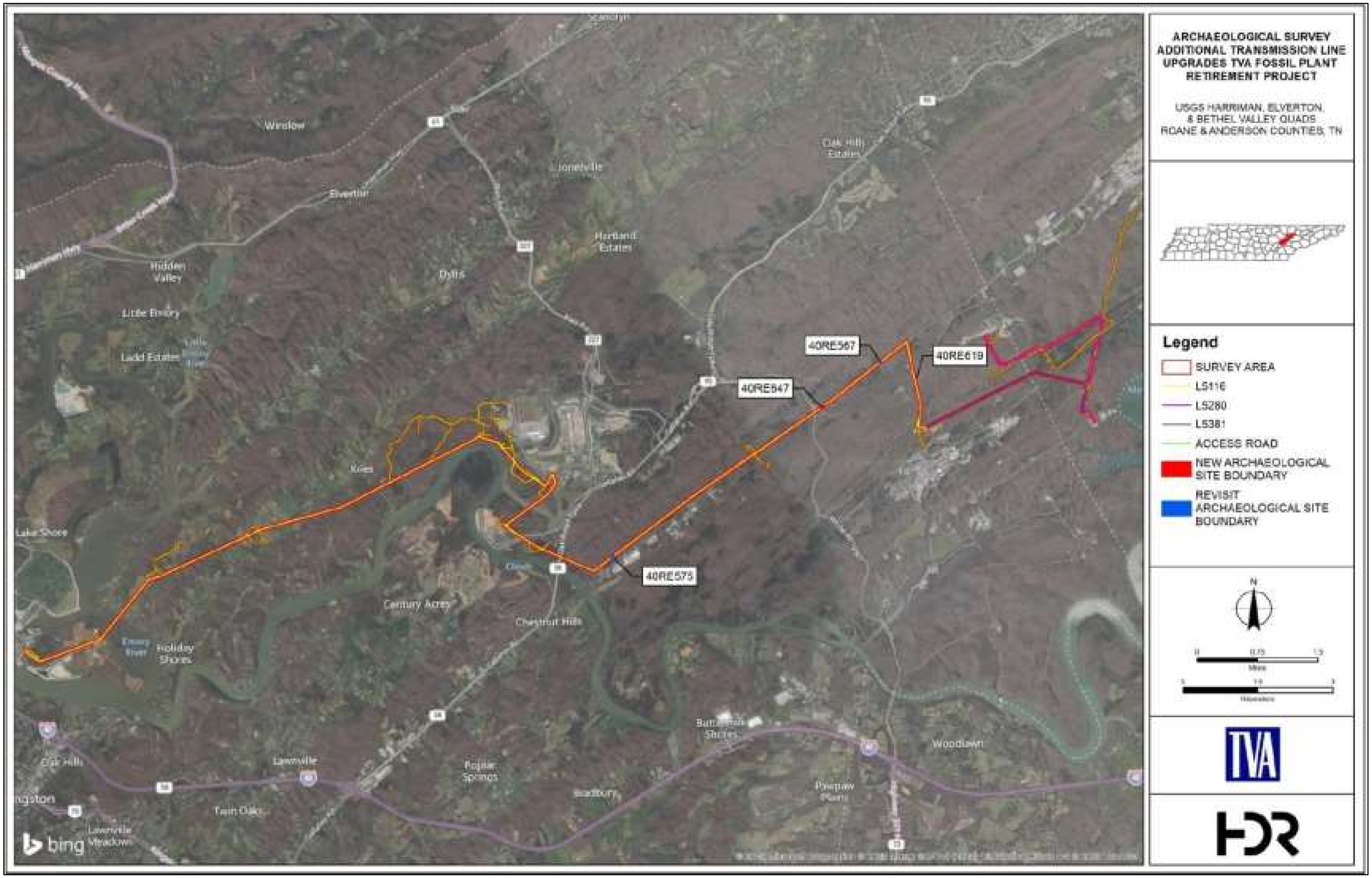


Figure 1. Location of the new portion of the APE, with archaeological sites investigated in the survey. Map prepared by HDR. The Kingston Reservation is at the far western end of this portion of the APE.

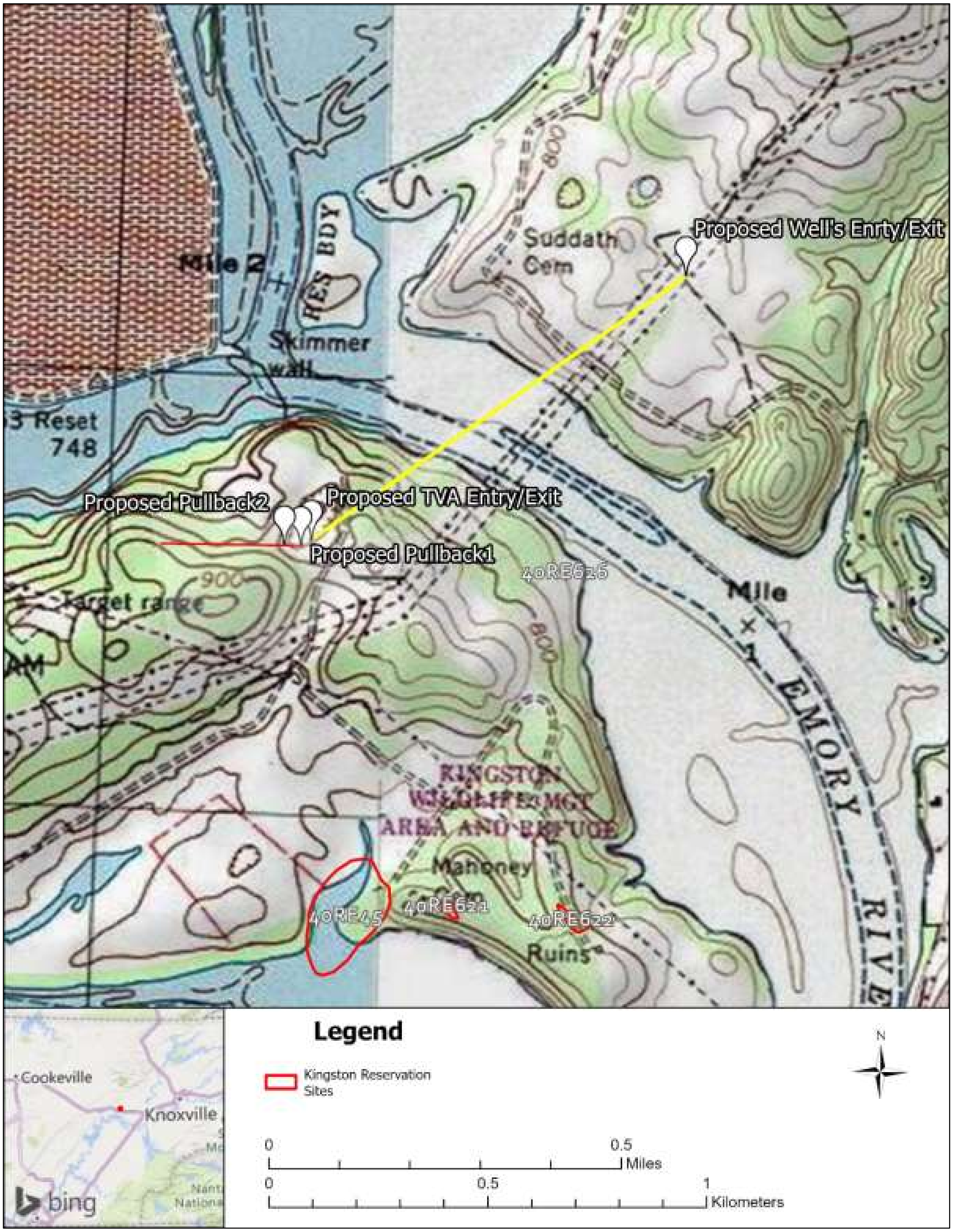


Figure 2. Proposed location for gas pipeline connection (yellow line) and metering station (at "Proposed TVA Entry/Exit"), with eligible and potentially eligible archaeological sites and the Green/Mahoney Cemetery (40RE621).

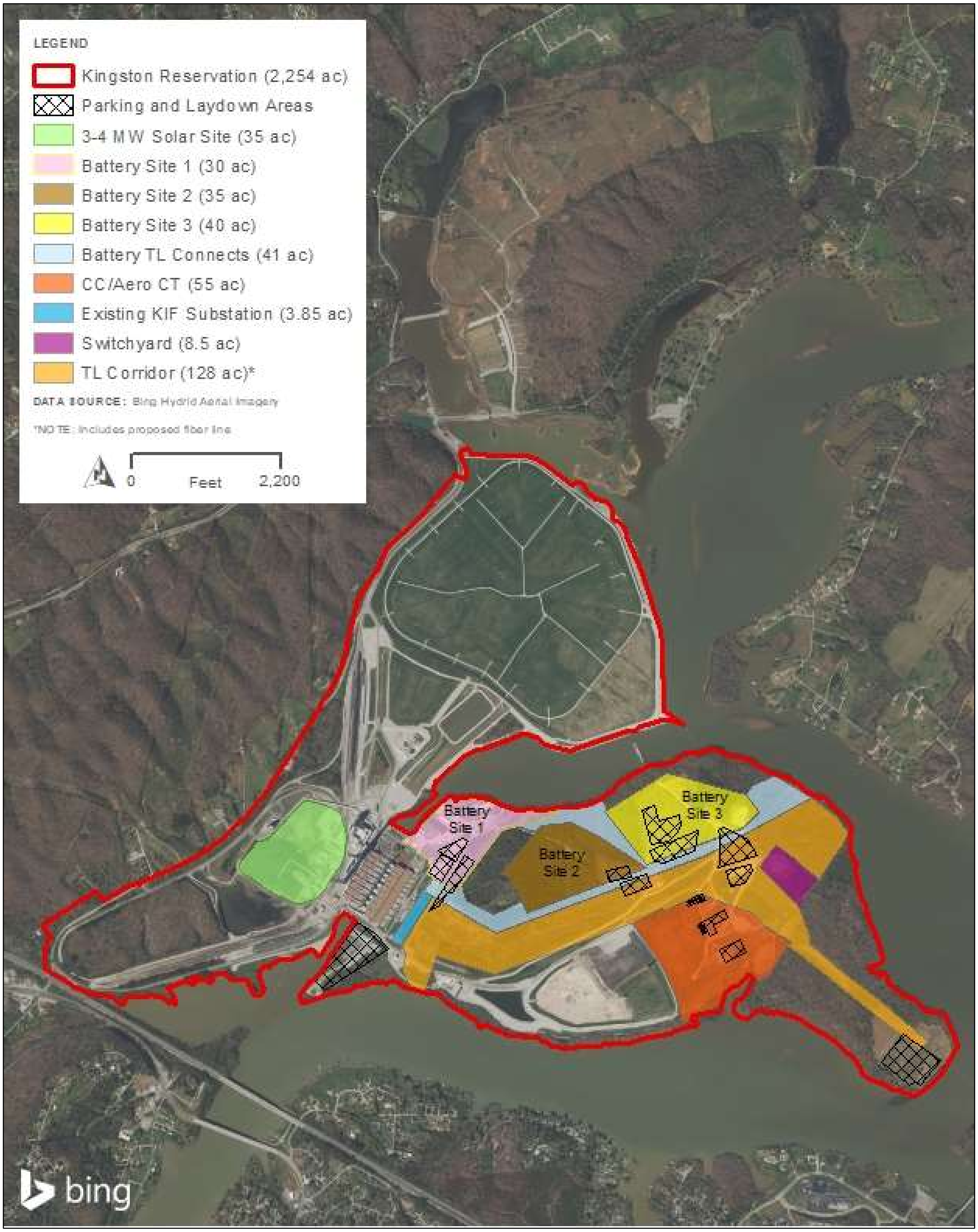


Figure 3. Proposed parking and/or laydown areas (hatching).

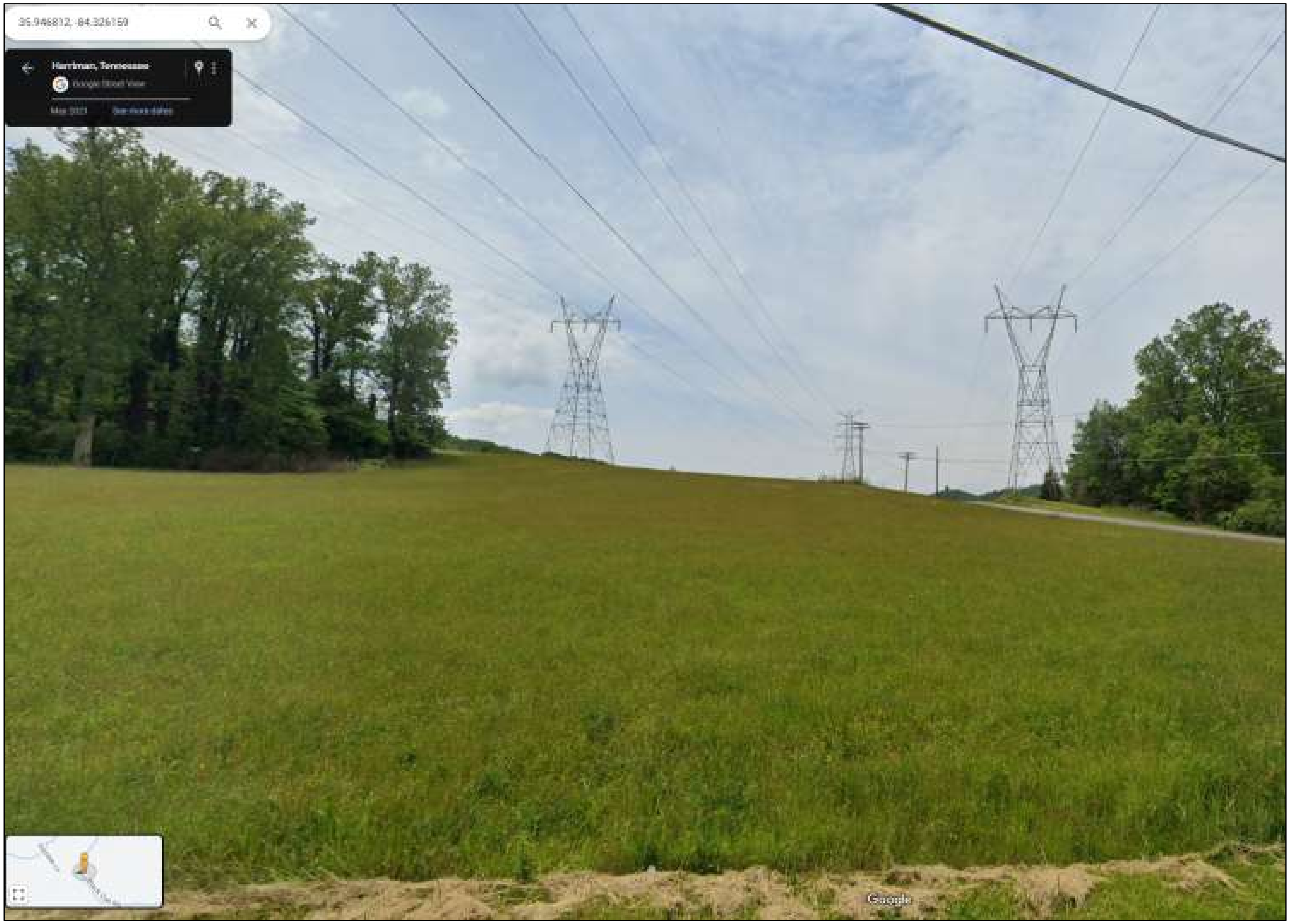


Figure 4. View east along the TVA ROW that contains three existing 161-kV transmission lines, from Google Street View (vantage point from Black Oak Road, between Kingston and Oak Ridge). The lines are, from right to left: L5108, built 1953; L5786, built 1955 (tall structure in far distance); and L5116, built 1953. Of these three lines only L5116 would be affected by the undertaking.

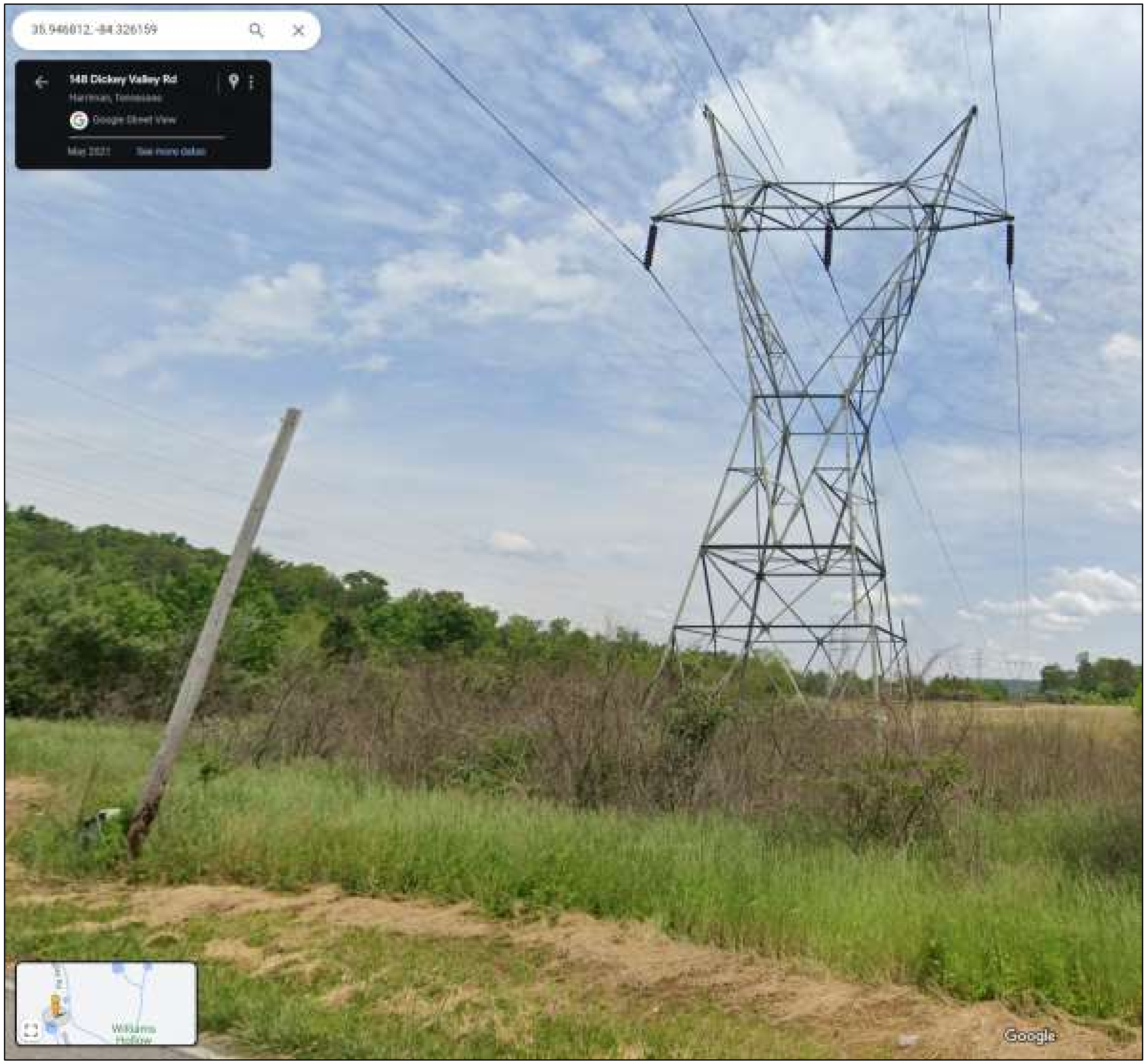


Figure 5. View of a structure in L5116 from a vantage point along Dickey Valley Road; from Google Street View.

Figure 6. A typical example of the S1G type of steel pole structure (not from the current APE).

Appendix L – Cooperating Agency Comments during EIS Development

This document incorporates comments received from cooperating agencies, the U.S. Environmental Protection Agency (USEPA) and the National Park Service (NPS) in response to their review of the draft Environmental Impact Statement (DEIS) and presents TVA’s responses to those comments. The tables below incorporate comments submitted via letter to TVA and those comments provided in the tracked change version of the Draft EIS submitted to USEPA and NPS for review. Comments submitted and TVA's responses to those comments are summarized for USEPA comments in Table L1.1 and Table L1.2, and for NPS comments in TableL1.3.

Table L1.1. Response to USEPA Comments on the Draft EIS Document

Section	Commentor	Comment	Comment Resolution/Updates to the Document
3.7	USEPA	Recommend deleting this sentence, as it is not a relevant comparison. SF6 has 26000 times the global warming potential of CO2, and SF6 has a lifespan of over 3000 years. Hence, even very small amounts of SF6 contribute to climate change and most of the SF6 produced will eventually contribute. Irrespective of the relatively small onsite leaks, the lifecycle of SF6 starting from manufacturing, is what produces significant SF6 emissions. Hence, EPA has partnered with utilities to reduce and phase out the use of this pollutant, as have other countries. Given that the life of a switchgear is over 30 years – EPA suggests that TVA's upgrade of its system and installation of new switchgears represents the ideal time to switch to SF6-free switchgears, which would represent reasonable mitigation, and prevent over 30 years of production of additional SF6 for the TVA system. In addition, the SF6 free switchgears are reported to have lower operation and maintenance costs and higher reliability. EPA would be happy to connect TVA with further resources on SF6 free switchgears.	Sentence has been deleted from the DEIS.
3.7.1.1.6	USEPA	DEIS should include any applicable General Conformity analysis in the DEIS or provide an explanation of why the analysis is not required.	Additional language added: General Conformity is discussed further in Section 3.7.2.3.1.2.
3.7.1.1.8.3	USEPA	Consistent with the January 9, 2023, CEQ interim GHG guidance, EPA recommends that TVA avoid representing GHG emissions as a small fraction of global or domestic emissions, "because this approach does not reveal anything beyond the nature of the climate change challenge itself—the fact that diverse individual sources of emissions each make a relatively small addition to global atmospheric GHG concentrations that collectively have a large effect." https://www.federalregister.gov/documents/2023/01/09/2023-00158/national-environmental-policy-act-guidance-on-consideration-of-greenhouse-gas-emissions-and-climate	The DEIS has been updated to clarify that a geographic emissions analysis methodology was employed to illustrate the contribution of Kingston emissions to local, regional, and national GHG emissions and by comparing the anticipated contributions under Action Alternatives A and B.
3.7.2.3.1.2	USEPA	EPA recommends revising this statement to more accurately disclose that the BACT requirements would only be applicable to CO in this case. It could be inferred that the facility would be required to apply BACT for all pollutants/equipment.	TVA expects to net out of BACT review for all pollutants except CO. The emissions of CO would be reduced through the use of Catalytic Oxidation (CATOX) emission control system. TVA is currently in discussions with the equipment vendor to see if CO emissions from the CATOX system can be further reduced so that KIF may "net out" of PSD review.

Table L1.1. Response to EPA Comments on the Draft EIS Document

Section	Commentor	Comment	Comment Resolution/Updates to the Document
3.7.2.3.1.2	USEPA	EPA recommends deleting or revising this statement, as in this context it is misleading given that the facility, under the preferred alternative, appears to net out of PSD for all pollutants but CO, and because the emissions from the preferred Alternative A are significant. Netting out of PSD review, for a grandfathered coal-fired facility of this size, does not ensure that air quality effects of the preferred alternative are not significant. Emissions of PM10, NOx, CO, VOC and CO2 are all above the PSD significance thresholds and would require modelling and BACT if the facility was a greenfield source and TVA was not shutting down a coal-fired plant that was never required to go through PSD. EPA recommends that the above be more clearly disclosed in DEIS.	See immediately preceding response to EPA's comments on this section. TVA has revised the language to state that ..."impacts will not exceed the NAAQS" as will be demonstrated through the permitting process and by meeting the requirements and limitations of the air permit issued by the permitting agency for the construction of the replacement generation. There will be a net reduction in emissions of all criteria pollutants compared to the existing coal plant operations, which is an air quality benefit. The net reduction in emissions is an appropriate measure for assessing air quality since TVA's proposed action is to retire and replace generation of the existing coal-fired plant.
3.7.2.3.1.2	USEPA	It is unclear why TVA is using industry average capacity factors for emissions calculations, rather than TVA system forecasts for TVA Kingston under the proposed alternatives. 55% and 10% seem low given that these will be new state of the art CC and CT that TVA has indicated would displace older less efficient capacity elsewhere in the system and are needed for growth in the immediate region. The assumed low-capacity factors would seem to support that TVA could use natural gas capacity elsewhere in the system, such as Gallatin or Johnsonville, in the near term to allow time for long distance transmission grid updates (needed for renewables) and avoid the need for investment in and associated impact of a new 122 mile NG pipeline.	Since the individual GHG LCA evaluates each individual replacement resource option, it uses industry average capacity factors. The TVA system-wide LCA provides a more thorough and accurate view of overall GHG effects when comparing each alternative as it is based on simulated system-wide generation dispatch. It provides critical context into how the specific resource retirements and replacements, underpinning the assumptions of each of the Proposed Action Alternatives, integrate into the system overall. The system-wide comparison of emissions is the most effective way to accurately identify incremental emission differences between the alternatives because it illustrates how the entire TVA system is expected to operate with each alternative. Other sites that had existing gas were evaluated, including Gallatin and New Johnsonville, but were later dismissed from consideration due to several factors including the need for grid stability in the KIF area, the transmission upgrades or new construction that would be required, and additional environmental factors. Please see Sections 2.1.4, 2.1 and response to Comment 2 below for additional information.

Table L1.2. Response to USEPA Comments Submitted by Letter

Comment Number	USEPA Recommendations	TVA Response
1	The EPA is concerned that the Draft EIS does not adequately explain why an alternative was not preserved that allows for the transitional and peaking capacity that TVA requires to bridge to renewable energy and that does not require the construction of a new 122-mile pipeline. Given the capacity of the TVA system, it is unclear why this transitional and/or peaking capacity cannot be generated at TVA sites that would not require this extensive investment in long-term pipeline infrastructure. The 2019 IRP and Alternative A may not be aligned with subsequent developments such as TVA's carbon commitments, nor the significant incentives under the 2022 IRA that make many of the alternatives to combustion turbines much more cost effective. The analysis does not fully account for expected cost decreases of renewable energy and higher future natural gas prices. Most experts expect the costs of renewable energy production and battery storage to continue to fall along the timeline of this project due to subsidies from the IRA and other market factors. Similarly, the price of natural gas is expected to increase over time, particularly as U.S. exports of natural gas continue to climb. Appendix I, for instance, conducts system-wide Lifecycle Analysis modeling to project future GHG emissions. The Draft EIS notes that this "system-wide LCA reflects TVA's broader asset strategy and target power supply mix set by the 2019 IRP." However, it does not present the assumptions that underlie the model or the modeled distribution of future power generation. Also, in its rejection of alternatives involving renewables and storage, the Draft EIS uses the Energy Information Administration's (EIA) 2022 Annual Energy Outlook data to compare Levelized Cost of Electricity (LCOE) for gas with battery storage. The EIA Annual Energy Outlook 2023 report has just been released, which accounts for the IRA and should provide an updated accounting of levelized costs of electricity storage (LCOS). However, if TVA uses the LCOE to compare renewables and CC natural gas, the load profiles must be consistent across the options for the comparisons to be valid. Including the IRA incentives, the correct comparison should be between renewables plus batteries with the appropriate load profile for each and CC natural gas with the same load profile. As EIA notes, LCOE does "not capture all of the factors that contribute to actual investment decisions, making direct comparisons of LCOE across technologies problematic and misleading as a method to assess the economic competitiveness of various generation alternatives" (https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf). EIA then enumerates the limitations of using LCOE alone. Rather, EIA suggests using Levelized Avoided Cost of Electricity (LACE), along with LCOE and LCOS, to "provide a more intuitive indication of economic competitiveness for each technology than either metric separately when several technologies are available to meet load."	Transitional and/or peaking capacity does not meet the purpose and need of placing 1500MW of firm, dispatchable power in commercial operation by the end of 2027 to replace the generation lost by retiring the Kingston coal units. Further, Alternative B, the renewables and storage alternative, that assesses the solar/battery option was not selected as the Preferred Alternative because it fails to fully meet the Purpose and Need to have replacement generation in commercial operation as it will not be feasible by 2027. Within the context of the DEIS, the reference to LCOE is used merely as an example to compare the cost of different resources. Please refer to the Alternatives Evaluation in Appendix B for TVA's resource cost assumptions and overall cost comparison of alternatives that led to the selection of the Preferred Alternative. Although additional regulatory guidance has been published between the 2019 IRP and this DEIS, these regulations, executive orders, and guidance have been evaluated and incorporated where applicable and where there is enough information available about how each particular regulation, order, or guidance will affect TVA's actions regarding its generation fleet. The 2019 IRP continues to align with Alternative A, the Preferred Alternative, of the Draft EIS. The Preferred Alternative would provide firm, dispatchable generation and would provide and enable the facilitation and the implementation of 10,000 MW of solar and additional BESS resources outlined in the target supply mix of the 2019 IRP. Additionally, please refer to Section 2.1.4 to see more information on Alternatives Considered But Eliminated From Further Discussion and Section 1.2.2 to see more information on the IRA.

2	The EPA recommends that TVA consider a reasonable range of alternatives that reduce the size of their future carbon liabilities. Only considering two alternatives fails to disclose the available options between those two "endpoints" of a natural gas facility and 100% renewable. Another alternative could provide a transition strategy (perhaps comprised of a combination of peak shaving, increased generation from other production units, energy efficiency, and demand-management) that bridges the gap before sufficient renewable energy generation can completely meet the required long term generation capacity. Another alternative could provide a transitional solution that continues to meet capacity requirements through other strategies until sufficient renewable energy generation is fully available. In the Letter Agreement and Schedule document from Dawn Booker, Alternative A includes a 3-5 MW solar site and a 100 MW battery storage site. This is a comparatively small use of solar and does not seem to reflect future forecasts of increasing use of renewables. Moreover, the description of Alternative A in the "Draft Air Quality & GHG" section does not include solar, and Appendix I does not include any solar-related calculations. The EPA recommends considering a more substantive solar and battery component with Alternative A. The EPA recommends that the solar facility and battery storage facility be appropriately reflected in the calculations supporting Alternative A. Additionally, the analysis should assess wind power as a viable part of the TVA system, as an alternative, or in combination with existing alternatives. Wind potential in the southeast is growing and as the costs of technology decreases, several modeling efforts find that an expansion of wind is optimal for this area. Wind energy resources: • https://www.nrel.gov/gis/wind-supply-curves.html • https://www.biologicaldiversity.org/programs/energy-justice/pdfs/TVAs-Clean-Energy-Future.pdf • https://www.rff.org/events/rff-live/future-generation-exploring-the-new-baseline-for-electricity-in-the-presence-of-the-inflation-reduction-act/?mc_cid=fb2ba4aca8&mc_eid=73413f18e1 If TVA believes that the models and experts are incorrect about wind potential in the southeast, the TVA analysis should provide its support for this determination and explain why wind power is not being evaluated.	This proposed action is one piece of TVA's overall Asset Strategy, which blends a combination of resource technologies to allow TVA to support affordable, reliable, and cleaner energy for its customers. TVA's asset strategy, as reflected in the target supply mix adopted by the TVA Board through the 2019 IRP, already contemplates the blending of resources to provide the least-cost, optimal portfolio under a variety of future conditions, including the addition of 10,000 MW of solar by 2035. A key beneficial result of TVA's Asset Strategy is the reduction of carbon emissions. See DEIS Sections 1.1 and 1.2. As discussed in detail in DEIS Section 1.1, this action is a specific, discrete component of that asset strategy and is consistent with the need established by the 2019 IRP to establish new capacity in the TVA region, increase reliability and flexibility, increase energy efficiency, and meet TVA energy production goals. In conducting an alternatives analysis, agencies must "[e]valuate reasonable alternatives to the proposed action, and for alternatives that the agency eliminated from detailed study, briefly discuss the reasons for their elimination." 40 CFR § 1502.14(a). An agency must consider a reasonable number of alternatives, which are bounded by the purpose and need for the proposed agency action. Id. at § 1502.14(f), § 1502.13; see also Coal. for the Advancement of Reg'l Transp. v. Fed. Highway Admin., 576 F. App'x 477, 481 (6th Cir. 2014); Citizens Against Burlington, Inc. v. Busey, 938 F.2d 190, 195 (D.C. Cir. 1991) ("[A]n alternative is reasonable only if it will bring about the ends of the federal action."). In addition to the No Action Alternative, TVA considered two action alternatives in the Draft EIS: Alternative A- the retirement of KIF and construction and operation of a combined cycle (CC) and dual fuel Aero CT gas plant with 3-4 MW Solar and 100 MW Battery, on the KIF Reservation; Alternative B- the retirement of KIF and construction and operation of solar and storage facilities, with a portion in located in East Tennessee. The purpose of the proposed action is to retire the KIF coal units by the end of 2027 followed by the decommissioning of those units, and to implement replacement generation that can supply at least 1,500 MW of firm, dispatchable power by the end of 2027. The need for the Proposed Action is to ensure that TVA is able to meet required year-round generation and maximum capacity system demands and planning reserve margin targets, particularly during peak load events, upon the retirement of the coal units. TVA is evaluating implementing solar and battery throughout the valley. However, for purposes of this project, replacement generation is needed in the KIF area to fill the void left by the retiring Kingston coal units and there are limitations to the amount of on-site solar and BESS that the Kingston Reservation can accommodate. The proposed amount of solar and BESS that would be paired with the proposed gas units would be sufficient to provide station service support. Since solar and BESS components included in the preferred Alternative A would not contribute to air impacts, they were not included in air quality evaluation. Additional language has been added to the DEIS to clarify this point. The Draft EIS evaluates other potential renewable energy resources and other potential blended alternatives, many of which would not require a new natural gas pipeline. TVA concludes that these alternatives would not meet the project's purpose and need to retire all nine KIF coal units and to implement replacement generation that can supply at least 1,500 MW of firm, dispatchable power by the end of 2027. As part of the Scoping of this project, an additional action alternative – a gas alternative - was considered that would evaluate two CT plants at alternative locations in the Valley that either already had natural gas already provided or would require minimal additional gas pipeline construction. This alternative was later dismissed from detailed consideration due to site environmental, transmission needs, and timing concerns that made the alternative incompatible with

		the purpose and need of TVA's proposal in this EIS. Likewise, Section 2.1.5 of the DEIS discusses other alternatives and the reasons why TVA eliminated them from detailed study. See Section 2.1.3.2. of the Draft EIS (Site Evaluation for New CC / dual fuel Aero CT Plant) for an explanation of the benefits of locating the CC plant on the KIF Reservation and factors TVA used to select it as the site for the CC/Aero CT plant. Among other reasons, locating the CC/Aero CT plant on the Kingston reservation will support the local transmission system, takes advantage of existing transmission interconnection to the TVA system, fills the critical need for power in the Knoxville area resulting from the retirement of the coal plant, and would allow for the majority of the pipeline to be sited along an existing natural gas pipeline right-of-way, reducing potential environmental effects. Kingston Fossil's (KIF) location on the transmission system, specifically on the 161 kilovolt (kV) system near the Knoxville load center, makes KIF an integral part of the systems power flows and stability. The retirement of KIF would create a large gap in the power system in the Knoxville area and decreases the system stability for Watts Bar and Sequoyah nuclear plants. Significant transmission system upgrades in the local area would be needed if replacement generation is not provided and located on the 161 kV system near Knoxville. Retirement of Kingston Fossil without replacement generation in the area or without extensive transmission upgrades would significantly impact the ability to add additional load in the area, degrade the stability of Watts Bar and Sequoyah nuclear plants to a point where generation would need to be curtailed, and potentially violate NERC Transmission Planning (TPL-001) standard criteria. As discussed previously, the time necessary to make extensive transmission upgrades would be incompatible with the purpose and need for the project. Upon consideration of all siting criteria (including, but not limited to, transmission availability, required transmission upgrades (both those directly associated with the CC and regional upgrades required for grid stability), air permitting prospects, staffing, fuel supply, etc.), TVA determined that the Kingston Reservation was the preferred location. Further, the proposed CC/dual fuel Aero CT plant at KIF along with 3-4 MW of solar and 100 MW battery could be built and made operational sooner than other alternatives, which reduces economic, reliability and environmental risks. The timing for the replacement generation is an important criterion since TVA must replace the generation of the retiring coal units by the end of 2027. Section 2.1.5 further details alternatives that were "considered but not carried forward" for more detailed analysis because they do not meet the project purpose and need. In particular, in Section 2.1.5, TVA evaluated a number of other resource options for replacement generation, including: natural gas-fired CC, natural gas-fired CT, battery energy storage systems (BESS), utility-scale photovoltaic (PV) solar, hydro pumped storage, small modular reactors, wind, energy efficiency, demand response, and distributed generation. TVA also evaluated other blended alternatives, including one that combines a lower amount of natural gas with other technologies, such as solar and battery storage. These alternatives were not carried forward for more detailed review because…See Section 2.1.5 for explanations as to why these options did not meet the project's purpose and need. Section 1.2 of the KIF Retirement draft EIS discusses the recently enacted Inflation Reduction Act (IRA; Public Law No: 117-169) and the attributes of this act that would improve pricing and availability for renewable and storage resources. While the provisions of the IRA provide substantial incentives for various forms of clean energy, for a number of reasons, those provisions are of limited applicability with respect to the generation choice decisions confronting TVA at Kingston. TVA is optimistic that the IRA will enable faster adoption of renewable resources on TVA's system in the long term but its enactment does not alleviate the transmission-related time constraints described in the Draft EIS for Alternative B that impair the ability of this alternative to fully meet TVA's purpose and need for firm, dispatchable generation by the end of 2027. For these reasons, the IRA does not alter TVA's selection of the preferred

		alternative (Alternative A) nor does it change the least-cost planning analysis that led to TVA's adoption of the of panels and other equipment to accelerate the installation of solar generation s. Regulatory initiatives to which puts downward pressure on the supply of solar panels sourced from outside of the U.S. and cost for materials, such as steel, for which solar racking and tracking equipment is highly dependent, has also increased significantly. These impacts have led to a reversal of decades-old trend of decreasing solar prices and has led to many solar projects being postponed or canceled. While the IRA incentivizes the transition of the solar supply chain to the U.S., it is projected that it will take 3-5 years for domestic supply chain to mature and ease the current constraints on the supply. Additionally, the tax incentive provisions of the IRA are likely to take more time to implement than is available to TVA for purposes of choosing replacement energy for the KIF Plant. The selected replacement generation must be in place and operational prior to the retirement and demolition of KIF by the end of 2027. The Treasury Department must issue guidance to establish certain qualifications and processes for tax incentive provisions, which could take up to a year, if not longer. Wind was considered but dismissed as a resource option due to low wind speeds in the Tennessee Valley and higher transmission costs for out-of-Valley wind. Recent market intelligence indicates that wind is not cost competitive in the Valley.

3	Range of Alternatives and Consideration of IRA Incentives: The range of alternatives considered within the Draft EIS, which is limited to only two action alternatives, appears to be constrained by TVA's 2019 IRP. However, there have been significant statutory, regulatory, and technology changes since then. There is relevant Inflation Reduction Act (IRA) tax guidance likely to come out during the EIS process, and other analysts have worked with statutory language alone to generate estimated cost projections. Also, other utilities are finding creative and aggressive ways to reduce emissions on a timeline comparable with TVA's. • Virtual Power Plants – https://pv-magazine-usa.com/2023/03/08/sunnova-to-deploy-solar-and-storage-virtual-power-plant-in-texas/ • 100% Renewable Micro-grids – https://www.energy-storage.news/first-100-renewable-multi-customer-microgrid-online-in-california/ • Solar in public buildings – https://generation180.org/wp-content/uploads/2022/12/BrighterFuture2022.pdf Additionally, other companies have plans to retire coal plants in similar timeframes where they have developed lower GHG alternatives than a natural gas combined cycle unit. For example, instead of replacing a retired coal plant with CC natural gas plant as originally planned, Xcel Energy offered a new alternative that relies significantly on solar and wind for generation (see https://cubminnesota.org/xcel-is-no-longer-pursuing-gas-power-plant-proposes-more-renewable-power/). TVA's option for potential hydrogen co-firing, while welcome, is less aggressive than that of other utilities.	Please see response to Comment #2. TVA is situationally different from the other utilities in EPA's comment. Further, TVA is constrained in its decision-making by its statutory obligations to engage in least-cost planning and the provision of reliable, affordable electricity to the 6 million patrons of the Tennessee Valley Service Area. TVA has committed to ensuring that the design of the Alternative A CC/Aero CT plant would enable and accommodate potential future modifications for carbon capture and the combustion of hydrogen (CC units only) as a replacement or supplemental fuel for natural gas when these technologies mature to scale. The proposed CC units under Alternative A would be designed to be 5 percent hydrogen capable at commissioning by adding balance of plant equipment that includes areas for future hydrogen storage, appropriately sized piping, and a blending station during the original construction. TVA would also purchase a CC unit capable of burning at least 30 percent hydrogen, by volume, with modifications to the balance of plant once a hydrogen source is available. TVA would only consider burning hydrogen as a part of test burns or normal operations when it is commercially available at an acceptable chemical content that would reduce carbon emissions and be price competitive in the market at that time. It is important to note that once a viable option for future mitigation projects is identified, TVA would conduct additional analyses to determine proposed pipeline routes, costs, storage requirements, or other needs with hydrogen fuel incorporation. TVA would analyze the site- specific impacts associated with any future mitigation that is planned as additional details become available. TVA has considered the USEPA's draft whitepaper on reducing GHG emissions from CTs (USEPA 2022b) and anticipates the efficiency, effectiveness, scalability, and economics of these systems to improve in the next several years, allowing for more informed decisions in the future when adequate storage locations or pipelines are identified for both the delivery of hydrogen and the storage or use of captured CO2. TVA is exploring partnerships with federal agencies and peer utilities to advance the research and development of both alternative fuels and CCS technology, which could enable their use at existing or future TVA facilities. In addition to the current cost and maturity challenges with CCS, the potential geological features (i.e., karst instability and tendency to develop sinkholes) of the Kingston Reservation pose further challenges to the consideration of CCS at this site.
4	The EPA recommends against applying the SC-GHG estimates developed under EO 13783 that has since been revoked, because they fail to reflect the full impact of GHG emissions in multiple ways. First, those estimates fail to capture many climate impacts that can affect the welfare of U.S. citizens and residents. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. Assessing the benefits of U.S. GHG mitigation should also incorporate how those actions may affect mitigation activities by other countries, as those international actions will benefit U.S. citizens and residents. Scientific and economic experts have emphasized reciprocity as support for considering global damages of GHG emissions. Using a global estimate of damages in U.S. analyses allows the U.S. to continue to actively encourage other nations, including emerging major economies, to take significant steps to reduce emissions. The EPA also recommends that TVA remove any language from the Draft EIS indicating that there is "legal uncertainty" around the SC-GHG estimate and not reference ongoing litigation as a rationale for using the outdated estimates from the prior Administration.	Comment noted. First, as to scope of impacts, the social costs of GHG from the previous Administration are based largely on domestic effects while the social costs generated by the IWG for the current Administration are based on global effects. In the DEIS, TVA has used social cost metrics from both the current and previous Administrations. Presenting estimated social costs as a range of values from successive Administrations provides decision-makers and the public with better information in an area fraught with uncertainty. Because the DEIS considers the current Administration's social cost numbers, the global effects were not ignored in TVA's consideration of the social costs. Second, the "legal uncertainty" refers to the fact that the use of SCC by federal agencies has been the subject of litigation and inconsistent rulings and could be the subject of further litigation related to specific agency actions. Moreover, these estimates have changed from administration to administration. Nonetheless, TVA has used the SC-GHG estimates published by the IWG in its analysis, together with other SCC metrics used under previous Administrations to provide a range of potential impacts. Monetizing social costs of GHG is not an exact science and presenting the social costs as a range of values provides decisionmakers and the public with better information for making an informed decision.

	Finally, the EPA recommends that TVA avoid expressing project-level GHG emissions as a percentage of national or state GHG emissions. Instead, the EPA recommends TVA include a discussion of whether and to what extent the estimated GHG emission reductions from the proposed alternatives are consistent with meeting U.S. commitments, any relevant state or local goals, and TVA's own commitments to be carbon free by 2050.	CEQ's interim guidance on assessing GHG emissions encourages agencies to conduct an emissions analysis for each alternative and to contextualize those emission increases or decreases against climate goals and emission inventories. The proxy emissions analysis that, among other things, expresses emission reductions from alternatives as a percentage of state or national GHG emissions helps provide this context. The DEIS provides additional context by explaining how the reductions from the alternatives help advance climate goals. Along these lines, both action alternatives align with TVA's path to reduce carbon emissions 70 percent by 2030 and 80 percent by 2035, as set out in TVA's Strategic Intent and Guiding Principles (May 2021). TVA also has an aspiration to achieve net-zero carbon emissions by 2050 and the alternatives in the DEIS would advance the agency's aspiration. Moreover, the emission reductions that would result from adoption of the preferred alternative would also help advance the climate goals espoused in several Executive Orders issued by the Biden Administration. These reductions also advance the Nationally Determined Contributions (NDCs) goal for the United States in the Paris Agreement to reduce GHGs by 50-52% below its 2005 level by 2030 (Biden Administration: April 2021) Please see Sections 1.2 and 2.1 for additional details on TVA's carbon emission reduction goals.
6	The EPA recommends providing background documentation including spreadsheets used to estimate life cycle GHG emission for each alternative as well as the net present value (NPV) for both individual basis and system-wide basis. Without this information, it is difficult to verify the accuracy of TVA estimates and inform decisions about the project. The EPA also recommends providing citations including page numbers for the publications used as the basis for the LCA analysis. The EPA also recommends against presenting the SC-GHG as a point estimate at one discount rate, i.e., in Table 3.74, present SC-CO2 in 2028 at 3% discount rate. As emphasized in the IWG Technical Support Document, the discount rate is an important parameter in estimating the SC-GHG and to reflect uncertainty in that parameter, a range of discount rates should be considered. For transparency and to help the public understand the impacts, the EPA recommends that the climate damages be presented for each GHG from 2028-2050 at discount rates of 2.5%, 3.0%, and 5.0%. The EPA is willing to help with calculating the climate damages using the appropriate SC-GHG estimates. The current annual SC-GHG values are in 2020 dollars. The values should not be adjusted for inflation to create a nominal value as has been done in the Draft EIS (adjusted for 2% annual inflation). The EPA is willing to help with adjusting the SC-GHG correctly. Appendix I does not describe the system model used to estimate lifecycle GHG impacts, how it was used, nor the cost assumptions. For transparency and replicability of results, the EPA recommends TVA provide more details on the system-wide modeling and lifecycle modeling. Furthermore, the results of the system-wide LCA modeling are not fully presented. Only the emission-related outputs are presented. The EPA recommends also presenting the distribution of electricity generation in the system-wide model outputs. As it stands, it is not clear if the LCA system-wide model outputs satisfy TVA's commitments towards achieving Net Zero GHG emissions, as well as other policy goals. The EPA recommends presenting the full details about the assumptions of the model and the outputs across the TVA system.	The "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" (SC-GHG TSD) provides the interim SC-CO2, SC-CH4, and SC-N2O estimates in 2020 dollars. Furthermore, Tables 1-3 of this document, and corresponding footnotes, indicate that all values identified in the document are in 2020 dollars. Therefore, these estimates needed to be adjusted to account for inflation as the capacity expansion model relies on nominal inputs. The methodology and assumptions used in the Life Cycle Analyses are described in Appendix I. The basis for the LCAs is NREL publications. The system-wide LCA is based on simulated system-wide generation dispatch. An analysis for the entire TVA-wide power system was performed using industry standard capacity planning and production cost models, Anchor Power Solutions' EnCompass, and Energy Exemplar's Aurora. The capacity planning model develops a least-cost portfolio to meet demand and reserve margin, while the production cost model simulates economic dispatch of the plan. The output includes an estimate of anticipated future emissions across the entire TVA system for each year. The LCA system-wide model outputs do satisfy TVA's commitments towards achieving Net Zero GHG emissions, as well as other policy goals, because the preferred alternative provides reductions in GHGs, which goes towards achieving TVA's plan of reduced carbon of 70% by 2030 and a path towards 80% by 2035 and an aspiration of net zero carbon emissions by 2050. Model results represent TVA's current forecast for electric load, asset performance, and commodity prices, among other things. Differences in any of these forecasts could result in higher or lower anticipated carbon emissions. Future regulatory requirements or incentives would likely result in lower emissions than these estimates, depending on those requirements and TVA's fleet composition at the time. The differences between each alternative are specific to the decision to retire or not retire Kingston Fossil Plant and the associated replacement generation outlined in each alternative. Each alternative has subsequent impacts for other decisions in the future. Given this, there will be variations in simulated dispatch, which will result in differences in emissions, driven by the dynamic nature of power system modeling. All necessary generation data germane to the evaluation of the System-wide LCA analysis and the assessment of climate impacts is provided in the DEIS.

7	The EPA recommends that the Draft EIS include a more robust discussion of whether and to what extent estimated GHG emissions from the proposed alternatives are consistent with achieving science-based national GHG reduction targets, including the Paris Agreement targets, the 2050 goal for net-zero energy emissions, and the goal of achieving a carbon pollution-free electricity sector by 2035. This is particularly critical for projects that may perpetuate reliance on GHG-emitting energy sources beyond the timeframes set by national GHG reduction goals. The Draft EIS should also include more information about the Paris Agreements and the resulting targets, which are referenced without further explanation. Additionally, per 40 CFR 1506.2(d) the Draft EIS should disclose and discuss any inconsistency of the proposed action with State, Tribal, or local plans or laws, including local GHG emissions reduction goals. (https://www.knoxvilletn.gov/government/city_departments_offices/sustainability/climate_change#:~:text=Our%20new%20goal%20to%20reduce,which%20are%20outside%20City%20control).	See response to *Comment #5* above.
8	The Draft EIS should also discuss whether and how the preferred alternative aligns with TVA's goals of TVA's 2019 IRP, which calls for 14,000 MW of solar and 4,200 MW of wind energy by 2038. As noted, the 2019 IRP was developed prior to TVA's subsequent carbon commitments or the significant incentives under the IRA that make many of the alternatives to combustion turbined much more cost effective. The Draft EIS should thus also discuss alignment with subsequent agency GHG reduction goals and policies, including TVA's 2021 Strategic Intent and Guiding Principles document.	The 14,000 MW of solar and 4,200 MW of wind outlined in the 2019 IRP represent the upper end of the range of resource additions included in the Target Power Supply Mix adopted by TVA. See Chapter 2 for more information on the Target Power Supply Mix. The Preferred Alternative is expected to help TVA execute a plan to reduce carbon emissions 70 percent by 2030 with a path to an 80 percent reduction by 2035, and to attain the aspiration of net-zero carbon emissions by 2050 (TVA 2021h).
9	The EPA recommends the Draft EIS provide additional information behind the 2027 timeframe identified in the purpose and need, including whether the timeframes in the 2019 IRP remain consistent given the changes in the energy markets and statutory/regulatory developments, notably the IRA. The EPA recommends greater disclosure around how the 2027 timeframe limited the alternatives and mitigation options considered in the Draft EIS. Increased disclosure about these timing constraints could allow greater insight into whether other reasonable alternatives or mitigation measure may be available to TVA. Although the details of these future regulations are not yet public, the EPA recommends at least including a discussion of their expected impacts, particularly in terms of costs. TVA should be specific about the "recent and anticipated new regulations" that are referenced as a driver for the selection of Alternative A. One of these regulations appears to be EPA's proposed Steam Electric Effluent Limitation Guidelines, 88 Fed Reg 18824; public comments on this proposed rule are open until April 28, 2023. The EPA would prefer that proposed regulations not be referenced as a rationale for selecting an alternative. If the EPA's proposed (not final) regulations are going to be referenced as a reason for selecting Alternative A, it would be helpful to see more explanation about the costs that TVA anticipates would result from compliance with these proposed regulations, as well as an acknowledgment of any uncertainty because these regulations are not finalized.	The DEIS provides a discussion of the "end-of-life" timeframe for the Kingston coal units – end of 2027 - and of the need to replace the retiring generation in a timely manner with 1500MW of firm, dispatchable power. While the IRA will enable faster adoption of renewable resources on the TVA system in the long term, it does not help in the short term to install 1500MW of firm, dispatchable power by 2027 to replace the generation of the retiring Kingston coal units. As to the proposed ELG regulation, TVA took into account the potential cost of a future ELG regulation in the overall analysis that goes into the selection of the preferred alternative. This potential cost as it relates to complying with the 2020 ELG regulations has been added to the DEIS.

10	If TVA intends to install carbon mitigation measures in the future, these costs should be included in their analysis. Carbon capture and hydrogen fuel blending technologies should be considered in the plant design. Utilities similar in size to TVA's Kingston plant are displacing some portion of their natural gas generation with these technologies in a comparable timeframe. For example, the Intermountain Power new natural gas generating units, which will begin operation in 2025, will be designed to utilize 30 percent hydrogen fuel at start-up, transitioning to 100 percent hydrogen fuel by 2045 as technology improves (see https://www.ipautah.com/ipp-renewed/). While smaller in scale, other utilities are displacing a portion of their natural gas use with hydrogen. For example, (https://dailyenergyinsider.com/news/34040-florida-power-light-taps-cummins-for-its-green-hydrogen-facility/). And Competitive Power Ventures is constructing a CC natural gas generation facility using carbon capture technology (https://cpv.com/2022/12/12/cpv-selects-doddridge-county-for-location-of-3-billion-carbon-capture-project-in-west-virginia/) The EPA recommends deleting the sentence regarding comparison of SF6 leaks to combustion emissions, in Section 3.7, as it is not a relevant comparison and is misleading. Given that the life of a switchgear is over 30 years, the EPA suggests that TVA's upgrade of its system and installation of new switchgears represents the ideal time to switch to SF6 free switchgears, which would represent reasonable mitigation, and prevent over 30 years of production of additional SF6 for the TVA system. The EPA can connect TVA with further resources on SF6 free switchgears.	There are many uncertainties around the availability and cost of emerging technologies, such as carbon capture and hydrogen fuel blending. TVA's experience is that these technologies have not been adequately demonstrated to be considered technologically and economically feasible. However, because these technologies are promising, the combined cycle plant under Alternative A would be designed to accommodate future modifications necessary for incorporating CCS and for utilizing hydrogen fuel blending if and when these technologies mature to fruition. TVA is also aware that under EPA's Fall 2022 Unified Regulatory Agenda (published April 22, 2023), the agency expects to propose a GHG reduction rule applicable to new and existing electric generating units in Spring 2023. The construction and operation of any replacement generation would be consistent with the requirements in any such future regulation. The switchgear units that would be utilized for this project are manufactured to meet industry standards. As stated in Section 3.7.2.3.3 of the Final EIS, some older electrical equipment at the Kingston Reservation may contain the GHG sulfur hexafluoride (SF6) gas (e.g., electrical switchgear, circuit breakers), which have the potential for minor leaks, mostly associated with maintenance or long-term equipment degradation. Additionally, where newer equipment has been installed or is proposed, along with more efficient operation and maintenance techniques, and leak detection, these features would minimize the potential for sulfur hexafluoride leaks. The only other market-available switchgear option (vacuum) does not provide interruption to support NERC Protection and TVA reliability standards to provide safe reliable power for the Tennessee Valley. A system-wide review of SF6 switchgear conversion would be outside the scope of this analysis; however, TVA actively monitor evolving technology for future consideration in making system-wide changes. Revisions have been made in Section 3.7 to address EPA's comments here. Additionally, TVA has updated language to acknowledge the impending 111 GHG Rule to Section 2.1.4.2.
11	The EPA recommends that the discussion of climate change and GHGs acknowledge the disproportionate impact that GHG emissions have on already overburdened and vulnerable communities. See, e.g., Climate Change and Social Vulnerability in the United States, the EPA (2021). Similarly, the alternatives discussion should recognize the differences in the GHG emission impacts of each alternative on those vulnerable communities. Also, the environmental justice analysis of non-GHG stressors should include ongoing and projected climate-related impacts, consistent with section 219 of Executive Order 14008. The EPA also recommends that TVA provide details regarding whether there is any potential for rate increases or other costs related to the proposed CC/Aero Plant that could potentially affect consumers and whether those economic impacts could be amplified for low-income populations. The Draft EIS should identify potential impacts to residential properties associated with the pipeline regarding any amplified effects that may be experienced by People of Color and Low-Income populations, including from any potential eminent domain or construction-related activities. Finally, the EPA recommends that TVA provide additional details regarding potential impacts to People of Color and Low-Income populations from pipeline construction and operations related to any subsistence hunting, fishing, and gathering activities; to private drinking water sources; waste disposal sites; noise; and other identified EJ impacts identified in the Draft EIS, including the potential amplification of these impacts to EJ populations.	TVA has assessed the impacts on EJ populations for each resource area in the DEIS, evaluating the potential for any disproportionate impacts on EJ populations. While TVA did not identify any disproportionate impacts, the DEIS recognizes that there could be "amplified" effects on EJ populations due to their greater susceptibility as a result of the long-term history of social discrimination and due to their atypical cultural traditions and norms. TVA recognizes the potential for such "amplified" effects even when EJ and non-EJ communities may be subject to the same potential for harm as a result of project impacts

Table L1.3. Response to NPS Comments on the Draft EIS Document

Number	Section	Commentor	Comment	Comment Resolution/Updates to the Document
	Front Matter, Acronyms, Table of Contents, Figures and Tables			
1	Cover Sheet	AS	Please specify the number of combustion turbines that will be constructed under each configuration (combined cycle and peaking units). Both the air quality analysis sections and the emissions tables indicate that TVA intends to construct a combined cycle (CC) plant as well as dual-fuel Aeroderivative combustion turbine peaking units at the KIF site. This is not clear based on the language presented here, which could be interpreted to mean that the dual-fuel Aeroderivative CTs are components of the combined cycle plant. Based on information provided in the air quality sections of the analysis, the NPS has interpreted this to mean that TVA proposes to construct both a CC plant and CT peaking units—our comments are prepared accordingly. Please specify whether this understanding is correct.	The Draft EIS has been updated to clarify that TVA proposes under Alternative A to build a single gas-fired combined cycle gas plant and 16 dual-fuel Aeroderivative combustion turbines. Additional details and descriptions are provided in Chapter 2 - description of Alternative A - but are not repeated each time the proposed action is mentioned.
2	Cover Sheet	AS	See comment above regarding recommended clarification of the Alternative A proposal.	See response above.
3	Summary	DP	Awkward construction/repetition. Is this the correct description?	Section revised to improve construction and clarity.
4	Summary	AS	Executive Order (EO) 14008 underscores the urgency of addressing the present climate crisis and EO 14057 sets quantifiable goals for the government in reducing GHG emissions. As the nation's largest government-owned utility, TVA is in a unique position among federal entities to lead by example and dramatically shift the environmental and climate burden of energy production in the United States. If constructed, new natural gas fossil fuel-fired generation will be in place for decades to come, well beyond the time frames addressed in EO 14057 for establishing a carbon-pollution-free electricity sector by 2035. While natural gas-fired electricity generation is cleaner than coal-fired generation, it still emits criteria air pollutants that impact parks and approximately half the amount of carbon dioxide (CO_2) on a pound-per-megawatt basis, compared to coal. From a cost perspective, future retrofits with carbon capture and storage may be more costly than investing in renewable energy and storage options from the onset. Therefore, the NPS encourages TVA to move to carbon-free energy sources to the maximum extent possible and employ all available mitigation options to reduce GHG emissions now and in the future. TVA currently has a large systemwide carbon footprint and is considering similar natural gas-fired replacements for other coal-fired units in its power generation system. In the Air Quality Section of the DEIS, TVA states that "Alternative A would help achieve TVA's goal of reducing GHG emissions by 70% by 2030 as set out in TVA's Strategic Intent and Guiding Principles document." The NPS recognizes the significance of these reductions (we note that, based on the IRP, the 70% reduction goal is from a 2005 baseline). However, based on current emissions information, significant additional CO_2 emission reductions are still needed in the TVA system. According to information provided in the Environmental Protection Agency's Clean Air Markets Program Data (CAMPD) database, coal, oil, and natural gas-fired units across the TVA system emitted nearly 42.3 million short tons of CO_2 in 2021. The Energy Information Administration (EIA) also tracks emissions information by power plant and associated balancing authority. When ranking balancing authorities based on reported 2020 CO_2 emissions, the TVA region is ranked seventh among the top ten (out of 66 total) highest carbon dioxide-emitting power balancing authority regions. Comparisons of the EIA balancing authority information with 2020 CAMPD data show that TVA-owned facilities account for approximately 62.6% of the megawatt hours produced and 77.4% of the CO_2 emissions in the	Under the Energy Policy Act of 1992, TVA has a statutory obligation to conduct least-cost planning. The target supply mix approved by the TVA Board through the 2019 IRP is the product of the least cost planning process. The decision associated with this EIS is a specific, discrete component of TVA's blended asset strategy and consistent with the recommended target power supply mix in the 2019 IRP see Sections 1.2 and 2.1 for more information on the IRP and Target Power Supply Mix. New gas contributes to TVA's ~80% carbon reduction by 2035 path by enabling the retirement of the remaining coal plants by 2035, while emitting about 65-70% less CO_2 than aging coal plants. See Section 3.7.1.1.8.4 for more information on how all action alternatives address executive orders with GHG emissions reductions guidance. While Alternative B would result in greater carbon reductions than Alternative A, it is not feasible by 2027 due to significant transmission work, failing to meet the Purpose and Need. Please refer to the Alternatives Evaluation in Appendix B for more information on assumptions and methodology. TVA has updated all resource costs since the 2019 IRP, using NREL's 2022 Annual Technology Baseline as the source for long-term solar and storage costs. TVA is optimistic that the IRA will enable faster adoption of renewable resources on TVA's system in the long term, but its enactment does not alleviate the transmission-related time constraints described in the Draft EIS for Alternative B that impair the ability of this alternative to fully meet

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			TVA balancing authority region. This means that, as of 2021, TVA is responsible for nearly 80% of the CO2 emissions from the seventh highest CO2 emitting balancing authority region in the United States. We urge TVA to use this opportunity to take a hard look at the tradeoffs between the action alternatives. This includes a more in-depth, quantified, site-specific assessment of the costs of constructing fossil fuel-fired generation capacity under Alternative A versus renewable energy options under Alternative B. A growing body of evidence indicates that renewable energy sources are now cost-competitive with even the most economical fossil fuel-fired EGUs (e.g., see IRENA (2021), Renewable Power Generation Costs in 2020, International Renewable Energy Agency, Abu Dhabi. ISBN 978-92-9260-348-9). In their 2022 Annual Energy Outlook, the Energy Information Administration concludes that "[w]ind and solar incentives, along with falling technology costs, support robust competition with natural gas for electricity generation, while the shares of coal and nuclear power decrease in the U.S. electricity mix." We also recommend that TVA take a more-programmatic look at the long-term costs and financial risks of ongoing reliance on fossil fuel energy sources versus renewable energy options. This reflects a June 30, 2022, recommendation by the EPA on the Cumberland EIS that TVA more extensively "consider the long-term financial liabilities" associated with fossil fuel combustion in the alternatives analysis." If TVA were to factor the cost of retrofitting a gas plant with carbon capture and storage and/or future changes in GHG regulation, a new gas plant may have greater risk from a financial perspective than currently assumed.	TVA's purpose and need for firm, dispatchable generation by the end of 2027. As a result, the IRA does not alter TVA's selection of the preferred alternative (Alternative A) nor does it change the least-cost planning analysis that led to TVA's adoption of the target supply mix in the 2019 IRP. There are several market factors, including supply chain limitations, that are affecting both the cost and availability of solar alternatives in the near term. The regulatory initiatives to reduce greenhouse gas emissions have increased solar demand, putting pressure on manufacturers and the transportation industry. Solar panels are primarily produced overseas, and, at this time, the U.S. has little competitive onshore solar manufacturing capability. One example of this is Polysilicon, which is produced in China and the prices of Polysilicon have significantly increased since before the pandemic. Additionally, U.S. tariffs on Chinese imports, recent anti-dumping investigations on Southeast Asian imports, and enforcement process uncertainty with the Uyghur Forced Labor Prevention Act have created supply uncertainty on obtaining solar panels from primarily available sources. Ocean freight costs have also increased, which puts downward pressure on the supply of solar panels sourced from outside of the U.S. Although shipping costs are trending downward, levels remain higher than pre-pandemic. Additional demand and cost for materials, such as steel, for which solar racking and tracking equipment is highly dependent, has also increased significantly. These impacts have led to a reversal of decades-old trend of decreasing solar prices and has led to many solar projects being postponed or canceled. While the IRA incentivizes the transition of the solar supply chain to the U.S., it is projected that it will take 3-5 years for domestic supply chain to mature and ease the current constraints on the supply. Additionally, the tax incentive provisions of the IRA are likely to take more time to implement than is available to TVA for purposes of choosing replacement energy for the KIF Plant. The selected replacement generation must be in place and operational prior to the retirement and demolition of KIF by the end of 2027. The Treasury Department must issue guidance to establish certain qualifications and processes for tax incentive provisions, which could take up to a year, if not longer. TVA takes a more-programmatic look at cost and asset strategy, including detailed review of TVA's target power supply mix in the IRP. IRPs are performed every 4-5 years with the last completed one in 2019. A new IRP cycle will begin this year.

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6	Summary	DP.	Here and in the ETNG section below, how can this be true? Did you mean subsurface geologic resources? Unique	
7	Summary	DP	See previous comment.	See previous response.
8	Summary	DP	This paragraph does not address pipeline construction and operation.	Deleted discussion of pipeline from this paragraph.
9	Summary	DP	This is more precise. Not all of the Obed River itself is classified as Wild and Scenic, and there are other streams included in the Obed Wild and Scenic River designation.	Accepted revision.
10	Summary	DP	Why? Subsurface installation does not necessarily mean that there would be no visual impact. Pipeline markers and the permanently cleared ROW could be visible for example, and construction may produce its own set of relevant effects from temporary visibility, emissions, noise, vibration, etc.	In December 2021, [ETNG], in consultation with the SHPO, defined the Indirect APE for historic architectural resources along the pipeline corridor. It was determined that the proposed underground facilities along the Pipeline Corridor have a minimal potential to affect historic architectural resources. The pipeline component of the project would be located primarily within an existing ETNG right-of-way, whenever practicable, to minimize impacts to cultural resources, landowners, and the environment. To the extent practicable, ETNG does not plan to directly impact or remove existing historic buildings or historic structures, and upon completion of the project, any impacted landscape features, such as fences, would be restored post-construction; as such, potential for affects to historic architectural resources along the pipeline corridor to be affected are very low.
11	Glossary	DP	Please elaborate/compare to connected action.	Definition removed from Glossary to minimize confusion. A footnote has been added at the first use of "related action" directing the reader to See 40 C.F.R. § 1501.9(e)(1). This is the provision in the regulations that discusses/defines "connected actions".

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12	1.2	DP	Incomplete?	Sentence revised.
13	1.2	AS	The NPS recommends that TVA explore these cost comparisons more comprehensively in the DEIS and that cost information should be specific to the Kingston proposal. We preface this comment by noting that the values cited here and by TVA in the ADEIS are approximate costs based on averages and assumptions provided in EIA's annual Energy reports. We recommend that the ADEIS would benefit from a site-specific, detailed cost discussion in the NEPA document. It is important that the document take a detailed "hard look" at cost trade-offs between the alternatives given TVA's least-cost planning obligations in 16 U.S.C. § 831m-1 and the requirement in Section 15d(f) of the TVA Act to sell power "at rates as low as feasible." With that, we note that the DEIS discussion of EIA's 2022 annual energy outlook may be incomplete. For instance, the Levelized Costs of Electricity (LCOE) cited in this section of the ADEIS (1) do not attempt to quantify the effect of the IRA tax credits on the cost of a PV solar system coupled with battery storage, (2) only compare to the costs of a single CC plant, but do not factor in the costs of the aeroderivative CT peaking units, and incorrectly cites the costs of battery storage (3) do not consider the complete suite of information presented in the EIA report cited, and, (4) do not include a detailed discussion of capital and operation costs for the specific technology types assessed under the action alternatives although the IRP and ADEIS decisions are predicated on these cost assumptions. We believe TVA is quoting information presented in EIA's March 2022 Report titled "Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022" (available at: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf). Total system LCOEs cited in this table (levelized capital, operating and maintenance, variable and transmission costs) are as follows: Combined cycle (combustion turbine): $37.05/MWh Solar, hybrid (PV system coupled with a four-hour battery storage system): $58.62/MWh Combustion Turbine (simple cycle): $123.84/MWh (Note, based on this table, the LCOE incorrectly cited by TVA as battery storage is the LCOE value for combustion turbines.) Battery storage (arbitrage applications): $124.84/MWh (Note, EIA states this is the cost for energy arbitrage applications, not battery backup for renewable sources.) Footnotes to the EIA table state that solar hybrid technology is assumed to be "photovoltaic (PV) with single-axis tracking system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity." With reference to the first NPS concern (the DEIS does not attempt to quantify the effect of the IRA tax credits on the cost of a PV solar system coupled with battery storage), we note that the EIA report cited came out prior to enactment of the IRA, as acknowledged by TVA. As such, the EIA LCOE costs cited by TVA assume declining production tax credits and phase down of investment tax credits for utility scale renewable energy projects (see page 2 of the EIA report). We recommend that DEIS address how the renewable energy tax credits under the IRA would apply to TVA system units specifically.	See response to Comment #4. Within the context of the DEIS, the reference to LCOE is used as an example to compare the cost of different resources. Please refer to the Alternatives Evaluation in Appendix B for assumptions and methodology, including all resource costs. The Alternatives Evaluation reflects costs specific to Kingston. The IRA is not expected to affect this analysis over the short term over which this replacement proposal must be implemented to accommodate the retirement of KIF by the end of 2027. Section 1.2 of the KIF Retirement draft EIS discusses the recently enacted Inflation Reduction Act (IRA; Public Law No: 117-169) and the attributes of this act that would improve pricing and availability for renewable and storage resources. While the provisions of the IRA provide substantial incentives for various forms of clean energy, for a number of reasons, those provisions are of limited applicability with respect to the generation choice decisions confronting TVA at Kingston. TVA is optimistic that the IRA will enable faster adoption of renewable resources on TVA's system in the long term, but its enactment does not alleviate the transmission-related time constraints described in the Draft EIS for Alternative B that impair the ability of this alternative to fully meet TVA's purpose and need of firm, dispatchable generation by the end of 2027. The IRA does not alter TVA's selection of the preferred alternative (Alternative A) nor does it change the least-cost planning analysis that led to TVA's adoption of the target supply mix in the 2019 IRP. There are several market factors, including supply chain limitations, that are affecting both the cost and availability of solar alternatives in the near term. The regulatory initiatives to reduce greenhouse gas emissions have increased solar demand, putting pressure on manufacturers and the transportation industry. Solar panels are primarily produced overseas, and, at this time, the U.S. has little competitive onshore solar manufacturing capability. One example of this is Polysilicon, which is produced in China and the prices of Polysilicon have significantly increased since before the pandemic. Additionally, U.S. tariffs on Chinese imports, recent anti-dumping investigations on Southeast Asian imports, and enforcement process uncertainty with the Uyghur Forced Labor Prevention Act have created

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			With reference to the second NPS concern (the DEIS only compares to the costs of a single CC plant but does not factor in the costs of the aeroderivative CT peaking units, and incorrectly cites the costs of battery storage), we note that the EIA LCOE cited by TVA is the LCOE value for combustion turbines, not battery storage. With respect to battery storage costs, we recommend that the EIA LCOE costs for Solar hybrid ($54.71/MWh) systems may be a more appropriate approximation for LCOEs associated with Alternative B. A footnote to the EIA table indicates that the solar hybrid technology "is assumed to be a PV system coupled with a four-hour battery storage system." Page 2 of the EIA report notes that the battery storage costs included in the model ($124.84/MWh in Table 1a) represent "storage in energy arbitrage applications where the storage technology provides energy to the grid during periods of high-cost generation and recharges during periods of lower cost generation, not as providing generation capacity reliability." The capacity weighted LCOEs in Table 1a of EIA's report are $123.84/MWh for a combustion turbine, $37.05/MWh for a combined cycle unit and $58.62 for solar hybrid technology (a PV system coupled with a four-hour battery storage system). This suggests that the LCOE of a solar hybrid system may be lower than cited by TVA and significantly lower than the LCOE of constructing both a CC plant and CT peaking units. With reference to the third NPS concern (the DEIS does not consider the complete suite of information presented in the EIA report cited), we acknowledge that the EIA report also considers the levelized avoided cost of electricity (LACE), the "economic competitiveness between generation technologies a proxy measure for potential revenues from the sale of electricity generated from a candidate project displacing (or the cost of avoiding) another marginal asset." EIA Table 3—Regional variation in levelized avoided cost of electricity (LACE) for new resources entering service in 2027 (2021 dollars per megawatt hour) reports that the average capacity-weighted LACE value of a solar hybrid technology ($50.82/MWh) is potentially less than the individual LACE of a CC plus CT project (the combined LACE would depend on the utilization rate for each turbine configuration but was assessed at $37.45/MWh and $107.82/MWh, respectively). EIA's approach is described at length in their report, Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022 (available at: Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022 (eia.gov)). With reference to the fourth NPS concern (the DEIS does not include an assessment of capital and operation costs for the technology types assessed under the action alternatives), we note that TVA's "least cost determination" is predicated on the IRP systemwide cost analysis and that capital cost assumptions for new generating capacity underpinned part of the IRP analysis. For this reason, the NPS considered the capital cost assumptions presented in the IRP analysis. In this review, we reference another EIA report associated with the 2022 Annual Energy Outlook, the Electricity Market Module (available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf). Table 4 of this EIA document lists the overnight capital costs for various technologies, and estimates a total overnight capital cost as follows: combined cycle combustion turbines: $1,062/kW to $1,201/kW Simple cycle aeroderivative combustion turbines: $1,294/kW Solar PV with battery storage: $1,748/kW Combined-cycle turbine units with 90% carbon capture and storage: $2,845/kW Please note, the capital cost information should be considered in conjunction with the LCOEs, which included annual variable operating costs. The annual variable operating costs are likely much less for renewable energy options. Again, this information suggests that TVA may have underestimated cost of a CC plus peaking CT unit and	supply uncertainty on obtaining solar panels from primarily available sources. Ocean freight costs have also increased, which puts downward pressure on the supply of solar panels sourced from outside of the U.S. Although shipping costs are trending downward, levels remain higher than pre-pandemic. Additional demand and cost for materials, such as steel, for which solar racking and tracking equipment is highly dependent, has also increased significantly. These impacts have led to a reversal of decades-old trend of decreasing solar prices and has led to many solar projects being postponed or canceled. While the IRA incentivizes the transition of the solar supply chain to the U.S., it is projected that it will take 3-5 years for domestic supply chain to mature and ease the current constraints on the supply. Additionally, the tax incentive provisions of the IRA are likely to take more time to implement than is available to TVA for purposes of choosing replacement energy for the KIF Plant. The selected replacement generation must be in place and operational prior to the retirement and demolition of KIF by the end of 2027. The Treasury Department must issue guidance to establish certain qualifications and processes for tax incentive provisions, which could take up to a year, if not longer.

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			overestimated the costs of a PV system with battery backup (see comments on alternative A description). The renewable options considered under Alternative B may be more financially attractive than characterized in the DEIS and IRP, particularly if carbon capture is required in the future.	
15	1.5	TB	Section 10?	Section 10 has been added to Table 1.8-2 in Section 1.8.
16	1.6	DP	Undefined here or above. Here and elsewhere, the pipeline is not described as a connected action. Please explain the rationale/significance of "related action" in this context. CEQ's current NEPA Implementing Regulations do not define "related actions," but use the term "related" when defining connected actions, which are "closely related and therefore should be discussed in the same impact statement." 40 CFR § 1501.9(e)(1) And the pipeline seems to meet all the reasons actions are considered connected per the regs. That is, they: "(i) Automatically trigger other actions that may require environmental impact statements; (ii) Cannot or will not proceed unless other actions are taken previously or simultaneously; or (iii) Are interdependent parts of a larger action and depend on the larger action for their justification." Ibid. "Agencies shall evaluate in a single environmental impact statement proposals or parts of proposals that are related to each other closely enough to be, in effect, a single course of action." 40 CFR § 1502.4(a)	A footnote has been added at the first use of "related action" directing the reader to *See* 40 C.F.R. § 1501.9(e)(1). This is the provision in the regulations that discusses/defines "connected actions".
17	2.1	AS	The NPS has also reviewed TVA's 2019 IRP analysis, which underpins TVA's least-cost determination. We note that additional explanation may be helpful, as TVA's IRP estimates appear to be at odds with more recent economic projections of the costs of renewable energy, as detailed in this comment. However, we recognize that the cost estimates presented are approximations of capital investment and operational costs. None-the-less, they indicate that the cost-competitiveness of renewable energy has improved dramatically in recent years and the DEIS should take a hard look at costs when identifying the "least cost option." According to Appendix A to the IRP, TVA's capital cost estimates (in $/kW) for each technology type included in the cost analysis are based on 2017$. A more recent 2021 Lazard report, "Levelized Cost of Energy, Levelized Cost of Storage, and Levelized Cost of Hydrogen," indicates that TVA may have underestimated the capital costs for a combined cycle plant and overestimated the capital costs for a utility scale photovoltaic (PV) system with backup battery storage. TVA estimated the capital costs of a combined cycle plant would be $560 to $699/kW depending on the plant configuration. TVA's estimates are well below the capital cost range reported by Lazard of $700/kW to $1,300/kW for combined cycle plants and significantly below EIA's estimates of $1,062/kW to $1,201 for combined	Please refer to the Alternatives Evaluation in Appendix B for more information on assumptions and methodology. TVA has updated all resource costs since the 2019 IRP and these costs are represented in 2023 dollars. Please note that the decision to retire and replace Kingston Fossil Plant is one part of TVA's overall diverse asset strategy. The Draft EIS reflects both individual and system-wide LCAs, which include cost summaries. In an IRP, TVA takes a programmatic look at cost and asset strategy, providing a target power supply mix consistent with least cost planning requirements. IRPs are performed every 4-5 years with the last completed one in 2019. A new updated IRP cycle will begin this year.

Response Number	Section	Commentor	Comment	Comment Resolution/Updates to the Document
			cycle units in their 2022 annual energy outlook. (Capital costs used in the Lazard Report available at: https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf. Capital Costs used in the EIA analysis available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.) TVA's capital cost estimates for utility scale PV systems of $1,203/kW to $1,293/kW are well above the range reported by Lazard of $800-$950/kW. TVA's estimated capital costs for battery storage of $2,824/kW are six to sixteen times higher than the capital cost estimates provided by Lazard, which range from $169 to $460/kW. EIA estimated capital costs for a PV system with battery backup at $1,748/kW, significantly lower than TVA's combined capital cost estimate for PV system plus battery back-up (approximately $4,000/kW). Lazard notes that the levelized costs of energy (LCOEs) of "renewable energy technologies continue to decline globally, albeit at a slowing pace, reflecting reductions in capital costs, increased competition as the sector continues to mature and continued improvements in scale and technology." The Lazard report is not the only recent economic information indicating that the LCOE (in $/MWh) for renewable energy sources has decreased dramatically between 2010 and 2020. Renewable energy sources are now cost-competitive with even the most economical fossil fuel-fired EGUs. This is significant considering TVA's "core statutory objectives to provide the people of the Tennessee Valley with low-cost and reliable electricity, environmental stewardship, and a prosperous economy." (16 U.S.C. §§ 831 et seq.) TVA's systemwide cost assessment provided in the 2019 TVA IRP indicates that the system-average cost for strategy E (promoting renewables) is cost-competitive with the other strategies analyzed by TVA at $70-$76/MWh. However, we note that this is a systemwide analysis, which includes TVA's hydro, nuclear, coal, gas, and oil-fired assets. LCOEs for solar energy sources alone are significantly lower than TVA's systemwide projections (with a maximum of $42/MWh and an average of $34/MWh across the U.S.). The Lazard report suggests these LCOEs reflect "unsubsidized" costs for utility scale solar projects. Additional tax incentives and subsidies under the Inflation Reduction Act may shift the balance of costs for renewable energy sources more in their favor. In terms of reliability, storage, and dispatch concerns for renewable energy, the EIA found that electricity storage capacity has grown rapidly since 2020 and that growth is expected to continue. (These comments focus on solar because TVA only analyzed solar in the FEIS. However, we note that a mixed renewable strategy may be a cost-effective option that increases reliability of the renewable energy system.) Finally, capital costs and LCOE figures from the Reports cited above only reflect costs for infrastructure investments, not the social costs of GHGs. TVA's analyses show that Alternative A is associated with $6.7 billion in nominal dollars for total life cycle social cost of CO2 emissions using the current administration's values for the cost of GHGs. (We note that based on Table 3.7 4, it appears TVA is using a SCC value of approximately $70/metric ton. EPA is currently considering raising this cost to as much as $190/metric ton). We recommend that the TVA analysis more fully address this information in the DEIS and take a comprehensive look at the long-term costs and financial risks of ongoing reliance on fossil fuel energy sources versus renewable energy options.	
18	2.1.3.2.1	DP	It seems like it'd be more correct to focus on the greenfield disturbance needed with this statement.	Accepted recommended revision to focus on the reduction in impacts to greenfield properties.

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19	2.1.3.2.1	DP	Restatement of part of previous bullet.	Revised to avoid redundancy.
20	2.1.3.2.1	DP	The KIF Reservation?	Sentence revised: The Kingston Reservation has favorable air permitting prospects for a new CC paired with dual-fuel Aero CT units, since it would be replacing the existing higher GHG emitting coal units.
			Please specify the number of combustion turbines that will be constructed under each configuration (combined cycle and peaking units). Both the air quality analysis sections and the emissions tables indicate that TVA intends to construct a combined cycle (CC) plant as well as dual-fuel Aeroderivative combustion turbine peaking units at the KIF site. This is not clear based on the language presented here, which could be interpreted to mean that the dual-fuel Aeroderivative CTs are components of the combined cycle plant. Based on information provided in the air quality sections of the analysis, the NPS has interpreted this to mean that TVA proposes to construct both a CC plant and CT peaking units—our comments are prepared accordingly. Please specify whether this understanding is correct.	
22	2.1.3.5.2	DP	East Survey Area transmission lines run near portions of Manhattan Project National Historical Park. West Survey Area transmission lines cross the Obed River upstream of its WSR section.	Section figures and text have been revised to identify and discuss the Manhattan Project National Historical Park and the Obed River Wild and Scenic River.
23	2.1.3.6	DP	ETNG submitted a request for pre-filing to FERC on May 6, 2022, and submitted draft resource reports in June and December 2022. There are additional specific references to ETNG's December 9, 2022, draft resource report filing below that would benefit from improved context here. NPS understands that ETNG anticipates filing their application with FERC in July 2023.	Revised text to state that ENTG submitted draft Resource Reports to FERC under Docket No. PF22 in June 2022 followed by revised Resource Reports in December 2022.
24	2.1.5	DP	…but was not selected due to…	Updated text to state the conversion of the existing coal units to natural gas fuel was also considered as an alternative to the retirement of the existing KIF,but was eliminated from detailed review. Although this alternative would have utilized the existing plant boilers of the current KIF coal plant, the generating plant would have been approximately 30 percent less efficient than the proposed CC and would be expected to have shorter lifespan. This, in addition to the potential for continued material condition issues and the O&M of an older, larger plant, lead to this alternative being dismissed from more detailed consideration.
25	2.1.5.1	DP	NPS understands that these alternatives are ETNG's, but what about ETNG's Line 3200-1 system?	No change. Not provided in draft resource reports because The Line 3200-1 system was not included in ETNG's draft resource reports because it was ruled out early on due to substantially higher cost.

Response Number	Section	Commentor	Comment	Comment Resolution/Updates to the Document
27			From NPS Geomorphologist EB: The faults are ancient but have been reactivated to release stress accumulated through much of the eastern North	
			(MMI) (VI and greater) has caused significant slope failures during past seismic events. Using relationships between rock cliffs subjected to PGA and PGV in this range experienced rockfall. The lower limit for any seismic triggering of	
30	3.5.1.1.2.4	DP	From NPS Geomorphologist EB, here and elsewhere: "Unlikely to occur" and "low probability" are not necessarily the same thing unless "unlikely to occur" is specifically defined.	Revised to clarify that earthquakes are unlikely to occur in the vicinity of the Study Area and, as such, the potential for soil liquefaction to occur in the Study Area is low.
31	3.5.1.2.2.6	DP	See previous comment from NPS Geomorphologist EB.	See response to Comment #30 above.
32	3.5.1.2.2.6	DP	From NPS Geomorphologist EB: See previous comment about site specific steep slopes. The USGS landslide incidence and susceptibility mapping is not intended to replace site specific evaluations in area of steep slope.	Sentence deleted to avoid confusion.

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34	3.5.1.2.3.1	EB	Same comment as above: Because steeper slopes in this part of the country are more likely to be forested, this is somewhat misleading. Vegetation can reduce landslide frequency by affecting hydrologic conditions, but steeper slopes are more prone to landslides than less steep slopes with or without vegetation.	See response to Comment #28 above.
35	3.6.2.1.1.2	JD	Wild and Scenic River are protected by more than just Section 7(a). For example, Section 10 provides an antidegradation requirement. Maybe just say they are protected subject to the Wild and Scenic River Act.	Recommended revision accepted.
38	3.7.1.1	AS	This statement is misleading and should be revised. It is well established that pollutants from power plants and other industrial sources can undergo long-range transport, contributing to air quality issues in areas far downwind of the source.	Revised by adding a qualifying statement with comparison of coal/oil vs. natural gas combustion.
39	3.7.1.1.8.4	AS	The NPS agrees with this conclusion and as noted elsewhere in our comments, we recommend that TVA take a more detailed look at the cost comparisons between Alternatives A and B based on more-recent information.	The text was revised as follows: All action alternatives significantly reduce system carbon intensity, compared to the No Action Alternative. The highly efficient advanced-class CC and Aero CTs in Alternative A reduce system carbon emissions by offsetting coal generation and by improving the combined fuel efficiency of the entire TVA gas fleet. Solar facilities in Alternative B reduce system carbon emissions by offsetting coal and gas generation, and while existing fossil units increase generation for battery charging or when solar is not available, this Alternative has the lowest system carbon rate (see Appendix B, Appendix H, and Appendix I for details on the carbon rate analysis). Although Alternatives A and B would help achieve the Administration's goal of reducing emissions from overall federal operations, Alternative B likely would go further in achieving the goals outlined in EO 14057 and 14082, the targets agreed to in the Paris Agreement, and National net zero policy. The Alternatives Evaluation includes a carbon rate comparison and the LCA goes into more detail. TVA remains committed to achieving the goals under these Executive Orders to the extent these goals can be achieved consistent with other statutory mandates applicable to TVA under the TVA Act, such as the TVA Act's least-cost planning requirements and the requirement to provide power at rates as low as feasible. GHG mitigation measures and their impacts are further discussed in the Environmental Consequences section of this EIS. For more information on solar cost and supply chain issues please see response to #13.

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			acceleration from our two previous analyses. For more than three quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace." (See Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment, available at: https://energyinnovation.org/publication/coal-cost-crossover-3-0-local-renewables-plus-storage-create-new-opportunities-for-customer-savings-and-community-reinvestment/)	Comment noted.
41	3.7.2.3.1.4	AS	We appreciate that TVA included an Estimated Life Cycle GHG Emissions and Associated Social Costs assessment in the ADEIS and also presented the social costs for each individual KIF alternative rather than on a TVA systemwide basis. The life cycle assessment for each alternative improves transparency by considering the indirect effects of GHG emissions from upstream and midstream natural gas well drilling, production, and transport associated with Alternative A. It also provides a more meaningful method for comparison among alternatives by addressing the "cradle-to-grave" impact of natural gas combustion. TVA's analysis shows that, the preferred alternative, Alternative A, has the highest estimated GHG lifecycle emissions and associated future social cost of any of the action alternatives. As a federal agency, TVA has an opportunity to "lead by example" and replace the KIF coal-fired generation with renewable sources, measures that are necessary to implement the goals of EO 14057 to "achieve a carbon pollution-free electricity sector by 2035 and net-zero emissions economy-wide by no later than 2050." While natural gas-fired electricity generation is cleaner than coal-fired generation, it still emits criteria air pollutants that impact parks and approximately half the amount of carbon dioxide (CO_2) on a pound-per-megawatt basis, compared to coal (see emission summaries). It is anticipated that the natural gas plants constructed under Alternative A would require retrofits with carbon capture and storage to achieve a carbon-free electricity sector by 2035. Given this, it may be more cost-effective over the life of the plant to consider greater renewable replacement generation from the outset.	Comment noted.
42	3.7.2.3.1.4	AS	Again, natural gas-fired electricity generation is cleaner than coal-fired generation, but still emits approximately half the amount of carbon dioxide (CO_2) on a pound-per-megawatt basis, compared to coal (see emission summaries). In order to meet the goals of EO 14057, it is anticipated that the natural gas plants constructed under Alternative A would require retrofits with carbon capture and storage to achieve a carbon-free electricity sector by 2035. Given this, it may be more cost-effective over the life of the plant to consider greater renewable replacement generation from the outset.	Comment noted. TVA has committed to ensuring that the design of the Alternative A CC/Aero CT plant would enable and accommodate potential future modifications for carbon capture and the combustion of hydrogen (CC units only) as a replacement or supplemental fuel for natural gas when these technologies mature to scale. The proposed CC units under Alternative A would be designed to be 5 percent hydrogen capable at commissioning by adding balance of plant equipment that includes areas for future hydrogen storage, appropriately sized piping, and a blending station during the original construction. TVA would also purchase a CC unit capable of burning at least 30 percent hydrogen, by volume, with modifications to the balance of plant once a hydrogen source is available. TVA would only consider burning hydrogen as a part

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				of test burns or normal operations when it is commercially available at an acceptable chemical content that would reduce carbon emissions and be price competitive in the market at that time. It is important to note that once a viable option for future mitigation projects is identified, TVA would conduct additional analyses to determine proposed pipeline routes, costs, storage requirements, or other needs with hydrogen fuel incorporation. TVA would analyze the site- specific impacts associated with any future mitigation that is planned as additional details become available. TVA has considered the USEPA's draft whitepaper on reducing GHG emissions from CTs (USEPA 2022b) and anticipates the efficiency, effectiveness, scalability, and economics of these systems to improve in the next several years, allowing for more informed decisions in the future when adequate storage locations or pipelines are identified for both the delivery of hydrogen and the storage or use of captured CO2. TVA is exploring partnerships with federal agencies and peer utilities to advance the research and development of both alternative fuels and CCS technology, which could enable their use at existing or future TVA facilities. In addition to the current cost and maturity challenges with CCS, the potential geological features (i.e., karst instability and tendency to develop sinkholes) of the Kingston Reservation pose further challenges to the consideration of CCS at this site.
43	3.7.2.3.7	AS	The NPS appreciates that TVA intends to factor future retrofits of carbon capture and storage into the design of the proposed combined cycle plant. We recommend that TVA incorporate the costs of such future retrofits into their cost analyses and financial risk assessment. It is possible that the LCOE of carbon capture and storage retrofits may prove to be more costly (on a $/MWh basis) than developing renewables from the outset and this should be addressed in the DEIS.	There are many uncertainties around the availability and cost of carbon capture technology. The combined cycle plant in Alternative A is designed to support potential implementation but given this technology is not deployable today, it is not part of the Alternatives Evaluation. See Response to comment #42 and Section 2.1.4.2 in the DEIS.
44	3.7.2.4.1.2	AS	Table 3.7 8 reflects an estimated 9.8 million tons of total life cycle CO2 emissions are associated with Alternative B. However, as noted here, there are no operational emissions associated with Alternative B. The document does not disclose what solar-related activities these emissions are associated with (i.e., are they one-time construction emissions or associated with upstream or down-stream activities) or what emission factors were used to derive these estimates. We recommend that TVA disclose this information in the DEIS.	The total life cycle CO2 emissions associated with Alternative B come from upstream and downstream activities which include raw material extraction/acquisition, product manufacturing and transport, site construction, and future deconstruction/demolition and disposal. This is explained in the DEIS section 3.7.2.4.1.4 entitled GHG Effects from Direct and Indirect Emissions – Life Cycle Analyses for Alternative B and in the referenced Appendix I which contains details on the individual resource GHG LCAs.
45	3.7.2.4.1.4	AS	Please clarify what activities/emission sources the lifecycle CO2e emissions estimates of 9.8 million tons associated with Alternative B are attributed to. This is unclear because as noted in Section 3.7.2.4.1.2, "Operation of the solar and storage facilities are not expected to produce any emissions."	See response to Comment #44. Note that the statement referenced in this comment refers only to Alternative B emissions that occur during its operation. As noted in response to Comment #44, the lifecycle estimates for Alternative B include upstream and downstream activities, not just operation of the solar and storage facilities.

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47	3.9.1	AS	Emissions from TVA facilities have had a direct impact on the air quality in National Park System units across the Cave, and Shenandoah National Parks over the past forty years has shown that these airborne pollutants are	Section 3.9.1 updated with regional climate section that discusses GSMNP and Obed Wild and Scenic River.

This document incorporates comments received from cooperating agencies, the U.S. Environmental Protection Agency (USEPA) and the National Park Service (NPS), in response to their review of the Final Environmental Impact Statement (FEIS) prior to its public release and presents TVA's responses to those comments. Comments submitted and TVA's responses to those comments are summarized for USEPA comments in Table L2.1 and for NPS comments in Table L2.2.

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Table L2.1 Response to USEPA Comments on the Final EIS Document

Comment Number	Section	Commentor	Comment	Comment Resolution/Updates to the Document
1	3.7.1.1.8.2	EPA	EPA recommends that this section be updated based on the Fifth National Climate Assessment. NCA2023.globalchange.gov	NCA5 was reviewed but the updated data for this section of the EIS was not observed in NCA5. Therefore, appropriate data from the NOAA 2022 reference was used to update this section of the EIS.
2	3.7.2.1	EPA	This statement appears to be inconsistent with the construction permit application for Alternative A submitted to TDEC in November 2023. EPA requests and opportunity to discuss this disparity with TVA staff prior to issuance of the FEIS.	Direct emissions comparisons between the separate and distinct air construction permitting process and the NEPA EIS process are not appropriate as they represent two distinctly different emissions comparison methodologies. Under NEPA, TVA has assessed the reasonably foreseeable effects of expected future emissions. Thus, the KIF EIS Alternative A emissions represent projected actual emissions from operation, which are compared to the average of past (2018-2020) actual emissions from the operation of the existing nine Kingston coal-fired boilers to determine the net change in actual emissions for actual expected impacts. KIF EIS Alternative A actual emissions use an annual capacity factor. The annual capacity factor represents how TVA predicts and expects the associated emissions units to operate on an average basis over the life of the proposed project. In contrast, the October 2023 air permit-to-construct application submitted for the CC/Aero CT plant proposed under Alternative A of the EIS, a capacity factor is not used because the permit application must be completed in accordance with relevant regulatory requirements at 40 CFR 52.21(a)(2)(iv)(d) which require use of project potential emissions, as defined by 40 CFR 52.21(b)(4), and which are significantly higher than projected actual emissions, as would be expected for most any project. The methods used to determine potential emissions are explained in Appendix B of the October 2023 air permit-to-construct application submitted for the CC/Aero CT plant, as proposed under Alternative A of the EIS, and represent proposed emission units operating at maximum capacity either continuously (e.g., 24 hours per day, 365 days per year) or at the maximum hours allowed via the applicable regulation--neither of which are realistic for projecting actual operations, as explained in Appendix B of the air permit application (TVA 2023h). Furthermore, baseline actual emissions presented in Table 3-1 of the CC/Aero CT plant October 2023 air permit-to-construct application are defined by 40 CFR 52.21(b)(48) and represent the highest 24-month rolling average of the most recent 5-year contemporaneous operating period; the KIF EIS analysis of Alternative A used the "3-year averaged emissions" which is more representative of actual emissions from recent operation. Once the CC/Aero CC Plant is constructed and operational, TVA expects to retire KIF coal-fired units 1 through 9 from service. The emission caps that TDEC uses to ensure PSD avoidance are based on the highest two-year average baseline emissions for KIF coal-fired Units 1 through 9 plus the applicable 40 CFR §52.21 Significant Emission Rate for each criteria pollutant. TVA has reviewed this concern and was able to revise the air permit application to provide clarity and address the concerns identified in this EPA comment. The revised air permit-to-construct application was submitted by TVA in January 2024.
3	3.7.2.3.1.1	EPA	Suggested revisions given that a permit application for Alternative A has already been submitted to TDEC.	Revisions incorporated into FEIS.
4	3.7.2.3.1.2	EPA	These reported values are different, in some cases substantially, than those presented in the recently submitted construction application for Alternative A (KIG OCT 2023 p. 3-1). The application shows a potential increase in NOx, PM, VOC and GHG emissions. EPA requests the opportunity to discuss these disparities with TVA prior to release of the FEIS.	As addressed in response to Comment Number 2 above, the process for netting out of PSD is described in Appendix B of the air quality permit application (TVA 2023h). TVA reviewed this concern and was able to revise the air permit application to provide clarity and address the concerns identified in this EPA comment. The revised air permit-to-construct application was submitted by TVA in January 2024.
5	3.7.2.3.1.2	EPA	The air permit application and referenced netting analysis submitted to TDEC in November 2023 shows that the facility will net out of PSD review. However, it does not show a net reduction for all pollutants. Rather it shows a reduction below the PSD significance thresholds, with the exception of GHG emissions, for which there is a projected 344,785 TPY increase in emissions from Alternative A, compared to baseline average emissions from 2018 to 2020. (KIG OCT 2023 p. 3-1)	See response to Comment Number 2. The process for netting out of PSD is described in the air quality permit application.

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6	3.7.2.3.1.2	EPA	The differences between Table 3.7-3 and the corresponding table in the cited air permit application, Table 3-1 are significant. As mentioned elsewhere, the reasonably foreseeable emission estimates should be based on the best available data, which would include the forecasted emissions for this facility, rather than average EIA rates for existing facilities nationwide.	See response to Comment Number 2.
7	3.7.2.3.1.2 Table 3.7-3	EPA	These emissions estimates are in many cases substantially different that those presented in TVA's OCT 2023 construction permit application for Alternative A submitted to TDEC in November 2023. For example, the construction permit estimated the GHG emissions of KIG to be approximately 4.5 million TPY, rather than the 1.7 million TPY given in the EIS. This is due to the low average national EIA load factors TVA assumed for this analysis, instead of using load factors derived from more relevant source specific analysis, such as TVA's load modelling. As drafted, this analysis does not appear to provide an assessment of reasonably foreseeable emissions and, hence, impacts. Per CEQ guidance, this analysis should be based on the best science/data using the most accurate load forecasts, which can include a range of modeled demands for these units. The national EIA data does not represent operation of new highly efficient units and does not appear to be consistent with TVAs representations of the need for at least 1500MW to 1600MW of firm dispatchable power in the Knoxville area to replace the KIF units and meet growing demand. In addition, it would be highly inefficient to operate the SCR systems and oxidation catalysts at the loads assumed. Given that EPA commented on this concern in the draft EIS and it is fundamental to the air quality and GHG/climate impact analysis, EPA requests the opportunity to discuss this disparity with TVA prior to the release of the FEIS.	See response to Comment Number 2. Table 3.7-3 provides a comparison of estimated pollutant operational emissions. The EIS also includes two GHG LCAs that estimate future direct and indirect GHG emissions and associated social costs for each alternative. The first LCA (individual) is on an individual replacement resource by alternative basis while the second LCA (system-wide) reflects simulated system-wide generation dispatch of the TVA fleet. The system-wide LCA provides a more thorough and accurate view of overall GHG effects when comparing each alternative. The system-wide view provides critical context into how the specific resource retirements and replacements, underpinning the assumptions of each of the Proposed Action Alternatives, integrates into the system overall and meets TVA's load forecast. TVA needs at least 1,500 MW of firm, dispatchable power to replace Kingston Fossil so as not to leave TVA short on required generation and capacity to meet system demands and planning reserve margin targets. This value is based on Kingston Fossil's capacity and TVA's expected load growth. Firm, dispatchable power ensures that TVA can call on the generating capacity year-round, particularly during peak load events. The annual capacity factors discussed and utilized do not represent, or equate to, emissions-unit operational loads. The EIS analysis assumed full load operations of each emissions unit to which the annual capacity factor is applied. TVA disagrees with EPA's statement that it would be "highly inefficient to operate the SCR systems and oxidization catalysts" because the SCR equipment is designed and expected to function efficiently under most load sizes except low load sizes. The installation of post-combustion controls is not indicative of projected actual operations. Post-combustion controls are installed to accommodate air permitting requirements under 40 CFR 52.21 (see response to Comment Number 2).
8	3.7.2.3.1.5	EPA	This sentence appears out of place and its relationship to the rest of the paragraph is unclear. The sentence appears to be related to the subsequent paragraph. EPA recommends that such assertions include references to the NCA5 or IPPC reports.	Moved sentenced to beginning of following paragraph. Other information in these paragraphs is not based on NCA5 or IPPC information but specific climate change effects on Alternative A.
9	3.7.2.4.1.5	EPA	See parallel paragraph for Alternative A above (3.7.2.3.1.5) which indicates "the main impacts of climate change are flooding from increased precipitation and the increase in sea level due to the melting of ice resulting from increases in global temperatures," which is different than the statement here. Does TVA intend to indicate in these paragraphs what the main impacts of climate change are on the proposed facilities? If so, suggest clarifying these sentences and including appropriate references.	Referenced paragraph has been revised in the final EIS for clarification.

Table L2.1 Response to USEPA Comments on the Final EIS Document

Comment Number	Section	Commentor	Comment	Comment Resolution/Updates to the Document
10	Range of Alternatives	EPA	The U.S. Environmental Protection Agency (EPA) continues to have concerns that the range of alternatives considered within the administrative draft Final Environmental Impact Statement (FEIS) is limited to only two action alternatives, the preferred alternative and an alternative consisting of 100% renewable energy generation. Only considering two alternatives fails to disclose the available options between those two "endpoints" of a 1,500 MW natural gas fueled CC/Aero CT Plant and 100% renewable energy, which Tennessee Valley Authority (TVA) has essentially dismissed as not meeting the necessary timelines of coal boiler retirement. As written, the administrative draft FEIS essentially presents only the preferred Alternative A and the No Action Alternative as viable. The EPA recommends that the TVA consider a reasonable range of alternatives that considers at least one alternative for formal analysis that provides for a decarbonization transition strategy at this facility, and still meets replacement power generation and growth requirements - perhaps comprised of a combination of peak shaving, increased generation from other production units, energy efficiency, and demand-management to meet capacity requirements just until greater renewable energy generation is available or a blended strategy that combines a more balanced mix of renewables and natural gas.	In conducting an alternatives analysis, agencies must "[e]valuate reasonable alternatives to the proposed action, and for alternatives that the agency eliminated from detailed study, briefly discuss the reasons for their elimination." 40 CFR § 1502.14(a). An agency must consider a reasonable number of alternatives that are "technically and economically feasible," 42 U.S.C. § 4332(C), which are bounded by the purpose and need for the proposed agency action. Id. at § 1502.14(f), § 1502.13; see also Coal. for the Advancement of Reg'l Transp. v. Fed. Highway Admin., 576 F. App'x 477, 481 (6th Cir. 2014); Citizens Against Burlington, Inc. v. Busey, 938 F.2d 190, 195 (D.C. Cir. 1991) ("[A]n alternative is reasonable only if it will bring about the ends of the federal action."). The purpose of the proposed action is to retire and decommission all nine of the KIF coal units by the end of 2027, and to implement replacement generation that can supply at least 1,500 MW of firm, dispatchable power by the time the units are retired at the end of 2027. The need for the Proposed Action is to ensure that TVA is able to meet required year-round generation and maximum capacity system demands and planning reserve margin targets, particularly during peak load events. To this end, the replacement generation must have the capability to provide firm, dispatchable power to ensure grid stability in the East Tennessee region. This proposed action is one piece of TVA's overall asset strategy, which blends a combination of resource technologies to allow TVA to support affordable, reliable, and cleaner energy for its customers. TVA's asset strategy already contemplates the blending of resources to provide the least-cost, optimal portfolio under a variety of future conditions, including the addition of 10,000 MW of solar by 2035. A key beneficial result of TVA's asset strategy is the reduction of carbon emissions. As discussed in detail in EIS Section 1.1, this action is a specific, discrete component of that asset strategy and is consistent with the 2019 IRP and the need to establish new capacity in the TVA region, increase reliability and flexibility, integrate larger amounts of renewables on the grid, increase energy efficiency, and meet TVA energy production goals. In addition to the No Action Alternative, TVA considered two action alternatives in the DEIS: Alternative A- the retirement of KIF and construction and operation of a combined cycle (CC)/Aero CT gas plant at the same site with solar and battery and Alternative B- the retirement of KIF and construction and operation of solar and storage facilities, primarily at alternate locations. All natural, cultural and socioeconomic impacts associated with each alternative are analyzed in Chapter 3 of the EIS. Section 2.1.5 of the EIS has been revised to further describe alternatives that were "considered but not carried forward" for more detailed analysis because they do not meet the project purpose and need. In particular, in EIS Section 2.1.5, TVA evaluated a number of other resource options for replacement generation, including: natural gas-fired CC, natural gas-fired CT, battery energy storage systems (BESS), utility-scale photovoltaic (PV) solar, hydro pumped storage, small modular reactors, wind, energy efficiency, demand response, and distributed generation. TVA also evaluated other blended alternatives, including one that combines a lower amount of natural gas with other technologies, such as solar and battery storage. Other blended alternatives would not meet the purpose and need because they would not provide 1500 MW of firm, dispatchable power by 2027. TVA is already planning for a system-wide blend that includes the addition of significant renewable generation on the TVA system. In this asset-specific EIS, any blended alternative analyzed would have a substantial renewable/storage component, which would require similar transmission work and durations (i.e., 8-9 years) associated with Alternative B. Therefore, any such blended alternative would not meet the purpose and need to have 1500 MW of firm, dispatchable operation in commercial operation by the end of 2027. Additionally, the pipeline project is necessary to support the peaking requirements of the natural gas generation units as designed. A blended alternative with lesser amounts of natural gas does not meet the purpose and need since the non-gas component could not be installed by 2027 and would not provide firm, dispatchable power necessary to ensure grid stability in the Eastern Tennessee region. Further, as described in Resource Report 10 of ETNG's application, the purpose of the Ridgeline Project is to provide 300,000 Dth/day (300,000,000 standard cubic feet per day) of natural gas transportation capacity and 95,000 Dth (95,000,000 standard cubic feet per day) of parking capability to deliver gas to TVA's Kingston Plant site if TVA chooses to replace coal-fired generation at KIF with the CC/Aero CT Alternative at the same site. Any viable blended alternative that utilizes the Kingston Reservation would still require the evaluation and construction of ETNG's Ridgeline Expansion Project.

Table L2.1 Response to USEPA Comments on the Final EIS Document

Comment Number	Section	Commentor	Comment	Comment Resolution/Updates to the Document
11	Air Quality Emissions Estimates and Load Factors	EPA	The administrative draft of the FEIS continues to use Energy Information Administration (EIA) national average load values (of 55% and 10% respectively) for the use of the new highly efficient combined and simple cycle KIF combustion turbines in the facility level air quality and greenhouse gas (GHG) analysis. These load assumptions appear inconsistent with TVA's statement of purpose and need and appear to substantially underestimate the GHG and criteria pollutant emissions for these units. The emissions estimates in the administrative draft FEIS are, for most of the pollutants, substantially lower than those presented in TVA's October 2023 construction permit application for Alternative A submitted to the Tennessee Department of Environment and Conservation (TDEC) in November 2023 and referenced in this administrative draft FEIS. For example, the construction permit estimates the GHG emissions of KIF to be approximately 4.5 million tons per year (TPY), rather than the 1.7 million TPY estimated in the administrative draft FEIS. TVA has indicated that these values were chosen due to operational uncertainty. However, differences from the air permit application and system-wide analysis are beyond the range of typical uncertainty. This is due to the low 10-year average national EIA load factors TVA assumed for this analysis. This national EIA data typically does not represent operation of new highly efficient units with the demand TVA has described in the administrative draft FEIS. As drafted, and without further support, this analysis does not appear to provide an assessment of reasonably foreseeable emissions and, hence, impacts. Per Council on Environmental Quality (CEQ) guidance, this analysis should be based on the best science/data using the most accurate load forecasts, which can include a range of modeled demands for these units. In addition, our comments on Chapter 3.7 of the administrative draft FEIS identify several statements in the document that are inconsistent with the outcome of the referenced analyses in the air permit application. Given that the EPA commented on this concern previously and it is fundamental to the air quality and GHG/climate impact analysis, the EPA requests the opportunity to discuss this disparity with TVA prior to the release of the FEIS.	See response to Comment Number 2 and Number 7. TVA disagrees that the load assumptions used in TVA's GHG analysis are inconsistent with TVA's stated purpose and need. TVA has estimated the 55 percent and 10 percent capacity factors as a lifetime average based on U.S. Energy Information Administration (EIA) industry averages of actual capacity factors over the last 5 to 10 years. TVA believes these are reasonable estimates for use as part of the lifetime analysis considering there are many unknown or variable factors affecting capacity factors that will occur in the future that cannot be predicted. TVA's reasoning regarding the capacity factors used in this EIS is detailed in the individual resource LCA methodology discussion provided in Appendix J. TVA believes the statements in Section 3.7 remain consistent with the outcome of the referenced analyses in the air permit application. The air permit application provides emissions in terms of potential to emit whereas the EIS provides emissions under reasonably foreseeable actual operating conditions. Potential to emit represents the worst-case conditions using maximum capacity and continuous operation. Actual operating conditions over the life of the plant would generate less emissions than a potential to emit scenario that is unrealistic.

Table L2.1 Response to USEPA Comments on the Final EIS Document

Comment Number	Section	Commentor	Comment	Comment Resolution/Updates to the Document
12	Social Cost of Greenhouse Gas (SC-GHG) Estimates	EPA	On January 20, 2021, President Biden issued Executive Order (EO) 13990: Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, which reaffirmed applying the SC-GHG values from the peer reviewed 2021 Interagency Working Group (IWG) report. This EO revoked President Trump's EO 13783 which used SC-GHG estimates that attempted to focus on the domestic impacts of climate change as estimated by the models to occur within U.S. borders and were calculated using two discount rates recommended by the Office of Management and Budget's (OMB) Circular A-4, 3 percent and 7 percent. EPA indicated in our DEIS comment letter that the 2020 Social Cost of Greenhouse Gas (SC-GHG) estimates do not reflect current scientific literature on climate change and its impacts and therefore should not be used. However, the administrative draft FEIS continues to include and use the 2020 SC-GHG estimates, which may mislead the public and decision makers on the scope of the environmental impacts of TVA's preferred alternative. These estimates do not reflect the best available science, have not undergone expert peer review, and should not be applied in any NEPA analysis. Furthermore, there is no mention of EO 13990 in the administrative draft FEIS even though several other EOs that address GHG reductions are described. TVA should follow the current Administration's direction provided under EO 13990 and the guidance issued by CEQ on analyzing GHG and climate change effects of proposed actions under NEPA, which is consistent with EO 13990. In the regulatory impact analysis of the EPA's December 2023 Final Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review", the EPA estimated climate benefits using a new set of SC-GHG estimates that reflect the state-of-the-science and address recommendations from the National Academies of Science, Engineering, and Medicine (NASEM) on estimating SC-GHG. Given TVA would like to present the social cost as a range, the EPA recommends that TVA monetize the climate damages of their alternatives using the EPA estimates of SC-GHG, which incorporate the most recent scientific advances on climate change and its economic impacts, in the FEIS. These values have undergone an expert peer review and are consistent with the recommendations of the NASEM.	In the EIS, TVA has social cost metrics from both the current and previous Administrations. Presenting estimated social costs as a range of values from successive Administrations provides decision-makers and the public with better information in an area fraught with uncertainty. These estimates have changed from Administration to Administration. Nonetheless, TVA has used the SC-GHG estimates published by the IWG in its analysis, together with other SCC metrics used under the previous Administration to provide a range of potential impacts. These points are explained in the EIS, so it is unclear how TVA's analysis "may mislead the public and decision makers on the scope of the [preferred alternative's] environmental impacts." Monetizing social costs of GHG is not an exact science and presenting the social costs as a range of values provides decisionmakers and the public with better information for making an informed decision. Indeed, the IWG does not require agencies to prioritize or select one discount rate over another. In fact, a recent memo from the IWG (December 22, 2023: https://www.whitehouse.gov/wp-content/uploads/2023/12/IWG-Memo-12.22.23.pdf) states that agencies should "use their professional judgment to determine which estimates of the SC-GHG . . . reflect the best available evidence, are most appropriate for particular analytical contexts, and best facilitate sound decision-making." Another consideration is that no matter what social cost of GHG rates are used, the percent difference in social costs when comparing each action alternative to the no action alternative is effectively the same. The use of February 2021 IWG SC-GHG rates is referenced in the CEQ January 9, 2023, NEPA GHG guidance document for SC-GHG calculations. The guidance states that agencies should "apply the best available estimates of the SC-GHG [61]", and footnote 61 refers to the February 2021 IWG SC-GHG rates. Although the EPA has recently developed different SC-GHG rates under a specific rulemaking, the IWG has not published new rates since the February 2021 Technical Support Document. TVA has used a range in the EIS based on social cost metrics from different Administrations rather than specific figures that may have been used by a federal agency in a particular rulemaking. The EIS has been revised to include a description of EO 13990. Note that even without this addition, the EIS conforms to the subsequent NEPA GHG policy guidance issued by CEQ on January 9, 2023. This guidance document states it is consistent with EO 13990, as well as others mentioned in the EIS, including EO 14008 and EO 14057. The EIS addresses all of the primary elements in this guidance document regarding GHG emissions analysis and climate change and presentation of SC-GHG. There are no other relevant directives in EO 13990 regarding GHG and climate change and SC-GHG that are not covered by the CEQ January 9, 2023, guidance document.

Table L2.1 Response to USEPA Comments on the Final EIS Document

Comment Number	Section	Commentor	Comment	Comment Resolution/Updates to the Document
13	Using SC-GHG Values	EPA	TVA continues to adjust the SC-GHG values from the IWG report, which are reported in 2020 dollars, by 2% to account for inflation, claiming a nominal value for their capacity expansion model is needed. However, it is incorrect to adjust the SC-GHG values for inflation prior to multiplying them by the emission changes to calculate the monetized climate damages. The SC-GHG is the monetary value of the net harm to society associated with adding a small amount of GHG to the atmosphere in a given year. In principle, it includes the value of all climate change impacts from the additional GHG, ranging from human health effects to property damage from increased flood risk natural disasters. The SC-GHG, therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton. As explained in the 2021 IWG report, to calculate the SC-GHG for a given year, the stream of future climate damages (timeframes of more than a decade) from an additional unit of emissions was estimated. To get the value of emissions the year it was released, year t, the stream of future damages is discounted to the present value year t. This calculation was done for each year from 2020 to 2050 for discount values of 2.5%, 3%, 5% and the 95th percentile of estimates at the 3% discount rate. Using the annual Gross Domestic Product (GDP) Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) National Income and Product Accounts, the annual SC-GHG are reported in 2020 dollars for emission years 2020-2050 in Tables A-1, A-2, and A-3 in the IWG Technical Support Document. The SC-GHG values represent the future market and nonmarket damages associated with climate change and as the EPA stated in our letter on the DEIS, the values should not be adjusted for inflation to create a nominal value. The nominal values, which are not appropriate measures of the climate impact, are cited and described throughout the document. The EPA is willing to provide technical assistance on the appropriate use of the SC-GHG values. On page 392 of the administrative draft FEIS, the document states "the SC-GHG results for TVA system-wide effects essentially show that both action alternatives are within the same order of magnitude, regarding their overall potential GHG effects, therefore, due to the purpose and need of this EIS, the SC-GHG outcome was not determinative for the Preferred Alternative decision." However, Table 3.7-4 shows over $100 million in direct effects per year for operational emissions. This is not the same order of magnitude, especially over the life of the plant, when there are billions of dollars in differences. Page 408 states "The associated social monetary benefit of CO2 reductions would be approximately $37 million per year (nominal dollars) starting in 2032 and $123 million per year (nominal dollars) starting in 2035 and would increase in each consecutive year based on the annual increase in social cost $/ton rates." The FEIS should identify the value that is being used here to monetize.	The "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" (SC-GHG TSD) provides the interim SC-CO2, SC-CH4, and SC-N2O estimates in 2020 dollars. Furthermore, Tables 1-3 of this document, and corresponding footnotes, indicate that all values identified in the document are in 2020 dollars. Therefore, these estimates needed to be adjusted to account for inflation as the capacity expansion model relies on nominal inputs. A TVA system-wide approach provides critical context into how the specific resource retirements and replacements, underpinning the assumptions of each proposed action alternative, integrate to the system overall, and completes the overall characterization of the cumulative impact of the combined system and its performance. A TVA system-wide comparison of GHG emissions is the most effective way to accurately identify incremental emission differences between the alternatives because it illustrates how the entire TVA system is expected to operate with each alternative. The $7 billion SC-GHG for Alternative A comparison to the $1.05 billion SC-GHG for Alternative B in the DEIS is only for the individual resource LCA, which does not take into account how the rest of the TVA power generation system would operate under those alternatives. In addition, the $7 billion and $1.05 billion are absolute nominal values and have been updated in the FEIS to $7.7 billion and $672 million, respectively. These nominal values correspond to $2.07 billion and $347 million, respectively, in Net Present Value (NPV, 2023 $). The system wide LCA is a more holistic analysis that accounts for how the entire TVA system would operate under each alternative. The system wide LCA analysis results in a narrower divergence between the SC-GHG savings for Alternative A ($1.85 billion NPV 2023 $) and Alternative B ($2.26 billion NPV 2023$) compared to the No Action Alternative (NAA), which is a difference of approximately $417 million NPV 2023 $.

Table L2.1 Response to USEPA Comments on the Final EIS Document

Comment Number	Section	Commentor	Comment	Comment Resolution/Updates to the Document
14	Environmental Justice	EPA	The administrative draft FEIS documents do not indicate the positive or negative presence of potential disproportionate impacts on environmental justice communities resulting from the GHG emissions of the Action Alternatives. The EPA continues to recommend that the discussion of climate change and GHG acknowledge the disproportionate impact, both in exposure and vulnerability, that GHG emissions have on already overburdened and vulnerable communities.[1] This would be consistent with Executive Order 14096, Revitalizing Our Nation's Commitment to Environmental Justice for All, which affirms the national policy to advance environmental justice for all and defines environmental justice as "the just treatment and meaningful involvement of all people, regardless of income, race, color, national origin, Tribal affiliation, or disability, in agency decision-making and other Federal activities that affect human health and the environmental so that people are fully protected from disproportionate and adverse human health and environmental effects (including risks) and hazards including those related to climate change, the cumulative impacts of environmental and other burdens, and the legacy of racism or other structural or systemic barriers." (Section 2(b)(i)). [1] See, e.g., Climate Change and Social Vulnerability in the United States, the EPA (2021).	The second paragraph of Section 3.4 (the Environmental Justice section) of the EIS lists some of the vulnerabilities particular to minority and low-income populations, including higher levels of disease, disability, and other health problems, that were considered in TVA's analyses. Additionally, TVA added reference to Executive Order 14096 to the introduction of this section. TVA also modified the air quality, greenhouse gas emissions, and climate change conclusions in the Final EIS to recognize that, as there are environmental justice (EJ) populations in the vicinity of the Kingston reservation and these populations have histories of health vulnerabilities, disproportionate effects to EJ populations are possible with Kingston coal retirement and D4 activities and the implementation of other actions under Alternative A or Alternative B.

Table L2.2. Response to NPS Comments on the Final EIS Document

Response Number	Section	Comment	Comment Resolution/Updates to the Document
1	Summary	It has come to our attention that TVA recently submitted a Permit-to-Construct application (no. 230825) to the Tennessee Division of Air Pollution Control (DAPC). The application, which was received by DAPC on November 2, includes information that conflicts with information presented in the FEIS. For example, in the permit application, TVA is requesting a facility-wide emission limit that would allow TVA to continue to operate some of the coal fired units in addition to constructing the combined cycle unit and 16 CTs: "At completion of the project, TVA expects to retire KIF coal-fired Units 1 through 9 from service. However, TVA may seek to operate existing and proposed generating assets (e.g., several KIF coal-fired units along with KIG) to meet load demand while operating under emission restrictions (i.e., caps). The emission caps are proposed to be the highest two-year average baseline emissions for KIF coal-fired Units 1 through 9 plus the applicable 40 CFR § 52.21 Significant Emission Rate for each criteria pollutant. TVA may request a modification to the KIF Title V permit to add the emission caps." TVA's request presented in the DAPC permit application appears to be a blend of the no action alternative (continued operation of the nine coal-fired units) and the proposed action (shutdown of the nine coal-fired units and construction of the CC and 16 CTs) presented in the FEIS. The number of coal-fired units that would remain operational or how long they would operate is not addressed in the permit application. However, it appears the requested DAPC permit caps would allow TVA the flexibility to keep all nine units operating indefinitely as long as they remain below the emission caps. In addition, there are large discrepancies between the emissions presented in the DAPC permit application versus the FEIS. For example, the NOx emissions associated with the CC generation train and 16 aeroderivative simple CTs are significantly higher in Table 2-1 of the permit application than what is presented in Table 3.7-3 of the FEIS. According to the DAPC permit application, the CC generation train will emit 802 TPY of NOx and the 16 aeroderivative simple CTs will emit 642 TPY of NOx, but Table 3.7-3 in the FEIS reflects only 95 TPY and 84.2 TPY of NOx for the CC and CTs, respectively. The NOx emissions reported in the FEIS are 1,264.8 TPY lower than the potential NOx emissions reported in the permit. Likewise, the CO2e emission presented in the DAPC permit application are more than 2.7 million tons per year higher than those presented in the FEIS. This discrepancy suggests that the GHG and climate analyses presented in the FEIS could be significantly underestimated relative to the limits requested in the DAPC permit. Finally, in the FEIS, TVA proposes to retire and demolish the nine coal-fired units at the KIF and to construct and operate natural gas-fired or solar generating facilities to replace the retired generation for commercial operation by the end of 2027. The DAPC permit application notes that if TVA elects to shutdown some or all of the coal-fired units, this would not occur until 2028. Can TVA clarify these discrepancies in between the DAPC permit application and the proposed action and the potential emissions described in the FEIS? Does TVA intend to keep some (or all) of the coal-fired units operational after the CC and CTs units are constructed? We recommend that these are critical issues to address prior to moving forward with either the FEIS or the DAPC permit as they affect both the proposed action presented in the FEIS and the resulting analysis, including the air quality and GHG analyses.	As to the expected date of retirement of the KIF coal units, TVA clarifies that it expects to retire the coal units by the end of 2027 consistent with the purpose and need of the EIS. Any confusion created by the paragraph from the permit application quoted by NPS has been addressed by revising this paragraph in the application to eliminate language suggesting the coal-fired units would operate beyond 2027. Direct emissions comparisons between the air construction permitting process and the NEPA EIS process are not appropriate as they represent two distinctly different emissions comparison methodologies. These numbers do not create a discrepancy; instead, they reflect the distinct analyses required by these different types of environmental reviews. Under NEPA, TVA has assessed the reasonably foreseeable future effects based on *expected* future emissions. Thus, the KIF EIS Alternative A emissions represent *projected actual emissions* from operation, which are compared to the average of past (2018-2020) actual emissions from the operation of the existing nine Kingston coal-fired boilers to determine the *net change in actual emissions* for *actual expected impacts*. KIF EIS Alternative A actual emissions use an annual capacity factor. The annual capacity factor represents how TVA predicts and/or expects the associated emissions units to operate on an average basis over the life of the proposed project. In contrast, the October 2023 air permit-to-construct application submitted for the CC/Aero CT plant proposed under Alternative A of the EIS does not utilize a capacity factor because the permit application must be completed in accordance with relevant regulatory requirements at 40 CFR 52.21(a)(2)(iv)(d) which require use of *project potential emissions*, as defined by 40 CFR 52.21(b)(4), and which are significantly higher than projected actual emissions, as would be expected for most any project. More simply stated, the air permit application reflects the maximum amount of emissions that could result from the proposed action while the NEPA review reflects the expected emissions based on the projected operation of the plant. The methods used to determine potential emissions are explained in Appendix B of the October 2023 air permit-to-construct application submitted for the CC/Aero CT plant, as proposed under Alternative A of the EIS, and represent proposed emission units operating at maximum capacity either continuously (e.g., 24 hours per day, 365 days per year) or at the maximum hours allowed via the applicable regulation - neither of which are realistic for projecting actual operations. Furthermore, baseline actual emissions presented in Table 3-1 of the CC/Aero CT plant October 2023 air permit-to-construct application are defined by 40 CFR 52.21(b)(48) and represent the highest 24-month rolling average of the most recent 5-year contemporaneous operating period; the KIF EIS analysis of Alternative A used the "3-year averaged emissions," which is more representative of actual emissions from recent operation. Once the CC/Aero CC Plant is constructed and operational, TVA expects to retire KIF coal-fired units 1 through 9 from service by the end of 2027. The DAPC permit application has been revised accordingly. The emission caps that TDEC uses to ensure PSD avoidance are based on the highest two-year average baseline emissions for KIF coal-fired Units 1 through 9 plus the applicable 40 CFR § 52.21 Significant Emission Rate for each criteria pollutant.
2	Contents	Appendix P[1] introductory note only identifies the EPA as a source of comments.	The EIS included a separate page between the USEPA comment response table and the NPS comment response table. Appendix L[1] has been updated to clarify that the Appendix includes tables with responses to comments from the USEPA and the NPS.
3	3.6.2.1.1.2	Wild and Scenic Rivers should be capitalized.	Updated in FEIS.
4	3.7.2.3.1.2	Thank you for clarifying that SCR NOx controls will apply to both the combined cycle and simple cycle turbines. This is consistent with DOI/NPS recommendations provided in our July 3, 2023, comments provided on the DEIS.	Comment noted.

Table L2.2. Response to NPS Comments on the Final EIS Document

Response Number	Section	Comment	Comment Resolution/Updates to the Document
5	3.7.2.3.1.3	As noted in our DOI/NPS July 3, 2023, comment memo on the DEIS, future retrofits to reduce GHGs may be more costly and difficult than investing in renewable energy and storage options from the onset. We again encourage TVA to increase the renewable component of their generation fleet mix to the maximum extent feasible when selecting power generation replacement options for KIF and throughout the TVA system. We recommend that TVA provide a more detailed review of renewable energy options discussed under Alternative B.	This proposed action is one piece of TVA's overall asset strategy, which blends a combination of resource technologies to allow TVA to support affordable, reliable, and cleaner energy for its customers. TVA's asset strategy already contemplates the blending of resources to provide the least-cost, optimal portfolio under a variety of future conditions, including the addition of 10,000 MW of solar by 2035. A key beneficial result of TVA's asset strategy is the reduction of carbon emissions. As discussed in detail in EIS Section 1.1, this action is a specific, discrete component of that asset strategy. The purpose of the proposed action is to retire and decommission all nine of the KIF coal units by the end of 2027, and to implement replacement generation that can supply at least 1,500 MW of firm, dispatchable power by the time the units are retired at the end of 2027. The need for the Proposed Action is to ensure that TVA is able to meet required year-round generation and maximum capacity system demands and planning reserve margin targets, particularly during peak load events. To this end, the replacement generation must have the capability to provide firm, dispatchable power to ensure grid stability in the East Tennessee region. The current EIS analysis provides detailed assessment for both action alternatives. All natural, cultural and socioeconomic impacts associated with each alternative are analyzed in Chapter 3 of the EIS. For example, regarding air quality and GHG: (1) affected environment, existing conditions, and air quality status are discussed in detail for both alternatives; (2) operational emissions, where relevant/appreciable to the alternative, are calculated and compared to the No Action Alternative for both; (3) the individual resource life cycle analyses calculate emissions for both (the FEIS expands upon the individual life cycle segments for Alternative B by breaking out each segments' contribution); (4) the TVA system-wide life cycle analyses calculates emissions in the same manner for both Action Alternatives and compares to the No Action Alternative; and (5) social costs of GHG emissions are calculated and compared to the No Action Alternative in the same way for both Action Alternatives. Note that capital/operational cost estimates for Alternative B (found in Appendix B of the FEIS) have been revised for the FEIS to account for renewable energy credits to be implemented under the 2023 Inflation Reduction Act. Section 2.1.5 of the FEIS has been revised to further describe alternatives that were "considered but not carried forward" for more detailed analysis because they do not meet the project purpose and need. In particular, EIS Section 2.1.5 describes a number of other resource options that TVA evaluated for replacement generation, including: natural gas-fired CC, natural gas-fired CT, battery energy storage systems, utility-scale photovoltaic solar, hydro pumped storage, small modular reactors, wind, energy efficiency, demand response, and distributed generation. TVA also evaluated other blended alternatives, including one that combines a lower amount of natural gas with other technologies, such as solar and battery storage. As discussed further in Section 2.1.5, other blended alternatives would not meet the purpose and need because they would not provide 1500 MW of firm, dispatchable power by 2027.
6	3.7.2.3.1.4	As noted in our DOI/NPS July 3, 2023, comment memo on the DEIS, future retrofits to reduce GHGs may be more costly and difficult than investing in renewable energy and storage options from the onset. We again encourage TVA to increase the renewable component of their generation fleet mix to the maximum extent feasible when selecting power generation replacement options for KIF and throughout the TVA system. We recommend that TVA provide a more detailed review of renewable energy options discussed under Alternative B	See response to comment #5 above.
7	3.7.2.3.7	As noted in our DOI/NPS July 3, 2023, comment memo on the DEIS, the NPS continues to support the retirement of coal-fired EGUs and recommends more detailed consideration of renewable energy alternatives for replacement generation in the KIF proposal. This recommendation supports goals established in Executive Order 14057 to achieve a carbon pollution-free electricity sector by 2035.	See response to comment #5 above.
8	Appendix Q[3] – 10	No affiliation given.	No affiliation was listed by the individual in their comment submission.
9	Appendix Q[3] – 107	National Park Service, here and elsewhere.	Updated in Response to Comments, Appendix D[3], where Commentor is listed in parentheses it now states "National Park Service". Confirmed that references in the FEIS document have been updated to accurately reflect National Park Service or NPS.

[1]Appendix P from the DEIS is now Appendix L in the FEIS.
[2]Appendix C from the DEIS is now Appendix B in the FEIS.
[3]Appendix Q from the DEIS is now Appendix D in the FEIS.

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Appendix M – Concentric Report – Submitted for the Cumberland Fossil Plant Retirement FEIS

ASSESSMENT OF THE DRAFT ENVIRONMENTAL IMPACT STUDY AND RESPONSE TO CERTAIN REPORTS

PREPARED FOR:
TENNESEE VALLEY AUTHORITY

OCTOBER 3, 2022

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ATTACHMENTS

REPORT SCOPE AND SUMMARY OF FINDINGS

Background

The Tennessee Valley Authority (TVA) is proposing to retire two coal-fired units at the Cumberland Fossil Plant (CUF). As part of an assessment of the environmental impacts of retiring the two coal-fired units and replacing the generation provided by one of the retired CUF units, TVA is preparing an Environmental Impact Statement (EIS) in which TVA is assessing various alternatives for replacement generation, including: Alternative A - Retirement of CUF and construction and operation of a combined cycle combustion turbine (CC) Gas Plant at the same site; Alternative B - Retirement of CUF and construction and operation of simple cycle combustion turbine (CT) Gas Plants at alternate locations; and Alternative C - Retirement of CUF and construction and operation of Solar and Storage Facilities, primarily at alternate locations.

The scope of this report is to assess the reasonableness of TVA's identification of Alternative A as the preferred alternative in its Draft EIS. Alternative A involves the retirement of the two CUF coal-fired units and the replacement of the generation of one unit with a 1450 MW CC plant. In addition, this report responds to Attachment 2 submitted by the Southern Environmental Law Center titled "Critique of TVA's Alternatives Analysis in the Utility's Cumberland Fossil Plant Retirement, Draft Environmental Impact Statement"' authored by Grid Strategies, LLC and dated June 13, 2022 (Grid Strategies report) as well as Attachment 1 submitted by the Sierra Club titled "Clean Portfolio Replacement at Tennessee Valley Authority" authored by Synapse Energy Economics, Inc. and dated May 2022 (Synapse report).

Summary of Findings

Observation #1: The Board Approved 2019 IRP provides a solid basis and analytic framework for future resource decisions. TVA's 2019 Integrated Resource Plan (IRP) serves as the backdrop for near-term and long-term resource additions that will build on TVA's existing diverse asset portfolio to ensure low-cost, reliable, and clean electricity for TVA customers into the future. The 2019 IRP included an analysis of a broad set of resources, portfolios, inputs, future worlds, and sensitivities to provide a robust view of possible future outcomes. The resulting long-term strategy involves the pursuit of up to 14 gigawatts (GW) of solar, up to 5 GW of storage, and 2 to 17 GW of natural gas generation by 2038.

Observation #2: The Cumberland retirement and resulting replacement resources represent an early step of a broader strategic plan. The evaluation of the near-term implementation measures to implement the strategy outlined in the IRP should be more about testing the consistency of the measures with the strategy as opposed to attempting to reset TVA's broad direction or decisions. There is general alignment about the retirement of the Cumberland facility as well as the need for future solar and storage; however, an important component of TVA's long-term plan to meet reliability and environmental mandates is the inclusion of both combined cycle and simple cycle natural gas generators. Concurrent with the steps outlined in Alternative A and consistent with its 2019 IRP, TVA is completing a demand side management (DSM) market potential study, installing up to 8 GW of solar resources by 2028, deploying up to 2,400 megawatts (MW) of battery storage by 2028, and investing in transmission infrastructure, while working closely with its local distributors, to support higher penetration of renewable energy.

Observation #3: Long-term resource plans that exclude natural gas rely on overly optimistic assumptions. Focusing on narrow and optimistic long-term future assumptions about the cost and operation of still nascent technologies can have significant financial and reliability impacts. For example, lowering the assumed cost of renewable technologies results in an understatement of the cost of alternative “clean replacement” portfolios by more than $10 billion. Instead, as TVA did, resource portfolio strategies should be evaluated against a range of scenarios and critical input sensitivities to choose a target supply mix that achieves the desired objectives while mitigating risk.

Observation #4: Near-term deployment of combined cycle generation provides a solid foundation for aggressive renewable energy deployment. A diverse energy mix offers reliability and resilience and has proven to be particularly valuable during difficult operating conditions, like peak power demand during high summer temperatures or bitter cold during deep freezes. Recognizing industry studies have shown that the complexity of renewable integration escalates with the growing penetration of renewable energy, flexible and dispatchable natural gas resources will be a valuable part of TVA’s resource portfolio to achieve its reliability requirements.

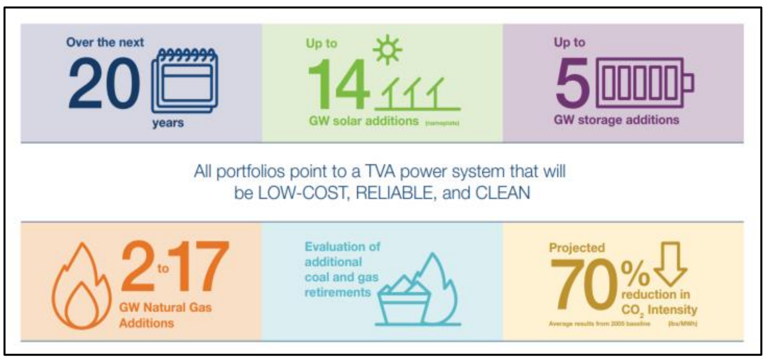
Conclusion: Alternative A is a practical and reasonable near-term implementation plan. There is alignment about the retirement of CUF and the need for replacement capacity. Adding natural gas combined cycle generation to the existing Cumberland site is an executable and reliable plan within the required timeframe. In contrast, orchestrating a symphony of assumed capabilities and costs of energy efficiency, solar, wind, and batteries along with the accompanying transmission upgrades is simply not a viable or rigorous approach as a near-term alternative that meets system reliability requirements. TVA’s thorough and broad long-term planning consistently identifies the need for a diverse set of resources and load reduction measures, along with natural gas generation, solar and storage resources, with the amounts of each driven by future market conditions.

Supplemental Observation: The Inflation Reduction Act influences the amount and timing of resources within the ranges contained in the IRP. The comprehensive impacts of the Inflation Reduction Act (IRA) are uncertain and will take time to fully understand. Even so, questions about the effects of the IRA can be qualitatively assessed by considering whether the potential impacts would trend resource amounts higher or lower within the 2019 IRP ranges. While the IRA impacts must be more fully modeled and explored, fundamental concepts and conclusions will remain unchanged, such as the escalating complexity of adding renewable resources, the need for broad and rigorous analyses, and ultimately the need for dispatchable generation as part of a diverse and reliable generation portfolio.

OBSERVATION #1: THE BOARD APPROVED 2019 IRP PROVIDES SOLID BASIS AND ANALYTIC FRAMEWORK FOR FUTURE RESOURCE DECISIONS

The TVA 2019 IRP, as approved by the TVA Board, provides a roadmap to meeting forecasted energy demand using both supply and demand-side resources to ensure reliable service to customers in the most cost-effective manner. The plan outlines clear and achievable long-term goals and aspirations that will bolster TVA's potential to incorporate increasing amounts of renewable energy capacity and distributed energy resources. More specifically, it frames how TVA will offer low-cost and reliable electricity, facilitate environmental stewardship, and spur economic development over the next 20 years, all while ensuring system reliability. As shown below, TVA's study results underscore its commitment to a diverse portfolio that recognizes the inherent and unique tradeoffs associated with balancing competing priorities.

Figure 1: TVA's 2019 IRP Direction



The objective of the IRP process is to evaluate competing investment and purchase decisions to meet customer demand. The range of options available to utilities to balance supply and demand are expanding as new generation, load control, storage, and smart grid technologies become available and affordable. The characteristics of supply and demand resources are changing as well. Historically, load was viewed as a fixed obligation which utilities planned to meet with dispatchable supply. Higher penetration of intermittent generation and controllable loads mean that utilities must plan for a future in which both demand and supply behave in ways that are different from the past.

TVA's 2019 IRP reflects a robust evaluation of a diverse set of both supply-side and demand-side options to meet its customers' need for energy at the lowest cost over the forecast period, including environmental and economic costs. TVA employed a strategy combining investments and expenditures on traditional energy supply resources, distributed energy resources (DER), and comprehensive energy efficiency programs. These investments include diverse resources like renewables, battery storage, and DER, as well as more traditional supply-side resources that will be critical to ensuring grid reliability and resilience as new technologies emerge and mature.

Importantly, the IRP recognizes TVA's role as an environmental steward by outlining a roadmap by which TVA will dramatically reduce its greenhouse gas emissions over the next 20 years. The IRP shows that, by 2038, TVA will have reduced greenhouse emissions by an average of 70 percent from 2005 levels across all strategies studied. TVA's subsequent "Aging Coal Fleet Evaluation" (May 2021) and "Strategic Intent and Guiding Principles" (May 2021) build on the recommendations from the IRP and lay out TVA's current strategy to phase out its coal fleet by 2035, along with adding 10,000 MW of solar and leveraging new technology; all together supporting TVA's plan to 70% carbon reduction by 2030, development of a path to approximately 80% carbon reduction by 2035, and aspiration to achieve net-zero carbon emissions by 2050.

To achieve these objectives, TVA utilized a least-cost based analysis that weighed a range of future strategies to gauge how certain power generation portfolios and demand reduction measures could perform under a diverse array of external market and regulatory conditions. This analysis was informed by an IRP Working Group comprised of twenty members ranging from government officials to advocacy groups, each representing unique interests in the Tennessee Valley. Together, this group assisted TVA in designing five distinct strategies, employable across six different future scenarios, which resulted in thirty different alternative resource plans. This broad list of alternative resource plans laid the foundation for a robust analysis.

Based on TVA's mission of providing clean, dependable power to customers in the Tennessee Valley at a low-cost, TVA outlined five performance categories to evaluate resource plans. The performance categories included: Cost, Risk, Environmental Stewardship, Operational Flexibility, and Valley Economics. The figure below lists the five performance categories as well as the 14 different metrics used to measure the performance of each of the 30 different resource portfolios.

Figure 2: TVA's 2019 IRP Scorecard

IRP Scorecard Metrics		Low-Cost Reliable Power	TVA Mission Economic Development	Environmental Stewardship
Cost	PVRR ($Bn)	✓	✓	
	System Average Cost ($/MWh)	✓	✓	
	Total Resource Cost ($Bn)	✓		
Risk	Risk/Benefit Ratio	✓		
	Risk Exposure ($Bn)	✓		
Environmental Stewardship	CO2 (MMTons)		✓	✓
	CO2 Intensity (lbs/MWh)		✓	✓
	Water Consumption (MMGallons)			✓
	Waste (MMTons)			✓
	Land Use (Acres)			✓
Operational Flexibility	Flexible Resource Coverage Ratio	✓		
	Flexibility Turn Down Factor	✓		
Valley Economics	Percent Difference in Real Per Capita Income	✓	✓	
	Percent Difference in Employment		✓	

Each category is underpinned by complex analysis, which augments the broader evaluation. For example, TVA executed stochastic analysis to understand the risks and uncertainty within the planning assumptions for each portfolio. More specifically, Monte Carlo simulations were used to assess the multitude of possible futures and the relevant likelihoods. The Monte Carlo simulations, which are employed to emulate the probability of different outcomes in a model with multiple random variables, covered 16 input variables under four main risk categories. The evaluation of the scenarios' uncertainties takes into consideration the number of realistic future scenarios and the probability distribution tied to the expected forecasts. As a result, the probability distributions and ranges of the 16 variables were used to simulate a range of plausible outcomes at the 95th and 5th percentile, which provides important insight into the ranges of outcomes and risk trade-offs across all 30 resource plans.

The energy market and the macro environment are ever evolving and require ongoing planning and monitoring. The results of the IRP analyses indicate the most influential macro environment indicators on future resource plans, which include demand for electricity, natural gas prices, regulatory requirements, cost and performance of emerging technologies, customer expectations, operating costs of existing units, and the cost and performance of wind and solar. These indicators, or signposts, will impact the amount and timing of future resource decisions.

Summary

TVA's 2019 IRP represents both the analytical rigor and broad scope necessary to serve as the backdrop for near-term resource decisions that are consistent with the long-term strategy. Planning over a twenty-year horizon inherently relies on future projections for a multitude of modeling inputs and drivers. As TVA did, analyzing a broad set of resources, portfolios, inputs, future worlds, and sensitivities provides a robust view of possible future outcomes. TVA also measured its results against a meaningful set of performance metrics to clearly understand the trade-offs between resource portfolios and strategies across a set of scenarios. Broadening the analytical scope to include analyses of reserve margin, impacts of intermittent resources, and the benefits of flexible resources was highly relevant as TVA expects to be adding significant amounts of renewable energy. Including public input and working group input in the planning process is also an important element of a comprehensive planning process.

OBSERVATION #2: THE CUMBERLAND RETIREMENT AND RESULTING REPLACEMENT RESOURCES REPRESENT AN EARLY STEP OF A BROADER STRATEGIC PLAN

As part of its 2019 IRP and subsequent Aging Coal Fleet Evaluation, TVA evaluated the economics, reliability, portfolio fit, and environmental factors associated with its coal fleet. In furthering its analysis of the continued operation of its coal fleet, TVA determined that the first Cumberland unit should be retired as early as 2026, followed by the second unit as early as 2028. Coal plant retirements (and even the potential of early coal plant retirements) are entirely consistent with the direction of the 2019 IRP. In fact, the retirement of CUF is not disputed in the Grid Strategies or Synapse reports; instead, the reports take issue with how to replace the lost capacity from the CUF retirement.

Resource planning involves a series of tactical steps to implement the long-term strategy outlined in the IRP. At any given time, TVA is taking multiple actions to move along its long-term strategic path. For instance, TVA is completing a DSM market potential study, deploying up to 8 GW of solar by 2028, deploying up to 2,400 MW of battery storage by 2028, investing in transmission infrastructure to support higher penetration of renewable energy, as well as taking steps to support the addition of natural gas generation. During implementation, signposts are monitored for material shifts in critical IRP inputs then, ultimately, the process repeats with a full-scale check-in on progress and direction in the next IRP.

Therefore, the evaluation of near-term implementation steps, such as the replacement of CUF capacity at issue here, should be more about testing the consistency of the replacement plan with the strategy outlined in the 2019 IRP instead of attempting to reset the broader direction or decisions. In fact, many of the arguments in the Synapse report and Grid Strategies report represent fundamental differences in future industry characterizations and resource alternatives already explored by the 2019 IRP. The Synapse report, Grid Strategies report, and TVA's 2019 IRP all support the adoption of large amounts of solar and batteries. In contrast though, an important component of TVA's plan to meet system reliability needs at lowest cost is the inclusion of both combined cycle and simple cycle natural gas generators. More precisely, the elemental disagreement at hand is the need for new dispatchable generation. While both the Synapse and Grid Strategies reports suggest large amounts of renewable resources can be added to the system without impacting system reliability and resilience, TVA appropriately recognizes that increasing the amount of intermittent generation and resources based on emerging technologies will require dispatchable generation to ensure that customer energy and capacity needs are met around the clock. Given the significant amount of solar, battery storage, and DER expected in the medium-term, it is prudent for TVA to deploy new dispatchable generation by the time the two CUF units are retired at the end of their lives in 2026 and 2028.

The following sections of this report explore the areas where the Synapse report and Grid Strategies report disagree with TVA's assessments and direction. Based on a review of both reports, retiring CUF and selecting Alternative A represent reasonable near-term implementation steps entirely consistent with TVA's broader direction and analytic conclusions as outlined in the 2019 IRP.

OBSERVATION #3: LONG-TERM RESOURCE PLANS THAT EXCLUDE NATURAL GAS RELY ON OVERLY OPTIMISTIC ASSUMPTIONS

Even though the Synapse report, Grid Strategies report, and TVA's 2019 IRP all support the adoption of large amounts of solar and battery resources, there are fundamental differences in the assumed capital and operating costs of generating resources, as well as the expected contributions of these resources to system reliability and resiliency. To set the strategic direction outlined in the 2019 IRP, TVA evaluated six different strategies across five different future world scenarios, varying the ranges of 16 inputs, assessing 14 different performance metrics, and then evaluating 10 additional sensitivities. In contrast, the Synapse report modeled two scenarios by strategically adjusting input assumptions that drive additional adoption of solar, storage, energy efficiency, behind-the-meter resources, and wind. Conversely, the Grid Strategies report presented a narrow version of a lifetime cost analysis by substituting certain resource characterizations with more optimistic assumptions.

The Synapse report and Grid Strategies report include assumptions about critical inputs to the IRP analysis that are optimistic when compared to publicly available data: the availability of low-cost wind imported into the TVA service territory via inter-regional transmission projects, low-cost energy efficiency measures, and unlimited operational flexibility of battery storage resources. The points directly below highlight how using alternative and more realistic assumptions would impact the conclusions of the Synapse and Grid Strategies reports.

Wind

TVA does not include the addition of onshore wind resources in its 2019 IRP due to its high capital cost, while the Synapse report includes the addition of over 3,600 MW by 2030 and a total of 5,400 MW of wind by 2042 via imports from the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP). The Grid Strategies report and Synapse report assert that the reason for this difference in the projected addition of wind resources is caused by TVA's overestimation of capital cost estimates for onshore wind. In its 2019 IRP, TVA used \$1,807/kW[1] for the MISO and SPP regions (\$1,904/kW for the Tennessee Valley) based on actual completed wind project costs in 2016 in the Interior region of the United States[2]. Importantly, for MISO and SPP wind projects, TVA also included the cost of interconnection, including network upgrades, of \$192/kW[3] resulting in overnight costs without interconnection costs of \$1,615/kW. This estimate is very similar to the 2020 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)

[1] 2019$ escalated using 1.8% inflation adjustment from the 2016$ source data
[2] U.S. Department of Energy's 2016 Wind Technologies Market Report, Figure 44
[3] 2019$

estimate of $1,605/kW[4]. Subsequently, the 2021 NREL overnight wind cost estimates dropped to $1,376/kW[5] based on its modeling of the underlying components for a generic wind project. In stark contrast, the U.S. Department of Energy's 2022 Land-Based Wind Market Report showed costs of wind for SPP and MISO of $1,500/kW and $1,600/kW[6] respectively, based on actual 2021 completed project costs. These comparisons demonstrate both the reasonableness of TVA's cost estimates and the importance of analyzing a range of inputs as TVA did. If the 5,400 MW of wind modeled in the Synapse report reflected more reasonable cost estimates and interconnection costs, the additional overnight capital cost would have increased by $2.3 billion.[7]

In addition to the capital cost differences, the Grid Strategies report and Synapse report fail to recognize the difficulty in building inter-regional transmission projects to move wind output from its source to load centers. These resource intensive projects tend to have lengthy planning, approval, and implementation timelines. The Grid Strategies report reference to the Southern Cross transmission line is an excellent example of the challenges and high cost of building inter-regional transmission. The cited news article indicates that the Southern Cross project[8] will cost $2 billion with 2,000 MW of capacity, or $1,000/kW for the cost of transmission alone. Interestingly, the article referenced by the Grid Strategies report also notes that even if the project starts in 2023 and is completed in 2026 it will have been 17 years from conception to completion. While improvements in inter-regional transmission planning are promising, optimistically assuming readily available transmission capacity to import wind from neighboring regions as replacement capacity for the retirement of CUF is not realistic.

Importantly, TVA's 2019 IRP included a sensitivity case to assess the impact of low-cost wind. Assuming a cost of roughly half the base case, TVA's sensitivity analysis showed that 4,200 MW of wind could be economical and displace 3,100 MW of solar generation by 2038. The 2019 IRP analysis of wind provided the key conclusion that if wind costs decline significantly compared to alternative resource options and there is access to a higher wind capacity factor, then wind can be a viable replacement for future capacity retirements. At this time, however, onshore wind is not economic compared to alternative resources. Therefore, TVA is focused on the near-term addition of up to

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4 Based on the average of Class 4 and Class 6, the NREL wind overnight costs also excluded transmission interconnection costs

5 2019 cost estimate in 2019$, from NREL's 2021 Annual Technology Baseline

6 2021$

7 This is a conservative estimate based on 2019 costs. TVA's 2019 IRP modeled wind costs increasing at a rate moderately below inflation while NREL cost forecasts decline significantly over the planning horizon. These differences in expected future costs would result in a larger capital cost difference in future years.

8 The Southern Cross transmission project is proposed to be a 400-mile high-voltage direct current line from Texas through Louisiana and Mississippi to western Arkansas

8,000 MW solar by 2028, 2,400 MW of battery storage by 2028, and adding dispatchable gas generation to prepare the system for higher levels of renewable energy.

Energy Efficiency

By 2028, TVA's demand-side resource portfolio is expected to include up to 1,800 MW of peak reduction capabilities. However, the Synapse and Grid Strategies reports argue that more savings are available at a low cost. The Grid Strategies report assumes the costs of energy efficiency will be $10-$25/MWh[9] while the Synapse report assumed a cost of $27/MWh[10]. Neither the Grid Strategies report nor the Synapse report provide specifics about which end use measures or delivery mechanisms could be used to achieve future energy savings and instead rely on broad expectations based on backward looking data references. Contrary to those assumptions, historical energy efficiency performance and costs are not a reliable indicator of the future. As low cost and low investment measures are exhausted, such as light-emitting diode (LED) lighting, and other efficiency building codes and appliance standards usurp utility energy efficiency offers, future utility programs are likely to be much more costly with fewer savings than historically experienced.

The Synapse report incorporated two major assumptions regarding energy efficiency into its modeling with regards to the Clean Portfolio Replacement scenario. First, the assumption about the highest adoption case of behind-the-meter solar and storage and second, the inclusion of an energy efficiency portfolio reaching and maintaining 1% incremental annual energy savings. For the behind-the-meter solar and storage impacts, the Synapse report relied on TVA's 2019 IRP estimates, but it appears the Synapse report did not include the cost to drive those levels of adoption. Importantly, TVA's 2019 IRP estimates of behind-the-meter solar and storage adoption rely on TVA providing programmatic incentives to participating customers which cover the full incremental cost of the installations. The present value of those costs over the planning period total $479 million, a meaningful amount assumed away in the Synapse report.

Next, for the assumptions about future energy efficiency savings and costs, the Synapse report relied on a study covering 2011-2017 to support its cost estimates and a study of 2020 utility program performance to support its future energy savings targets. A mainstay of historical utility energy efficiency programs was compact fluorescent lamp (CFL) and LED lighting upgrades. However, electric utilities are now competing with market transformations and federal efficiency standards for future energy savings. That trend will also likely impact commercial lighting savings from LEDs. In fact, the IRA allotted $1 billion to assist the adoption of more efficient building codes; a change that would significantly reduce future savings opportunities for utility-sponsored energy efficiency programs. Energy savings outside the lighting category tend to have higher rebates as well as higher

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9 Grid Strategies report, page 29

10 Synapse report, page 30

out-of-pocket matches from participating customers. Furthermore, if utilities continue to allocate more energy efficiency resources towards disadvantaged communities, then the future costs of savings will be significantly higher as those program designs include significantly higher rebates and are not necessarily required to be cost effective. Connecticut is a concrete example of a recently approved energy efficiency plan[11] to demonstrate this point. Connecticut has been rated in the top 10 on the American Council for an Energy Efficient Economy's scorecard for more than a decade. Importantly, Connecticut's most recently approved electric energy efficiency plan for 2022-2024 includes annual savings of 0.7% of load with a first-year cost of $1.05 per kWh. The Synapse Clean Replacement Portfolio scenario assumed energy savings would begin at 0.1% of load and ramp up to 1% by 2035. Being conservative and starting with $0.2225 per kWh first-year cost[12] and ramping up to and continuing at an inflation adjusted[13] $1.05 per kWh first-year cost in 2032 (when annual savings reach 0.7% of load) would increase the planning horizon present value cost to Synapse's Clean Replacement Portfolio by $8.1 billion[14] and would result in an *annual* budget of $2 billion in 2035 to achieve 1% savings, which would then continue in perpetuity.

The Grid Strategies report made similar assertions about the availability of low-cost energy efficiency. To support its levelized cost range of $10-$25 per MWh for energy efficiency, the Grid Strategies report referenced a figure in TVA's 2019 IRP. While it is true TVA's estimates for commercial and industrial energy efficiency costs are within the levelized $10-$25 per MWh range, it is also true the residential energy efficiency levelized cost range exceeded $250 per MWh, a fact the Grid Strategies report failed to acknowledge. Moreover, the amount of savings available at those cost levels in TVA's 2019 IRP was constrained to reflect adoption limitations with the underlying delivery strategies and incentive levels. This point was entirely ignored by the Grid Strategies report, which referenced the same source as the Synapse report to support the assertion that more energy efficiency savings were readily available.

In response to feedback during the 2019 IRP process, TVA analyzed a sensitivity case of adding significantly more energy efficiency and demand response. The analysis indicated that about 2,100 MW of additional demand-side resources were economically reasonable compared to the base case if higher volumes could be realized at the assumed costs. In the model, the additional demand-side resources displaced about 2,200 MW of solar and about 2,000 MW of combustion turbine capacity. The overall results showed a similar lifetime cost, higher system average cost, and 10 percent lower

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11 https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Final-2022-2024-Plan-to-EEB-1112021.pdf

12 The equivalent first year cost per kWh for the levelized cost of 2.7 cents per kWh, using an 8% discount rate (consistent with TVA's 2019 IRP) and 12-year useful life (consistent with the Synapse report)

13 Assuming 2.5% inflation

14 Assumes the Synapse report multiplied the annual cumulative savings by $0.027 per kWh for each year of the planning horizon

carbon emissions. The sensitivity case clearly demonstrated the amount and cost of the demand-side savings is an important factor that will drive the amount of future resources needed, which is also why TVA is actively conducting a market potential study to inform the future of its energy efficiency and demand response portfolio.

Storage

Storage is a meaningful element of TVA's future resource additions. The 2019 IRP range includes battery storage up to 2,400 MW by 2028 and up to 5,300 MW by 2038 (depending on technology costs, performance, and load growth). The Grid Strategies report characterizes batteries as a resource akin to a baseload generating resource capable of providing baseload energy and capacity across a majority of hours, while the Synapse report adds 32,000 MW of battery storage plus nearly 30,000 MW of solar in the Solar/Storage Replacement scenario. To put this in context, the 2042 TVA winter peak with reserve margin is roughly 40,000 MW being served by 29,100 MW of other generation resources (nuclear, gas, hydro, and behind-the-meter solar) and the Synapse model needed an additional 30,000 MW of solar and 32,000 MW of battery storage to meet the energy and demand needs of the system; meaning there would be 91,100 MW of nameplate capacity to serve 40,000 MW of peak winter demand.

While battery storage is making technological advancements, industry understanding and modeling of how large amounts of battery storage will impact the grid is based on limited experience. In 2019, the U.S. Energy Information Administration indicated there was a total combined battery storage capacity of about 1,000 MW which grew to 1,500 in 2020 and then to over 4,500 in 2021. [15] As part of Alternative C, adding 1,700 MW of storage by 2026 for the CUF retirement would result in TVA adding, owning, and operating more battery storage capacity over the next 4 years than the entire United States had in 2020. The figure below illustrates how historical battery storage adoption across the U.S. compares to Alternative C and gives further context to the already significant battery storage ranges in TVA's 2019 IRP.

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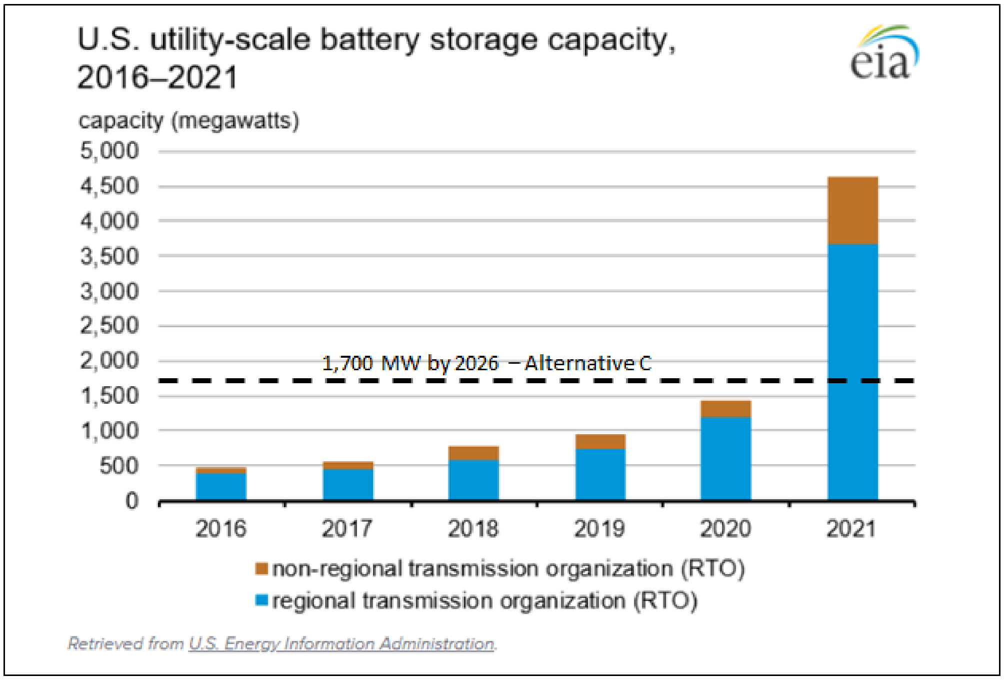
15 Data from the *Annual Electric Generator Report*

Figure 3: EIA U.S. Utility-Scale Battery Storage Capacity 2016 - 2021



In assessing the economics of adding battery storage to the TVA portfolio of resources over the twenty-year forecast period, the Synapse report relied on NREL's battery storage costs estimates. In characterizing battery storage, NREL selected a fixed operations and maintenance expense (FOM) for battery storage and assumed it would be sufficient to maintain the battery's design capacity over its useful life. However, NREL noted: "If the battery is operating at a much higher rate of cycling, then this FOM value might not be sufficient to counteract degradation."[16] This highlights the uncertainty inherent in the Synapse report's conclusions and undermines the Grid Strategies report assumptions about the long-term capabilities of batteries. As an analogy, consider tips and guidance on how to prolong the life of an electric vehicle battery. A recent AAA article recommended the following practices to prolong vehicle battery life: opt for slow charging, when possible, keep the battery charge comfortably above zero, limit how often you fully charge the battery, and pay attention to the battery temperature[17]. These electric vehicle operation strategies differ moderately across vehicle manufacturers, but they all support the common conclusion that how batteries are used and charged directly impacts performance and longevity.

[16] Cole, W., Frazier, A., Augustine. *Cost Projections for Utility-Scale Battery Storage: 2021 Update.* NREL. June 2021. https://www.nrel.gov/docs/fy21osti/79236.pdf.

[17] https://mwg.aaa.com/via/car/how-extend-life-electric-vehicle-batteries

NREL's 2038 'Moderate' estimate for FOM expense for a 4-hour capable battery is about $28 per kW year (in 2038$[18]), which means the annual FOM expense for 32 GW of batteries in 2038 from Synapse's Solar/Storage Replacement scenario would be $902 million. To understand the uncertainty of FOM alone, it is important to understand NREL's FOM cost estimate is assumed to be a static 2.5% of the battery cost in each of NREL's FOM scenarios and instead the FOM ranges vary proportionally with capital cost.

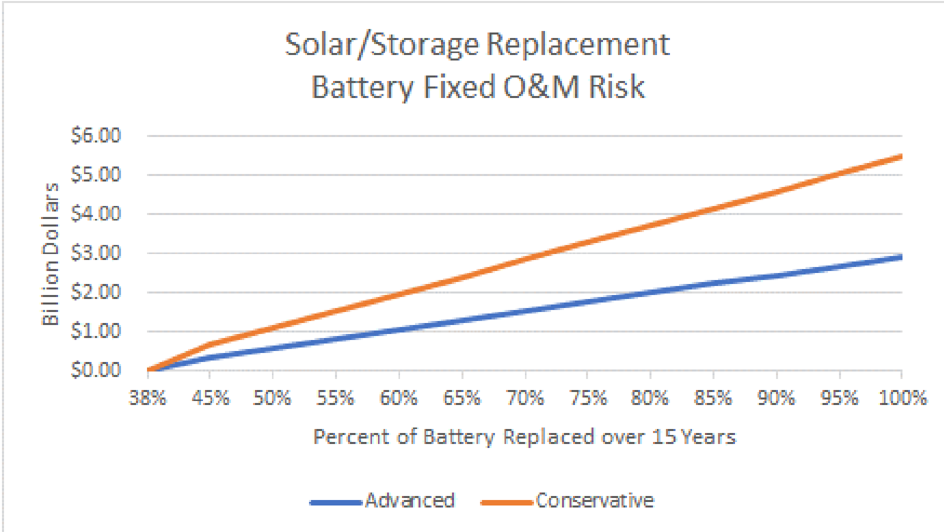
While battery storage has the potential to provide important system benefits, neither the Synapse report or Grid Strategies report appear to consider battery performance specifications and/or specify a technology. Battery storage technology and performance factors are critically important to system reliability and stability. For instance, a battery's useful life is impacted by the number of times it is cycled (i.e., how many times it is dispatched) and the depth of those discharges (i.e., how much of its capacity is used when it is dispatched). It is logical to assume that as the more battery capacity is relied upon for peak load needs and system reliability needs, they will experience more cycles and deeper discharges. In particular, the Solar/Storage Replacement scenario from the Synapse report would rely heavily on batteries for peak loads and system reliability needs.[19]

The figure below directly illustrates the FOM risk of reducing battery storage life through increased operational use. NREL assumes a 2.5% annual FOM expense which implies over the 15-year life of the battery, 37.5% of it has been replaced at some time during its life (conservatively assuming 100% of the FOM dollars go to new battery cells). The figure below shows how the FOM expenses increase relative to the base of 37.5% up to replacing 100% of the battery over its 15-year life. It is apparent for the Solar/Storage Replacement scenario, which includes 32 GW of battery storage, the FOM uncertainty alone could increase the costs of the scenario materially.

[18] NREL's 2021 Annual Technology Baseline provided utility scale battery storage costs in 2019$. The 2019$ amount is about 18 per kW and applying an annual 2.5% inflation factor results in about $28 per kW.

[19] The Synapse report appears to assume running a base case portfolio through a production cost model that solves for enough resources, including imports, is sufficient to support a statement that the scenario provides the same level of reliability as portfolios with natural gas generation. Such a conclusion must rely on side-by-side stress testing of the portfolios with variations in inputs as well as assessing performance metrics beyond the present value of revenue requirements.

Figure 4: Battery Fixed O&M Expenses, Advanced and Conservative Cases



Summary

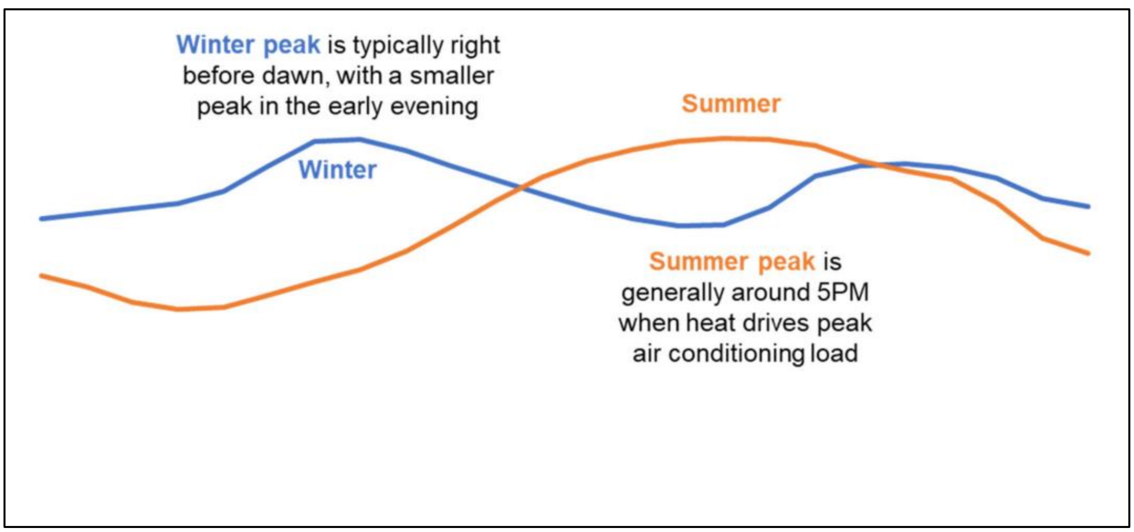
Cost-effective future resource plans that exclude natural gas rely on compounding assumptions, which are favorable yet unrealistic. This section highlights the need to evaluate a range of resource portfolio strategies over iterations of future scenarios with a multitude of critical inputs and sensitivities, and then evaluate the performance using pertinent metrics. Strictly focusing on idealized long-term future assumptions is not a persuasive methodology to reset TVA's overall resource direction and strategy, which is methodically outlined in its 2019 IRP.

OBSERVATION #4: NEAR-TERM DEPLOYMENT OF COMBINED CYCLE PROVIDES A SOLID FOUNDATION FOR AGGRESSIVE RENEWABLE ENERGY DEPLOYMENT

A reliable flow of power to our electricity grid is no longer the only measure by which customers assess the performance of their electric utility. Customers are increasingly demanding that electricity supply be both reliable and clean. Adding solar and wind resources achieves environmental objectives, but when the sun isn't shining or the wind isn't blowing, other types of generating resources are needed to maintain critical grid reliability. A diverse energy mix offers reliability and resilience, which has proven to be particularly valuable during difficult operating conditions, such as peak power demand during high summer or bitter cold during deep freezes. The optionality offered by a diverse portfolio of generating resources also supports affordability. Should the price of one fuel spike, or should bad weather compromise the supply of one power source, another lower cost option can be substituted, holding down energy prices for consumers.

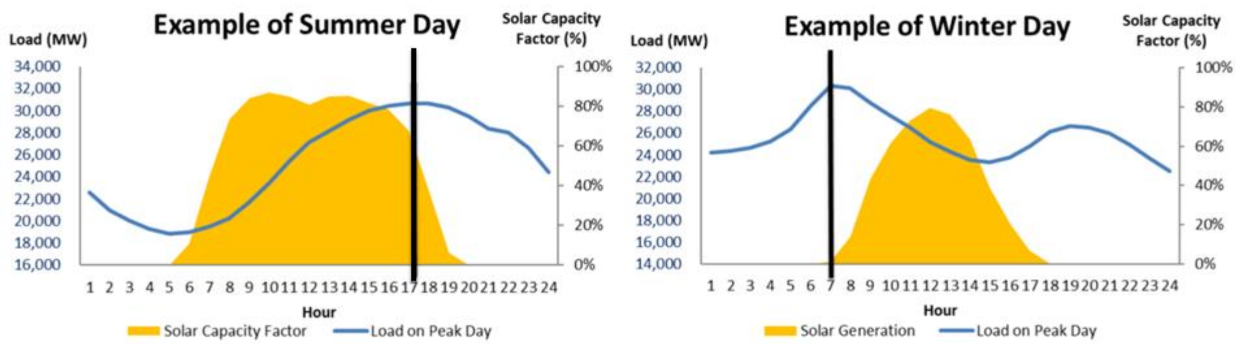
In operating a reliable system, the goal is to have enough capacity available to meet peak demand. As shown in Figure 5 below, the TVA winter peak occurs at approximately 7am, while the TVA summer peak occurs at approximately 5pm.

Figure 5: TVA Winter and Summer Peak Day Load Profiles



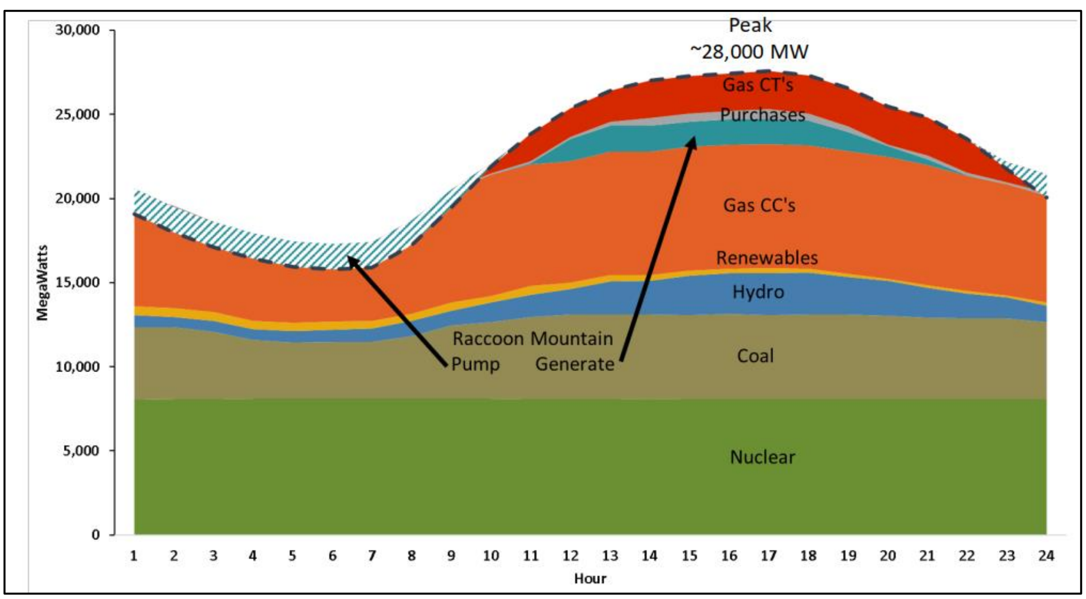
As can be seen below, solar output is declining as the summer peak hour approaches; and, although solar output increases later in the morning during the winter, it is completely unavailable for the near peak pre-dawn loads.

Figure 6: Solar Output on Peak Summer and Winter Days



Wind output also mismatches with these peak loads, with summer wind output at 14% of its capacity at the time of summer peak and 31% of its capacity at the time of winter peak. This mismatch in solar and wind output compared to peak demand requires that other resources, including nuclear and fossil resources, be available for dispatch to meet peak demand. As shown below, TVA dispatches its diverse generating fleet of nuclear, coal, gas, hydro, and renewables by both availability and cost. In the lower load hours, these resources are sufficient to meet customer demand. However, in the peak hours, gas fired units are crucial in meeting peak demand in the summer and winter.

Figure 7: TVA Load Dispatch on a Typical Summer Day



The broader industry has been exploring the place wind and solar have in the evolving grid. Importantly, there is no bulk power system operating today with significant penetration of wind and solar resources, limiting the ability to learn from others. These resources differ from fossil and nuclear generation in that their ability to produce power is dependent on the weather, which creates uncertainty in terms of their availability. Also, these machines' electrical properties are unique from those traditionally built in that they are inverter based (i.e., electronically connected to the grid rather than mechanically connected).

Due to environmental mandates requiring "clean" generating resources by a certain date, and the uncertainty around the impact of a high penetration of zero-emitting generating resources on the power system, system operators have conducted highly detailed studies to explore how wind and solar growth would affect reliability and resiliency. These studies, as further described below, have shown that the complexity of renewable integration escalates with the growing penetration of renewable energy, requiring significant physical and operational changes to the bulk power system. Over some renewable penetration ranges, complexity is constant when spare capacity and flexibility exist. However, at specific penetration levels, complexity rises dramatically as the excess capacity and flexibility are exhausted. These represent system inflection points, where the underlying infrastructure, system operations, or both need to be significantly modified to reliably achieve the next tranche of renewable deployment.

MISO undertook an assessment to systematically find system integration inflection points driven by increasing renewable integration.[20] The MISO assessment found that when the percentage of annual load served by renewable resources is less than 30% system-wide, the integration of wind and solar faces challenges but appears manageable with significant changes to transmission expansion, operating, market, and planning practices within the existing framework. Above the 30% level, significant system-wide complications arise, driven by the increased variability of wind and solar, changes in resource availability, and an overall lack of transmission capacity in the region. Addressing these complications through system upgrades and operational changes can enable the grid to be operated reliably with up to 50% of the energy served by wind and solar resources.[21]

In addition, NREL conducted a study to analyze the effects of increased wind and solar penetration on the operation of the bulk power system and found that estimated U.S. electricity demand in 2050 could be met with 80% of generation from renewable electricity technologies with varying degrees of dispatchability. However, this amount of renewables generation on the system would require a mix of flexible conventional generation and grid storage, additional transmission, more robust load response measures and changes to power system operations. While this analysis suggests such a high renewable generation future is possible, a transformation of the electricity system would need to occur to make this future a reality. This transformation would involve every element of the grid, including adequate planning and operating reserves, increased flexibility of the electric system,

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20 MISO's Renewable Integration Impact Assessment Summary Report, February 2021.

21 Id., page 13.

expanded multi-state transmission infrastructure, development and adoption of technology advances, new operating procedures, evolved business models, and new market rules.[22]

TVA's Planning Incorporates the Dynamic Impacts of Increasing Renewables

In order to underpin TVA's 2019 IRP to understand detailed system outcomes under a wide range of operating conditions, Astrapé was retained to build and run the Strategic Energy and Risk Valuation Model (SERVM) model to assess reserve margin and loss of load impacts from the addition of increasing level of renewables on the system. The model reflects more than 30 years of historical load and weather relationships, demand-side resource operating constraints, details about the operating capabilities of TVA's existing supply-side generation resources, weather impacts on hydroelectric generation capabilities, ancillary service requirements, specific operating reserve requirements, as well as import and export constraints for 20 zones of neighboring systems. The model is capable of hourly and sub-hourly simulations providing rich insights to real-world operational outcomes.

Beyond reserve margin analysis, loss of load modeling in SERVM is a useful methodology to determine capacity levels needed from renewable resources because it accounts for the dynamic effects of adding renewables while ensuring overall reliability targets are achieved. In fact, the capacity levels of solar and storage needed in Alternative C were modeled using this approach. First, TVA modeled the solar capacity needed to replace the lost generation from a retired CUF unit which resulted in 3,000 MW of solar capacity with a 22% capacity factor to replace the CUF generation.[23] Then, the SERVM model was run with the 3,000 MW of solar to determine the level of battery storage needed to maintain the industry reliability standard of a one-day-in-ten years loss of load event, resulting in 1,700 MW of battery storage capacity needed. In contrast, the dynamic reliability effects of adding a dispatchable combined cycle plant are expected to be less than adding increased renewables resources and the loss of load modeling is not a necessary step to determine the combined cycle capacity amount. Further, combined cycle units have much larger ranges of modularity than renewable resources and it was determined a two-unit combined cycle plant with a 1,450 MW capacity would be sufficient to meet reliability requirements. For instance, the next capacity increment of a combined cycle plant would be another 725 MW, far more than the amount needed. Finally, combined cycle units do not have the same energy limitations as batteries, which have typical durations of 4 hours. Combined cycle units can run across many hours and days to support prolonged periods of high loads, which reduces relative risk for a loss of load event.

The Grid Strategies report highlighted concerns about the addition of combined cycle generation to replace the retired CUF generation in terms of natural gas reliability and correlated outages. In fact,

22 National Renewable Energy Laboratory Renewable Electricity Futures Study, 2012.

23 Note the Draft EIS stated 'approximately 25%' while the underlying analysis reflected a 22% capacity factor based on TVA's system experience with existing solar resources.

TVA's natural gas generating fleet has several advantages that mitigate the risk of fuel supply outages in its natural gas generating fleet. According to TVA's 10-K filing for the fiscal year ending September 30, 2021:

- 80 of TVA's combustion turbines (about 80%) were dual-fuel capable, and TVA has fuel oil stored on each of these sites as a backup to natural gas.
- Transportation of natural gas occurs across nine separate pipelines, with approximately 66 percent being transported on two pipelines.
- Approximately 1,517,000 million British thermal units is maintained per day of firm transportation capacity on seven major pipelines, with approximately 59 percent of total firm transportation capacity being maintained on two pipelines.
- TVA utilizes natural gas storage services at seven facilities with a total capacity of 7.25 billion per cubic feet (Bcf) of firm service and 5.00 Bcf of interruptible service to manage the daily balancing requirements of the nine pipelines used by TVA, with approximately 59 percent of the total storage capacity being maintained at two facilities. During 2021, storage levels were generally maintained at between 40 and 80 percent of the maximum contracted capacity at each facility. As TVA's natural gas requirements grow, it is anticipated that additional storage capacity may need to be acquired to meet the needs of the generating assets. In 2022, TVA expects to increase its storage portfolio by approximately 10 percent.

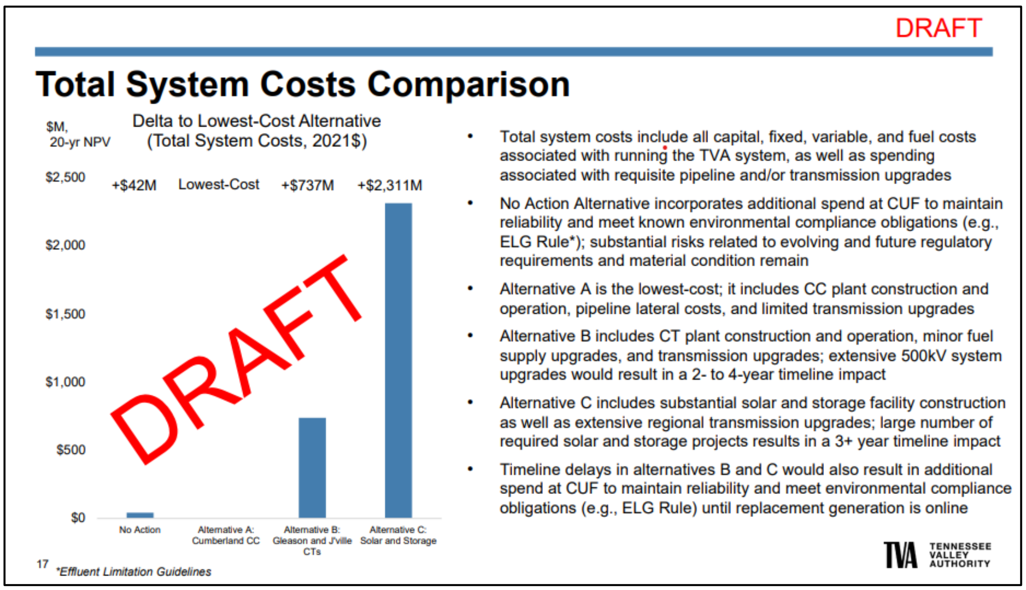
Summary

A diverse generation portfolio offers reliability and resiliency benefits and is particularly valuable during challenging operating conditions, like peak power demand during high summer temperatures or bitter cold during deep freezes. Industry studies have shown that the complexity of renewable integration escalates with the growing penetration of renewable energy. Flexible and dispatchable resources will be critical to meeting system reliability and resiliency needs, as TVA increases the renewable resource capacity on its system. Near-term deployment of combined cycle generation under Alternative A provides a solid foundation for aggressive renewable energy deployment while accelerating the retirement of TVA's coal fleet.

CONCLUSION: ALTERNATIVE A IS A PRACTICAL AND REASONABLE NEAR-TERM IMPLEMENTATION PLAN

The retirement of the CUF unit is not controversial. Instead, the issues are about how much and what types of replacement capacity should be used. The figure below shows the lifetime cost differences between the alternatives presented in the Draft EIS. It is apparent Alternative A is the least-cost outcome while conversely Alternative C is the costliest alternative. A significant value driver of Alternative A is that it can be implemented quickly, resulting in an earlier retirement of CUF and displacement of more costly generation resources serving load. The following discussion contrasts the implementation characteristics of Alternative A and Alternative C, which supports the modeling timelines within the figure below.

Figure 8: Cost Comparison of Alternatives[24]



Feasibility of Alternative A

Alternative A includes a proposed combined cycle plant at the existing Cumberland site which allows for a readily available transmission interconnection and requires a 32-mile natural gas pipeline extension. The site work would begin in 2023 while the physical construction would begin in the fall of 2023 with commercial operation as early as the summer of 2026. Alternative A was identified as TVA's preferred alternative in the Draft EIS in part because it has several factors that reduce execution risk; some of which center around the Cumberland Reservation being an existing

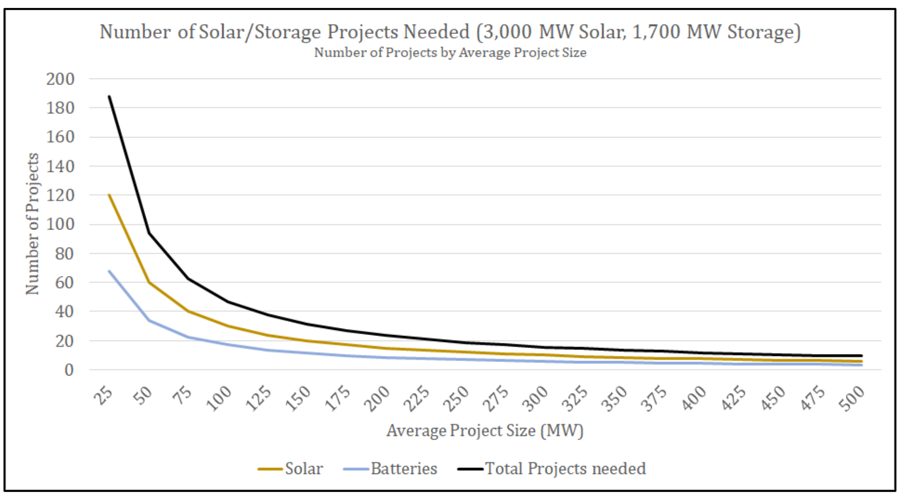
24 https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/environment/cuf_eis_alternativesevaluation_20220423-vfinal21a071b9-0fd1-4a8a-841a-8d9e74ba3ba5.pdf?sfvrsn=a7efe477_5

brownfield generation site. The brownfield location allows for repurposing existing resources and infrastructure while concurrently avoiding the need to supplement the existing transmission once CUF is shuttered. It is noteworthy that combined cycle natural gas plants are a mature technology with 42 GW installed from 2015 through 2022 in the United States.[25] Alternative A would certainly reflect the risks of typical major construction projects; even so, the project timelines and scope appear to be achievable given general expectations about how long it takes to complete a project of this nature.

Feasibility of Alternative C

Alternative C requires 3,000 MW of solar plus 1,700 MW of battery storage. In this alternative, the specific projects and accompanying locations to provide the necessary capacity are not known at this time. Further, it is unknown how many projects would be needed because the size of each project can vary with its location and design. To illustrate the challenge, the figure below shows the number of projects needed based on average project size. TVA's current interconnection queue for solar and storage indicates an average project size of 138.5 MW which would require 34 projects to achieve a combined 4,700 MW of solar and storage capacity. In addition, even if the average project size is larger, the number of projects implemented could be higher because the portfolio of projects could be comprised of many smaller projects along with a few much larger projects. To complicate the task further, each of the projects would have unique project development timelines, studies, and environmental impacts.

Figure 9: Solar and Storage Projects Needed for Alternative C

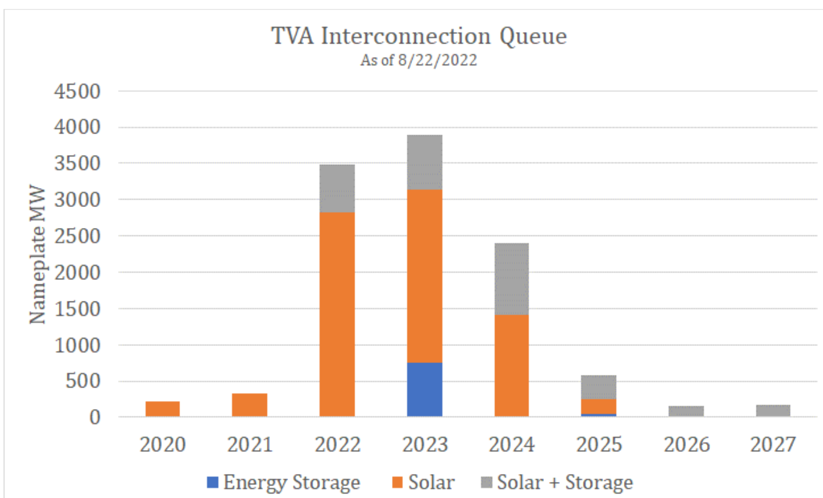


The backdrop for near-term decisions is TVA's 2019 IRP and strategic direction outlined in the subsequent Strategic Intent and Guiding Principles (May 2021) document, so it is important to consider TVA's broader plan to add up to 10,000 MW of solar by 2035, complemented with storage.

25 U.S. Energy Information Agency, Electric Power Annual 2020 published March 2022, Table 4.8.A

Alternative C requires an additional 1,700 MW of battery storage and 3,000 MW of solar by 2026 on top of these planned additions. The figure below shows TVA's interconnection queue for solar and storage by year. The data shows a total of 822 MW of proposed storage projects and possibly another 1,168 MW of storage if 38%[26] of the solar/storage projects are battery storage capacity. Additionally, TVA's 2021 10-K includes nearly 250 MW of battery storage under Power Purchase Agreements (PPA) with power delivery expected to commence in either 2023 or 2025. Therefore, with only 1,740 MW of battery storage remaining in the queue, TVA would need every single storage project to be completed on schedule to support Alternative C; leaving no battery storage capacity available to complement the large amounts of planned solar additions. Moreover, the total solar capacity in TVA's interconnection queue is 10,400 MW with 6,561 of those megawatts having completed a system impact study. Per TVA's 2021 10-K, TVA has nearly 2,000 MW of solar PPAs and self-directed solar projects planned with power delivery expected to commence between 2022 and 2025. While there are more planned solar projects than storage, TVA's interconnection queue demonstrates that its planned levels of solar will need a significant portion of proposed solar projects to be completed; and even so, those levels could be insufficient to meet the needs of both the CUF retirement as well as keeping TVA on track to reach up to 10,000 MW of solar by 2035.

Figure 10: TVA's Interconnection Queue



Interestingly, there are still projects from 2020 in the queue that have not been completed which highlights the fact that not all projects get completed and not all projects get completed on schedule. The current TVA interconnection queue[27] shows, on average, it takes 3.25 years from the time a solar

[26] The interconnection queue only provides the total capacity for each project. It is assumed that the capacity reported is the capacity of the solar arrays with an unknown amount of storage. For estimation purposes, 38.5% was used based on NREL's 2021 Annual Technology Baseline solar plus storage project being characterized as 130MW of nameplate solar plus 50 MW of battery storage capacity.

[27] As of August 22, 2022

and/or storage project is listed in the queue until the time it is forecasted to be in-service. In addition, recent major solar projects that TVA has contracted with were completed, on average, 1.6 years behind the initial in-service provided when the project entered the interconnection queue. This indicates it is reasonable to expect (or at least plan for) solar and storage projects to take close to 5 years from the time a project joins the interconnection queue to the time it is commercially operational, on average. To further highlight the risk of taking the interconnection queue forecasted in-service dates at face value, as of August 22, 2022 there were 3,344 MW of solar projects having completed a system impact study and expected to be in-service before September 30, 2022 (and by 2021 yearend); only one project of 147 MW was listed as in the construction phase.

In addition to the complexity and scale of project development for Alternative C, the accompanying transmission and distribution upgrades have not been fully studied, primarily because the location of the new solar and storage projects are not fully known. In fact, those system impact studies are an important part of the interconnection process. Further, the Draft EIS indicates transmission upgrades could be needed at the CUF site to support system stability while additional transmission support for the Nashville area could be needed. In contrast, the Grid Strategies report assumes no transmission upgrades would be necessary because a combination of solar, battery storage, and other devices like a synchronous condenser can be installed in strategic locations to avoid costly system upgrades. To the contrary, because power plant retirements fundamentally change the flow of power on the transmission system, a holistic analysis of the transmission system is needed to confirm the necessary remedies. In the meantime, it is reasonable to expect transmission upgrades will be needed; especially for the retirement of CUF, one of the top ten largest coal plants in the U.S.

Summary

There is alignment about the retirement of CUF, which will result in additional capacity additions. Adding natural gas combined cycle generation to the exiting Cumberland site is an executable and reliable plan within the required timeframe, resulting in the accelerated retirement of a large coal unit. In contrast, adding significant near-term amounts of solar and storage beyond TVA's stated intention of up to 10,000 MW by 2035 would exhaust or go beyond TVA's current interconnection queue, requiring TVA to find resources outside its control area and heightening the risk of needing transmission upgrades to support system stability with the retirement of CUF.

Furthermore, as the Synapse report recommends, changing courses entirely and orchestrating a symphony of assumed capabilities and costs of energy efficiency, solar, wind, and batteries along with the accompanying transmission and distribution upgrades is simply not viable or based on a rigorous approach that meets system reliability requirements. TVA's thorough and broad long-term planning consistently identifies the need for natural gas generation, along with solar and storage, while the long-term amounts will be driven by future market conditions.

SUPPLEMENTAL OBSERVATION: THE INFLATION REDUCTION ACT INFLUENCES THE AMOUNT AND TIMING OF RESOURCES WITHIN THE RANGES CONTAINED IN THE IRP

TVA's 2019 IRP considered a wide range of strategies, scenarios, and sensitivities. As a result, TVA's long-term plans reflect ranges of future resource needs anticipating the need to adjust resources levels up or down depending on market conditions at the time of the decision. The comprehensive impacts of the IRA are uncertain and will take time to fully understand. Even so, because TVA's analyses explored a wide range of possible future outcomes, questions about the effects of the IRA can be qualitatively assessed by considering whether the potential impacts would trend resource amounts higher or lower within the 2019 IRP ranges. To that end, the figure below summarizes the potential IRA impacts to the level of future resources within the 2019 IRP ranges.

While the IRA impacts must be more fully modeled and explored, fundamental concepts and conclusions remain unchanged, such as the escalating complexity of adding renewable resources, the need for broad and rigorous analyses, and ultimately the need for dispatchable generation as part of a diverse and reliable generation portfolio. From a near-term perspective, the practicality of Alternative A over Alternative C is unchanged. While the IRA would improve the economics for Alternative C, the cost improvements would not eliminate its implementation barriers.

Figure 11: Potential Impacts Within 2019 IRP Resource Ranges

Resource Type	2019 IRP Range	Potential IRA Impact Within 2019 IRP Resource Ranges
Peak Demand	-0.7% to 1.7%	Uncertain net impact: load growth by electrification and focus on domestic manufacturing offset by load reductions from building codes and efficiency funding
Solar	Up to 14 GW	Uncertain net impact: improved wind economics reduce solar within the range, improved solar economics increase solar within the range, net load impacts are uncertain
Storage	Up to 5 GW	Trend up within the range if storage economics sustainably improve
Wind	Up to 4.2 GW if economic	Trend towards adding wind to the portfolio with the amount and timing uncertain, additional wind reduces solar, transmission uncertainties largely unchanged
DSM	Up to 2.1 GW if economic	Downward pressure: Federal funding for state administered programs and efficient building codes reduce utility sponsored opportunities
Combustion Turbine	Up to 8.6 GW	Downward pressure: trend lower within the range if more economic wind, trend lower within the range if battery storage is more economic, long-term gas prices are uncertain, net load impacts are uncertain, reliability needs unchanged or enhanced
Combined Cycle	Up to 9.8 GW	Downward pressure: trend lower within the range if more economic wind, trend lower within the range if battery storage is more economic, long-term gas prices are uncertain, net load impacts are uncertain, reliability needs unchanged or enhanced

WILLIAM (BILL) R. DAVIS
ASSISTANT VICE PRESIDENT

Mr. Davis is an energy industry professional with sixteen years of experience from a major Midwest electric and gas utility (Ameren). His career covers a variety of topics including load research, sales and revenue forecasting, integrated resource planning, project oversight, renewable energy standards, rate design, class cost of service studies, standby rates, demand-side resources pre-approval filings, demand-side resources market potential studies, implementation of energy efficiency portfolios, design of performance mechanisms for demand-side portfolios, lost revenue recovery, and prudence reviews.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2022 – Present)

Assistant Vice President

Ameren – St. Louis, MO (2005 –2021)

Director, Energy Solutions (2016 –2021)

Economic Analysis and Pricing Manager (2013 –2016)

Senior Corporate Planning Analyst (2011 – 2013)

Senior Load Research Specialist – Corporate Planning (2007 –2011)

Forecasting and Load Research Specialist–Corporate Planning (2005 - 2007)

Caterpillar Inc. – Peoria, IL (Feb. 2004 - May 2005)

Advanced Quantitative Analyst – Business Economics Group

EDUCATION

Illinois State University

Bachelor of Science in Economics (2002)
Masters of Science Degree in Economics (2003)

PROFESSIONAL EXPERIENCE

- Provided strategic direction for Ameren Missouri’s energy efficiency and renewable energy programs. Responsible for the planning, implementation, and evaluation of Ameren Missouri’s annual $50-$70 million energy efficiency portfolio
- Served as public spokesperson for energy efficiency on live or recorded television and radio.
- Responsible for meeting or exceeding Ameren Missouri’s approved energy efficiency performance targets; resulting in annual $6-$13 million of additional revenue.

- Collaborated with regulators, interveners, including political and special interest groups, to obtain consensus, support, and/or regulatory approval
- Analyzed the economic and financial impacts of regulatory and legislative initiatives
- Developed and analyzed pricing options for Ameren Missouri's retail customers**.**
- Led cross-functional projects including workgroups such as budgeting, demand-side management, regulatory, legal, forecasting, power operations, transmission and distribution planning, treasury, environmental, renewables, and power trading
- Team leader to implement a custom application that automated and streamlined project oversight reporting and workflows
- Provided oversight for projects in excess of $10 million to ensure projects follow proper project management procedures and reduce risk associated with project execution
- Acted as a change agent to drive behavioral changes in project management practices
- Provided expert testimony to the Missouri Public Service Commission in Ameren Missouri's electric rate case regarding a proposal to mitigate the negative financial effects to the company caused by the implementation of energy efficiency programs
- Championed the analysis and adoption of a new residential rate design for Ameren Missouri's natural gas distribution business that significantly reduced the volatility of revenues and prevented a sustained annual revenue shortfall
- Provided quantitative analysis and recommended actions directly to Ameren executive leadership regarding long-term resource and regulatory decisions
- Team leader for Ameren Missouri's 2011 Integrated Resource Plan which provides the long-term direction for future demand-side and supply-side resource decisions
- Statistical modeling to forecast long-term electric and gas sales to support resource planning and budgeting. Other responsibilities include load research, sample design, weather normalization, margin impacts of weather, unbilled estimation, profiling, revenue/customer forecasting, regulatory support, and process optimization

Accomplishments

- Public Utilities Fortnightly Under 40 class of 2020. Public Utilities Fortnightly is the forum for stakeholders in utility regulation and policy and the Under 40 classes are a nomination-based recognition of rising stars in the public utility industry.
- 2019/2020 Leadership St. Louis Class. The Leadership St. Louis program is an immersive experience into the community to learn directly about regional challenges and opportunities.
- 2018 Zhi-Xing Eisenhower Fellow, one of nine Americans to spend 4 weeks in China for a cultural immersion and professional development experience. The Eisenhower Fellowship mission is to connect innovative leaders in a global network committed to creating a world more peaceful, prosperous and just.
- Leadership Missouri Class of 2014 graduate, which is a program hosted by the Missouri Chamber of Commerce designed to enhance leadership skills and deepen knowledge of the state's opportunities and challenges
- Project leader of an End-to-End Energy Efficiency Study which received Technology Transfer Award from the Electric Power Research Institute

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Illinois Commerce Commission				
Ameren Illinois Company	2012	Ameren Illinois	Docket No. 12-0244	Cost benefit analysis
Missouri Public Service Commission				
Union Electric Company	2010 2011	Ameren Missouri	Case No. ER-2011-0028	Alternative ratemaking approaches
Union Electric Company	2012	Ameren Missouri	Case No. ER-2012-0166	Revenue requirement and rate design
Union Electric Company	2012 2016	Ameren Missouri	File No. EO-2012-0142	Pre-approval, alternative ratemaking (energy efficiency)
Union Electric Company	2014 2015	Ameren Missouri	File No. ER-2014-0258	Rate design, pricing, cost of service
Union Electric Company	2014	Ameren Missouri	Case No. ER-2015-0132	Revenue requirement (energy efficiency)
Union Electric Company	2014	Ameren Missouri	File No. EC-2014-0224	Cost of service, pricing
Union Electric Company	2014	Ameren Missouri	Case No. EA-2014-0136	Renewable energy justification
Union Electric Company	2015 2016 2017 2018	Ameren Missouri	File No. EO-2015-0055	Pre-approval, alternative ratemaking (energy efficiency)
Union Electric Company	2015	Ameren Missouri	Case No. ER-2016-0131	Revenue requirement, incentive ratemaking (energy efficiency)
Union Electric Company	2015	Ameren Missouri	File No. ET-2016-0152	Pricing, Tariff design
Union Electric Company	2016 2017	Ameren Missouri	File No. ER-2016-0179	Rate design, cost of service study, tariff design
Union Electric Company	2016	Ameren Missouri	Case No. ER-2017-0149	Revenue requirement, incentive ratemaking (energy efficiency)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Union Electric Company	2017	Ameren Missouri	File No. ER-2018-0144	Revenue requirement, incentive ratemaking, prudence review (energy efficiency)
Union Electric Company	2018	Ameren Missouri	Case No. ER-2019-0151	Revenue requirement, incentive ratemaking (energy efficiency)
Union Electric Company	2018 2020	Ameren Missouri	File No. EO-2018-0211	Pre-approval, alternative ratemaking (energy efficiency)
Union Electric Company	2019	Ameren Missouri	Case No. ER-2020-0147	Revenue requirement, incentive ratemaking (energy efficiency)
Union Electric Company	2020	Ameren Missouri	Case No. ER-2021-0158	Revenue requirement, incentive ratemaking (energy efficiency)

Appendix N – Concentric Report – Kingston Fossil Plant Retirement FEIS

ASSESSMENT OF THE DRAFT ENVIRONMENTAL IMPACT STATEMENT AND RESPONSE TO CERTAIN REPORTS

PREPARED FOR:
TENNESEE VALLEY AUTHORITY

JANUARY 10, 2024

WWW.CEADVISORS.COM

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ATTACHMENTS

REPORT SCOPE AND SUMMARY OF FINDINGS

Background

The Tennessee Valley Authority ("TVA") is proposing to retire nine coal-fired units at the Kingston Fossil Plant ("Kingston" or "KIF") and construct facilities to replace the retired generation. TVA is developing an Environmental Impact Statement "(EIS") to evaluate the environmental and social impacts associated with the proposed retirement of KIF and the addition of at least 1,500 megawatts ("MW") of replacement generation by 2027. The EIS includes three scenarios: (1) No Action Alternative in which TVA would not retire the KIF units and additional maintenance would be required to maintain system reliability; (2) Alternative A, retire Kingston and develop a single combined cycle ("CC") combustion turbine gas plant coupled with 16 dual-fuel aeroderivative combustion turbine ("CT") units, a 3 to 4 MW solar facility, and a 100 MW battery storage facility at the existing Kingston site; and (3) Alternative B, retire KIF and develop solar generation and energy storage facilities at different locations, which includes locations in East Tennessee.

This report responds to a report titled, "Critique of TVA's Alternatives Analysis in the Utility's 'Kingston Fossil Plant Retirement, Draft Environmental Impact Statement'" authored by Grid Strategies, LLC, and dated July 3, 2023 ("Grid Strategies report"), and a report titled, "Assessing TVA's IRP Planning Practices" authored by Applied Economics Clinic and dated June 2023 ("AEC report"). This report also assesses the reasonableness of TVA's identification of Alternative A as the preferred alternative in the Kington Draft EIS.

Summary of Findings

TVA's Preferred Alternative is predicated on a robust planning process.

TVA's Integrated Resource Plan ("IRP") process stems from the requirements outlined in the Energy Policy Act of 1992 ("EPAct"), which requires TVA to consider a diverse range of energy sources, promote energy efficiency, integrate renewable energy, and ensure the reliability and resilience of the electric grid. These efforts are consistent with the broader goals and principles outlined in the EPAct, a federal law that addresses various aspects of energy policy, including provisions related to electric utilities. Section 113 of the EPAct, codified as 16 U.S.C. § 831m-1, requires that TVA conduct a least-cost planning program that "employ[s] and implement[s] a planning and selection process for new energy resources which evaluates the full range of existing and incremental resources (including new power supplies, energy conservation and efficiency, and renewable energy resources) in order to provide adequate and reliable service to electric customers of the Tennessee Valley Authority at the lowest system cost," where "system cost" is defined to mean "all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, transportation, utilization, waste management, environmental compliance, and, in the case of imported energy resources, maintaining access to foreign sources of supply."[1] The EPAct requires that TVA's process:

- "take into account necessary features for system operation, including diversity, reliability, dispatchability, and other factors of risk;"
- "take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and"
- "treat demand and supply resources on a consistent and integrated basis."

TVA's IRP process implements the requirements of the EPAct, and the resulting IRP serves as a guiding document that is designed to accommodate change. The ability to make adjustments allows organizations to strike a balance between cost, reliability and environmental goals. The flexibility embedded in IRPs allows decision-makers to make informed choices in response to changing conditions. For example, if there's a breakthrough in renewable energy technology or a shift in regulatory policies, the near-term execution strategy can be adjusted to incorporate these changes within the Board approved target supply mix.

In essence, TVA's IRP process reflects a strategic approach to planning that acknowledges the uncertainty of the future. TVA's 2019 IRP includes a "current outlook scenario" that essentially includes assumptions that reflect expected future conditions. TVA includes five additional scenarios that reflect higher demand, policy changes that require increased reductions in greenhouse gas emissions, and additional changes to the expected generating portfolio. TVA then adds in business strategies to these scenarios to develop a portfolio of resource additions and retirements to arrive at a roadmap for the future generation portfolio needed to meet cost and reliability targets while making progress toward emission reductions. The recommendations contained in the 2019 IRP use ranges that are centered on results in the current outlook scenario. The other scenario and sensitivity results provide a sense of how the target power supply mix might change as the future changes. Recognizing that a variety of future scenarios are possible, all IRP results are included in the recommendation to provide flexibility for how the future evolves.

11 EPAct Section 831m-1.

The Grid Strategies report relies on selective assumptions.

Focusing on narrow and optimistic long-term future assumptions about the cost and operation of still nascent technologies is not a sufficiently rigorous planning approach. For example, changing only two of the optimistic assumptions in the Grid Strategies report eliminates the purported cost savings of the presented analysis.

TVA's approach to determining the amount of replacement resources appropriately reflects the dynamic impacts of increasing renewables; whereas the Grid Strategies report relies on winter capacity ratings of solar that are out of line with industry planning parameters. Furthermore, the Grid Strategies report's assumptions about wind, energy efficiency, as well as transmission costs and timing are overly optimistic and inconsistent with industry observations.

The 2019 IRP and the analysis of Alternative A appropriately recognize the reality that the near-term deployment of natural gas generation provides a solid foundation for aggressive renewable expansion. TVA's long-term strategy, based on least-cost planning, involves the pursuit of up to 14 GW of solar and up to 5.3 GW of storage. The Grid Strategies report does not adequately recognize the pace at which large amounts of renewables and battery storage can be deployed. TVA is building its operational experiences with battery storage at scale and those experiences will influence the future pace of battery storage adoption, along with the economics.

The Grid Strategies report downplays the critical role natural gas generation plays in the overall system. TVA's natural gas fleet is an important tool to balance intermittent resources and provide critical system and peak demand resources. TVA's 2019 IRP included a Reserve Margin Analysis, an Intermittent Resources Study, and a Flexibility Study to robustly model dynamic and interactive system uncertainties and the impacts of intermittent resources. Each of these individually robust studies played a role in how generation resources were characterized and how resource portfolios were constructed.

Despite concerns in the Grid Strategies report, the Inflation Reduction Act ("IRA") influences the amount and timing of resources but does not change the ranges or resource additions and retirements contained in the 2019 IRP. For clarity and consistency, it would be appropriate for TVA to update the tax credit assumption to 30% along with the latest capital cost information for the Final EIS. Although, since the 2023 National Renewable Energy Laboratory Annual Technology Baseline forecasted cost curves for solar and storage are higher than the 2022 vintage, the net result of updated modeling assumptions of cost and tax credits will not change the relative economics between Alternative A and Alternative B; that is, Alternative A remaining the lowest cost option.

The AEC report overstates the purpose of TVA's IRP.

The AEC report contends that TVA's planning process is flawed and deems the 2019 IRP obsolete, arguing it lacks a basis for evaluating recommendations on resource additions and retirements. AEC exaggerates the IRP's purpose, portraying it as a set of inflexible commitments for future decisions. In fact, TVA has voluntarily chosen to meet the requirements under the EPAct through an IRP process. The 2019 IRP is an outcome of this process, and serves as a flexible roadmap, offering a framework for informed decision-making while allowing adjustments in response to evolving factors. The term "integrated" implies a holistic approach, considering various elements and potential shifts. Long-term plans, like TVA's IRP, are not intended to be rigid; they must adapt to changing circumstances, technological advancements, and market trends. An effective IRP includes mechanisms for ongoing monitoring and evaluation, enabling organizations to assess strategy effectiveness and make real-time adjustments. This flexibility establishes a feedback loop, ensuring adaptability in a dynamic environment. TVA's 2019 IRP reflects the characteristics of an IRP as a strategic and forward-looking tool and serves as a solid basis that guides decision-making to ensure a reliable and cost-effective energy future. The 2019 IRP continues to be valid for guiding TVA's energy planning.

TVA'S PREFERRED ALTERNATIVE IS PREDICATED ON A ROBUST PLANNING PROCESS

TVA's resource planning process and methodology comply with the requirements of the Energy Policy Act.

The EPAct requires TVA to conduct a least-cost planning program that employs and implements "a planning and selection process for new energy resources which evaluates the full range of existing and incremental resources (including new power supplies, energy conservation and efficiency, and renewable energy resources) in order to provide adequate and reliable service to electric customers of the TVA at the lowest system cost."[2] TVA uses an IRP to meet the requirements of the EPAct and to outline a comprehensive strategy for meeting the future energy needs of TVA's customers in a cost-effective and reliable manner. TVA's 2019 IRP reflects a strategic approach to resource planning that recognizes the uncertainty of the future and produces a dynamic framework designed to guide TVA's resource decisions. It serves as the backdrop for near-term and long-term resource additions that build on TVA's existing diverse asset portfolio to ensure low-cost, reliable, and clean electricity for TVA customers into the future. The 2019 IRP includes an analysis of a broad set of resources, portfolios, inputs, future worlds, and sensitivities to provide a robust view of possible future outcomes. The resulting long-term power supply strategy involves the pursuit of up to 14 gigawatts ("GW") of solar, up to 5.3 GW of storage, and 2 GW to 17 GW of natural gas generation by 2038.

The Kingston retirement and resulting replacement proposal represent one step in TVA's broader strategic plan. Any evaluation of the near-term implementation measures to implement the strategy outlined in the IRP should be more about testing the consistency of the measures with the strategy as opposed to attempting to reset TVA's broad direction or decisions. There is alignment about the retirement of the Kingston facility as well as the need for future solar and storage. However, an important component of TVA's long-term plan to meet reliability and environmental requirements is the inclusion of both combined cycle and simple cycle natural gas generators in its generation portfolio. Concurrent with the steps outlined in Alternative A, and consistent with its 2019 IRP, TVA is completing a demand side management ("DSM") market potential study, installing up to 8 GW of solar resources by 2028, deploying up to 2,400 MW of battery storage by 2028, and investing in transmission infrastructure, while working closely with the local power companies ("LPCs") that purchase TVA-produced electricity, to support a higher penetration of renewable energy.

Alternative A is a practical and reasonable near-term action consistent with the power supply mix adopted by TVA's Board from the 2019 IRP. There is alignment about the retirement of the Kingston facility and the need for replacement capacity. Adding natural gas combined cycle and combustion turbine generation, 3 to 4 MW of solar, and 100 MW of battery storage to the existing Kingston site

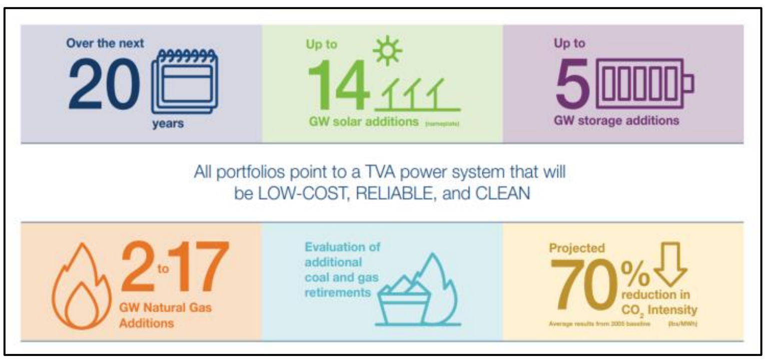
[2] Energy Policy Act Section 831m-1(b)(1).

is an executable and reliable plan within the required timeframe. In contrast, the distributed and locational deployment of significant solar and battery storage resources along with long-lead transmission upgrades is simply not a viable approach as a near-term alternative to replace the retiring Kingston generation, that meets system reliability requirements.

The Board-approved 2019 IRP provides a solid basis and analytic framework for future resource decisions.

The TVA 2019 IRP, as approved by the TVA Board, provides a roadmap to meeting forecasted energy demand using both supply and demand-side resources to ensure reliable service to customers in a cost-effective manner. The plan outlines clear and achievable long-term goals and aspirations that will bolster TVA's potential to incorporate increasing amounts of renewable energy capacity and distributed energy resources. More specifically, it frames how TVA will offer low-cost and reliable electricity, facilitate environmental stewardship, and spur economic development over the next 20 years, all while ensuring system reliability. As shown below, TVA's study results underscore its commitment to a diverse portfolio that recognizes the inherent and unique tradeoffs associated with balancing competing priorities.

Figure 1: TVA's 2019 IRP Direction



The objective of the IRP process is to evaluate competing investment and purchase decisions to meet customer demand. The range of options available to utilities to balance supply and demand are expanding as new generation, load control, storage, and smart grid technologies become available and affordable. The characteristics of supply and demand resources are changing as well. Historically, load was viewed as a fixed obligation that utilities planned to meet with dispatchable supply. Higher penetration of intermittent generation and controllable loads mean that utilities must plan for a future in which both demand and supply behave in ways that are different from the past.

TVA's 2019 IRP reflects a robust evaluation of a diverse set of both supply-side and demand-side options to meet its customers' need for energy at the lowest cost over the forecast period, including environmental and economic costs. TVA employed a strategy combining investments and expenditures on traditional energy supply resources, distributed energy resources ("DER"), and comprehensive energy efficiency ("EE") programs. These investments include diverse resources like renewables, battery storage, and DER, as well as more traditional supply-side resources that will be critical to ensuring grid reliability and resilience as new technologies emerge and mature.

Importantly, the IRP recognizes TVA's role as an environmental steward by outlining a roadmap by which TVA will dramatically reduce its greenhouse gas emissions over the next 20 years. The IRP shows that, by 2038, TVA will have reduced greenhouse emissions by an average of 70 percent from 2005 levels across all strategies studied. TVA's subsequent "Aging Coal Fleet Evaluation" (May 2021) and "Strategic Intent and Guiding Principles" (May 2021) build on the recommendations from the IRP and lay out TVA's current strategy to phase out its coal fleet by 2035, along with adding up to 10,000 MW of solar and leveraging new technology, all together supporting TVA's plan to achieve a 70% carbon reduction by 2030, development of a path to approximately 80% carbon reduction by 2035, and aspiration to achieve net-zero carbon emissions by 2050.

TVA's 2019 IRP utilized a least-cost based analysis that weighed a range of future strategies to gauge how certain power generation portfolios and demand reduction measures could perform under a diverse array of external market and regulatory conditions. This analysis was informed by an IRP Working Group comprised of twenty members ranging from government officials to advocacy groups, each representing unique interests in the Tennessee Valley. Together, this group assisted TVA in designing five distinct strategies, employable across six different future scenarios, which resulted in thirty different alternative resource plans. This broad list of alternative resource plans lays the foundation for a robust analysis.

Based on TVA's mission of providing dependable power to customers in the Tennessee Valley at rates as low as are feasible, TVA outlined five performance categories to evaluate resource plans. The performance categories included: Cost, Risk, Environmental Stewardship, Operational Flexibility, and Valley Economics. The figure below lists the five performance categories as well as the 14 different metrics used to measure the performance of each of the 30 different resource portfolios.

Figure 2: TVA's 2019 IRP Scorecard

IRP Scorecard Metrics		Low-Cost Reliable Power	TVA Mission Economic Development	Environmental Stewardship
Cost	PVRR ($Bn)	✓	✓	
	System Average Cost ($/MWh)	✓	✓	
	Total Resource Cost ($Bn)	✓		
Risk	Risk/Benefit Ratio	✓		
	Risk Exposure ($Bn)	✓		
Environmental Stewardship	CO2 (MMTons)		✓	✓
	CO2 Intensity (lbs/MWh)		✓	✓
	Water Consumption (MMGallons)			✓
	Waste (MMTons)			✓
	Land Use (Acres)			✓
Operational Flexibility	Flexible Resource Coverage Ratio	✓		
	Flexibility Turn Down Factor	✓		
Valley Economics	Percent Difference in Real Per Capita Income	✓	✓	
	Percent Difference in Employment		✓	

Each category is underpinned by complex analysis, which augments the broader evaluation. For example, TVA executed stochastic analysis to understand the risks and uncertainty within the planning assumptions for each portfolio. More specifically, Monte Carlo simulations were used to assess the multitude of possible futures and the relevant likelihoods. The Monte Carlo simulations, which are employed to emulate the probability of different outcomes in a model with multiple random variables, covered 16 input variables under four main risk categories. The evaluation of the scenarios' uncertainties takes into consideration the number of realistic future scenarios and the probability distribution tied to the expected forecasts. As a result, the probability distributions and ranges of the 16 variables were used to simulate a range of plausible outcomes at the 95th and 5th percentile, which provides important insight into the ranges of outcomes and risk trade-offs across all 30 resource plans.

The energy market and the macro environment are ever-evolving and require ongoing planning and monitoring. The results of the IRP analyses indicate the most influential macro environment indicators on future resource plans, which include demand for electricity, natural gas prices, regulatory requirements, cost and performance of emerging technologies, customer expectations, operating costs of existing units, and the cost and performance of wind and solar. These indicators, or signposts, will impact the amount and timing of future resource decisions.

TVA's 2019 IRP continues to represent both the analytical rigor and broad scope necessary to serve as the backdrop for near-term resource decisions that are consistent with the long-term strategy.

Planning over a twenty-year horizon inherently relies on future projections for a multitude of modeling inputs and drivers. As TVA did, analyzing a broad set of resources, portfolios, inputs, future worlds, and sensitivities provides a robust view of possible future outcomes. TVA also measured its results against a meaningful set of performance metrics to clearly understand the trade-offs between resource portfolios and strategies across a set of scenarios. Broadening the analytical scope to include analyses of reserve margin, impacts of intermittent resources, and the benefits of flexible resources was highly relevant as TVA expects to be adding significant amounts of renewable energy. Including public input and working group input in the planning process is also an important element of a comprehensive planning process.

The Kingston Retirement and resulting replacement resource represents one step in a broader strategic plan to enable a transition to a clean energy portfolio.

The 2019 IRP set the direction towards a least-cost clean energy portfolio. Consistent with the 2019 IRP, certain near-term actions are necessary to implement the target supply mix. Therefore, a series of concurrent actions have been and are being undertaken by TVA. For instance, TVA is completing a demand side management ("DSM") market potential study, deploying solar and battery storage, investing in transmission infrastructure to support higher penetration of renewable energy, as well as taking steps to support the addition of natural gas generation. To help accomplish these objectives, in July 2022, TVA issued a request for proposals for up to 5,000 megawatts of carbon-free energy that must be operational before 2029.[3]

A stated signpost for TVA to monitor is the operating cost for existing units and a related near-term action item from the 2019 IRP was to evaluate engineering end-of-life dates for aging fossil units. TVA completed the Aging Coal Fleet Evaluation in May 2021, which identified the Kingston units for retirement. The retirement of the Kingston units is not controversial. Instead, the issues are about how much and what types of replacement capacity should be used.

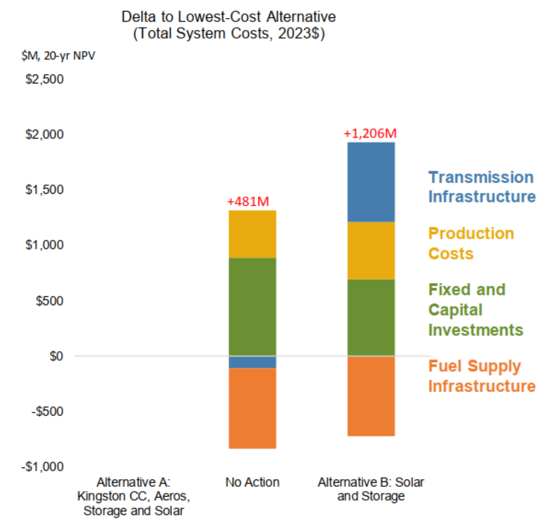
TVA considered a full range of resource options in its Draft EIS to replace the Kingston units and account for load growth with 1,500 MW of firm, dispatchable power needed to maintain system reliability. Pumped hydro, small modular nuclear, energy efficiency, wind, demand response, distributed energy resources, and hydrogen were among the options screened out as alternatives primarily based on the relative economics, availability by 2027, inability to provide firm power, and inability to meet the locational need in East Tennessee. From the longer list of alternatives considered, the Evaluation Analysis was narrowed to the No Action Alternative (operational and environmental upgrades necessary to keep Kingston operating), Alternative A (natural gas combined

[3] Tennessee Valley Authority. TVA Issues One of the Nation's Largest Requests for Carbon-Free Energy. July 12, 2022. https://www.tva.com/newsroom/press-releases/tva-issues-one-of-the-nation-s-largest-requests-for-carbon-free-energy.

cycle and aeroderivative combustion turbines, 3-4 MW of solar, and 100 MW of battery storage), and Alternative B (solar and battery storage).

The figure below shows the lifetime cost differences between the alternatives presented in the Draft EIS. It is apparent Alternative A is the lowest-cost outcome while conversely Alternative B is the costliest alternative. A meaningful value driver of Alternative A is that it avoids significant transmission infrastructure investments that are both costly and require significant time to implement. It is also noteworthy that Alternative A supports black start capabilities and although it is a rare service needed, it is an important element of a robust system design.

Figure 3:Total System Cost Comparison of Alternatives[4]



Total system costs includes all capital, fixed, variable, and fuel costs associated with running the TVA system, as well as spending for requisite pipeline and transmission upgrades in each alternative

Alternative	Production Costs^	Fixed and Capital Costs	Transmission Infrastructure	Fuel Supply Infrastructure
Alternative A: Kingston CC, Aeros, storage, and solar	Lowest	Lowest	Lowest	Lowest
	Included are costs associated with CC and Aero plant construction and operation, transmission upgrades, and pipeline lateral construction.			
No Action Alternative	Higher	Higher	Lower	Lower
	Substantial risks related to evolving and future regulatory requirements such as the ELG* Rule and plant material condition			
Alternative B: Solar and Storage	Higher	Higher	Higher	Lower
	Solar and storage and transmission projects fail to meet 2027 timeline and higher costs for reliability and environmental compliance at KIF			

*Effluent Limitation Guidelines
^Production Costs include ongoing fuel, start, and variable O&M costs

The Draft EIS Alternatives Evaluation Analysis reflects TVA's latest modeling assumptions for key signposts and resource characterizations. The table below from the Draft EIS[5] briefly describes the status of the signposts and the relative or directional impact compared to the 2019 IRP.

4 Tenn. Valley Auth., Kingston Fossil Plant Retirement Draft Environmental Impact Statement. Appendix C – 28 (May 2023), https://www.tva.com/environment/environmental-stewardship/environmentalreviews/nepa-detail/kingston-fossil-plant-retirement.

5 *Ibid*. Appendix C – 18.

Table 1: TVA's 2019 IRP Key Signposts

Key Signposts	Updates Aligned with the 2019 IRP
Demand for electricity	Growth driven by Valley in-migration, energy intensive sectors, and Economic Development momentum
Natural gas prices	Near-term COVID-19 and supply-driven volatility, with lower fundamental prices over the long term
Stakeholder expectations	Increasing customer and stakeholder emphasis on renewable and clean energy; Preference for low-cost energy
Regulatory requirements	Biden policy on climate change, pipeline challenges, and pending updates to regulations (ex: Inflation Reduction Act)
Operating costs for existing units	Better understanding of fleet investments needed, helping inform portfolio direction
Solar and wind costs	Competitive solar offers with declining costs, but solar supply chain challenges persisting
Emerging and developmental technologies	Continued advancements in storage; DOE and utilities partnering to advance new clean technologies

The Draft EIS Alternatives Evaluation further demonstrates how the latest modeling assumptions are largely within and consistent with the 2019 IRP modeling ranges. For the Alternatives Evaluation, the cost of storage is notably lower than the 2019 IRP and the cost of solar, which is informed by pricing from recent requests for proposal responses, reflecting near- and medium-term cost increases. The Alternatives Evaluation further incorporates a 10% Investment Tax Credit assumption for solar as an initial application of the potential tax credits from the IRA. For clarity and consistency, it would be appropriate for TVA to update the tax credit assumption to 30% along with the latest capital cost information for the Final EIS. Since the 2023 National Renewable Energy Laboratory Annual Technology Baseline forecasted cost curves for solar and storage are higher than the 2022 vintage, the net result of updated modeling assumptions of cost and tax credits will not change the relative economics between Alternative A and Alternative B; that is, Alternative A remaining the lowest project cost option.

Feasibility of Alternative A

Alternative A includes a proposed combined cycle plant, aeroderivative combustion turbines, 3-4 MW of solar and 100 MW of battery storage at the existing Kingston site. The site will require a 122-mile natural gas pipeline, to be built and owned by East Tennessee Natural Gas ("ETNG"), under Federal Energy Regulatory Commission ("FERC") jurisdiction. The site work would begin in 2024 while the physical construction would begin in the fall of 2024 with commercial operation as early as the winter of 2027.

While the brownfield location allows for repurposing existing resources and infrastructure, both Alternative A and B also require off-site transmission system upgrades, including uprating, reconductoring, or rebuilding transmission lines within existing rights-of-way, as well as replacing terminal equipment, bus work, or jumpers.

Alternative A would certainly reflect the risks of typical major construction projects; even so, the project timelines and scope appear to be achievable given general expectations about how long it takes to complete projects of this nature. TVA has considerable experience with gas plant construction projects. Recently, in July 2023, three new combustion turbine units became operational ahead of schedule at the Colbert site in North Alabama; and, in December 2023, three new combustion turbine units began pre-commercial plant operations at the Paradise site in Kentucky. Combined cycle generation plants were also constructed by TVA at the John Sevier facility in East Tennessee and the Allen facility in West Tennessee in 2012 and 2018, respectively.

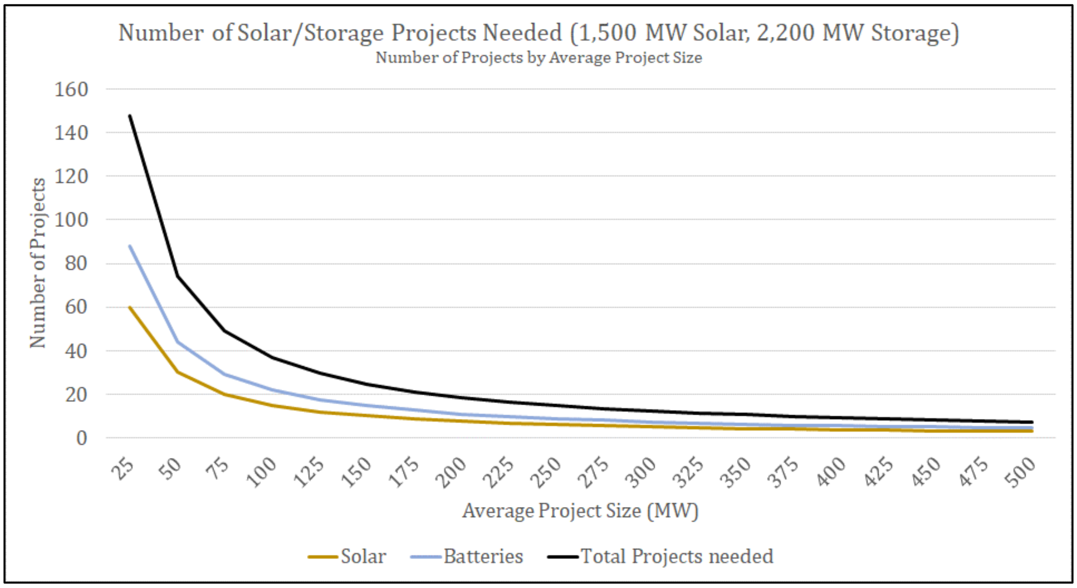
Feasibility of Alternative B

Alternative B requires 1,500 MW of solar plus 2,200 MW of battery storage. In this alternative, the specific projects and accompanying locations to provide the necessary capacity are not known at this time.[6] However, it is expected for projects to be located in Eastern Tennessee to support the nearby Knoxville load center and manage necessary transmission upgrades following the retirement of the KIF. Importantly, Alternative B would include the construction, operation, and maintenance of new transmission line rights-of-way.

It is unknown how many projects would be needed because the size of each project can vary with its location and design. To illustrate the challenge, the figure below shows the number of projects needed based on average project size. TVA's current interconnection queue for solar and storage indicates an average project size of 124 MW which would require 30 projects to achieve a combined 3,700 MW of solar and storage capacity. In addition, even if the average project size is larger, the number of projects implemented could be higher because the portfolio of projects could be comprised of many smaller projects along with a few much larger projects. To complicate the task further, each of the projects would have unique project development timelines, studies, and environmental impacts.

6 The Draft EIS assumed there would be fifteen or more solar sites.

Figure 4: Solar and Storage Projects Needed for Alternative B



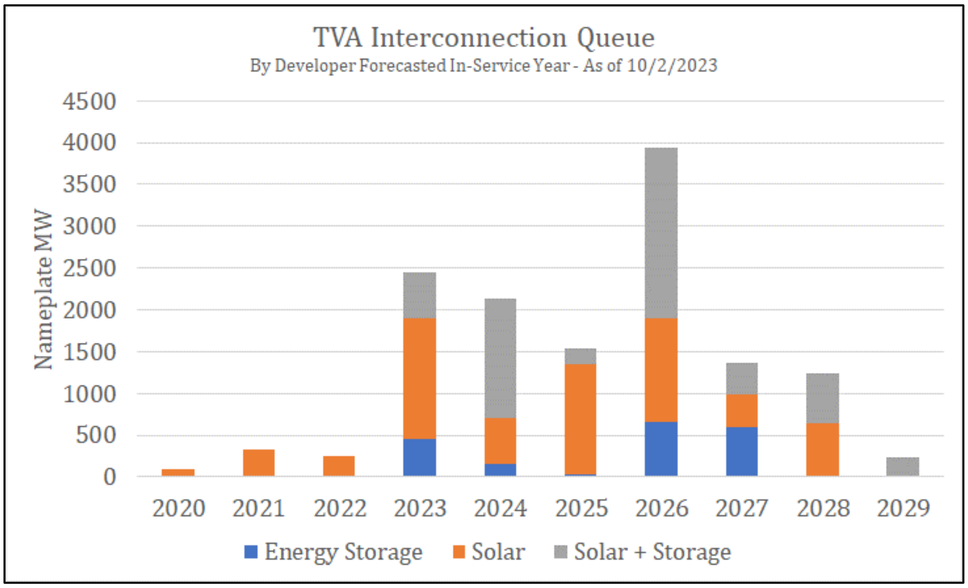
The backdrop for near-term decisions is TVA's 2019 IRP and strategic direction outlined in the subsequent Strategic Intent and Guiding Principles (May 2021) document, so it is important to consider TVA's broader plan to add up to 10,000 MW of solar by 2035, complemented with storage. Alternative B requires an additional 2,200 MW of battery storage and 1,500 MW of solar by 2027 on top of these planned additions. The figure below shows TVA's interconnection queue for solar and storage by year based on the developers' forecasted in-service date. The data shows total of 1,900 MW of proposed storage projects and possibly another 2,020 MW of storage if 37.5%[7] of the solar/storage capacity represents the battery storage component of the reported capacity. Moreover, the total solar capacity in TVA's interconnection queue is 9,640 MW. According to the Lawrence Berkley National Laboratory, the share of capacity requesting interconnection from 2000-2017 that reached commercial operation is relatively low across regions, ranging from 8% to 24% of capacity.[8] This indicates it is reasonable to expect between 314 MW and 940 MW of the battery storage capacity in the queue and between 770 MW and 2,310 MW of the solar capacity in the queue will reach commercial operation within the next five years. Importantly, TVA's 2023 10-K, noting challenges associated with contracted Power Purchase Agreements ("PPAs") not yet online, includes 150 MW of battery storage and nearly 2,000 MW of solar PPAs planned with power delivery expected to

7 The interconnection queue only provides the total capacity for each project. It is assumed that the capacity reported is the capacity of the solar arrays with an unknown amount of storage. For estimation purposes, 37.5% was used based on NREL's 2023 Annual Technology Baseline solar plus storage project being characterized as 130 MW of nameplate solar plus 78 MW of nameplate battery storage capacity.

8 Lawrence Berkley National Laboratory. Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022. https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf.

commence between 2024 and 2025. TVA's interconnection queue demonstrates that its planned levels of storage and solar will need a significant portion of proposed projects to be completed; and even so, those levels could be insufficient to also meet the needs of the KIF retirement.

Figure 5: TVA's Interconnection Queue



Consistent with the industry, there are still projects from 2020 in the queue that have not been completed which highlights the fact that not all projects get completed and not all projects get completed on schedule. The current TVA interconnection queue[9] shows, on average, it takes about 3.5 years from the time a solar and/or storage project is listed in the queue until the time the developer forecasts the project to be in-service. In addition, recent major solar projects that TVA has contracted with were completed, on average, 1.6 years behind the initial in-service provided when the project entered the interconnection queue. This indicates it is reasonable to expect (or at least plan for) solar and storage projects to take at least 5 years from the time a project joins the interconnection queue to the time it is commercially operational, on average. The U.S. interconnection requests in 2022 were nearly 5 times[10] the number of requests in 2013, driven partially by decarbonization goals, federal tax incentives, and improved economics of solar, wind, and battery storage. This increase in volume of projects, some of which are speculative, along with increased lead time for materials and increased environmental reviews contribute to the longer time in the queue, especially when one considers 72% of the projects proposed over 2000-2017 had

[9] As of October 22, 2023

[10] Lawrence Berkley National Laboratory. Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022. https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf.

withdrawn from an interconnection queue by 2022,[11] indicating resources are being used to process projects that never get completed.

Recent macroeconomic forces have also affected the deliverability of solar and battery projects that were previously planned. In December 2022, TVA signed four PPAs for 160 MW of total solar generation, which is expected to be operational by 2025. According to TVA's 2023 10-K, the majority of its PPAs that are not online are experiencing delays and price increases. In the second quarter of 2023, TVA terminated a PPA agreement after one of the counterparties failed to comply with the terms, which stranded 66 MW of solar and 66 MW of battery storage.[12] Beyond the specific solar and battery storage sites, the Draft EIS indicates significant transmission upgrades will be needed to support system stability. TVA's evaluation for the Draft EIS indicated the necessary infrastructure upgrades could take eight to nine years, which pushes implementation of Alternative B beyond the intended purpose and need.

There is alignment about the retirement of Kingston, which will result in additional capacity additions. Adding natural gas combined cycle and aeroderivative generation, solar, and battery storage to the exiting Kingston site is an executable and reliable plan within the required timeframe, resulting in the retirement of a coal facility. In contrast, adding significant near-term amounts of solar and storage beyond TVA's stated intention of up to 10,000 MW by 2035 would rely heavily on or go beyond TVA's current interconnection queue, in addition to the fact that the costly transmission upgrades likely cannot be completed to meet the KIF retirement timeline.

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11 *Ibid.*

12 SEC Form 10-K – fiscal year ended September 2023. Tennessee Valley Authority. November 14, 2023, https://d18rn0p25nwr6d.cloudfront.net/CIK-0001376986/b1d84fa0-fedc-4285-a4c7-cddd3b623ec0.pdf.

THE GRID STRATEGIES REPORT RELIES ON SELECTIVE ASSUMPTIONS

The Grid Strategies report and TVA's 2019 IRP support the adoption of solar and battery resources. However, there are fundamental differences in the assumed capital and operating costs of generating resources, as well as the expected contributions of these resources to system reliability and resiliency. To set the strategic direction outlined in the 2019 IRP, TVA evaluated six scenarios and five strategies, varying the ranges of 16 inputs, assessing 14 different performance metrics, and then evaluating 10 additional sensitivities. Conversely, the Grid Strategies report presents a narrow version of a lifetime cost analysis by substituting certain resource characterizations with more optimistic assumptions. The Grid Strategies report includes assumptions about critical inputs to the IRP analysis that are optimistic when compared to publicly available data: the availability of low-cost wind imported into the TVA service territory via inter-regional transmission projects, low-cost energy efficiency measures, and unlimited operational flexibility of battery storage resources. The points directly below highlight how using alternative and more realistic assumptions would impact the conclusions of the Grid Strategies report.

As part of its 2019 IRP and subsequent Aging Coal Fleet Evaluation, TVA evaluated the economics, reliability, portfolio fit, and environmental factors associated with its coal fleet. In furthering its analysis of the continued operation of its coal fleet, TVA determined that the Kingston units should be retired by 2027. Coal plant retirements (and even the potential of early coal plant retirements) are entirely consistent with the direction of the 2019 IRP. In fact, the retirement of Kingston is not disputed in the Grid Strategies report; instead, the reports take issue with how to replace the lost capacity from the Kingston retirement.

Resource planning involves a series of tactical steps to implement the long-term strategy outlined in the IRP. At any given time, TVA is taking multiple actions to move along its long-term strategic path. For instance, TVA is completing a DSM market potential study, deploying solar and battery storage, investing in transmission infrastructure to support higher penetration of renewable energy, as well as taking steps to support the addition of natural gas generation. During implementation, signposts are monitored for material shifts in critical IRP inputs then, ultimately, the process repeats with a full-scale check-in on progress and direction in the next IRP.

Therefore, the evaluation of near-term implementation steps, such as the replacement of Kingston capacity at issue here, should be more about testing the consistency of the replacement plan with the strategy outlined in the 2019 IRP instead of attempting to reset the broader direction or decisions. In fact, many of the arguments in the Grid Strategies report represent fundamental differences in future industry characterizations and resource alternatives already explored by the 2019 IRP. The Grid Strategies report and TVA's 2019 IRP both support the adoption of large amounts of solar and batteries. In contrast though, an important component of TVA's plan to meet system reliability needs at lowest system cost is the inclusion of both combined cycle and simple cycle natural gas generators. More precisely, the elemental disagreement at hand is the need for new dispatchable generation. While the Grid Strategies report suggests large amounts of renewable resources can be added to the system without impacting system reliability and resilience, TVA appropriately recognizes that increasing the amount of intermittent generation and resources based on emerging technologies will require dispatchable generation to ensure that customer energy and capacity needs are met around the clock. Given the significant amount of solar, battery storage, and DER expected in the medium-term, it is prudent for TVA to deploy new dispatchable generation by the time the nine Kingston units are retired at the end of their lives in 2027.

The following sections of this report explore the areas where the Grid Strategies report disagrees with TVA's assessments and direction. Based on a review of both reports, retiring Kingston units and selecting Alternative A represent reasonable near-term implementation steps entirely consistent with TVA's broader direction and analytic conclusions as outlined in the 2019 IRP.

The Grid Strategies report's analysis of solar capacity to replace the Kingston facility is flawed. The Grid Strategies report underestimates the amount of solar energy needed to replace the generation from the Kingston coal units by only considering the output of KIF from 2020-2022. There is meaningful variation in the three years considered by the Grid Strategies report which ranges from 1.5 million MWh to 3.1 million MWh. The Kingston average generation used in the Grid Strategies report is not representative of the amount of replacement energy needed for planning purposes since the years selected include the Covid pandemic. Considering an additional three years of historical output from KIF indicates a more reasonable energy replacement target would be nearly 3.1 million MWh, which implies 1,400 MW of solar capacity would be needed at a 25% capacity factor (without accounting for growth).

Next, the Grid Strategies report suggests the marginal capacity value of solar should be 46.95% of the nameplate capacity, which ignores the dual peaking (summer and winter) planning needs of TVA. The table below demonstrates that the unrealistic winter capacity value is inconsistent with values calculated in other regions for winter capacity planning. Regional Transmission Organizations and utility companies in comparable geographic territories use low and inconsequential winter solar capacity values. TVA uses zero as the winter capacity for solar in its modeling and the results of the Alternatives Evaluation would not change if TVA implemented a nominal value for winter solar capacity value.

Table 2: Winter Solar Capacity Values

Regional Transmission Organization or Utility Company	Winter Solar Capacity Value
PJM Interconnection	2%[13]
Midcontinent Independent System Operator	5%[14]
Duke Energy Carolinas	2.4%-6.1%[15]
Georgia Power	10%[16]

Following its unrealistically high winter capacity value for solar, the Grid Strategies report assumes 1,124 MW of solar (528 MW capacity value) plus 972 MW of battery storage would be sufficient to achieve the 1,500 MW of replacement capacity needed. These critical assumptions meaningfully understate the costs. In fact, updating the Grid Strategies report's simplified assumptions to 1) account for a more reasonable energy planning need of 3.1 million MWh and 2) reflect a more realistic winter capacity rating for solar, eliminates the Grid Strategies report's purported NPV cost savings. For instance, 1,400 MW of solar (to achieve 3.1 million MWh of energy) with a 2% winter capacity value is 28 MW of capacity resulting in at least 1,472 MW of battery storage. The additional 276 MW of solar at a cost of $1,350 per kW and an additional 500 MW of battery storage at a cost of $1,750 per kW[17] would result in an additional capital cost of $1.2 billion dollars.

TVA's Planning Incorporates the Dynamic Impacts of Increasing Renewables.

In order to underpin TVA's 2019 IRP to understand detailed system outcomes under a wide range of operating conditions, Astrape was retained to build and run the Strategic Energy and Risk Valuation Model ("SERVM") to assess reserve margin and loss of load impacts from the addition of increasing level of renewables on the system. The model reflects more than 30 years of historical load and weather relationships, demand-side resource operating constraints, details about the operating capabilities of TVA's existing supply-side generation resources, weather impacts on hydroelectric generation capabilities, ancillary service requirements, specific operating reserve requirements, as

13 Update on Reliability Risk Modeling – CIFP-Resource Adequacy. PJM Interconnection. July 17, 2023.

14 Planning Year 2023-2024 – Wind and Solar Capacity Credit Report. Midcontinent Independent System Operator. March 2023.

15 Duke Energy Carolinas and Duke Energy Progress Effective Load Carrying Capability (ELCC) Study. Astrape Consulting. April 25, 2022. https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=4ff77646-b2b8-44fd-859d-a1da38e65d30.

16 2023 Integrated Resource Plan Update. Georgia Power. October 2023. https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/2023-irp-update-main-document.pdf

17 The $1,350/kW for solar and $1,750/kW are approximate and consistent with the 2023 NREL Annual Technology Baseline overnight capital costs for the years 2023 and 2024.

well as import and export constraints for 20 zones of neighboring systems. The model is capable of hourly and sub-hourly simulations providing rich insights to real-world operational outcomes.

Beyond reserve margin analysis, loss of load modeling in SERVM is a useful methodology to determine capacity levels needed from renewable resources because it accounts for the dynamic effects of adding renewables while ensuring overall reliability targets are achieved. In contrast to the simplified approach in the Grid Strategies Report, the capacity levels of solar and storage needed in Alternative B were modeled using this approach. First, TVA modeled the solar capacity needed to replace the lost generation from the retired KIF which resulted in 1,500 MW of solar capacity with a 25% capacity factor. Then, the SERVM model was run with 1,500 MW of solar to determine the level of battery storage needed to maintain the industry reliability standard of a one-day-in-ten years loss of load event, resulting in 2,200 MW of battery storage capacity needed. In contrast, the dynamic reliability effects of adding a dispatchable natural gas plant are expected to be less than adding increased renewables resources and the loss of load modeling is not a necessary step to determine the natural gas capacity amounts for Alternative A. Finally, combined cycle and aeroderivative combustion turbine units do not have the same energy limitations as batteries, which have typical durations of 4 hours. The natural gas plants can run across many hours and days to support prolonged periods of high loads, which reduces relative risk for a loss of load event.

Long-term resource plans that exclude natural gas rely on overly optimistic assumptions.

Near-term wind potential in the Southeast is minimal.

The Grid Strategies report documented that TVA's interconnection queue includes one wind project with 204 MW of planned generation. The project was added in March 2023 with 18 months to in-service, and it is currently in the feasibility study phase. Projects should expect to spend at least five years in the interconnection queue before being fully operational, according to data from the Lawrence Berkeley National Laboratory.[18] Therefore, the 18-month interconnection timeline appears unrealistic based on historical trends. In addition, the Grid Strategies report references a Georgia Power tall wind turbine project from its 2022 Integrated Resource Plan as an example of how new technology can enable wind power throughout the Southeast. The referenced demonstration wind project was for two wind turbines up to four megawatts each with a hub height of 140 – 165 meters. Although the cited tall wind project was included in a settlement, the Georgia Public Service Commission ("PSC") explicitly rejected the tall wind project when approving portions of the settlement. As part of the discussion for rejecting the demonstration project, some Georgia PSC Commissioners expressed concerns about the costs and risks of the new technology.[19] This is not to say that wind technologies will not improve and that hub heights (and turbine blade lengths) will not

18 Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection. Lawrence Berkeley National Laboratory. April 2023. https://emp.lbl.gov/queues.

19 Georgia Public Service Commission. Administrative Session – 07/21/2022. Minute 25. https://www.youtube.com/watch?v=SFqDZqMSu3M.

continue to trend upward, instead this is an example of the pace at which change can be expected and that wind is not expected to be a viable alternative for the Kingston retirement.

Importantly, TVA's 2019 IRP included a sensitivity case to assess the impact of low-cost wind. Assuming a cost of roughly half the base case, TVA's sensitivity analysis showed that 4,200 MW of wind could be economical and displace 3,100 MW of solar generation by 2038. The 2019 IRP analysis of wind provided the key conclusion that if wind costs decline significantly compared to alternative resource options and there is access to a higher wind capacity factor, then wind can be a viable replacement for future capacity retirements. At this time, however, onshore wind is not economic compared to alternative resources. Therefore, TVA is focused on the near-term addition of solar and battery storage as well as adding dispatchable gas generation to prepare the system for higher levels of renewable energy.

Energy efficiency costs cited by Grid Strategies do not reflect the future costs to deliver energy efficiency. By 2028, TVA's demand-side resource portfolio may include up to 1,800 MW of peak reduction capabilities. However, the Grid Strategies report argues that more savings are available at a low cost. The Grid Strategies report assumes the costs of energy efficiency will be $10-$25/MWh.[20] While it is true that TVA's estimates for commercial and industrial energy efficiency costs are within the levelized $10-$25 per MWh range, it is also true the residential energy efficiency levelized cost range exceeded $250 per MWh, a fact the Grid Strategies report fails to acknowledge. Moreover, the amount of savings available at those cost levels in TVA's 2019 IRP was constrained to reflect adoption limitations with the underlying delivery strategies and incentive levels. The Grid Strategies report does not provide specifics about which end-use measures or delivery mechanisms could be used to achieve future energy savings and instead relies on broad expectations based on backward looking data references. Contrary to those assumptions, historical energy efficiency performance and costs are not a reliable indicator of the future. As low cost and low investment measures are exhausted, such as light-emitting diode ("LED") lighting, and other efficiency building codes and appliance standards usurp utility energy efficiency offers, future utility programs are likely to be much more costly with fewer savings than historically experienced. In fact, the IRA allotted $1 billion to assist the adoption of more efficient building codes, a change that would significantly reduce future savings opportunities for utility-sponsored energy efficiency programs.

In response to feedback during the 2019 IRP process, TVA analyzed a sensitivity case of adding significantly more energy efficiency and demand response. The analysis indicated that about 2,100 MW of additional demand-side resources were economically reasonable compared to the base case if higher volumes could be realized at the assumed costs. In the model, the additional demand-side resources displaced about 2,200 MW of solar and about 2,000 MW of combustion turbine capacity.

20 Critique of TVA's Alternatives Analysis in the Utility's "Kingston Fossil Plant Retirement, Draft Environmental Impact Statement," Michael Goggin, Grid Strategies, LLC (July 3, 2023), 29.

The overall results showed a similar lifetime cost, higher system average cost, and 10 percent lower carbon emissions. The sensitivity case clearly demonstrated the amount and cost of the demand-side savings is an important factor that will drive the amount of future resources needed, which is also why one of the near-term action items in the 2019 IRP is for TVA to conduct market potential study for energy efficiency and demand response. Furthermore, TVA is working to offset approximately 30% of new load growth in the next 10 years through energy efficiency and demand response programs.[21] Consistent with the range in the Board-approved power supply mix, TVA announced $1.5 billion in funding for energy efficiency and demand management through TVA's 2028 fiscal year.[22]

Grid Strategies significantly understates the reality of costs and timing of transmission upgrades and options.

In addition to the capital cost differences, the Grid Strategies report fails to recognize the difficulty in building interregional transmission projects to move wind output from its source to load centers. These resource-intensive projects tend to have lengthy planning, approval, and implementation timelines. The North American Electric Reliability Corporation ("NERC") recognizes the need for more transmission to connect renewable power generation to load supply centers, but it understands that high-voltage transmission projects are time-intensive and can face challenges related to transmission siting and complicated permitting structures.[23] The amount of time necessary to plan and construct high-voltage transmission projects is often underestimated. For example, the California Public Utilities Commission anticipates projects to span five to six years from the concept proposal to the completion date; however, in reality, system operators account for longer project timelines.[24] The California ISO ("CAISO") expects the build-out of its new suite of transmission projects to phase in over eight to ten years.[25] CAISO's Transmission Plan for 2021-2022 included ongoing transmission projects with anticipated costs exceeding $50 million that have experienced more than five years of delays. Fourteen of those projects have passed their original in-service date and are experiencing delays that are on average three times longer than the projects' anticipated

21 Tennessee Valley Authority. TVA Plans to Invest $15 billion over the Next Three Years to Meet Region's Growth. August 24, 2023. https://www.tva.com/newsroom/press-releases/tva-plans-to-invest--15-billion-over-the-next-three-years-to-meet-region-s-growth.

22 Tennessee Valley Authority. Energy Efficiency & Demand Management Expansion. November 2023. https://www.cleanenergy.org/wp-content/uploads/TVA-EE-DR-Expansion-Overview-External-11.2023.pdf.

23 North American Electric Reliability Corporation. *2021 Long-Term Reliability Assessment*. December 2021. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

24 California Public Utilities Commission (CPUC), *General Information on Permitting Electric Transmission Projects at the CPUC,* June 2009. https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/g/5065-general-information-on-permitting-electric-transmission.pdf.

25 California ISO. *2022-2023 Transmission Plan*. https://www.caiso.com/InitiativeDocuments/Draft-2022-2023-Transmission-Plan.pdf.

duration.[26] Moreover, NREL conducted a study in Texas analyzing the access of renewable energy zones to transmission systems, and estimated that planning and constructing new transmission systems can require five to ten years.[27] The Midcontinent Independent System Operator ("MISO") acknowledges that high-voltage transmission projects are time-intensive but MISO remains optimistic about project completion timelines. The 2023 MISO Transmission Expansion Plan includes eighteen approved Tranche 1 projects that are expected to take seven to nine years to complete which is less than the ten to twelve that has been required, according to Aubrey Johnson, a vice president of system planning for MISO.[28][29] While improvements in inter-regional transmission planning are promising, optimistically assuming readily available transmission capacity to import wind from neighboring regions as replacement capacity for the retirement of Kingston is not realistic.

The Southern Spirit project (formerly named Southern Cross) and the Plains & Eastern transmission line referenced in the Grid Strategies report are prime examples of the challenges and high costs of building interregional transmission. Southern Cross Transmission LLC filed an initial application in 2017 estimating that construction was to begin in 2021; however, the supplemental application filed in 2023 accounted for a four-year delay, stating that construction was to begin in 2025 and conclude in 2028.[30][31] If the current timeline materializes, the project will have spanned seventeen years from when Southern Cross LLC submitted an application for interconnection under sections 210, 211, and 212 of the Federal Power Act.[32] The total construction cost across Texas, Louisiana, and Mississippi will be approximately $2.68 billion with 3,000 MW of capacity or $893/kW.[33] Similarly, Clean Line Energy Partners proposed the Plains & Eastern transmission line in 2010, a $2.2 billion project with 3,500 MW of capacity or $629/kW.[34][35] The Plains & Eastern project was expected to break ground in

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26 Clean Air Task Force. *Transmission Development in California – What's the Slowdown?* January 2023. https://cdn.catf.us/wp-content/uploads/2023/03/16151853/california-transmission-development.pdf.

27 Lee et al. National Renewable Energy Laboratory. Renewable Energy Zone (REZ) Transmission Planning Process: A Guidebook for Practitioners. September 2017. https://www.nrel.gov/docs/fy17osti/69043.pdf.

28 Midcontinent Independent System Operator. MISO Transmission Expansion Plan - Full Report. 2023.

29 Catherine Clifford. *Why it's so hard to build new electrical transmission lines in the US*. CNBC. February 21, 2023. Why it's so hard to add electrical transmission lines in the U.S. (cnbc.com)

30 Petition for Certificate of Public Convenience and Necessity. Southern Cross Transmission LLC. Mississippi Public Service Commission – Docket No. 2017-UA-079. April 25, 2017.

31 Supplemental Petition for Certificate of Public Convenience and Necessity. Southern Cross Transmission LLC. Mississippi Public Service Commission – Docket No. 2017-UA-079. January 14, 2023.

32 Final Order Directing Interconnection and Transmission Service. Southern Cross Transmission LLC. Federal Energy Regulatory Commission – Docket No. TX11-1-001. May 15, 2014.

33 Supplemental Petition for Certificate of Public Convenience and Necessity. Southern Cross Transmission LLC. Mississippi Public Service Commission – Docket No. 2017-UA-079. January 14, 2023.

34 Plains & Eastern Project Proposal. Clean Line Energy Partners. July 2010. Plains & Eastern Clean Line Project Proposal for New or Upgraded Transmission Line Projects Under Section 1222 of the Energy Policy Act of 2005 (July 2010).

35 Plains & Eastern Clean Line Project Cost Estimate. Department of Energy. 1222 6.b Plains and Eastern Project Cost.xlsx (energy.gov).

2016 and be complete by 2018, but the Department of Energy terminated its partnership with the project and political factors hampered development.[36] Clean Line sold its share of the transmission segment to NextEra Energy after the project was under development for eight years. The examples cited by the Grid Strategies report serve as case studies about how interregional transmission projects are expensive and the necessary time to complete a project is underestimated.

To mimic interregional access to wind, TVA's 2019 IRP included a High Voltage Direct Current ("HVDC") wind option that would use a direct current bulk transmission system. The HVDC option would require a third-party to permit and build a new transmission line, driving a later availability date than the other wind options. It was assumed that the wind would be from Oklahoma with a 55 percent capacity factor. Even so, this wind resource option was not selected as an economic option by the capacity expansion model.

TVA, other balancing authorities, and other utilities manage how much they rely on external generation resources, such as purchased power and imports to meet system load during extreme weather events. Winter Storm Elliot affected the load requirements and generation capacity of balancing authorities adjacent to TVA, which resulted in the curtailment of TVA's import power from multiple sources contributing to the need to order 10 percent load shed.[37] Without new dispatchable generation, the addition of intermittent sources of generation coupled with the retirement of coal-fired plants can exacerbate the strain on regional systems as well as TVA's system and may require further substantial transmission upgrades.

Interconnection of resources to the transmission system is a lengthy process across the U.S. The Grid Strategies report proposal to hire external resources to expedite the interconnection process is a vast oversimplification of a challenge not unique to TVA. Based on Lawrence Berkeley National Laboratory's 2022 U.S. interconnection data, renewable energy projects spend approximately five years, on average, in the interconnection queue before being commercially available. It is important to recognize that project-level implementation influences when projects are completed so attempting to expedite interconnection planning and processes would not alleviate all drivers of the timing between when resources enter the queue and when those projects are completed.

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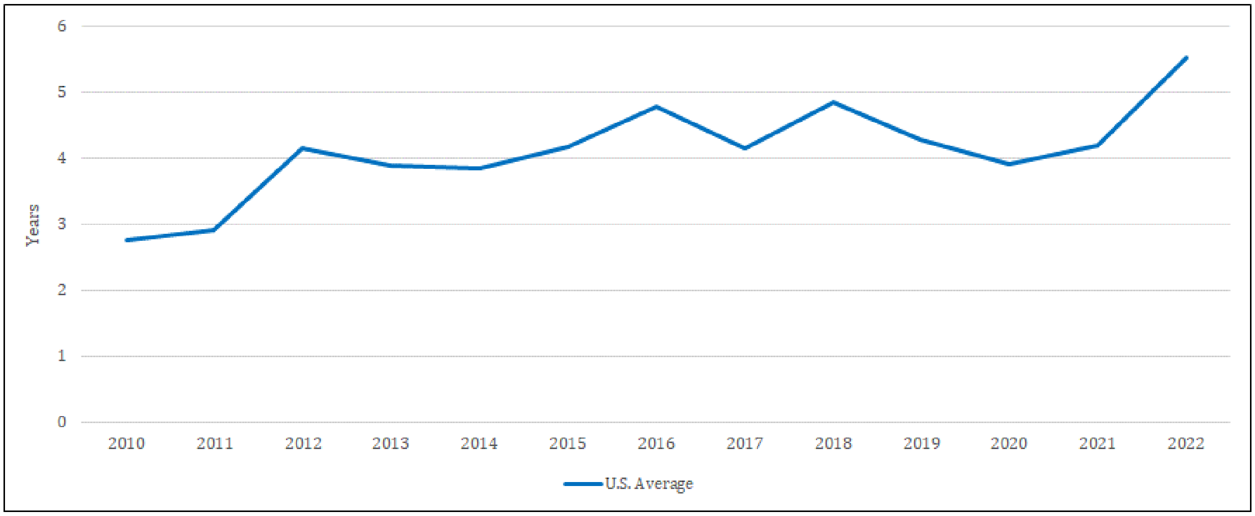
36 Letter from Mario Hurtado. Clean Line Energy Partners. December 15, 2014. CleanLinePt2-Appendix-9-B.pdf (energy.gov).

37 Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliot. FERC, NERC and Regional Staff Report. October 2023. https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott,

Figure 6: Average Time for a Project from Entering the Interconnection Queue to being Fully Operational.[38]



Near-term deployment of natural gas generation resources provides a solid foundation for aggressive renewable energy deployment.

Natural gas is a dispatchable resource that supports the power system during the rapid deployment of variable energy resources, such as wind and solar, which are not dispatchable. NERC issued a Long-Term Reliability Assessment in December 2022, which highlighted how natural gas is essential to the reliability of the bulk power system during the current energy transition, supporting the use of natural gas as a bridge fuel.[39] James Robb, President and CEO of NERC, issued testimony before the Committee on Energy and Natural Resources that underscored the importance of natural gas.

> Natural gas will remain essential to reliability for total energy and as a balancing resource. In many areas, natural gas-fueled generation is needed to meet energy demand during shoulder periods between times of high and low renewable energy availability, and to set frequency needed by IBRs until advanced grid forming inverters are in placed coupled with energy storage. And on a daily basis in areas with significant solar generation, the natural gas fleet is a flexible generation resource to fill the gap. The criticality of natural gas as the "fuel that keeps the lights on" will remain until very large-scale and long-duration battery deployments are feasible or an alternative

38 Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection. Lawrence Berkeley National Laboratory. April 2023. https://emp.lbl.gov/queues.

39 NERC. Long Term Reliability Assessment. December 2022. 8. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

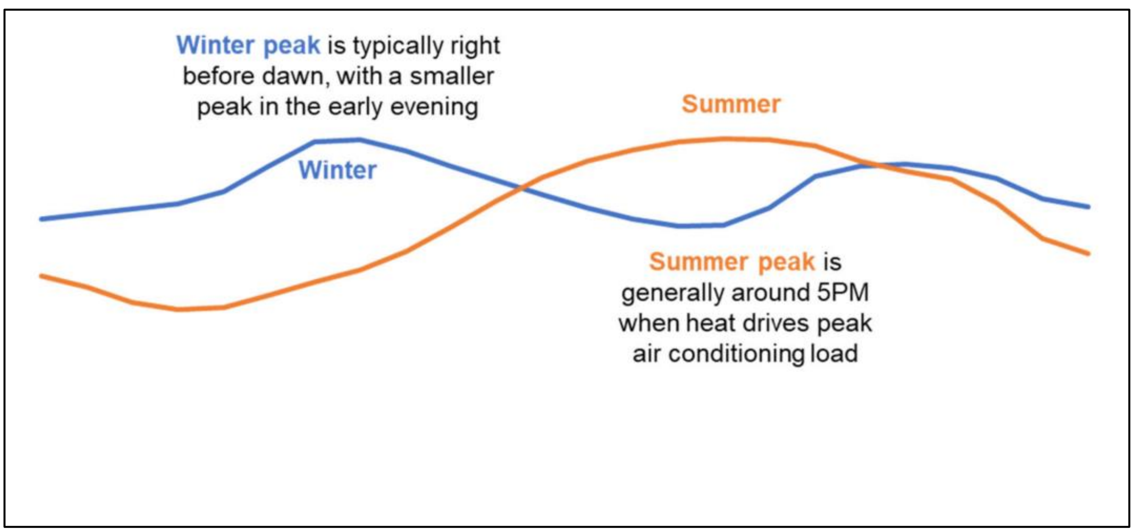
flexible fuel such as hydrogen, or small nuclear reactors can be developed and deployed at scale.[40]

Dispatchable generation is critical for electric system reliability, and it must be retained to fulfill the expected peak demand and reliably operate the bulk power system.

A reliable flow of power to our electricity grid is no longer the only measure by which customers assess the performance of their electric utility. Customers are increasingly demanding that electricity supply be both reliable and clean. Adding solar and wind resources achieves environmental objectives, but when the sun is not shining or the wind isn't blowing, other types of generating resources are needed to maintain critical grid reliability. A diverse energy mix offers reliability and resilience, which has proven to be particularly valuable during difficult operating conditions, such as peak power demand during high summer or bitter cold during deep freezes. The optionality offered by a diverse portfolio of generating resources also supports affordability. Should the price of one fuel spike, or should bad weather compromise the supply of one power source, another lower-cost option can be substituted, holding down energy prices for consumers.

In operating a reliable system, the goal is to have enough capacity available to meet peak demand. As shown in Figure 7 below, the TVA winter peak occurs at approximately 7am, while the TVA summer peak occurs at approximately 5pm.

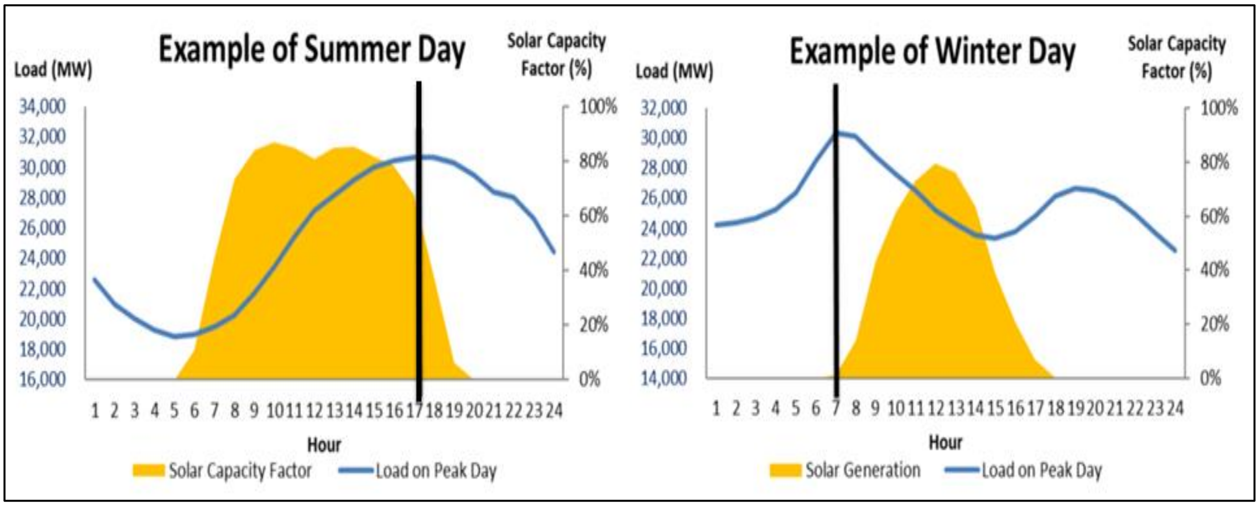
Figure 7: TVA Winter and Summer Peak Day Load Profiles



40 Testimony of James B. Robb. The Reliability and Resiliency of Electric Service in the United States in Light of Recent Reliability Assessments and Alters – Before the Committee on Energy and Natural Resources – Unites States Senate. June 1, 2023. https://www.energy.senate.gov/services/files/D47C2B83-A0A7-4E0B-ABF2-9574D9990C11.

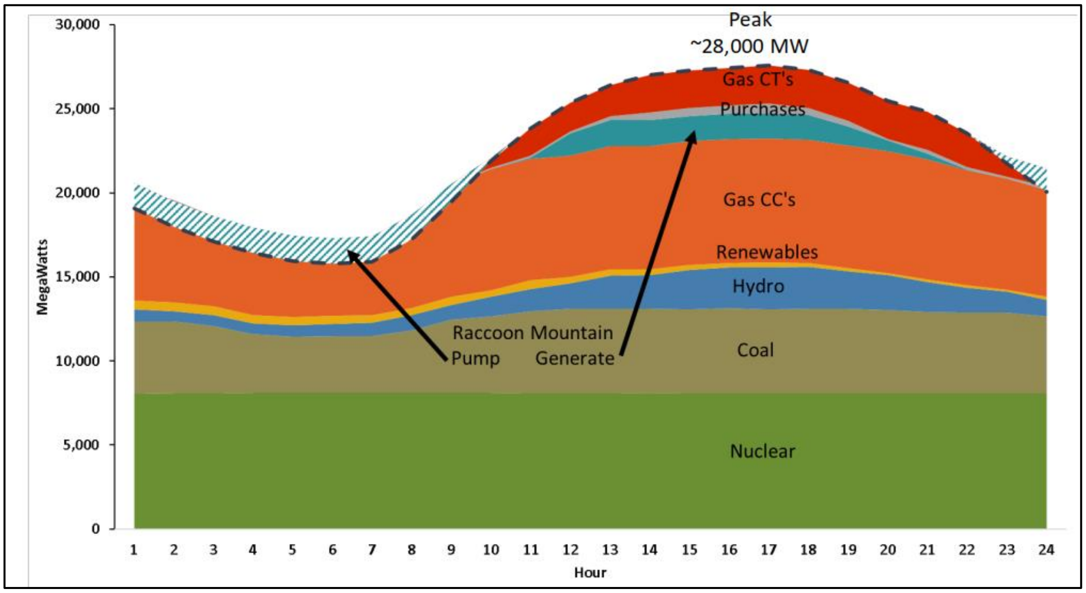
As can be seen below, solar output is declining as the summer peak hour approaches and, although solar output increases later in the morning during the winter, it is completely unavailable for the near peak pre-dawn loads.

Figure 8: Solar Output on Peak Summer and Winter Days



Wind output also mismatches with these peak loads, with summer wind output at 14% of its capacity at the time of summer peak and 31% of its capacity at the time of winter peak. This mismatch in solar and wind output compared to peak demand requires that other resources, including nuclear and fossil resources, be available for dispatch to meet peak demand. As shown below, TVA dispatches its diverse generating fleet of nuclear, coal, gas, hydro, and renewables by both availability and cost. In the lower load hours, these resources are sufficient to meet customer demand. However, in the peak hours, gas fired units are crucial in meeting peak demand in the summer and winter.

Figure 9: TVA Load Dispatch on a Typical Summer Day



The broader industry has been exploring the place wind and solar have in the evolving grid. Importantly, there is no bulk power system operating today with significant penetration of wind and solar resources, limiting the ability to learn from others. These resources differ from fossil and nuclear generation in that their ability to produce power is dependent on the weather, which creates uncertainty in terms of their availability. Also, these machines' electrical properties are unique from those traditionally built in that they are inverter based (i.e., electronically connected to the grid rather than mechanically connected).

Due to environmental mandates requiring "clean" generating resources by a certain date, and the uncertainty around the impact of a high penetration of zero-emitting generating resources on the power system, system operators have conducted highly detailed studies to explore how wind and solar growth would affect reliability and resiliency. These studies, as further described below, have shown that the complexity of renewable integration escalates with the growing penetration of renewable energy, requiring significant physical and operational changes to the bulk power system. Over some renewable penetration ranges, complexity is constant when spare capacity and flexibility exist. However, at specific penetration levels, complexity rises dramatically as the excess capacity and flexibility are exhausted. These represent system inflection points, where the underlying infrastructure, system operations, or both need to be significantly modified to reliably achieve the next tranche of renewable deployment.

MISO undertook an assessment to systematically find system integration inflection points driven by increasing renewable integration.[41] The MISO assessment found that when the percentage of annual load served by renewable resources is less than 30% system-wide, the integration of wind and solar faces challenges but appears manageable with significant changes to transmission expansion, operating, market, and planning practices within the existing framework. Above the 30% level, significant system-wide complications arise, driven by the increased variability of wind and solar, changes in resource availability, and an overall lack of transmission capacity in the region. Addressing these complications through system upgrades and operational changes can enable the grid to be operated reliably with up to 50% of the energy served by wind and solar resources.[42]

In addition, NREL conducted a study to analyze the effects of increased wind and solar penetration on the operation of the bulk power system and found that estimated U.S. electricity demand in 2050 could be met with 80% of generation from renewable electricity technologies with varying degrees of dispatchability. However, this amount of renewables generation on the system would require a mix of flexible conventional generation and grid storage, additional transmission, more robust load response measures and changes to power system operations. While this analysis suggests such a high renewable generation future is possible, a transformation of the electricity system would need to occur to make this future a reality. This transformation would involve every element of the grid, including adequate planning and operating reserves, increased flexibility of the electric system, expanded multi-state transmission infrastructure, development and adoption of technology advances, new operating procedures, evolved business models, and new market rules.[43]

Inverter-based resources, such as battery storage, are utilized to expedite grid modernization. These resources have demonstrated transformative potential, but they can also introduce reliability risks to the bulk power system. NERC has studied the application of battery storage in California's burgeoning market and noted significant events involving the unexpected performance of battery storage systems. NERC highlighted two abnormal power reduction events in Southern California during the spring of 2022 which originated from battery storage facilities that were exhibiting unreliable performance.[44] The battery storage plants experienced multiple inverter trips due to three main causes: (1) inverter instantaneous ac overcurrent, (2) inverter instantaneous AC overvoltage

41 MISO's Renewable Integration Impact Assessment Summary Report, February 2021. https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

42 *Id.*, pg. 13.

43 National Renewable Energy Laboratory Renewable Electricity Futures Study, 2012. https://www.nrel.gov/docs/fy12osti/52409-1.pdf.

44 2022 California Battery Energy Storage System Disturbances. North American Electric Reliability Corporation. September 2023. https://www.nerc.com/comm/RSTC/Documents/NERC_BESS_Disturbance_Report_2023.pdf.

tripping, and (3) inverter voltage unbalance tripping.[45] NERC recognizes the importance of battery systems for grid modernization, but it asserts that the growing sector of battery systems must be properly planned, modeled, and constructed to ensure reliability.

Battery storage is a promising resource option for which TVA seeks to build experience.

Storage is a meaningful element of TVA's future resource additions. The 2019 IRP range includes battery storage up to 2,400 MW by 2028 and up to 5,300 MW by 2038 (depending on technology costs, performance, and load growth). In October 2023, EIA reported that TVA has one operating battery storge plant within its balancing authority jurisdiction with a nameplate capacity of 1 MW. According to TVA's 10-K filing in November 2023, TVA has three battery storage contracts, not yet online, that have a total nameplate capacity of 150 MW compared to a total operating capacity of approximately 43 GW reported by EIA.[46] [47] TVA's operating and contracted battery storage capacity accounts for 0.35% of TVA's total operating capacity which indicates that TVA is beginning to build its experience with batteries.

The Grid Strategies report claims batteries provide reliability services better than natural gas generators. While battery storage is making technological advancements, industry understanding and modeling of how large amounts of battery storage will impact the grid is limited. In 2019, the U.S. Energy Information Administration indicated there was a total combined utility-scale battery storage capacity of about 170 MW which grew to nearly 500 MW in 2020, to over 3,200 MW in 2021, and up to nearly 8,850 MW in 2022.[48] The figure below illustrates how historical battery storage adoption across the U.S. compares to Alternative B and gives further context to the already significant battery storage ranges in TVA's 2019 IRP.

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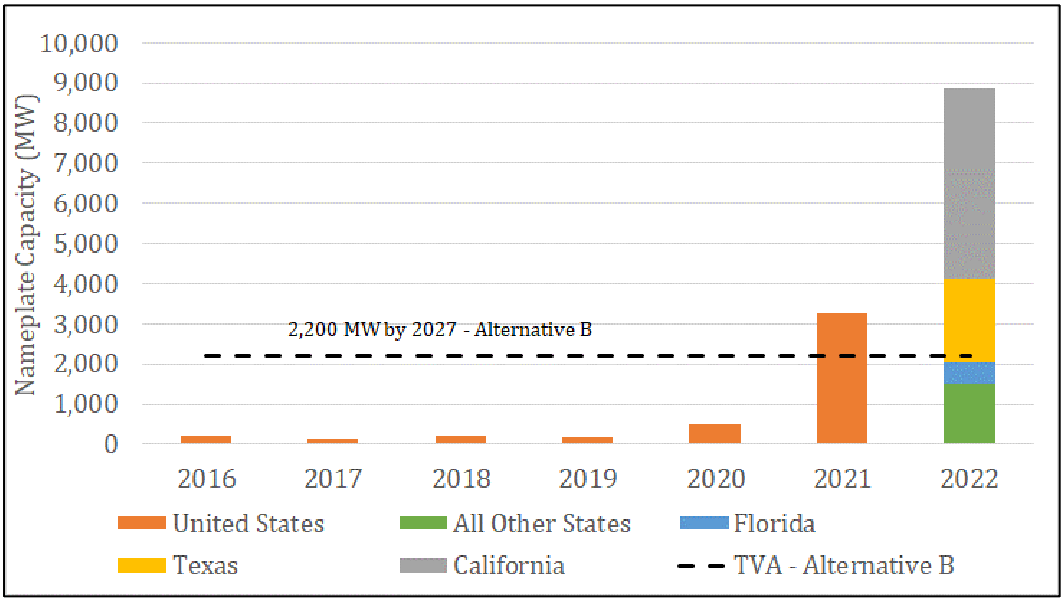
45 2022 California Battery Energy Storage System Disturbances. North American Electric Reliability Corporation. September 2023. https://www.nerc.com/comm/RSTC/Documents/NERC_BESS_Disturbance_Report_2023.pdf

46 Tennessee Valley Authority. Form 10-K. November 14, 2023.

47 Preliminary Monthly Electric Generator Inventory. Energy Information Agency. November 22, 2023. https://www.eia.gov/electricity/data/eia860m/.

48 Data from the *Annual Electric Generator Report.*

Figure 10: U.S. Battery Storage Capacity 2016-2022



Source: U.S. Energy Information Administration, Annual Electric Generator Report and Preliminary Monthly Electric Generator Inventory, February 2022-2023.

Battery energy storage systems are concentrated in a select few states. California, Texas, and Florida account for approximately 84% of the total power capacity (MW) of battery storage systems in the United States. Battery storage systems are growing exponentially, but the geographic distribution is not equal. As part of Alternative B, adding 2,200 MW of storage by 2027 for the KIF retirement would result in TVA adding, owning, and operating more battery storage capacity over the next 4 years than All Other States[49] had in 2022. The expectation that TVA should deploy battery storage systems at the same rate as the select few states that account for the vast majority of operating systems is unreasonable.

Federal and select state legislators have begun incentivizing utilities to retire coal plants and replace them with solar and battery storage systems, although not necessarily the same energy and capacity at the same location. In Illinois, for example, the Energy Transition Act established a Coal-to-Solar Program which incentivizes utilities to replace coal plants with up to 300 MW of utility-scale solar and 150 MW of battery energy storage systems. Vistra plans to participate in the Coal-to-Solar Program by replacing six coal plants with combined utility-scale and battery energy storage systems.[50] However, the coal plants are not being replaced with the same operating capacity.

[49] States other than California, Texas, and Florida as seen in Figure 10.

[50] Vistra. Illinois General Assembly Passes Vistra's Coal to Solar & Energy Storage Act. September 13, 2021. https://vistracorp.com/illinois-general-assembly-passes-vistras-coal-to-solar-energy-storage-act/.

Table 3: Vistra's Proposed Replacement Capacity[51]

Plant Name	Existing Nameplate Capacity 2017	Vistra's Proposed Utility Scale Solar Capacity	Vistra's Proposed Battery Energy Storage Capacity
Baldwin Energy Complex	1,894 MW	68 MW	9 MW
Coffeen	1,005 MW	44 MW	6 MW
Duck Creek	441 MW	20 MW	3 MW
Hennepin Power Station	306 MW	50 MW	6 MW
Kincaid Generation	1,319 MW	60 MW	8 MW
Newton	617 MW	52 MW	7 MW

While battery storage has the potential to provide important system benefits, the Grid Strategies report does not appear to consider battery performance specifications and/or specify a technology. Battery storage technology and performance factors are critically important to system reliability and stability. For instance, a battery's useful life is impacted by the number of times it is cycled (i.e., how many times it is dispatched) and the depth of those discharges (i.e., how much of its capacity is used when it is dispatched). It is logical to assume that as the more battery capacity is relied upon for peak load needs and system reliability needs, they will experience more cycles and deeper discharges.

The Grid Strategies report downplays the critical role natural gas generation serves in TVA's overall system.

The Grid Strategies report makes several assertions regarding the capacity planning and performance of natural gas resources and renewable energy resources. While some of the observations are important planning considerations, they overstate the implications and do not recognize the robustness of TVA's 2019 IRP analysis. For instance, to properly characterize planning uncertainty and different generation resource impacts to the system (even at the sub-hourly level), TVA's 2019 IRP included a Reserve Margin Analysis, an Intermittent Resources Study, and a Flexibility Study. Each of these individually robust studies played a role in how generation resources were characterized and how resource portfolios were constructed.

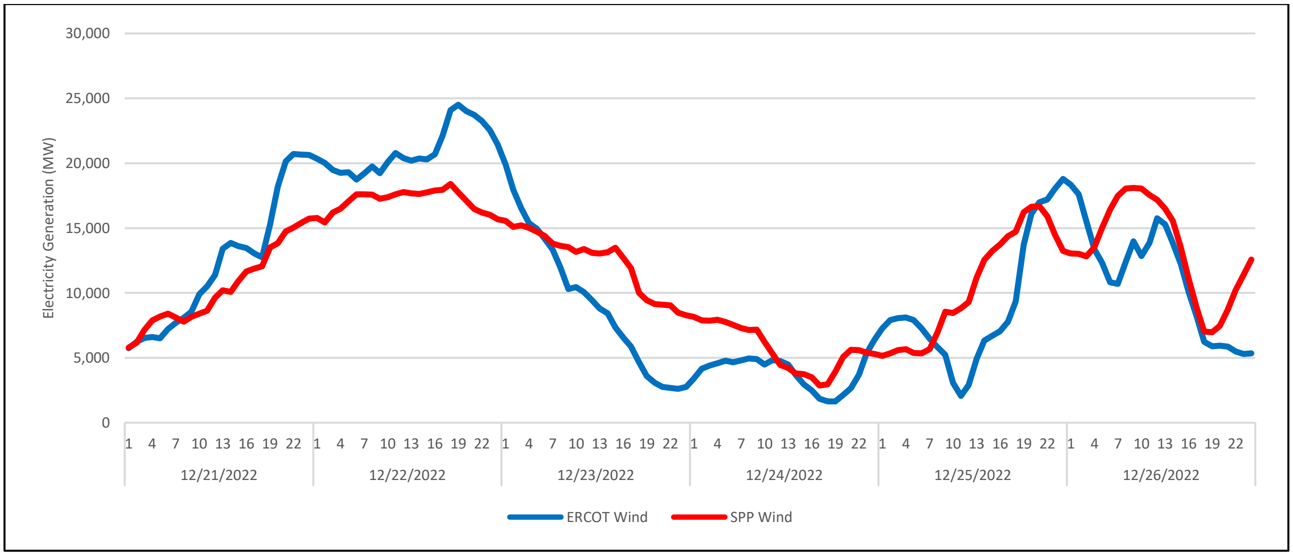
With regard to recent events during Winter Storm Elliot, the Grid Strategies report states that wind output was strong across ERCOT and SPP territories, suggesting, in hindsight, that wind sourced from these areas would have supported TVA's ability to prevent generation shortages. Contrary to that claim, EIA-930 electricity generation data for ERCOT and SPP provides clarity on the status of wind generation output during Winter Storm Elliot.[52] The figure below depicts a decline in wind output

51 Energy Information Agency. Preliminary Monthly Electric Generator Inventory. 2017. https://www.eia.gov/electricity/data/eia860m/.

52 Hourly Electricity Generation by energy source – Balancing Authority / Regional Files. U.S. Energy Information Agency. November 29, 2023.

coinciding with Winter Storm Elliot, most notably on December 23, 2022, and December 24, 2022, as those were the times when weather and load conditions were the most challenging for TVA's system.

Figure 11: ERCOT and SPP Wind Generation – Winter Storm Elliot



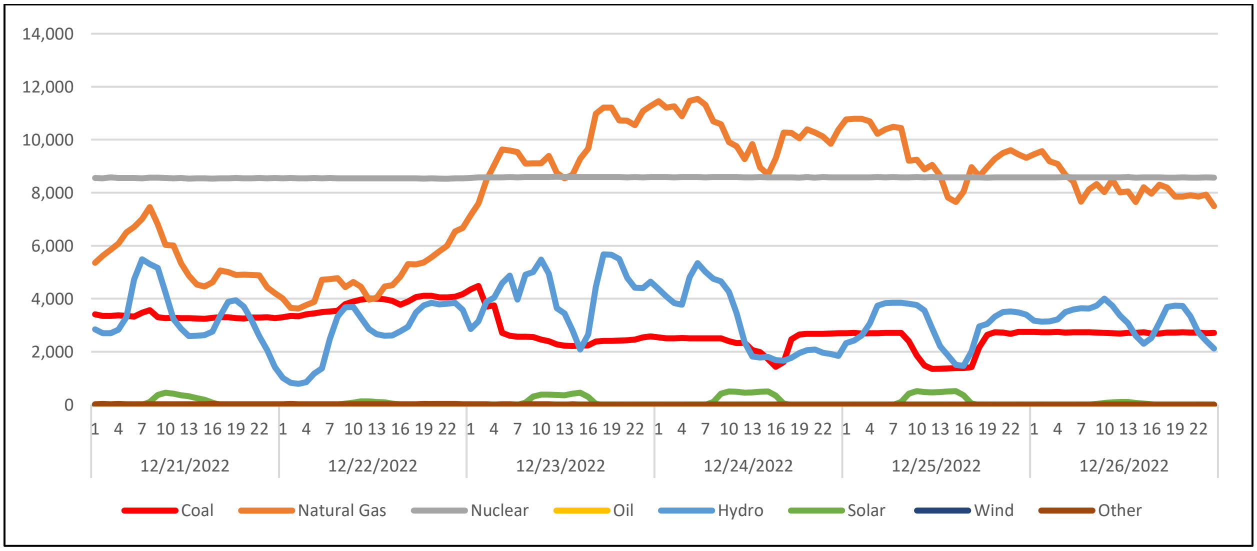
The Grid Strategies report highlights concerns about the addition of combined cycle generation to replace the retired Kingston generation in terms of natural gas reliability and correlated outages. In fact, TVA's natural gas generating fleet has several advantages that mitigate the risk of fuel supply outages in its natural gas generating fleet. According to TVA's 10-K filing for the fiscal year ending September 30, 2023:

- 83 of TVA's combustion turbines (about 80%) were dual-fuel capable, and TVA has fuel oil stored on each of these sites as a backup to natural gas.
- Transportation of natural gas occurs across eight separate pipelines, with approximately 69 percent being transported on two pipelines.
- Approximately 1,716,000 million British thermal units is maintained per day of firm transportation capacity on seven major pipelines, with approximately 60 percent of total firm transportation capacity being maintained on two pipelines.
- TVA utilizes natural gas storage services at seven facilities with a total capacity of 7.75 billion per cubic feet (Bcf) of firm service and 6.275 Bcf of interruptible service to manage the daily balancing requirements of the nine pipelines used by TVA, with approximately 55 percent of the total storage capacity being maintained at two facilities. During 2023, storage levels were generally maintained at between 40 and 80 percent of the maximum contracted capacity at each facility. As TVA's natural gas requirements grow, it is anticipated that additional storage capacity may need to be

acquired to meet the needs of the generating assets. In 2024, TVA expects to increase its storage portfolio by approximately 7 percent.

Regarding recent events during Winter Storm Elliot, the EIA-930 electricity generation data below for TVA illustrates the significant increase in gas-fired electricity generation during Winter Storm Elliot.[53]

Figure 12: TVA Electricity Generation by Energy Source – Winter Storm Elliot



On Friday December 23, 2022, TVA had lost 6,705 MW of generation from coal, combined cycle gas, and independent power producers. While no gas generation units tripped offline because of gas pressure issues from the interstate pipelines, TVA identified opportunities for improved communication across the fleet to enhance coordination and visibility related to gas supply, pressure alignment and troubleshooting.[54] The Aging Coal Fleet Evaluation noted the KIF's high cost and challenged condition are factors driving the retirement decision in addition to the higher unplanned outage rates compared to peers. So, to the extent age and condition of older coal units were a factor in the Winter Storm Elliott, then that supports TVA's decisions to phase-out the older coal units and replace them with newer more dependable dispatchable generation.

It is also important that TVA, along with other utilities and reliability councils, have learned important lessons from recent major storms. Those lessons drive continuous improvement in generation performance and system reliability during future major events. The historic and extreme conditions during Winter Storm Elliot strained the grid and forced TVA to request demand response

53 Hourly Electricity Generation by energy source – Tennessee Valley Authority. U.S. Energy Information Agency. November 29, 2023.

54 Tennessee Valley Authority. Winter Storm Elliot After Action Report. https://www.tva.com/about-tva/reports.

customers to reduce energy consumption. TVA identified areas to improve and made 250 near-term mitigation actions to strengthen reliance by hardening assets for future events. In addition to modifying design standard to increase system resilience during extreme events, TVA intends to better utilize data to account for risk and uncertainty in energy usage and markets as well as to bolster emergency protocols and communication methods to improve information sharing.

The Inflation Reduction Act influences the amount and timing of resources but does not change the ranges or resource additions and retirements contained in the 2019 IRP.

TVA's 2019 IRP considered a wide range of strategies, scenarios, and sensitivities. As a result, TVA's long-term plans reflect ranges of future resource needs anticipating the need to adjust resources levels up or down depending on market conditions at the time of a particular decision. Even so, because TVA's analyses explored a wide range of possible future outcomes, questions about the effects of the IRA can be qualitatively assessed by considering whether the potential impacts would trend resource amounts higher or lower within the 2019 IRP ranges. To that end, the figure below summarizes the potential IRA impacts to the level of future resources within the 2019 IRP ranges.

While the IRA impacts must be more fully modeled and explored, fundamental concepts and conclusions remain unchanged, such as the escalating complexity of adding renewable resources, the need for broad and rigorous analyses, and ultimately the need for dispatchable generation as part of a diverse and reliable generation portfolio. From a near-term perspective, the practicality of Alternative A over Alternative B is unchanged by the IRA's enactment. While the IRA improves the economics for Alternative B, the cost improvements would not eliminate its implementation barriers or overcome the cost savings from Alternative A.

Figure 13: Potential Impacts Within 2019 IRP Resource Ranges

Resource Type	2019 IRP Range	Potential IRA Impact Within 2019 IRP Resource Ranges
Peak demand	-0.7% to 1.7%	Uncertain net impact: load growth by electrification and focus on domestic manufacturing offset by load reductions from building codes and efficiency funding
Solar	Up to 14 GW	Uncertain net impact: improved wind economics reduce solar within the range, improved solar economics increase solar within the range, net load impacts are uncertain
Storage	Up to 5.3 GW	Trend up within the range if storage economics sustainably improve
Wind	Up to 4.2 GW if economic	Trend towards adding wind to the portfolio with the amount and timing uncertain, additional wind reduces solar, transmission uncertainties largely unchanged
DSM	Up to 2.1 GW if economic	Downward pressure: Federal funding for state administered programs and efficient building codes reduce utility sponsored opportunities
Combustion Turbine	Up to 8.6 GW	Downward pressure: trend lower within the range if more economic wind, trend lower within the range if battery storage is more economic, long-term gas prices are uncertain, net load impacts are uncertain, reliability needs unchanged or enhanced
Combined Cycle	Up to 9.8 GW	Downward pressure: trend lower within the range if more economic wind, trend lower within the range if battery storage is more economic, long-term gas prices are uncertain, net load impacts are uncertain, reliability needs unchanged or enhanced

The Alternatives Evaluation in the Draft EIS incorporates a 10% Investment Tax Credit for solar as an initial application of the potential tax credits from the IRA. It would be appropriate for TVA to update the tax credit assumption to 30% along with the latest capital cost information for the Final EIS. Since the 2023 National Renewable Energy Laboratory Annual Technology Baseline forecasted cost curves for solar and storage are higher than the 2022 vintage, the net result of updated modeling assumptions of cost and tax credits will not change the relative economics between Alternative A and Alternative B; that is, Alternative A remaining the lowest cost option.

THE APPLIED ECONOMICS CLINIC REPORT OVERSTATES THE PURPOSE OF TVA'S IRP

TVA's Preferred Alternative is predicated on a robust planning process and is consistent with industry norms.

TVA is bound by the requirements of the EPAct to consider a diverse range of energy sources, promote energy efficiency, integrate renewable energy, and ensure the reliability and resilience of the electric grid. TVA is not required to but has chosen to use an IRP process as a tool to meet these requirements. The AEC report asserts that TVA's planning process is flawed and therefore the 2019 IRP cannot be relied upon to assess whether TVA's Preferred Alternative, which includes the retirement and replacement of the Kingston facility with natural gas-fired generation, is reasonable. In fact, TVA's planning process and the 2019 IRP is a robust and comprehensive means for TVA to achieve its statutory mandates. TVA's 2019 IRP is also consistent with industry standards. The 2019 IRP serves as a solid basis for future resource decisions. The Kingston EIS is one step in the execution of TVA's 2019 IRP that will facilitate the transition to a cleaner grid.

An industry standard IRP is an electric utility's plan that serves as a strategic roadmap to meet both short-term and longer-term future energy needs in a reliable and cost-effective manner. At its core, an IRP involves a thorough analysis of the current energy landscape, including the evaluation of existing generation assets, demand forecasts, and consideration of regulatory and environmental factors. An IRP encompasses a detailed review of various resource options, such as renewable energy sources (solar, wind, hydro), conventional power plants (natural gas, coal, nuclear), energy storage technologies, and demand-side management programs. The goal is to create a diversified and resilient energy portfolio that minimizes environmental impact, enhances grid stability, increases reliability, and ensures long-term energy affordability.

A robust IRP also incorporates a comprehensive risk assessment, accounting for uncertainties in fuel prices, technology advancements, and regulatory changes. The plan should be adaptive, allowing for periodic reviews and updates to accommodate emerging trends and breakthroughs in the energy sector. Additionally, a well-crafted IRP considers the integration of smart grid technologies, grid modernization efforts, and the potential for electrification of transportation and other sectors. TVA's IRP included the 30 primary cases and the sensitivity cases, providing a robust set of potential resource additions and retirement. Through the original scenario and strategy analysis, and the sensitivity cases, TVA uses ranges that are centered on results obtained under the "current outlook scenario." The other scenario and sensitivity results provide a sense of how the recommended mix might change as the future changes.

The AEC report asserts that because TVA develops recommended ranges for capacity additions and retirements over a 20-year planning horizon as opposed to the "widely used practice" of utility IRPs determining a single "preferred portfolio," the IRP is limited in the degree to which it can be used to assess whether TVA is actually achieving a least-cost portfolio or decarbonization aspirational goals. In fact, utilities that use a "preferred scenario" approach in their IRP process also include various scenarios and sensitivities, recognizing that there is a wide range of variability in inputs and assumptions. This provides the flexibility needed for a utility to adjust its approach to achieving decarbonization, least cost, and reliability goals. The appropriate assessment of a utility's progress in achieving these goals must be based on trends in customer rates, reliability metrics, and emissions reductions, not an arbitrary comparison of planned to actual capacity additions and retirements.

The IRP planning process should also be designed to welcome various opportunities for public education and participation, including stakeholder involvement, thereby ensuring the IRP remains reflective of its customer base. Throughout the IRP process, TVA went beyond the requirements of the EPAct to engage a diverse group of external stakeholders to understand diverse opinions and to challenge assumptions. TVA established the IRP Working Group, whose 20 members represent diverse interests across TVA's service territory. The IRP Working Group met approximately monthly to review input assumptions and preliminary results and to enable its members to provide their respective views to TVA. TVA also presented IRP progress updates to the Regional Energy Resource Council ("RERC"), a federal advisory committee that provides advice to the TVA Board of Directors on a range of energy-related matters, including the IRP. During a 60-day scoping period from February 15 through April 16, 2018, TVA obtained public comments on the scope of the effort to develop this IRP, which helped shape the draft IRP and associated EIS. After the release of the draft IRP and EIS on February 15, 2019, TVA provided a public comment period through April 8, 2019. TVA held meetings across the Tennessee Valley and an online webinar, and accepted public comments via mail, email, online and in-person at the meetings. Input was critical in shaping the IRP and EIS, and many of the sensitivity analyses that were performed were informed by stakeholder and public input.

TVA's planning process and the resulting 2019 IRP meet all the characteristics of a thorough and well-executed integrated resource planning process and complies with all requirements set out by Section 113 of the EPAct. TVA's 2019 IRP sets a planning direction with guideposts that represent key variables that TVA monitors to inform future actions. The IRP is not a "stake in the ground" but rather a dynamic plan that can adapt to future market conditions, consistent with the approved target supply mix.

The Kingston EIS is one step in the execution of TVA's resource planning process that will facilitate the transition to a cleaner grid. As stated in TVA's Strategic Intent and Guiding Principles document, TVA is committed to providing low-cost, reliable energy through a diverse and increasingly clean generation portfolio. This commitment, as reflected in the 2019 IRP, has resulted in a 63% reduction in mass carbon emissions since 2005. At the same time, TVA must provide reliable, resilient and low-cost energy to its customers. The addition of gas-fired generation at the Kingston site allows TVA to continue to make progress on its environmental aspirations while providing customers with reliable low-cost power.

TVA's 2019 IRP is grounded in least-cost planning while recognizing environmental aspirations and ensuring reliability.

As required by the U.S. Energy Policy Act of 1992, TVA's IRP planning process is grounded in least-cost planning, which is based on an evaluation of a full range of existing and incremental resources, driving meaningful economic and environmental goals. TVA employs a comprehensive, least-cost approach that evaluates various perspectives of the future to assess the potential performance of power generation resources under diverse market and external circumstances.

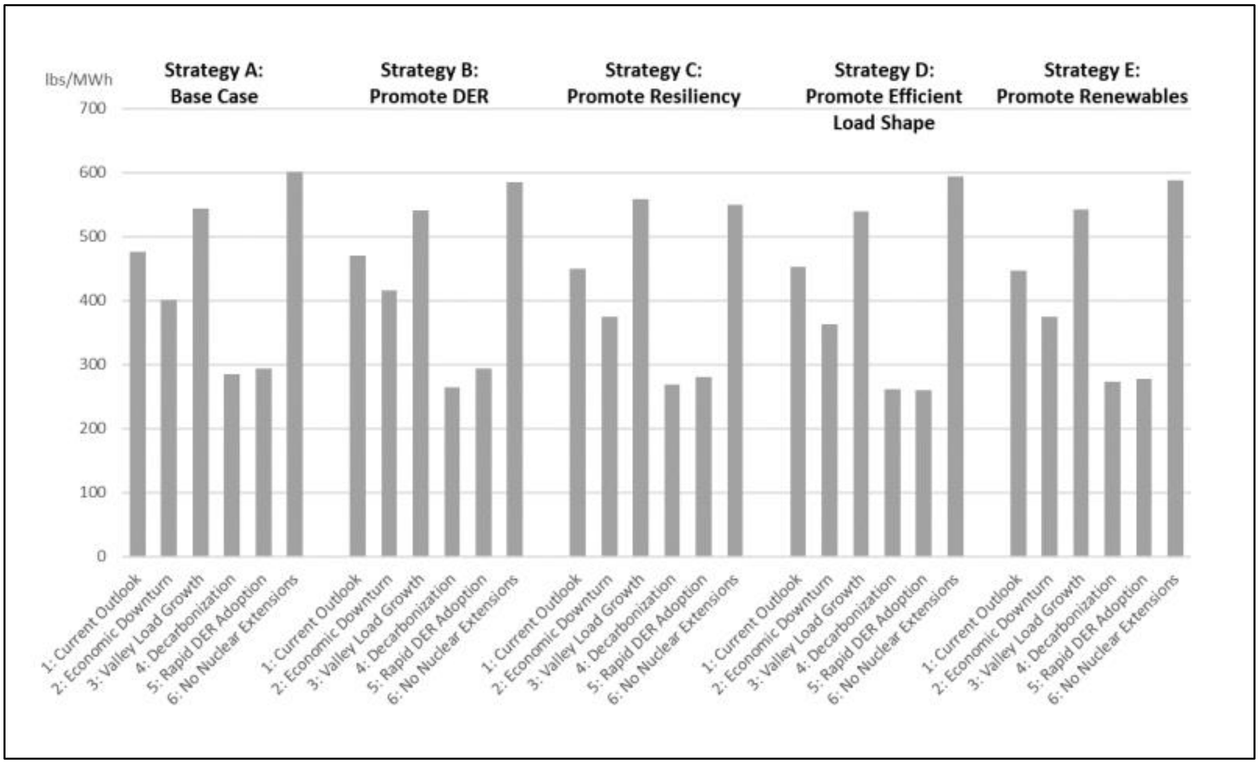
When developing a long-term plan for a power system, utilities typically use a least-cost decision-making framework that focuses on a single view of the future. TVA also uses a least-cost decision-making framework but considers multiple views of the future to determine how potential resource portfolios could perform across multiple futures, while considering environmental impacts and delivering rate stability to its customers.

TVA's IRP process also supports TVA's efforts to support environmental stewardship. TVA sees a path to achieve 80% emissions reductions by 2035 and aspires to be net zero by 2050. In order to assess the impact of various strategies on environmental stewardship, TVA uses a scorecard in its IRPs to measure the impact of various strategies on air, water and waste. The scorecard includes five measures:

- Carbon Tons – the expected annual average tons of CO2 emitted over the study period;
- Carbon Intensity – the expected CO2 emissions expressed as an emission intensity, computed by dividing emissions by energy generated and purchased;
- Water consumption – the expected annual average gallons of water consumed over the study period;
- Waste – the expected annual average quantity of coal ash, sludge and slag based on energy production in each portfolio; and
- Land Use – the expected acreage needed for expansion units in each portfolio in 2038.

These five measures are used to evaluate the trade-offs among the various strategies under various scenarios, as shown in the figure below.

Figure 14: Portfolio Carbon Intensity



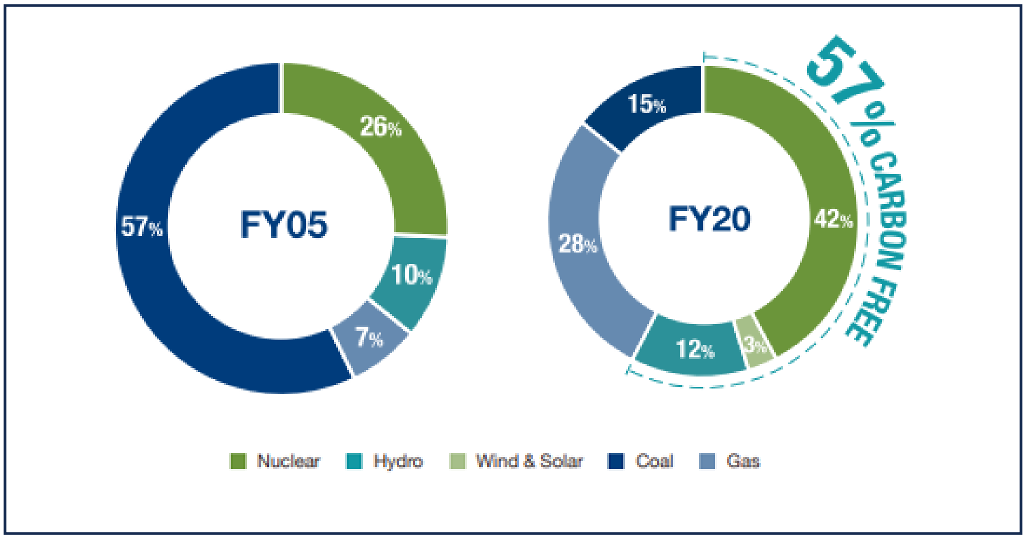
The AEC report asserts that TVA must set aggressive climate goals, and that "numerous federal executive orders have reiterated that federal agencies (like TVA) must prioritize, facilitate, and/or otherwise achieve a carbon pollution-free electric sector by 2035 and net-zero emissions economy-wide by no later than 2050."[55] In fact, TVA's commitment to environmental stewardship is consistent with executive orders directing the federal government to "lead by example" in order to achieve a carbon pollution–free electricity sector by 2035 and net-zero emissions economy-wide by no later than 2050.[56] TVA has continually emphasized environmental stewardship as part of its mission, and its commitment to this principle is reflected in several key areas. TVA has been working to diversify its energy mix and increase the share of renewable energy sources in its generation portfolio, as shown in the figure below. This includes investments in solar, wind, and other clean energy technologies to reduce the environmental impact of its power generation. It also involves investment in research and development initiatives to explore and implement innovative technologies that can further enhance environmental stewardship. This includes exploring advanced energy storage

55 Applied Economics Clinic, pg 7.

56 Executive Order on Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability, EO 14057 (December 8, 2021); Executive Order on Tackling the Climate Crisis at Home and Aboard, EO 14008 (January 27, 2021).

solutions, smart grid technologies, and other innovations that can contribute to a more sustainable energy future.

Figure 15: Comparison of Generation Portfolio 2005 v 2020



To mitigate the environmental impacts associated with its generation supply, TVA has implemented measures to reduce emissions from its power plants. This involves adopting cleaner technologies, improving efficiency, and, where possible, retiring or retrofitting older and less environmentally friendly facilities. TVA is also involved in managing and protecting the natural resources within the Tennessee Valley region. This includes efforts to conserve biodiversity, protect water quality, and manage public lands responsibly. TVA works collaboratively with various stakeholders, including environmental organizations and local communities, to strike a balance between energy production and environmental preservation. Furthermore, TVA has implemented energy efficiency programs to promote responsible energy consumption. These programs aim to reduce overall energy demand, which can have positive environmental effects by lowering the need for additional power generation and associated environmental impacts. Finally, TVA complies with federal and state environmental regulations that involve meeting or exceeding standards set by agencies such as the Environmental Protection Agency ("EPA") to ensure that its operations have minimal adverse effects on the environment.

At the same time, TVA must meet customer demand reliably and cost effectively. The IRP represents a compass to a cleaner power system, but reliability and lowest cost remain important pillars of TVA's energy transition. To meet forecasted customer demand and achieve reductions in carbon emissions, TVA must strike a balance between the increasing demand for electricity, reducing carbon emissions and ensuring system reliability. Achieving this reliability while simultaneously shifting towards renewable energy is challenging.

Renewable sources like solar and wind are inherently intermittent, making it necessary to "back-up" these resources. While battery storage can provide some measure of back-up over short periods of time, long term battery storage technology is still being developed. Gas-fired resources are the only mature technology that allows for the addition of renewable energy while maintaining low cost and reliability. Gas-fired power plants offer grid flexibility by being able to quickly respond to fluctuations in demand. This characteristic makes them suitable for balancing the intermittent nature of renewable energy sources like solar and wind.

Gas-fired plants have the advantage of fast ramp-up and ramp-down rates. When renewable energy production is low, gas-fired plants can ramp up quickly to meet the demand, providing a stable power supply. Gas-fired resources can also adjust their power output rapidly to accommodate changes in electricity demand or compensate for variations in renewable energy generation. This flexibility is crucial for maintaining grid stability in the presence of intermittent renewables.

In its 2022 State of Reliability Report, the North American Electric Reliability Corporation ("NERC"), acknowledged the critical role that gas-fired generation will continue to play for the foreseeable future:

> Until storage technology is fully developed and deployed at scale, natural-gas-fired generation will remain a necessary balancing resource to provide increasing flexibility needs. Resource planning and policy decisions must ensure that sufficient balancing resources are developed and maintained for reliability. As [inverter based resources ("IBRs")] and [distributed energy resources ("DERs")] continue to transform the grid, sufficient flexible resources are needed to ensure a reliable grid transformation given the variable energy nature of IBRs and DERs.[57]

TVA has appropriately and realistically planned for decarbonization.

The AEC report asserts that TVA did not plan appropriately for the decarbonization of their system in previous IRPs. To support this assertion, the report includes a comparison of expected coal plant retirements in previous IRPs to the actual announced retirements. As previously discussed, the recommendations in TVA's IRP are predicated on assumptions and sensitivities that are based on the best available information at the time and are not firm commitments. As market conditions and regulations change, "planned" actions in the IRP must be reassessed and revised to continue to serve customers with a generation portfolio that is reliable and cost-effective.

Planning for the retirement of coal plants involves a complex interplay of economic, environmental, and regulatory factors, and the uncertainty introduced by constantly changing regulations adds an additional layer of difficulty to the planning process. Power plants, especially coal plants, are capital-intensive investments with long lifespans. Frequent changes in regulations make it challenging for

57 NERC 2022 State of Reliability, pg. 26.

investors to predict the future operational and economic landscape. Regulations affecting coal plants in the United States have continuously changed over the last two decades in response to environmental, health, and safety concerns. Below is a timeline highlighting some key regulations related to coal plants:

Table 4: Key Environmental Regulations Affecting Coal Plants

Environmental Regulation	Description
2011 – Cross-State Air Pollution Rule (CSAPR)	The Cross-State Air Pollution Rule (CSAPR) establishes a cap-and-trade program for SO2 and NOx to address air pollution from upwind states that impacts air quality in downwind states. To comply with this rule, coal plant owners can buy allowances in the cap-and-trade market, change the fuel used, install control equipment, or retire. The EPA updated and expanded the program in 2023 with respect to rules to achieve the 2015 ozone standard.
2012 - Mercury and Air Toxics Standards (MATS)	MATS, also known as the Utility MACT (Maximum Achievable Control Technology) standards, set limits on mercury and other toxic air pollutants from coal and oil-fired power plants. It required the installation of pollution control technologies to reduce emissions.
2014 - Coal Combustion Residuals (CCR)	CCRs were first regulated in 2014 under the Disposal of Coal Combustion Residuals from Electric Utilities rule, which established technical requirements for the handling of coal ash for safe disposal. To comply with the CCR rule, coal plants can either install equipment for ash handling and disposal or retire the plant. It was amended most recently in 2020.
2015 - Clean Power Plan	The Clean Power Plan aimed to regulate carbon dioxide (CO2) emissions from existing power plants, including coal-fired facilities. It set state-specific carbon reduction goals, encouraging the transition to cleaner energy sources.
2016 – Updated CSAPR	Updated to further reduce summertime NOx emissions.

Environmental Regulation	Description
2017 – Updated Regional Haze Rule	The Regional Haze Rule requires states to establish goals and submit plans for achievement of visibility improvement in national parks and other wilderness areas. The plans detail emissions reduction strategies for pollutants that contribute to haze, including SO2 and NOx. The rule was first established in July 1999 and was most recently updated in January 2017. To comply with the Regional Haze Rule, coal plants can switch fuel to other types of coal or to natural gas, install control equipment, or retire the plant.
2019 - Affordable Clean Energy (ACE) Rule	The ACE Rule replaced the Clean Power Plan, giving more flexibility to states in regulating emissions from coal plants. It focused on improving the efficiency of individual power plants rather than promoting broader renewable energy adoption.
2021 - Repeal of ACE Rule and Introduction of the Clean Energy Performance Program (CEPP):	The ACE Rule was officially repealed, and the Biden administration introduced the CEPP, aiming to reduce carbon emissions from the power sector and incentivize clean energy production.
2021 - Updated CSAPR	Updated to further reduce summertime NOx emissions.
2021 – Effluent Limitations Guidelines	Limits the levels of toxic metals and other pollutants that power plants can release in their wastewater. To comply with the ELG standards, coal plants can either install control equipment, or retire the plant.

In addition to changing regulations, uncertainty regarding emission standards, tax incentives, and other regulatory requirements can impact the financial viability of coal plants and their potential for retirement. Further, planning for the retirement of a coal plant involves long lead times due to the time required for environmental impact assessments, obtaining permits, and transitioning to alternative energy sources. Changing regulations during this planning period can disrupt the established timeline, leading to delays, increased costs, and potential inefficiencies in the transition to cleaner energy alternatives. Furthermore, the transition away from coal often involves investing in new technologies and infrastructure to support cleaner energy sources. Uncertain or changing regulations can make it difficult for companies to confidently commit to these investments, slowing down the adoption of more sustainable technologies.

TVA's past IRPs, including the 2019 IRP, appropriately considered the economic, environmental and reliability impacts of potential coal plant retirements at the time the IRP was being developed. In the 2019 IRP, TVA committed to continuing to evaluate future coal plant retirements, recognizing that the dynamic nature of regulatory environments can significantly complicate the planning process for coal plant retirements. This evaluation culminated in the development of the Aging Coal Fleet Evaluation (2021) study that, among other things, identified 2027 as the end-of-life for the Kingston coal units. Refining retirement decisions to achieve a balance between cost-effective and reliable power to customers is crucial for facilitating a smooth and effective transition to cleaner energy sources.

The use of ranges in the 2019 IRP is reasonable.

The AEC report scrutinizes TVA's strategy of using published ranges of resource additions and retirements, stating that the use of ranges "limits the IRP's ability to function as a planning tool, as the capacity ranges proposed by TVA have been large— leaving open a broad set of plausible capacity additions or retirements."[58] The notion that TVA cannot disclose exactly how much they will need, and when they will need it, highlights the importance of flexibility in an IRP process. TVA's recommended capacity ranges represent an evolving energy industry, which is comprised of technological advancements, new policies and regulations, shifting market demands, and economic factors. As the economics of renewables and distributed energy resources continue to improve, operational flexibility will be increasingly important to successfully integrate these resources into TVA's generation portfolio. Due to their intermittent nature, TVA needs flexible resources that can quickly respond to dynamic loads. Recognizing that a variety of future scenarios are possible and each strategy has positive aspects, all results are included in TVA's IRPs to maintain full transparency with its customers.

It is possible that TVA may need more or less of various resource types, depending on market conditions, as expected by monitoring signposts. As conditions vary with technology development, policy changes, and market fluctuations, TVA will adjust and refine its planning within the guidelines, strategies, and the target supply mix of the 2019 IRP. Accordingly, TVA's IRP complies with the requirements of the EPAct and the use of planned ranges does not render the 2019 IRP, or any other prior IRP, as baseless. The implementation of planned ranges in TVA's IRPs is used to meet fluctuations in demand and support industry growth, while also meeting regulatory requirements, reducing costs for customers, and ensuring clean and reliable energy delivery. As with any long-term plan, TVA uses the best-known information when building each IRP and what they can reasonably expect for the coming years. Specifically, with respect to the Kingston retirement and replacement proposal, the gas additions are within the ranges of the target supply mix developed in the 2019 IRP.

58 "Assessing TVA's IRP Planning Practices," Applied Economics Clinic, June 2023, pg 16.

TVA's reliance on a balance of PPAs and owned resources is a proven approach to portfolio planning and is well documented.

TVA acquires power from various power producers using a mix of long-term and short-term PPAs and spot market purchases. As of September 2023, 92% of TVA's acquired power came from long-term PPAs, including agreements for renewable energy sources, while approximately 6% came from short-term PPAs and 2% from spot market purchases.[59] TVA's capability provided by PPAs is primarily provided under contracts that expire through 2043 and are described in the table below.

59 Tennessee Valley Authority Annual Form 10-K for the fiscal year ended September 30, 2023, Commission file number 000-51313, pg. 18.

Table 5: TVA's Power Purchase Agreements[60]

Type of Facility	Location	Number of Contracts	Contract Capacity, MW	Contract Termination Date
Renewable PPAs				
Operating				
Solar	Tennessee	6	413	2032 - 2043
Solar	Alabama	2	302	2037 - 2041
Total Operating Solar		8	715	
Wind	Tennessee	1	25	2025
Wind	Iowa	2	299	2030 - 2031
Wind	Kansas	2	366	2032 - 2033
Wind	Illinois	3	550	2032 - 2033
Total Operating Wind		8	1,240	
Hydroelectric	Tennessee, Kentucky, and North Carolina	2	779	2025 and upon three years notice
Landfill Gas	Tennessee	1	5	2031
Subtotal Operating		19	2,739	
Contract Renewable Resources			322	
Total Renewable Operating PPAs		19	3,061	
Contracted (not yet online)				
Solar		16	1,867	
Total Renewable Contracted PPAs		16	1,867	
Nonrenewable PPAs				
Operating				
Diesel	Tennessee	4	59	2028 - 2032
Diesel	Alabama	1	10	2035
Diesel	Mississippi	2	46	2028
Total Operating Diesel		7	115	
Natural Gas	Alabama	3	2,068	2024 - 2033
Natural Gas	Georgia	3	742	2023 - 2025
Natural Gas	Illinois	1	495	2025
Natural Gas	Pennsylvania	1	500	2024
Total Operating Natural Gas		8	3,805	
Delivered Energy	Various	3	1,050	2023
Lignite	Mississippi	1	440	2032
Total Nonrenewable Operating PPAs		19	5,410	
Contracted (not yet online)				
Battery Storage		3	150	
Delivered Energy		1	500	
Total Nonrenewable Contracted PPAs		4	650	

60 *Id.*, pg 19.

TVA purchases a portion of its power supply from third-party operators under long-term PPAs. TVA's generation supply consists of a combination of existing TVA-owned resources, budgeted and approved projects such as new plant additions and updates to existing assets, and existing PPAs. PPAs are an integral part of TVA's portfolio, as they provide the stability needed to meet the shifting demands of its consumers. Reliance on PPAs also allows TVA to diversify its energy portfolio by sourcing power from various suppliers with various forms of clean energy. TVA's long-term PPAs often provide a layer of cost predictability to its consumers for the contract duration, which is beneficial for IRP planning, budgeting operational expenses, and reducing exposure to market price volatility. It is important to note that prior to the IRA, TVA could not receive tax benefits and, therefore, PPAs were a more cost-effective method of meeting regulatory requirements and renewable energy targets. The IRA now allows TVA to capture tax benefits associated with owning and developing new renewables. As mentioned in previous sections of this report, the IRA influences the amount and timing of resources but does not change the target supply mix contained in the 2019 IRP.

The Board-approved 2019 IRP is transparent.

The AEC report asserts that the 2019 IRP lacks the transparency necessary for it to be a reliable source of information on which to assess TVA's decision-making. This mischaracterizes TVA's IRP process and, by extension, the 2019 IRP. Throughout the development of the 2019 IRP, TVA clearly identified issues important to the public; developed scenarios, resource options, and business strategies based on these issues; evaluated how a future portfolio might change under different conditions; and evaluated the performance of the 30 different resource portfolios. Despite claims in the AEC report that "TVA does not make publicly available the assumptions, parameters, and other modeling details used to arrive at [their] results," the 2019 IRP reviews all steps of the planning process, including scenario and strategy development, optimization modeling, portfolio analysis, and the resulting strategy assessment.[61] Assumptions used to inform each scenario's results are provided throughout the IRP, as well as in the report's appendices. Figure 16 below presents Table A-1 of TVA's 2019 IRP – Appendix A, which provides inputs to the capacity expansion model and costs benchmarked by TVA's independent third-party contractor, Navigant Consulting, Inc. ("Navigant"), including each resource's capacity and capital cost.

61 "Assessing TVA's IRP Planning Practices," Applied Economics Clinic, June 2023, pg. 10.

Figure 16: Capacities and Capital Costs of Resources

Supply Option[1]		Unit Characteristics	
		Summer Net Dependable Capacity (MW)	Total Overnight Capital Cost[2] (2017 $/kW)
Natural Gas	RICE 12x	226	$948
	RICE 6x	113	$1,071
	RICE 2x	36	$1,656
	Combustion Turbine 6x (LMS 100)	576	$796
	Combustion Turbine 4x (LMS 100)	384	$831
	Combustion Turbine 2x (LMS 100)	192	$925
	Combustion Turbine 3x (7FA)	703	$560
	Combustion Turbine 4x (7FA)	934	$540
	Combined Cycle 1x1	591	$699
	Combined Cycle 2x1	1,182	$612
	Combined Cycle 3x1	1,773	$560
	Combined Cycle With Carbon Capture and Storage	1,593	$2,165
Coal	Integrated Gasification Combined Cycle Coal	550	$3,834
	Pulverized Coal 1x8	800	$2,880
	Pulverized Coal 2x8	1,600	$2,682
	Integrated Gasification Combined Cycle Coal with Carbon Capture and Storage	515	$7,326
	Pulverized Coal 1x8 with Carbon Capture and Storage	617	$7,003
	Pulverized Coal 2x8 with Carbon Capture and Storage	1,200	$6,275

Supply Option[1]		Unit Characteristics	
		Summer Net Dependable Capacity (MW)	Total Overnight Capital Cost[2] (2017 $/kW)
Nuclear[3]	PWR	1,260	$5,981
	APWR	1,117	$8,040
	Small Modular Reactors	600	$5,369
Storage	Pump Storage	850	$2,332
	Utility Battery Storage (4 hour)	100	$2,824
	Residential Battery Storage (4 hour)	0.005	$2,998
	Compressed Air Energy Storage	330	$855
	Fuel Cells	25	$4,050
	Advanced Chemical Battery	25	$2,871
Hydro	Hydro Spill Addition	40	$2,429
	Hydro Space Addition	30	$1,988
	Hydro Run of River	25	$2,816
Solar[4, 5]	Utility Tracking Solar (20 Year PPA)	50	$1,293
	Utility Tracking Solar	25	$1,293
	Utility Fixed-Panel Solar	25	$1,203
	Small Commercial Rooftop Solar	0.2	$1,850
	Large Commercial Rooftop Solar	1	$1,740
	Residential Solar	0.006	$2,800
Wind[5]	MISO Wind	200	$1,744
	SPP Wind	200	$1,744
	In-Valley Wind	120	$1,838
	HVDC Wind	200	$1,719
Biomass	New Direct Combustion Biomass	115	$4,687
	Repowering Existing Coal with Biomass	124	$2,271

TVA engaged Navigant in an assessment of their cost and performance assumptions, which revealed consistency between TVA's assumptions and typical values contained in publicly available documents. Many of TVA's assumptions were modified based on Navigant's recommendations and any assumptions outside of Navigant's benchmark ranges were based on actual costs of TVA projects or vendor quotes. The remainder of TVA's Appendices cover additional assumptions by scenario through an extensive collection of figures and tables, including but not limited to economic conditions, commodity prices, energy and power projections, peak load, customer sales, storage parameters, and energy serving requirements.

The AEC report's argument that "TVA must be more transparent regarding its assumptions and modeling inputs" appears subjective in nature, as it requests more transparent assumptions without the consideration of broader viewpoints or objective data.[62] Assumptions, parameters, and other

62 "Assessing TVA's IRP Planning Practices," Applied Economics Clinic, June 2023, pg. i.

modeling details are provided in Chapter 6 of TVA's 2019 IRP, and further scenario development, including more detailed assumptions, strategies, optimization, and portfolio analysis can be found in the IRP's appendices, specifically Appendix A and Appendix E.

Furthermore, the AEC report argues that TVA should conduct an all-resource RFP to develop cost assumptions for different resource options. However, this statement ignores the fact that an RFP was indeed used to develop TVA's short-term forecast with a transition to a longer-term price forecast. Furthermore, in July 2022 TVA issued a request for proposals for up to 5,000 megawatts of carbon-free energy that must be operational before 2029. For the Alternatives Evaluation in the Kingston Draft EIS, the cost of storage is notably lower than the 2019 IRP and the cost of solar, which is informed by pricing from recent request for proposal responses and reflects near- and medium-term cost increases.

TVA's assumed capital costs for wind and solar resources are reasonable.

The AEC report claims that TVA's wind capital cost assumptions from a Concentric Energy Advisors ("Concentric") assessment of the draft Cumberland EIS are unreasonably high compared to other industry estimates. Specifically, the AEC report uses the 2022 NREL ATB resource costs as a point of reference, stating that: "TVA's wind capital cost assumption of $1,807 per kilowatt (kW) is higher than other recent estimates [and] it includes interconnection costs. NREL's 2022 ATB resource costs, which also include interconnection costs, price new wind at $1,462 per kW. Concentric and the TVA 2019 IRP both cite NREL's 2019 ATB costs. NREL's latest wind cost estimates – including interconnection costs – represent a 19 percent decrease from the costs used in TVA modeling."[63] However, this argument is flawed because both NREL's 2019 and 2022 ATB resource costs do not include interconnection costs. As explained under NREL's "Annual Technology Baseline," specifically land-based wind, "project interconnection (i.e., tie line and new/upgrade substation) costs are not included in CAPEX."[64] Also, within NREL's annual ATB resource cost models, all grid interconnection cost inputs for each scenario are $0. Therefore, the comparison between Concentric's $1,807/kW and NREL's $1,462/kW is both inconsistent and invalid.

In addition, TVA's use of $1,807/kW[65] for the MISO and SPP regions ($1,904/kW for the Tennessee Valley) is based on actual completed wind project costs in 2016 in the Interior region of the United States[66]. Importantly, for MISO and SPP wind projects, TVA also included the cost of interconnection, including network upgrades, of $192/kW,[67] resulting in overnight costs without interconnection

[63] "Assessing TVA's IRP Planning Practices," Applied Economics Clinic, June 2023, pgs. 25-26.
[64] "Land-Based Wind," National Renewable Energy Laboratory Annual Technology Baseline, 2022, https://atb.nrel.gov/electricity/2023/land-based_wind.
[65] 2019$ escalated using 1.8% inflation adjustment from the 2016$ source data.
[66] U.S. Department of Energy's 2016 Wind Technologies Market Report, Figure 44.
[67] 2019$

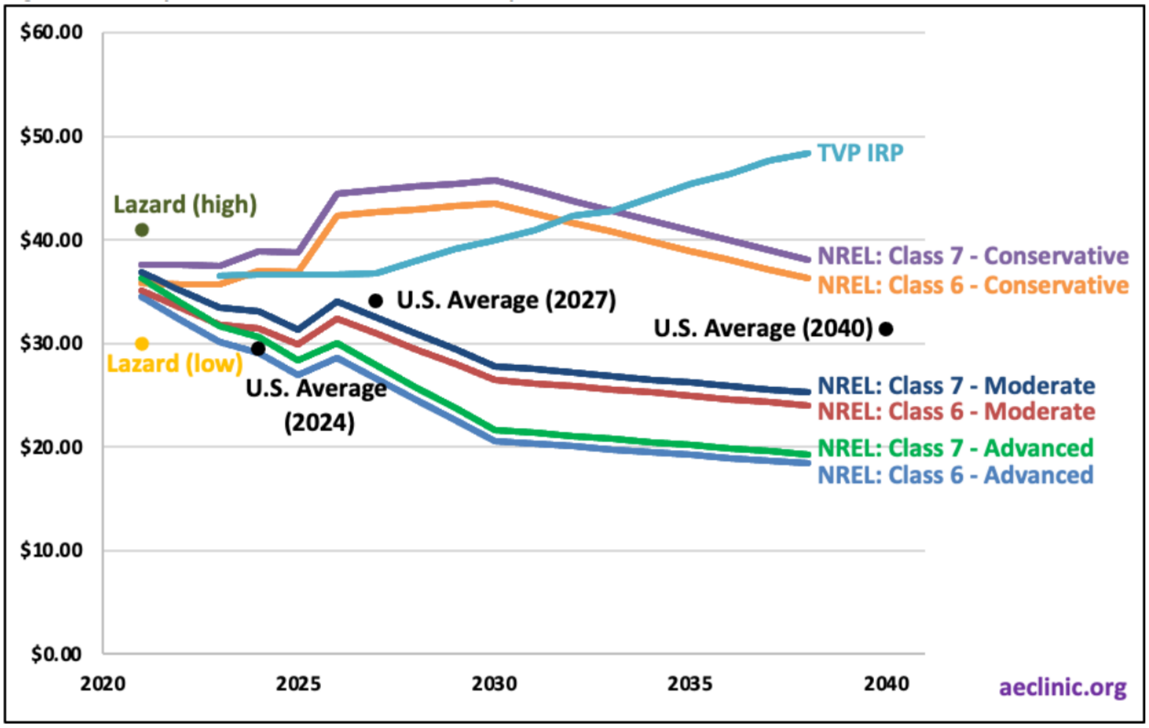
costs of $1,615/kW. This estimate is very similar to the 2020 NREL ATB estimate of $1,605/kW.[68] Subsequently, the 2021 NREL overnight wind cost estimates dropped to $1,376/kW[69] based on its modeling of the underlying components for a generic wind project. In stark contrast, the U.S. Department of Energy's 2023 Land-Based Wind Market Report showed costs of wind for SPP and MISO of $1,468/kW and $1,725/kW[70] respectively, based on actual 2021 and 2022 completed project costs. These comparisons demonstrate both the reasonableness of TVA's cost estimates and the importance of analyzing a range of inputs as TVA did.

As mentioned in previous sections of this report, TVA's 2019 IRP also included a sensitivity case to assess the impact of low-cost wind, reducing base case cost assumptions by one-half. This analysis demonstrated that if there's a significant decrease in wind costs compared to other resource options, coupled with access to a higher wind capacity factor, wind could serve as a feasible substitute for forthcoming capacity retirements. Nevertheless, when compared with alternative resources, onshore wind does not emerge as an economically viable option. Therefore, TVA appropriately stands by its original financial assessment of onshore wind and the current role it plays in portfolio development.

The AEC report also makes the statement that "the TVA 2019 IRP assumes solar levelized costs of energy ("LCOE") to be $36.49 in 2023 rising to $48.40 in 2038, values that are substantially higher than other industry projections, particularly in later years when TVA's solar cost assumptions exceed all common industry estimates," with the following figure.[71]

68 Based on the average of Class 4 and Class 6, the NREL wind overnight costs also excluded transmission interconnection costs.
69 2019 cost estimate in 2019$, from NREL's 2021 Annual Technology Baseline.
70 2022$
71 "Assessing TVA's IRP Planning Practices," Applied Economics Clinic, June 2023, pg. 27.

Figure 17: Utility-Scale Solar Levelized Cost Comparison[72]

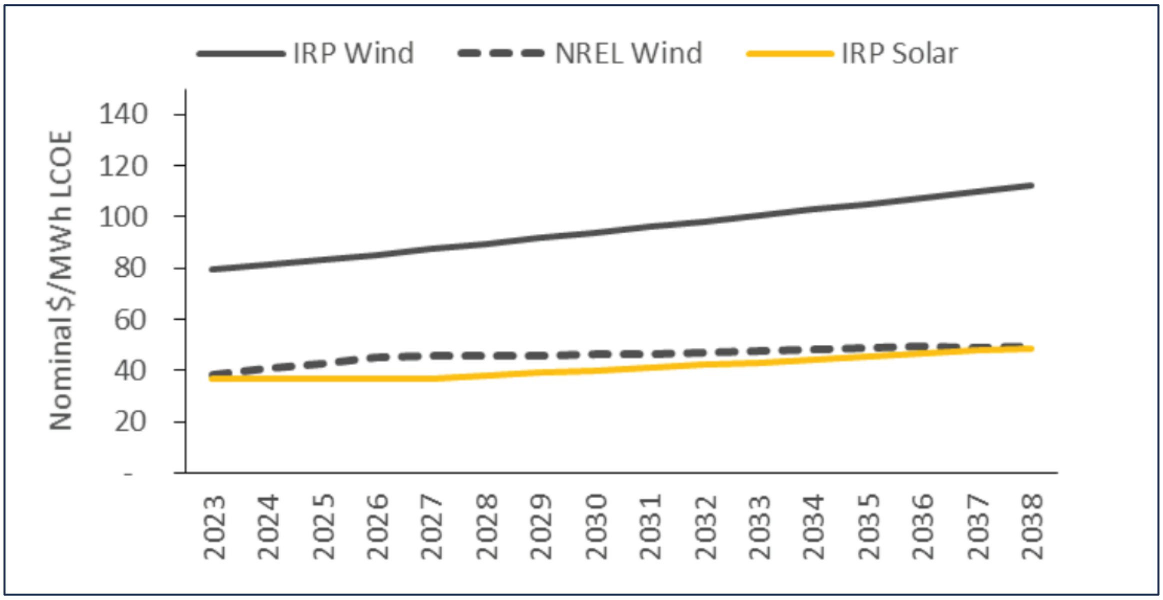


Note. Class 6 and 7 resources refer to the NREL Annual Technology Baseline's solar resource classes, which vary based on the

The AEC report figure depicts a misleading story because the prices reported in the AEC report from TVA's 2019 IRP are incorrect and overstated. The following figure from TVA's 2019 IRP shows that solar cost projections stay relatively consistent from 2023 to 2038, with the largest projection at around $43 in 2038.

72 *Ibid.*

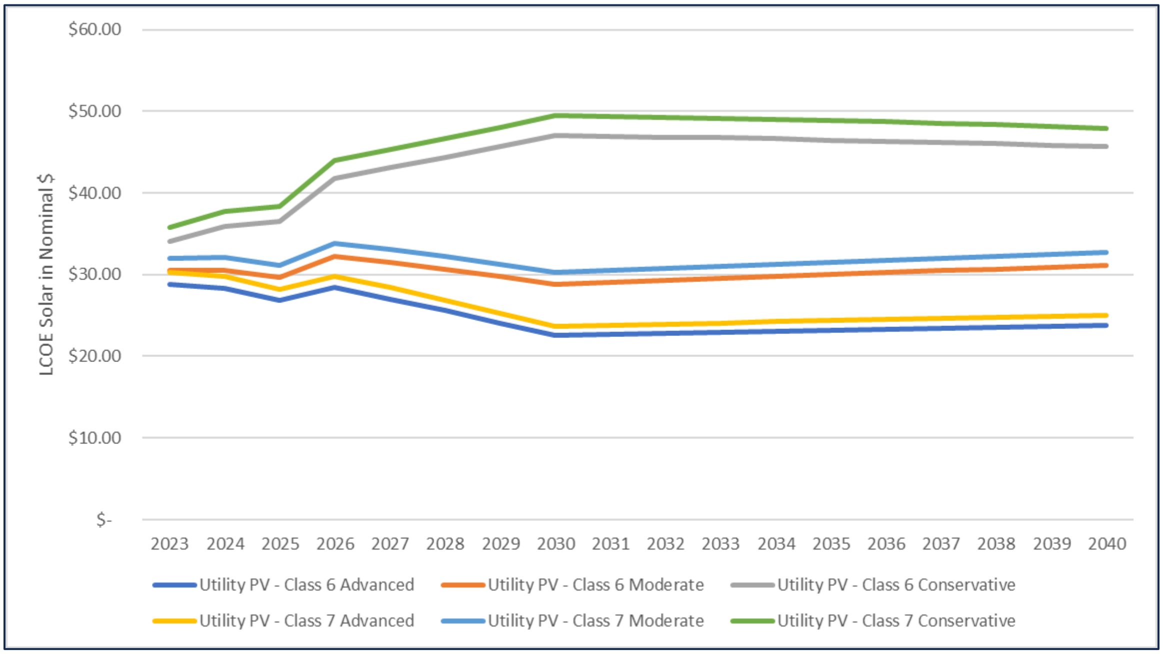
Figure 18: Wind and Solar Costs[73]



The AEC report also fails to record each common industry estimate's unit dollar, prompting the question of whether inflation could be the reason for such large discrepancies. The 2022 NREL LCOE costs used in Figure 18 from the AEC report are given in 2020 U.S. dollars, whereas LCOE costs provided by TVA in the figure above are given as nominal dollars. When converting NREL's LCOE costs to nominal dollars, TVA's anticipated LCOE solar costs are in line with industry standards, as proven by the figure below, and thus, reasonable.

73 "2019 Integrated Resource Plan: Volume I – Final Resource Plan," Tennessee Valley Authority, 2019, pgs. 8-15.

Figure 19: 2022 NREL LCOE Solar Costs in Nominal Dollars



NREL's 2022 study "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035" reviews the challenges associated with meeting demand during net load peaks. Specifically, NREL demonstrates "the important role of the [industry's] remaining fossil assets, which provide much of the capacity needed to meet peak demand on hot summer afternoons and during cold winter days."[74] The study foresees that in order to achieve a net-zero grid, the industry will also need some kind of gas generation to meet peak demand. In three of its four net-zero grid scenarios, turbines are still burning substantial amounts of natural gas in 2035, and the carbon is being captured, rather than being released into the atmosphere. In all scenarios, many gas turbines are retrofitted to burn zero-carbon hydrogen or remove carbon emissions with the use of carbon capture technologies. Many renewable sources of generation have inherently higher than average capital and other fixed costs, while having lower capacity factors. This poses challenges in recovering costs of plants with less generation compared to those that run more frequently. NREL explains that "this low utilization favors plants such as natural gas combustion turbines, which have lower capital cost, and for which variable cost is of less importance."[75] Achieving complete decarbonization will require offsetting these assets' emissions with other progressive technologies, but NREL stresses that this will be a small amount of energy on an annual basis.

Further, the EPA's Draft Greenhouse Gas Rule recognizes the need to maintain gas-fired and coal generation on the system. The EPA sets out new standards for power plants and emissions

74 Denholm, Paul, Patrick Brown, Wesley Cole, et al. 2022. Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. Golden, CO: National Renewable Energy Laboratory, pg. 33.

75 *Id.*, pg. 34.

guidelines; however, the draft rule also recognizes that in order to maintain a reliable grid and consider costs associated with many decarbonization measures, a diverse portfolio with gas-fired generation will play a critical role.

The proposed Kingston retirement and replacement decision is consistent with the 2019 IRP and an important step in the execution of the IRP.

The proposed retirement of the Kingston facility and the addition of reliable and flexible gas-fired generation is an important step in TVA's transition to a cleaner power supply portfolio. The AEC report claims that "the 2021 announcement of TVA's net zero goal by 2050 renders the 2019 IRP defunct."[76] This claim is unfounded and diminishes the ongoing actions being taken by TVA and countless utilities to meet nationwide decarbonization targets. A net zero aspiration by 2050 is an ambitious target and one that is crucial in the face of climate change. Despite statements made in the AEC report, this objective aligns with international agreements, such as the Paris Agreement, aiming to limit global warming to below 2 degrees Celsius above pre-industrial levels and limit the temperature increase to 1.5 degrees Celsius. TVA's aspiration of net zero emissions by 2050 promotes a sustainable future, policy support, technological advancements, and changes in consumer behavior. TVA's decarbonization targets are consistent with the 2019 IRP and render that IRP as anything but defunct. It shows responsibility and leadership in combatting climate change.

The decision to retire the Kingston facility does not represent a divergence from the 2019 IRP and does not warrant a new IRP. Rather, Alternative A to retire the Kingston coal plant and replace the retired generation with gas-based generation is consistent with the target supply mix in the 2019 IRP. As previously stated, the IRP is a roadmap for future system planning and an overreliance on the IRP as a prescriptive and rigid plan fails to recognize the importance of flexibility as market conditions and regulations change. The decision to recommend the retirement of the Kingston facility and the replacement with gas-fired generation is based on a comprehensive analysis of alternatives in terms of cost and reliability. While TVA is continuing to add sources of clean energy to its portfolio and transition towards decarbonization, adding intermittent resources without regard to reliability implications would be irresponsible and compromise system integrity. Gas-fired resources are critical to providing safe and reliable energy to TVA's customers and must continue to play a critical role in supporting the transition to cleaner sources of energy.

The AEC report claims that the assumptions regarding capital costs of various alternatives to gas-fired generation are overstated. However, a thorough analysis of the capital costs associated with wind, solar, energy efficiency, and demand response showed that the assumptions that TVA used to assess the economic impact of the addition of these resources as opposed to gas-fired generation were reasonable. Beyond the economic analysis, an assessment of the reliability impacts of adding intermittent resources to replace the Kingston generation showed that the reliability of the system

[76] "Assessing TVA's IRP Planning Practices," Applied Economics Clinic, June 2023, pg. 20.

was compromised without gas-fired generation to "firm" the intermittent resources. The replacement of the Kingston facility with gas-fired generation will support TVA's goal to transition to a cleaner and more sustainable energy system consistent with least-cost planning principles. Gas-fired generation will play a crucial role in the transition period by providing the grid reliability needed to support the integration of intermittent renewable resources. This integrated approach helps ensure a smooth and reliable power supply as TVA moves towards a more sustainable energy future.

CONCLUSION

TVA's IRP process aligns with the EPAct requirements and yields a guiding document designed for the adaptability and flexibility needed for TVA to balance cost and reliability objectives. TVA's 2019 IRP incorporates a "current outlook scenario," outlining assumptions reflecting anticipated future conditions. Additionally, five alternative scenarios consider higher demand, policy changes mandating increased greenhouse gas emission reductions, and modifications to the expected generating portfolio. Business strategies are integrated into these scenarios to formulate a resource addition and retirement portfolio, creating a roadmap for the future generation portfolio. The retirement of KIF and the proposed replacement is one component of TVA's strategic plan, which acknowledges the value of solar and storage but recognizes the need for combined cycle and simple cycle natural gas generators in its supply mix to bolster reliability. Alternative A is a reasonable near-term action that couples the pursuit of renewable generation with reliable natural gas generation, and it is aligned with the power supply mix adopted by TVA's Board from the 2019 IRP.

The Grid Strategies report relies on optimistic long-term future assumptions about the cost and operation of renewable technologies and minimizes the critical role that natural gas resources must play to ensure system reliability. Both the 2019 IRP and the assessment of Alternative A in the Kingston EIS aptly acknowledge the practicality of relying on the immediate deployment of natural gas generation as a robust foundation for a proactive expansion of renewable sources. TVA's overarching strategy, rooted in least-cost planning principles, entails the ambitious pursuit of up to 14 GW of solar capacity and up to 5.3 GW of storage. It is noteworthy that the Grid Strategies report falls short in adequately acknowledging the rapid pace at which substantial amounts of renewables and battery storage can be implemented. TVA is actively accruing operational expertise in large-scale battery storage, and these experiences will influence the future adoption rate and economic considerations of battery storage.

The AEC report exaggerates the purpose of an IRP as a set of binding commitments for future decisions. TVA is bound by the requirements of the EPAct and voluntarily produces IRPs to meet these requirements. The 2019 IRP is a result of a planning process that provides a flexible framework for decision-making and enables TVA to assess the plausibility and effectiveness of power supply strategies and make adjustments as necessary. TVA's 2019 IRP, which continues to be valid, serves as the backdrop for near-term and long-term resource additions and as a solid basis for decision-making to ensure a reliable and cost-effective energy future.

ATTACHMENT A:

DANIELLE S. POWERS
EXECUTIVE VICE PRESIDENT

Ms. Powers has over 30 years of experience in the energy industry with specific expertise in the areas of wholesale power market design and operations, resource planning, power generation, and transmission system planning and operations. Ms. Powers has been extensively involved in the design, implementation, and operation of installed capacity markets across North America. She has experience in electric resource planning, including assessing the costs and benefits of various energy sources, including renewable energy sources, to support a resource portfolio that can meet reliability, environmental and cost objectives. Ms. Powers has also prepared market assessments and forecasts and has advised several clients on the procurement of competitive electricity. She has also evaluated regional transmission tariffs, assessed the benefits of new transmission projects, and analyzed the costs and benefits of transmission company and transmission project sales and acquisitions.

REPRESENTATIVE PROJECT EXPERIENCE

Wholesale Market Assessment and Design

Ms. Powers has worked with ISO-NE for the past 14 years supporting analysis on wholesale energy and capacity market implementation and operation. This work has involved analyzing the cost of installing and operating a variety of candidate technologies for new entry into the market, production cost modeling to calculate the expected energy and ancillary service revenues that would be earned by the technology, and financial analysis to calculate the appropriate capital structure for the new technology. These technologies included gas-fired generation, wind and solar resources, demand response and energy efficiency resources, and energy storage resources. As part of her responsibility for the design and approval of the New England Forward Capacity Market for ISO-NE, Ms. Powers was responsible for managing the market design effort, designing the processes and procedures around resource qualification, resource bids and offers, auction clearing determination of installed capacity requirements and market settlement. She was responsible for all stakeholder interactions and meeting facilitation involving approximately 20 meetings over a six-month period. This involved forming several external project teams made up of New England participants to gather input on major market design elements to ensure that the final design reflected the involvement of affected parties and addressed their business concerns.

Resource Planning

Ms. Powers has provided a broad spectrum of resource planning services to electric and combination utilities throughout North America. This work has included the evaluation of the feasibility of various energy sources, including renewable energy sources such as solar, wind, and hydroelectric power, as well as non-renewable sources such as natural gas, coal, and nuclear power. This work has also involved the assessment of the costs and benefits of various energy efficiency and demand-side management strategies to reduce energy consumption and lower costs for consumers. Ms. Powers has provided third-party assessments of resource plans and procurement decisions and has managed competitive solicitations for power on behalf of several clients. Ms. Powers has supported the implementation of approved resource plans with underlying analysis to support certificates of public need and necessity.

Expert Testimony and Litigation Support

Ms. Powers has provided expert testimony in regulatory proceedings on energy and capacity market design and operational issues, as well as transmission rights of first refusal. In addition to developing and sponsoring expert testimony, specific services provided include collaborating with counsel as well as business and technical staff to clients to develop litigation strategies; preparing and reviewing discovery and briefing materials; and preparing materials and participating in sessions with regulators and interveners.

Transmission Planning and Interconnections

Ms. Powers has worked with several clients in evaluating transmission alternatives, both regulated and competitive. This work has involved evaluating transmission tariffs, evaluating and managing interconnection processes, preparing and negotiating interconnection contracts, and performing project cost reconciliations. Ms. Powers has provided consultation on required Federal Energy Regulatory Commission (FERC) filings and is responsible for staying abreast of relevant regulatory issues to ensure compliance with regional and FERC requirements.

Asset Sales

Ms. Powers has managed and been involved in the sale of over 12,000 MW of generation resources, purchased power contracts, and transmission assets. This work included involvement in the areas of marketing, labor, environmental, transmission, market analysis, regulatory, terms of sale, legal, transition power sales, and bid evaluation. Acted as client representative for bidder groups providing technical expertise and assistance. Provided full support for the initial and final due diligence processes.

Retail Energy Planning and Business Development

Ms. Powers has been involved in securing electricity supply for various buying groups and end users. She has developed strategic energy plans to enable the competitive energy procurement and energy usage analysis. This work has included the development and implementation of business plans to evaluate the opportunities and risks associated with alternative supply of energy.

Power Plant Operations and Engineering

In her role as a production engineer, Ms. Powers managed several large-scale projects involving environmental controls and operational optimization. This work involved having overall responsibility for the operation, maintenance, and overall performance of station pollution control systems. She has managed all facets of various plant construction projects including project engineering, construction supervision, project estimating and scheduling, and budget tracking/analysis.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2005 – Present)
Executive Vice President
Senior Vice President
Vice President

Assistant Vice President

ISO New England (2003 – 2005)
Principal Analyst

Concentric Energy Advisors, Inc. (2003)
Executive Advisor

Navigant Consulting, Inc. (1999 – 2003)
Senior Engagement Manager

XENERGY, Inc. (1997 – 1999)
Manager of Strategic Energy Planning

New England Power Company (1989 – 1997)
Intern, Production Engineer

EDUCATION

Bentley University
M.B.A., *magna cum laude*, 2000

University of Massachusetts, Amherst
B.S., Mechanical Engineering, 1988

PROFESSIONAL AFFILIATIONS

Board Member – Atlantic Power Corporation

EIT Certification

Member of the Massachusetts Restructuring Roundtable

Total Quality Management - Certified Team Facilitator

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Regulatory Commission of Alaska				
Chugach Electric Association	4/22	Chugach Electric Association	Docket No. U-22-010	Power Pool Exchange and Settlement
Connecticut Siting Council				
Competitive Power Ventures	11/14	Competitive Power Ventures	CT Siting Council 192b	Expert Report regarding Certificate of Environmental Compatibility and Public Need
Federal Energy Regulatory Commission				
ISO New England	8/09	ISO New England	Docket No. ER09-1424-000	Resource Planning, Market Design & Rules, Power contract structure & negotiation
ISO New England	1/17	ISO New England	Docket No. ER17-795-000	Wholesale Market Design
ISO New England	12/20	ISO New England	Docket No. ER21-787-000	Wholesale Market Design
ISO New England	4/21	ISO New England	Docket No. ER21-1637-000	Generation Procurement, Market Assessments, Wholesale Market Design & Implementation
Illinois Commerce Commission				
Ameren Illinois Company	5/19	Ameren Illinois Company	Docket No. 18-1617	Acquisition of a transmission line and generating asset
Indiana Senate Utilities Committee				
Indiana Energy Association	04/23	N/A	N/A	Transmission Right of First Refusal
Indiana Utility Regulatory Commission				
Indianapolis Power & Light	2/21	Indianapolis Power & Light	45493	Resource Planning, Generation Procurement & CPCN, Revenue Requirement
Indianapolis Power & Light	7/21	Indianapolis Power & Light	45591	Resource Planning, Generation Procurement & CPCN, Revenue Requirement
Indianapolis Power & Light d/b/a AES Indiana	12/22	Indianapolis Power & Light d/b/a AES Indiana	45832	Resource Planning, Generation Procurement & CPCN, Revenue Requirement

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Indianapolis Power & Light d/b/a AES Indiana	1/23	Indianapolis Power & Light d/b/a AES Indiana	45493	Resource Planning, Generation Procurement & CPCN, Revenue Requirement
Massachusetts District Court				
GDF SUEZ Energy North America	10/14	Donna West vs. FirstLight Power Resources Services, LLC, et al.	Donna West vs. FirstLight Power Resources Services, LLC, et al.	Resource Planning, Market Design & Rules
Missouri House Utilities Committee				
Ameren	03/23	N/A	N/A	Transmission Right of First Refusal
New Brunswick Energy & Utilities Board				
New Brunswick Power Corporation (NB Power)	11/22	New Brunswick Power Corporation (NB Power)	Matter 541 2023/24	Fuel & Purchased Power Markets and Forecasts
New York State Public Service Commission				
Helix Generation	5/22	Helix Generation	Case 17-E-0016	Vertical Market Power Analysis
United States Bankruptcy Court				
Brazos Electric Power Cooperative, Inc.	1/22	Brazos Electric Power Cooperative, Inc.	Case No. 21-30725 (DRJ)	Wholesale Power Market Analysis, Damages Calculation

WILLIAM (BILL) R. DAVIS
ASSISTANT VICE PRESIDENT

Mr. Davis is an energy industry professional with seventeen years of experience from a major Midwest electric and gas utility (Ameren). His career covers a variety of topics including load research, sales and revenue forecasting, integrated resource planning, project oversight, renewable energy standards, rate design, class cost of service studies, standby rates, demand-side resources pre-approval filings, demand-side resources market potential studies, implementation of energy efficiency portfolios, design of performance mechanisms for demand-side portfolios, lost revenue recovery, and prudence reviews.

AREAS OF EXPERTISE

Regulatory & Ratemaking

- Collaborated with regulators, interveners, including political and special interest groups, to obtain consensus, support, and/or regulatory approval.
- Analyzed the economic and financial impacts of regulatory and legislative initiatives.
- Developed and analyzed pricing options for Ameren Missouri's retail customers.
- Provided expert testimony to the Missouri Public Service Commission in Ameren Missouri's electric rate case regarding a proposal to mitigate the negative financial effects to the company caused by the implementation of energy efficiency programs.
- Championed the analysis and adoption of a new residential rate design for Ameren Missouri's natural gas distribution business that significantly reduced the volatility of revenues and prevented a sustained annual revenue shortfall.

Implementation

- Provided strategic direction for Ameren Missouri's energy efficiency and renewable energy programs. Responsible for the planning, implementation, and evaluation of Ameren Missouri's annual $50-$70 million energy efficiency portfolio.
- Served as public spokesperson for energy efficiency on live or recorded television and radio.
- Responsible for meeting or exceeding Ameren Missouri's approved energy efficiency performance targets; resulting in annual $6-$13 million of additional revenue.
- Led cross-functional projects including workgroups such as budgeting, demand-side management, regulatory, legal, forecasting, power operations, transmission and distribution planning, treasury, environmental, renewables, and power trading.
- Team leader to implement a custom application that automated and streamlined project oversight reporting and workflows.
- Provided oversight for projects in excess of $10 million to ensure projects follow proper project management procedures and reduce risk associated with project execution.

- Acted as a change agent to drive behavioral changes in project management practices.

Forecasting and Planning

- Provided quantitative analysis and recommended actions directly to Ameren executive leadership regarding long-term resource and regulatory decisions.
- Team leader for Ameren Missouri's 2011 Integrated Resource Plan which provides the long-term direction for future demand-side and supply-side resource decisions.
- Statistical modeling to forecast long-term electric and gas sales to support resource planning and budgeting. Other responsibilities included load research, sample design, weather normalization, margin impacts of weather, unbilled estimation, profiling, revenue/customer forecasting, regulatory support, and process optimization.

ACCOMPLISHMENTS

- Public Utilities Fortnightly Under 40 class of 2020. Public Utilities Fortnightly is the forum for stakeholders in utility regulation and policy and the Under 40 classes are a nomination-based recognition of rising stars in the public utility industry.
- 2019/2020 Leadership St. Louis Class. The Leadership St. Louis program is an immersive experience into the community to learn directly about regional challenges and opportunities.
- 2018 Zhi-Xing Eisenhower Fellow, one of nine Americans to spend 4 weeks in China for a cultural immersion and professional development experience. The Eisenhower Fellowship mission is to connect innovative leaders in a global network committed to creating a world more peaceful, prosperous and just.
- Leadership Missouri Class of 2014 graduate, which is a program hosted by the Missouri Chamber of Commerce designed to enhance leadership skills and deepen knowledge of the State's opportunities and challenges.
- Project leader of an End-to-End Energy Efficiency Study which received a Technology Transfer Award from the Electric Power Research Institute.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2022-Present)
Assistant Vice President

Ameren – St. Louis, MO (2005 - 2021)
Director, Energy Solutions (2016-2021)
Economic Analysis and Pricing Manager (2013-2016)
Senior Corporate Planning Analyst (2011-2013)
Senior Load Research Specialist – Corporate Planning (2007-2011)
Forecasting and Load Research Specialist – Corporate Planning (2005-2007)

Caterpillar Inc. – Peoria, IL (Feb. 2004 - May 2005)
Advanced Quantitative Analyst – Business Economic Group

EDUCATION

Illinois State University
Bachelor of Science in Economics (2002)
Masters of Science Degree in Economics (2003)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Federal Energy Regulatory Commission				
DCR Transmission, L.L.C.	2023	DCR Transmission, L.L.C.	Docket No. ER23-2309-000	Transmission revenue requirement
Illinois Commerce Commission				
Ameren Illinois Company	2012	Ameren Illinois	Docket No. 12-0244	Cost benefit analysis
Missouri Public Service Commission				
Union Electric Company	2010 2011	Ameren Missouri	Case No. ER-2011-0028	Alternative ratemaking approaches
Union Electric Company	2012	Ameren Missouri	Case No. ER-2012-0166	Revenue requirement and rate design
Union Electric Company	2012 2016	Ameren Missouri	File No. EO-2012-0142	Pre-approval, alternative ratemaking (energy efficiency)
Union Electric Company	2014 2015	Ameren Missouri	File No. ER-2014-0258	Rate design, pricing, cost of service
Union Electric Company	2014	Ameren Missouri	Case No. ER-2015-0132	Revenue requirement (energy efficiency)
Union Electric Company	2014	Ameren Missouri	File No. EC-2014-0224	Cost of service, pricing
Union Electric Company	2014	Ameren Missouri	Case No. EA-2014-0136	Renewable energy justification
Union Electric Company	2015 2016 2017 2018	Ameren Missouri	File No. EO-2015-0055	Pre-approval, alternative ratemaking (energy efficiency)
Union Electric Company	2015	Ameren Missouri	Case No. ER-2016-0131	Revenue requirement, incentive ratemaking (energy efficiency)
Union Electric Company	2015	Ameren Missouri	File No. ET-2016-0152	Pricing, Tariff design
Union Electric Company	2016 2017	Ameren Missouri	File No. ER-2016-0179	Rate design, cost of service study, tariff design
Union Electric Company	2016	Ameren Missouri	Case No. ER-2017-0149	Revenue requirement, incentive ratemaking (energy efficiency)
Union Electric Company	2017	Ameren Missouri	File No. ER-2018-0144	Revenue requirement, incentive ratemaking, prudence review (energy efficiency)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Union Electric Company	2018	Ameren Missouri	Case No. ER-2019-0151	Revenue requirement, incentive ratemaking (energy efficiency)
Union Electric Company	2018 2020	Ameren Missouri	File No. EO-2018-0211	Pre-approval, alternative ratemaking (energy efficiency)
Union Electric Company	2019	Ameren Missouri	Case No. ER-2020-0147	Revenue requirement, incentive ratemaking (energy efficiency)
Union Electric Company	2020	Ameren Missouri	Case No. ER-2021-0158	Revenue requirement, incentive ratemaking (energy efficiency)
New York Public Service Commission				
Liberty Utilities Corp.	2023	Liberty Utilities (New York Water) Corp.	Case No. 23-W-0235	Rate Design, Billing Determinants, Forecasting, Class Cost of Service