June 6, 2024

*Via electronic delivery*

Adam Teitzman
Director, Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: **Docket No. 20240026-El**
**Petition for Rate Increase by Tampa Electric Company**

Dear Mr. Teitzman,

Enclosed for filing on Sierra Club's behalf is the Direct Testimony of Devi Glick in the above referenced docket. Should you have any questions regarding this filing, please contact me.

Sincerely,

__*/s/ Nihal Shrinath*______

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**BEFORE THE**

**FLORIDA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **Petition for Rate Increase by Tampa Electric Company** | ) | **DOCKET NO. 20240026-EI** |

**DIRECT TESTIMONY OF**

**DEVI GLICK**

**ON BEHALF OF SIERRA CLUB**

**June 6, 2024**

# TABLE OF CONTENTS

## LIST OF EXHIBITS

| | |
|---|---|
| DG-1: | Resume of Devi Glick |
| DG-2: | TECO response to Sierra Club 1st IRRs |
| DG-3: | TECO response to Sierra Club 2nd IRRs |
| DG-4: | TECO response to Sierra Club 3rd IRRs |
| DG-5: | TECO Ten-Year Site Plan, January 2024 – December 2033 |
| DG-6: | U.S. Department of Energy and Tampa Electric Company. 2000. *The Tampa Electric Integrated Gasification Combined-Cycle Project: An Update*. Topical Report Number 19 |
| DG-7: | TECO response to SC IRR 1-8, Attachment (BS 28921) 2018 – 2023 GFP.xlsx |
| DG-8: | TECO response to SC IRR 31, Attachment (BS 28967) Sierra Club 1st Set 2024 - 2033 Firm Generators and RM IRR Q31 |
| DG-9: | EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Unit-Level Costs and Loadings Estimates for the 2024 Final Rule (DCN SE11756A1), April 22, 2024 |
| DG-10: | EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule (DCN SE11756), April 22, 2024 |
| DG-11: | NERC, 2023 State of Reliability Technical Assessment, June 2023 |
| DG-12: | TECO response to SC IRR 8, Attachment (BS 28923) 2019 - 2023 Factor and Rates |
| DG-13: | Schlissel, D. 2017. *Using Coal Gasification to Generate Electricity: A Multibillion-Dollar Failure*. Institute for Energy Economics and Financial Analysis |
| DG-14: | U.S. EPA. 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo), Attachment 1 |

## LIST OF TABLES

## LIST OF FIGURES

## 1. INTRODUCTION AND PURPOSE OF TESTIMONY

**Q Please state your name and occupation.**

**A** My name is Devi Glick. I am a Senior Principal at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

**Q Please describe Synapse Energy Economics.**

**A** Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission, and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

**Q Please summarize your work experience and educational background.**

**A** At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in more than a dozen states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electric dispatch models. I have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than 11 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

**Q On whose behalf are you testifying in this case?**

A I am testifying on behalf of Sierra Club.

**Q Have you testified before the Florida Public Service ("Commission" or "FPSC")?**

A No. But I testified as an expert before the Siting Board of the Florida Department of Environmental Protection in Tampa Electric Company ("TECO" or the "Company")'s 2018 site certification application for the Big Bend Power Station, DOAH Case No 18-2124EPP, where the Company sought to build a new combined-cycle power plant ("CC") at the site of Big Bend Units 1 and 2.

**Q What is the purpose of your testimony in this proceeding?**

A The purpose of my testimony is to review the reasonableness of TECO's rate case requests for Polk Generating Station Unit 1 ("Polk 1") and Big Bend Generating Station Unit 4 ("Big Bend 4") based on the units' economics, the Company's capacity needs, and the Company's evaluation of alternatives. Specifically, I review the Company's request to convert Polk 1 to a simple-cycle combustion turbine ("CT") while retaining the ability to burn coal or petroleum coke ("petcoke") at the plant, and its request to continue operating Big Bend on coal and gas instead of retiring and replacing the unit. I review the likely environmental compliance costs the Company will incur at both units in the future, and the potential for utilizing funding available under the Energy Infrastructure Reinvestment ("EIR") program of the Inflation Reduction Act ("IRA") to finance replacing those plants and even refinance their remaining undepreciated balance.

**Q How is your testimony structured?**

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I introduce TECO's coal plants at Polk 1 and Big Bend 4 and its capacity position and future needs.

In Section 4, I summarize TECO's request, in this rate case, to convert Polk 1 to a simple-cycle CT while retaining the ability to operate the unit on petcoke in the future by keeping integrated gasification combined-cycle ("IGCC") components online or in reserve. I highlight my concerns with the Company's plan to continue maintaining the IGCC infrastructure at the plant, despite TECO's decision not to use the infrastructure since 2018. I also discuss my concerns with the Company's lack of analysis of retirement and replacement of the unit as an alternative to its plan to convert it to a CT. I summarize my own analysis on the recent and projected economic performance of the unit and present my recommendations that TECO should, under all circumstances, retire the IGCC components as soon as possible, and further, should not spend ratepayers' money on converting the unit to a CT without conducting a thorough alternatives analysis.

In Section 5, I summarize TECO's rate case requests for Big Bend 4. I discuss my concerns with the Company's request to continue recovering the costs of operating the unit without proper analysis demonstrating that is the most economic option for ratepayers. I summarize my own analysis on the recent and projected economic performance of the unit. I outline my recommendations that TECO submit an application under the EIR program to the U.S. Department of Energy ("DOE") Loan Programs Office ("LPO") to finance clean energy replacement resources for Big Bend 4. This funding can also be leveraged to refinance the undepreciated balance of existing fossil resources. I recommend that TECO simultaneously perform an alternatives analysis for Big Bend 4, which should include the assumption that TECO would leverage the EIR loan to finance replacement resources and refinance the remaining balance of Big Bend 4.

**Q** **What documents do you rely upon for your analysis, findings, and observations?**

**A** My analysis relies primarily upon the workpapers, exhibits, and discovery responses provided by TECO, TECO's Ten-Year Site Plans ("TYSPs"), as well as publicly available data.

## 2. Findings and Recommendations

**Q Please summarize your findings.**

A My primary findings are:

1. TECO has not supported its request to continue operating Big Bend 4 on coal and to include the associated costs in rates.
2. Big Bend 4 has seen declining utilization and was uneconomic to operate during three out of the last five years. Company data indicates that the plant will continue to be uneconomic to operate going forward, especially when operated on coal.
3. TECO has indicated that it costs less to operate Big Bend 4 on gas than coal and has not justified its decision to continue burning coal at the plant for the express purpose of keeping the solid fuel equipment viable.
4. TECO has not used the integrated gasification ("IG") technology at Polk 1 to operate the unit on coal since at least 2018, and has not justified incurring substantial costs for ratepayers to retain that equipment, which is providing no value to ratepayers.
5. TECO has not provided analysis to support its request for approval of $80.5 million for the Polk 1 Flexibility Project to convert Polk 1 to a simple-cycle CT and include the associated costs in rates.
6. TECO has not provided analysis to support its request to retain at Polk the IG, steam turbine ("ST"), and heat recovery steam generator ("HRSG") technology—none of which are needed to operate the plant as a simple-cycle CT—as part of the Polk Flexibility project and to include the associated costs in rates. It is speculative to maintain these components to preserve the option to operate the unit on coal or petcoke when operation

on petcoke is not projected to be economic, and this switch would take a full year and incur costs that TECO has yet calculated.

7. TECO has not provided a current alternatives analysis to support its rate requests related to Polk 1 and Big Bend 4.
8. Complying with recently enacted federal environmental rules and standards governing power plants could cost TECO tens to hundreds of millions of dollars at Polk 1 and Big Bend 4.
9. TECO should not view undepreciated balances at either plant as a barrier to retirement, especially where TECO is incurring fixed and avoidable costs to maintain assets that are providing no ratepayer value.
10. TECO has not properly evaluated its option to leverage EIR program funding to retire and replace Big Bend 4. EIR funding available under the IRA can benefit both the Company and ratepayers in financing renewable projects, paying off the undepreciated balance on the legacy assets, and improving the company’s credit ratings by restructuring its debt.

**Q Please summarize your recommendations.**

**A** Based on my findings, I offer the following recommendations:

1. The Commission should not allow inclusion in rates of any future spending on the IG technologies at Polk 1 and the Commission should require that TECO retire the IG components immediately (by the end of 2024), regardless of whether TECO converts Polk 1 to a CT.
2. The Commission should not allow TECO to convert Polk 1 to a simple-cycle CT, and include the associated costs in rates, unless TECO provides analysis demonstrating that converting the unit to a CT is lower cost than retiring the unit and replacing it with a clean energy portfolio.

3. If the Commission allows TECO to convert Polk 1 to a simple-cycle CT, it should require TECO to retire the ST and HRSG components (in addition to retiring the IG component).
4. The Commission should not allow TECO to continue to operate Big Bend 4 on coal and should require the Company to cease coal combustion and retire all solid-fuel-related equipment at the plant as soon as possible, and at the latest by the end of 2025.
5. The Commission should require TECO to evaluate how much spending on capital projects and environmental compliance is avoidable at both Polk 1 and Big Bend 4 by ceasing operations on coal and retiring all associated equipment. The Company should be required to justify to the Commission inclusion in rates of any costs incurred from decisions that deviate from what it finds to be most economic.
6. The Commission should not allow TECO to include in rates any operations and maintenance ("O&M") costs, nor any capital expenditures ("capex") at Polk 1 and Big Bend 4 that are avoidable with early retirement, without at least a proper economic analysis showing that continuing to rely on the unit costs less than alternatives.
7. The Commission should require TECO to submit an application to the DOE LPO for funding under the EIR program to replace Big Bend 4 with clean energy resources before September 2026, when applications are due. The Commission should require that TECO plan to use part of the EIR funding to refinance the plant balance at Big Bend 4.

## 3. <u>INTRODUCTION TO TECO'S COAL ASSETS AND CURRENT CAPACITY POSITION</u>

**Q What is TECO proposing in this docket related to its coal capacity?**

A TECO is seeking to include in rates $80.5 million for the Polk Flexibility Project[1] to convert Polk 1 to a CT and maintain the IGCC infrastructure, as well as the costs to operate and maintain Big Bend 4. This includes capex and O&M costs incurred during the test year.

**Q What is the application test year?**

A The application is based on the projected period of January 1, 2025 to December 31, 2025.[2]

**Q Please provide an overview of Polk 1 and Big Bend 4.**

A Polk 1 is a 220 MW[3] dual-fuel IGCC plant. The unit entered commercial operation in 1996[4] and is located in Polk County, Florida. The CC portion of the unit has a 1x1 configuration, meaning that it consists of one CT, one HRSG, and one ST.[5] Fuel is combusted in the CT to generate electricity. Hot exhaust gas then

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[1] Direct Testimony of Aldazabal at 44-46.

[2] Petition of Tampa Electric Company for approval of its 2020 Depreciation and Dismantlement Study and Capital Recovery Schedules (December 30, 2020) [hereafter "Petition"], at 5-6.

[3] Exhibit DG-5. TECO Ten-Year Site Plan, January 2024 – December 2033 [hereafter "2024 TYSP"], at 4.

[4] *Id*.

[5] Direct Testimony of Aldazabal at 10.

passes through the HRSG, which uses the waste heat to generate steam. The steam is fed to the steam turbine, which generates additional electricity.

Polk 1 also includes IG equipment, which can be used to generate syngas from coal. First, the gasifier oxidizes coal slurry, producing high-temperature syngas and slag.[6] The syngas is then cooled and passes through several scrubbing steps to remove contaminants, after which it is combusted in the CT in lieu of natural gas.[7] Steam from the syngas cooling process flows to the ST, supplementing steam produced by the HRSG.[8] Notably, TECO has not used the IG equipment at Polk since 2018; the unit was fueled exclusively by natural gas from 2019 to 2023.[9] Figure 1 below shows a process diagram of the layout of the IGCC equipment at Polk 1.

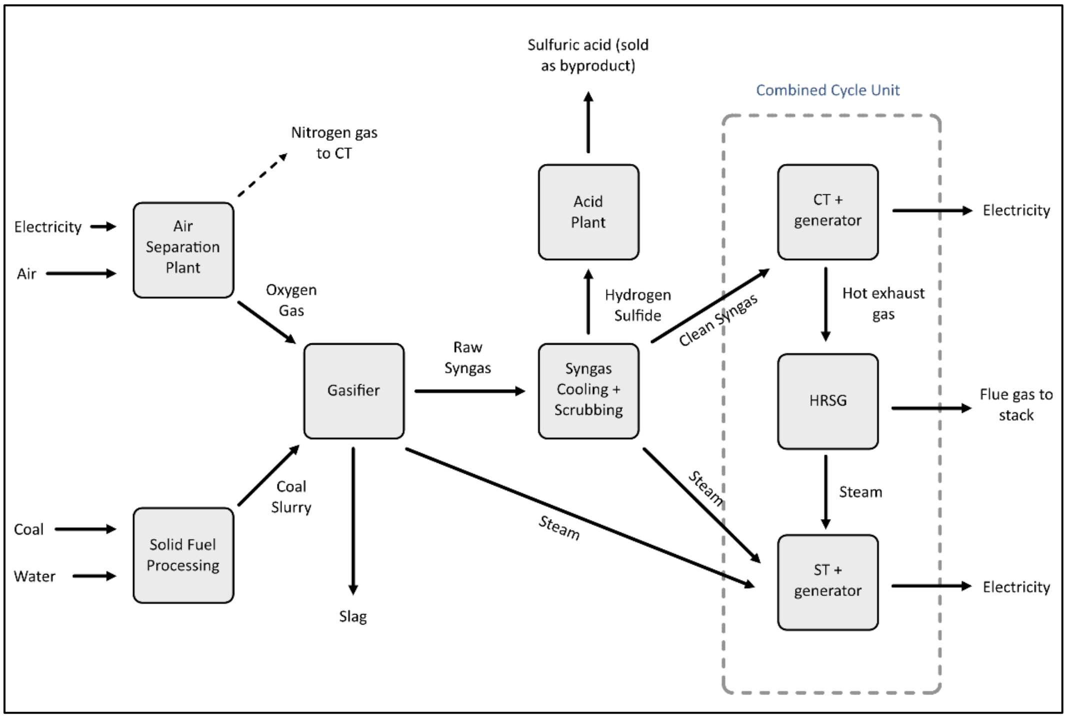
[6] Exhibit DG-6. U.S. Department of Energy and Tampa Electric Company. 2000. *The Tampa Electric Integrated Gasification Combined-Cycle Project: An Update*. Topical Report Number 19.

[7] *Id*.

[8] *Id*.

[9] Exhibit DG-7. TECO response to SC IRR 1-8, Attachment (BS 28921) 2018 – 2023 GFP.xlsx.

**Figure 1. Polk 1 IGCC process diagram**




*Source: U.S. Department of Energy and Tampa Electric Company. 2000. The Tampa Electric Integrated Gasification Combined-Cycle Project: An Update. Topical Report Number 19; Holt, N. 2001. Integrated Gasification Combined Cycle Power Plants. Encyclopedia of Physical Science and Technology, 3rd edition.*

Big Bend 4 is a 486 MW[10] dual-fuel coal-fired steam unit that can co-fire on gas. The unit entered commercial operation in 1985[11] and is located in Hillsborough County on Tampa Bay, adjacent to the community of Apollo Beach. Big Bend 4 has historically primarily used coal as a fuel,[12] but TECO is not renewing its coal supply contract and intends to purchase coal going forward on the spot market beyond December 31, 2024.[13]

[10] Exhibit DG-5. 2024 TYSP at 4.
[11] *Id.*
[12] Exhibit DG-7. TECO response to SC IRR 8, Attachment (BS 28921) 2018 – 2023 GFP.
[13] Exhibit DG-3. TECO response to SC IRR 79.

**Q What is the undepreciated balance at each plant?**

A At the end of 2023, the net book value of Polk 1 was $226 million and Big Bend 4 was $501 million (Table 1). Over half of the undepreciated balance at Polk 1 is from the gasification equipment, and the steam turbine and HRSG components of the CC unit account for an additional 24 percent. The CT accounts for only 20 percent.

**Table 1. Undepreciated balance at Polk 1 and Big Bend 4**

| Unit | Equipment | Undepreciated Balance (Dec 2023) | Percent of Total Undepreciated Balance |
|---|---|---|---|
| Polk 1 | TOTAL | $226,116,732 | - |
| | CT | $45,077,367 | 20% |
| | ST and HRSG | $54,471,062 | 24% |
| | IG | $125,100,611 | 55% |
| | GSU | $1,467,692 | 1% |
| Big Bend 4 | TOTAL | $501,265,153 | - |
| | Boiler | $315,725,624 | 63% |
| | FGD | $143,665,876 | 29% |
| | SCR | $41,873,654 | 8% |

*Source: Company response to SC IRR 1-7, Attachments (BS 28915)#7 Big Bend 4 Coal NBV recovery and (BS 28916)#7 Polk 1 NBV recovery.*

**Q Why is the undepreciated balance for the plant significant?**

A Utilities set depreciation schedules based on the anticipated useful life of an asset. TECO's most recent depreciation study from 2020 has TECO retiring Polk 1 in 2036 and Big Bend 4 in 2045.[14] Since 2020, market and regulatory forces have continued to change the economic viability of the coal plants. But TECO has not

[14] Petition at 39-1821, 45-47.

changed the retirement date nor depreciation schedule for Polk 1 and has only moved up Big Bend 4 a few years to 2040.

Utilities often view undepreciated plant balances as barriers to retirement before the currently planned retirement date. They may keep plants in rate base even when they are uneconomic or no longer providing value to ratepayers to ensure the undepreciated balance can be recovered. In this case, TECO has large undepreciated balances at both plants.

At Polk 1, 55 percent of the plant balance is for IG assets that have not been used since at least 2018, and another 24 percent is for ST and HRSG assets that will not be needed if the plant is converted to a simple-cycle CT. Three-quarters of the plant balance in rate base at Polk 1 is for assets that will be placed in reserve and not used to serve load if the plant is converted to a CT. Another 20 percent is for the existing CT, which TECO has stated it will replace with a new CT during the conversion. As I will discuss later in this testimony, TECO should retire the components of the plant that it does not need to operate as a CT. There are alternative rate mechanisms that the Company can use to address the balances.

**Q What is the Company's plan for each of these coal units?**

**A** According to TECO's most recent TYSP, the Company plans to operate Polk 1 until September 2036 and Big Bend 4 until January 2040.[15] It is unclear if this stated retirement date for Polk 1 takes into account the Company's stated plan to convert the unit to a CT.

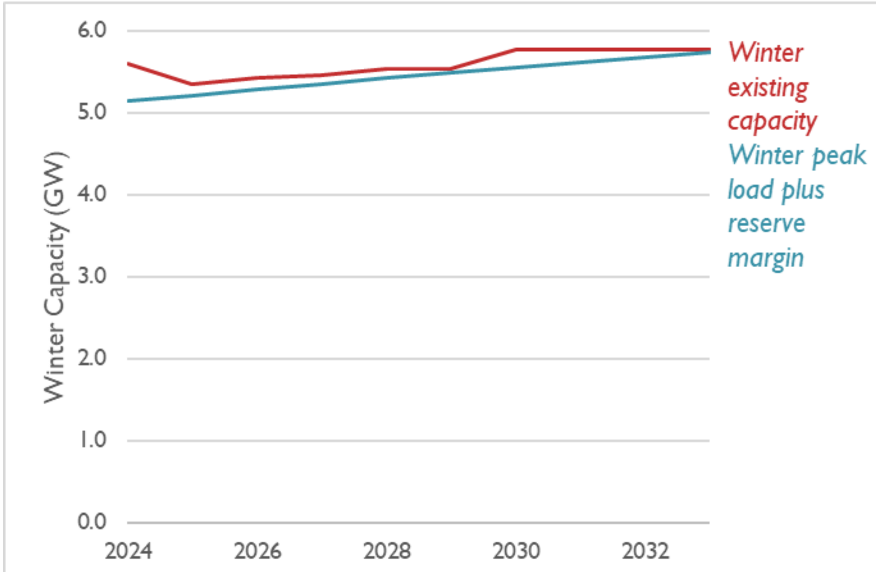
[15] Exhibit DG-5. 2024 TYSP at 4.

**Q What is TECO's capacity position?**

A TECO plans its system around a 20 percent reserve margin requirement.[16] While the Company must meet a minimum reserve margin of 20 percent, its actual resource mix can—and often does—result in a higher level of capacity and a reserve margin around 30 percent in the summer. Ratepayers are still required to fully finance this higher-than-needed amount of capacity. Based on the Company's current resource mix in its 2024 TYSP, between now and 2033, it projects a summer reserve margin of between 28 and 32 percent and a winter reserve margin of between 21 percent and 30 percent (Figure 2 and Figure 3).[17] This means that TECO currently has excess capacity and can retire older legacy fossil units that are costly and inefficient to operate.

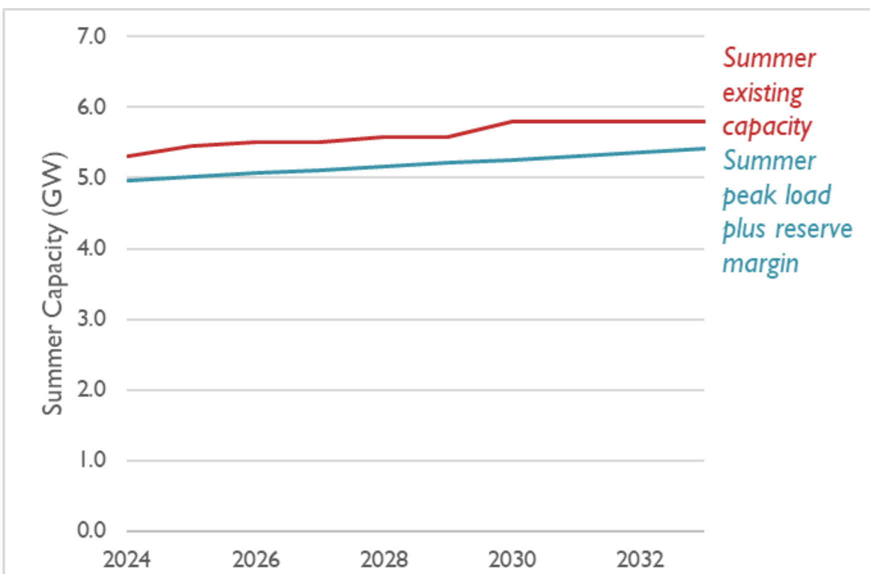
[16] *Id*. at 26.
[17] *Id*., Schedule 7.1 and 7.2.

**Figure 2. TECO winter capacity position (existing and planned)**




*Source: TECO response to SC IRR 31, Attachment (BS 28967) Sierra Club 1st Set 2024 - 2033 Firm Generators and RM IRR Q31. Existing capacity includes planned builds from the TYSP.*

**Figure 3. TECO summer capacity position (existing and planned)**




*Source: TECO response to SC IRR 31, Attachment (BS 28967) Sierra Club 1st Set 2024 - 2033 Firm Generators and RM IRR Q31. Existing capacity includes planned builds from the TYSP.*

## 4. TECO'S REQUEST TO RETAIN THE COAL-FIRING CAPABILITIES AT POLK 1 IS NOT JUSTIFIED BY ANALYSIS OR THE UNIT'S RECENT HISTORICAL AND PROJECTED ECONOMIC PERFORMANCE, NOR IS ITS REQUEST TO CONVERT POLK 1 TO A CT WITHOUT RETIRING THE IG, HRSG, AND ST COMPONENTS

**Q What is TECO requesting specifically for Polk 1 in this rate case?**

A TECO is requesting permission to convert Polk 1 to a simple-cycle CT while retaining the ability to operate the plant on petcoke or a blend of petcoke and coal. Specifically, this would involve disconnecting the CT from the HRSG and ST, enabling it to operate as a simple-cycle rather than combined-cycle unit. In this conversion, TECO will be performing maintenance upgrades on the CT that amount to retiring the existing gas turbine, as it is no longer supported by the manufacturer, and replacing it with current technology.[18]

TECO proposes to retain the HRSG, ST, and IG equipment in long-term standby, even though they will not be in active use under this scenario.[19] The Company claims it wants to retain the ability to convert the plant to operate on petcoke—or petcoke blended with coal—in the event that these fuels become more cost-effective than natural gas in the future.[20] This means that the Company will likely not be using any of the existing generation components from the IGCC after the conversion, yet it is still requesting to retain them all in rate base. Further, in the event that natural gas prices spike much higher than petcoke prices, TECO would

[18] Exhibit DG-3. TECO response to SC IRR 90.
[19] Exhibit DG-2. TECO response to SC IRR 2; Exhibit DG-3. TECO response to SC IRR 89 (g).
[20] Direct Testimony of Aldazabal at 45.

have to first conduct an economic analysis to ascertain the cost of this conversion. TECO estimates that the conversion would take a year to complete.

Polk 1 currently has an accredited capacity of 220 MW in both the summer and winter.[21] Converting the unit to a CT would decrease its firm capacity contribution to 190 MW in the summer and 203 MW in the winter (equivalent to 14 and 8 percent reductions, respectively).[22]

***i. <u>TECO has not justified its request to retain the HRSG, ST, or IG equipment at Polk 1 after it converts the plant to operate as a simple-cycle CT</u>***

**Q How has TECO been operating Polk in recent years?**

A TECO has been operating the unit on natural gas exclusively since 2018, rather than on syngas generated from coal in the gasifier. This means that much of the plant, specifically the IG and associated equipment, has been in reserve since 2019.[23] As discussed above, this represents more than half of the remaining plant balance.

**Q How much are ratepayers paying to maintain the unused parts of the plant?**

A TECO ratepayers are paying around a quarter of a million dollars per year in ongoing maintenance costs, as well as around half a million per year for capital expenditures for the unused IG portions of the plant. In discovery, TECO estimated the annual cost to maintain the IG equipment (presumably, O&M costs)

[21] Exhibit DG-2. TECO response to SC IRR 31.
[22] *Id*.
[23] Exhibit DG-7. TECO response to SC IRR 1-8, Attachment (BS 28921) 2018 – 2023 GFP.xlsx.

at $260,000 per year (Table 2).[24] The Company did not provide data on whether there would be additional sustaining capital expenditures required to maintain the ST and HRSG in long-term storage, but it is likely this will be an expense. Elsewhere in discovery, TECO stated that it included $500,000 per year in ongoing capital expenditures in its test year rate base for the IGCC equipment, out of $13 million in total for Polk 1.[25]

**Table 2. Annual maintenance costs for Polk 1 gasifier and associated equipment**

| Gasifier Equipment Category | Annual Maintenance |
|---|---|
| Total | $260,000 |
| Coal & Slurry Handling | $2,000 |
| Gasification Maintenance | $220,000 |
| Acid Plant Maintenance | $1,000 |
| Air Plant Maintenance | $37,000 |

*Source: TECO response to SC IRR 89 (c). Bates number 30482.*

**Q Why hasn't TECO removed and retired the portions of the plant that are no longer in use, rather than just placing them in reserve and continuing to accrue costs related to their maintenance?**

**A** TECO asserts that it wants to maintain the option to operate on coal or petcoke in the event that coal or petcoke prices become cost-competitive with natural gas prices.[26] But this is concerning because switching fuels requires a long-term fuel and planning strategy—neither of which TECO appears to have.

[24] Exhibit DG-3. TECO response to SC IRR 89 (c).
[25] Exhibit DG-2. TECO response to SC IRR 5.
[26] Direct Testimony of Aldazabal at 45.

At Polk 1, the IG equipment is currently in long-term standby, so it will take more than a year to bring it back online if TECO chooses to do so.[27] This means that TECO cannot utilize the IG to insulate ratepayers from volatility in the natural gas market. In 2022, TECO's own fuel price data shows that its average coal prices remained stable, while its gas prices spiked in response to the war in Ukraine.[28] Even still, TECO could not quickly make the decision to switch operation of the plant to coal during the gas price spike, and thus continued to rely on natural gas throughout that time. Ratepayers bore the brunt of those price spikes. Given that there is no indication the IG can provide a hedge for fuel price volatility as a reliability resource, the extraneous equipment should be retired.

Additionally, as I discuss below, once Polk is converted to a simple-cycle CT, switching Polk between gas and petcoke will be a long-term planning decision—not a short-term operational decision. TECO would need to regularly conduct long-term resource planning analysis to determine whether to make a switch, and it is unclear how TECO plans to do that.

**Q Could TECO realistically switch Polk to petcoke during a future gas price spike?**

**A** No. TECO estimates that re-enabling petcoke gasification at Polk 1 would take approximately one year.[29] Enabling petcoke usage would require bringing the gasification block (including solid fuel processing, air separation unit, gasifier, and acid plant) and steam cycle components (including HRSG, ST, and

[27] Exhibit DG-4. TECO response to SC IRR 92.
[28] Exhibit DG-2. TECO response to SC IRR 8 (l).
[29] Exhibit DG-2. TECO response to SC IRR 3 (d).

condensate system) out of long-term standby.[30] In addition, certain gas turbine components, such as the combustion system, could require modification to re-establish compatibility with syngas.[31] TECO did not provide a cost estimate for this undertaking,[32] but cited the "extensive capital investment" required by the HRSG and ST as one reason not to continue operation of the plant in combined-cycle mode today.[33]

The year-long lead time and cost of reactivating the gasification equipment at Polk 1 means TECO would have to believe that there are reasonable and likely scenarios under which operation on petcoke will be less costly over the long term. But TECO has presented no evidence of any likely future conditions where it believes this will be true. And in fact, TECO's assertion that it may operate Polk 1 on petcoke in the future is contrary to its own projections of dispatch costs at Polk (Figure 4). Last, as a reliability resource, Polk 1's firm capacity represents a small percentage of TECO's winter firm capacity, and Polk 1 can in any case run on gas. The Company has therefore not justified that the IG assets are used and useful and that ratepayers should continue paying ongoing capital expenditures to maintain them.

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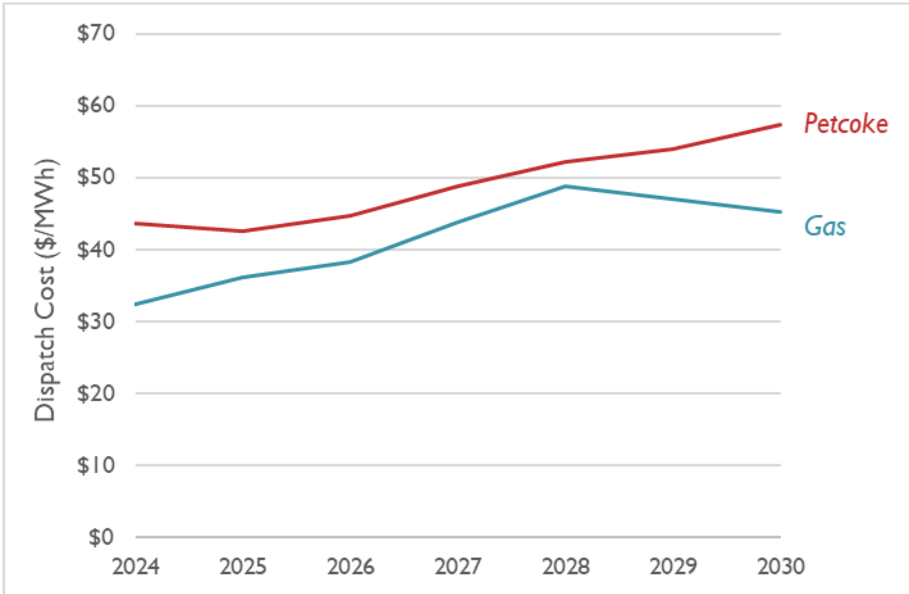
[30] Exhibit DG-3. TECO response to SC IRR 89 (g).
[31] *Id.*
[32] Exhibit DG-2. TECO response to SC IRR 3 (c).
[33] Exhibit DG-3. TECO response to SC IRR 89 (i).

**Figure 4. TECO projection of cost to generate electricity at Polk 1 on petcoke compared to natural gas**




*Source: TECO response to SC IRR 89(e).*

**Q What other motivation might TECO have for maintaining the full IGCC equipment at Polk?**

**A** As discussed above, TECO is likely motivated by a desire to keep the plant in rate base and to continue recovering undepreciated plant balance with a rate of return. If the plant is determined to be no longer "used and useful"[34] then TECO runs the risk of not recovering its costs from ratepayers for this equipment.

[34] Fl. Statues Chapter 366.06 (1), available at: http://www.leg.state.fl.us/statutes/index.cfm?App_mode=Display_Statute&Search_String=&URL=0300-0399/0366/Sections/0366.06.html.

Additionally, TECO noted that it is considering carbon capture and storage ("CCS") at Polk,[35] although the Company has not performed an analysis comparing the costs of this option with the cost of simply retiring the unit.[36] Because Section 45(q) of the federal tax code offers credits per ton of carbon captured, CCS tends to be more cost-effective—although even then, it is often less cost-effective than renewable alternatives—for units that operate at a high capacity factor. TECO has indicated that it is evaluating how CCS would enable Polk 1 to operate beyond 2032 as a combined-cycle unit. Elsewhere in its documents, TECO states that potential reasons to reactivate the HRSG and ST include "Hydrogen, Carbon-capture, Syngas, or other opportunit[ies]."[37] However, TECO has not clearly stated what its CCS plans are, nor has it evaluated the costs of CCS in detail. This surface-level speculation is certainly not justification for keeping costly components online, especially those that would likely incur additional environmental compliance costs (see Section 5(iii) below).

**Q Does the undepreciated balance, or the possibility of future CCS, justify maintaining the unused gasifier block and ST/HRSG at Polk?**

**A** No. Regarding the undepreciated plant balance, there are alternative ways to address the undepreciated balance that can mitigate ratepayer impacts. For example, this can be done through the creation of a regulatory asset. A regulatory asset allows the utility to retire a plant with an undepreciated balance remaining and transfer the balance to a sort of black box asset. The remaining balance remains in rate base and is amortized over the course of however long its payment provides benefits to customers—generally a timeframe that is shorter than the

[35] Exhibit DG-2, TECO response to SC IRR 43 (a); Direct testimony of Stryker at 34.
[36] Exhibit DG-2. TECO response to SC IRR 43 (b).
[37] Exhibit DG-3. TECO response to SC IRR 89 (i).

original asset life but beyond the retirement date. Here the Commission can decide what terms it will allow the utility to recover—whether it is just the capital investment and debt, or the full rate of return.

Regarding CCS, it does not justify the cost and risks it imposes on ratepayers. The Company would be better off retiring the unused equipment and using its capital to build out commercially available options, such as solar photovoltaic ("PV") and battery energy storage systems ("BESS"), to meet its energy needs while reducing emissions. The biggest risk with CCS is cost overruns. TECO provides no information about avoiding the possibility of cost overruns. While the 45(q) tax credit provides financial support for CCS projects that capture a sufficient quantity of carbon dioxide, the level of uncertainty around the cost for these types of retrofits is much greater than for existing non-emitting technologies, such as solar PV and BESS. Given the capital costs of CCS projects, TECO could be facing hundreds of millions to even billions of dollars of potential overages in terms of expenditures. For example, Southern Company's attempt to construct an IGCC unit with a CCS plant at Kemper resulted in costs that were three times the initial project estimate (from $2.5 billion to $7.5 billion)[38] before the Mississippi Public Service Commission ultimately pulled the plug on the project and ordered Mississippi Power Company to continue to operate the plant on just natural gas.[39] TECO has provided no analysis or assurances demonstrating that a similar project at Polk 1 would not face similar cost overruns to keep a much smaller unit online.

[38] Kristi Swartz, "Southern Co.'s clean coal plant hits a dead end," *EnergyWire* (June 22, 2017), available at https://subscriber.politicopro.com/article/eenews/1060056418.

[39] Kristi Swartz, "The Kemper project just collapsed. What it signifies for CCS," *EnergyWire* (October 2021), available at https://www.eenews net/articles/the-kemper-project-just-collapsed-what-it-signifies-for-ccs/.

Lastly, CCS requires considerable energy to run itself. Retrofitting a plant with CCS will reduce the energy that plant supplies to the grid based on the input of a given quantity of fuel, because some of that fuel and/or energy produced has to be cycled in to power the CCS technology. The resulting reduction in production, known as the energy penalty or parasitic load, is an effective derating of the plant. Polk is a 220 MW unit that already runs at a low capacity factor. It is thus the type of facility that is the least well-suited to CCS.

***ii. TECO could incur substantial costs to comply with new federal regulations at Polk if it operates the plant on petcoke or coal***

**Q Do the new greenhouse gas rules that were recently finalized under Section 111 of the Clean Air Act impact TECO's ability to burn petcoke at Polk?**

**A** Yes. My understanding is that the final Section 111(d) rule requires plants that run past 2032 and retire before 2039 to co-fire with at least 40 percent gas in order to achieve a 16 percent reduced greenhouse gas emission rate. Given Polk 1's stated retirement date of September 2036, if TECO wanted to operate the plant on petcoke or coal, it would have to at least achieve an emissions rate based on 40 percent co-firing with fossil gas to meet the U.S. Environmental Protection Agency ("EPA")'s greenhouse gas emissions standards beginning in 2030.[40] This means that if TECO converted the plant back to an IGCC, it would have to co-fire with fossil gas at least 40 percent of the time.

[40] U.S. Environmental Protection Agency. "Final Carbon Pollution Standards to Reduce Greenhouse Gas Emissions from Power Plants," April 25, 2025. Available at https://www.epa.gov/system/files/documents/2024-04/cps-presentation-final-rule-4-24-2024.pdf.

**Q Does the new Section 111(d) rule impact TECO's ability to use coal or petcoke as a hedge against gas prices?**

A Yes. TECO stated that it wants to retain the ability to operate Polk 1 on petcoke, or coal blended with petcoke, to provide fuel diversity benefits. But the gas co-firing requirement means that Polk cannot insulate TECO customers from gas price volatility by simply switching to petcoke or coal. In the event that gas prices rise or become volatile again, TECO cannot just switch to petcoke or coal—it still has to meet the 40 percent co-firing requirement. And customers would have to pay high gas prices to continue operating the plant. Any gas supply shortages would similarly impact the Company's ability to rely on Polk 1, as TECO would not be able to comply with the Section 111(d) rule without combusting gas.

It is also unclear how TECO would operate the plant on petcoke and achieve the low level of emissions required to comply with the Section 111(d) rule. Petcoke has higher greenhouse gas emissions than coal[41] and would require an even higher percentage of gas co-firing to comply with this rule.

**Q What does this say about Polk 1's utility as a reliability resource?**

A Because Polk 1 would be required to co-fire any coal or petcoke with a significant quantity of gas, TECO cannot use Polk 1's IGCC capacity to meet reliability needs if it faces issues with its gas supply.[42]

[41] U.S. Environmental Protection Agency. "Emission Factors for Greenhouse Gas Inventories." 2023. Available at https://www.epa.gov/system/files/documents/2023-03/ghg_emission_factors_hub.pdf.

[42] *See* TECO response to SC IRR 12 (a) ("Big Bend 4 has been operated on coal when economic, for environmental needs, for logistical needs, and for natural gas supply and delivery limitations.") (Exhibit DG-2).

**Q Do any of the other newly finalized environmental regulations for effluent limitations, mercury air toxins, and nitrogen oxide emissions impact TECO's cost or ability to burn petcoke or coal at Polk 1?**

A Likely yes. The recently finalized 2024 Effluent Limitation Guidelines ("ELG") rule strengthens the discharge standards for three types of wastewaters produced by coal-fired units: flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate. TECO states that it anticipates no additional compliance costs[43] because the ELG rule regulates surface water discharges, and the Polk plant discharges wastewater into a deep injection well. But the EPA has estimated that to meet these new standards and operate Polk's IG components past 2028, TECO will have to upgrade its system to comply with zero-discharge combustion residual leachate requirements at an estimated \$10,437,244 in capital costs and \$348,870 in annual O&M costs.[44] And TECO has not presented any analysis on how EPA's cost estimates will be mitigated by deep wastewater injection. Nor has it analyzed future O&M costs associated with deep wastewater injection or deep well leakage risks and potential costs.

Given these constraints and compliance costs stemming from these now-finalized federal environmental regulations, there is no reason why TECO should continue to maintain the petcoke and coal infrastructure (i.e., IG components) at the plant.

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[43] Exhibit DG-2. TECO response to SC IRR 16 (b).

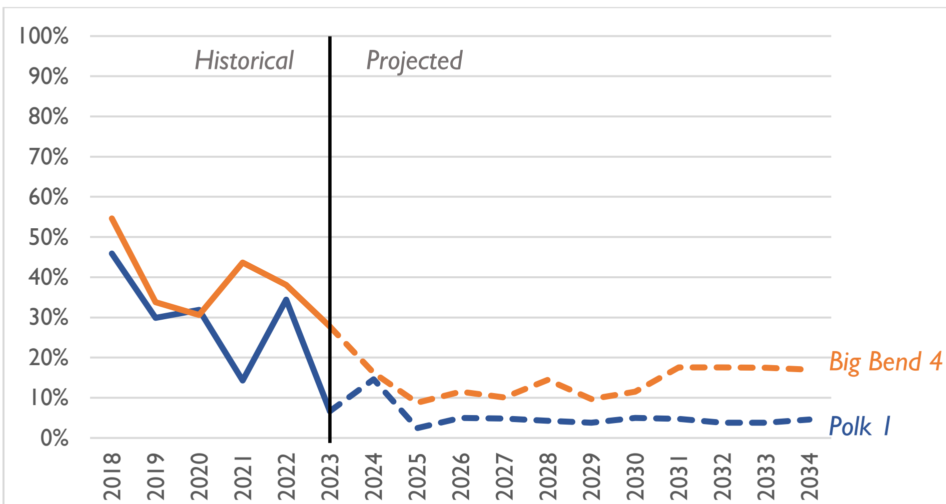
[44] Exhibit DG-9. EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Unit-Level Costs and Loadings Estimates for the 2024 Final Rule (DCN SE11756A1), April 22, 2024; Exhibit DG-10. EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule (DCN SE11756), April 22, 2024.

***iii. <u>Polk has been relatively unreliable in recent years</u>***

**Q Please summarize Polk 1's recent historical and projected utilization.**

**A** As shown in Figure 5 below, the capacity factors at Polk 1 over the past five years have ranged from just above 40 percent in 2019 down to around 7 percent in 2023.[45] Over the next few years, TECO projects the unit's utilization will not exceed 5 percent, which is a significant drop below historical levels. This is not surprising if TECO plans to operate it as a peaking plant.

**Figure 5. Utilization of Polk 1 and Big Bend 4**




*Source: TECO response to SCIRR 1-8 (e), Attachment BS (28921) 2018 - 2023 GFP and TECO response to SC IRR 1-9 (d), Attachment (BS 28927) Sierra Club 1st Set IRR Q9 .*

**Q How reliable has Polk 1 been in recent years?**

**A** Polk 1 has been relatively unreliable in the past five years, with a forced outage rate ranging from a low of 7.5 percent to a high of 67 percent (Table 3). This is substantially higher than the national average for fossil plants. According to the

[45] Exhibit DG-2. TECO Response to Sierra Club IRR 8 (e).

North American Electric Reliability Corporation ("NERC")'s 2023 State of Reliability Technical Assessment, the weighted equivalent forced outage rate for all conventional generators in 2022 was 8.5 percent.[46] This represented the highest level of unavailability since NERC started tracking it in 2013—and TECO still exceeded that level in three of the past five years. The data[47] TECO provided on individual outages showed a substantial number of prolonged, unplanned outages.

**Table 3. Polk 1 net equivalent forced outage rate (NEFOR)**

| | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| **Polk 1** | 8.54% | 27.35% | 67.40% | 30.11% | 7.52% |

*Source: TECO response to SC IRR 8, Attachment (BS 28923) 2019 - 2023 Factor and Rates.*

**Q Describe the unit's financial performance in recent historical years.**

A As discussed above, TECO has operated Polk 1 exclusively on gas for the past five years. The unit's performance has been marginal even on gas, with unit costs exceeding market value for two of the past five years. If TECO operated the plant on petcoke or coal instead, I expect its performance would have been much worse as coal and petcoke costs have been substantially higher than gas costs.

[46] Exhibit DG-11. NERC, 2023 State of Reliability Technical Assessment, June 2023, at 3.

[47] TECO response to SC IRR 11, Attachment (BS 28931) 2018 - 2023 Outage Listing.

***iv. <u>TECO has not provided analysis demonstrating that it is most economic to convert Polk 1 to operate as a CT relative to alternatives, including retirement and replacement with clean energy resources</u>***

**Q How is Polk 1 projected to perform going forward?**

A At a high level, the Company believes that converting the unit to a CT will offer operational benefits relative to its current configuration. Specifically, TECO claims the unit will have:

- Lower operating costs, less maintenance cycles, and improved reliability.[48]
- More flexibility, faster start-up, ramp rates, and lower turndowns.[49]
- Improved heat rate.[50]

But based on my analysis, I find that the unit is expected to be only marginally economic in most years by operating as a simple-cycle CT. And when I factor in the up-front conversion cost of around $80 million, I find that the unit is expected to have a negative net present value revenue requirement ("NPVRR") of around $30.5 million ($2023).[51] This is concerning because it means that ratepayers will not only be paying down the existing undepreciated plant balance through rates,

[48] Direct Testimony of Aldazabal at 46.
[49] *Id.*
[50] *Id.*
[51] Calculated based on the following data sources: Fuel costs from TECO response to SC IRR 8 d-g, Attachment (BS 28921) 2018 - 2023 GFP (Exhibit DG-7); energy revenues calculated using TECO response to SC IRR 30 (a) and (b); capacity value calculated from bilateral energy and capacity contracts SC Confidential ROG 1-25 (a-c); Capex from TECO response to SC IRR 8 (n), Attachment (BS 28920) 2018 - 2023 Capital SC IRR8n; O&M estimated based on projected VOM and FOM provided by TECO in response to SC IRR 9, Attachment (BS 28927) Sierra Club 1st Set IRR Q9.

but they will also be incurring substantial additional costs at the unit in excess of the unit's market value.

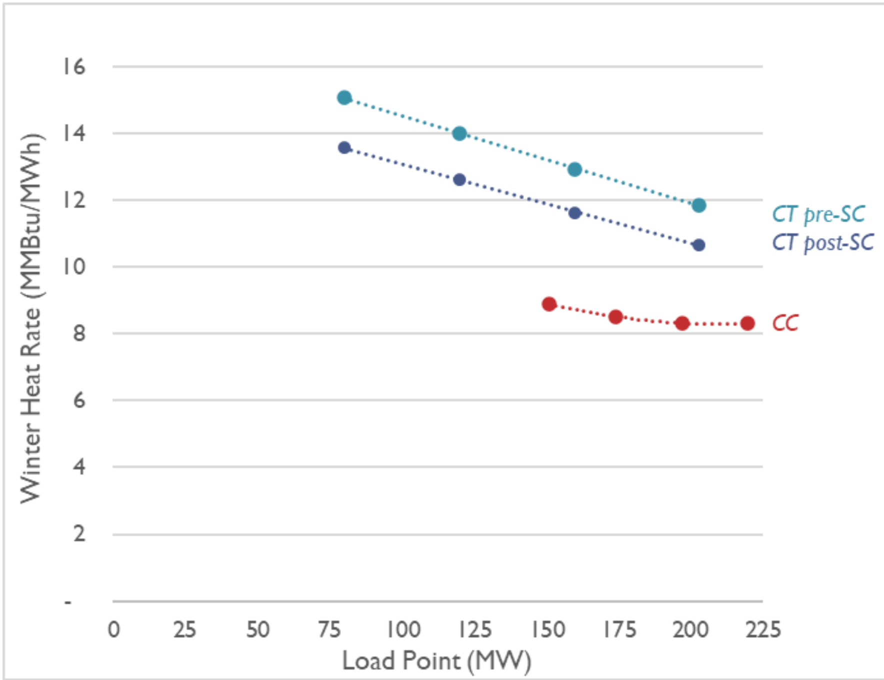
**Q How will the conversion to a CT affect the efficiency of Polk 1?**

**A** In his direct testimony, Company Witness Aldazabal lists an improved heat rate as one of the benefits of the conversion project, but the Company's data only partially supports this claim. Witness Aldazabal's statement is misleading—while the Polk 1 Flexibility Project will increase the efficiency of the CT component of Polk 1, it will decrease the efficiency of the unit as a whole.

Heat rate measures the amount of fuel a unit consumes to produce one unit of electricity, so lower heat rates indicate more efficient operation. All else being equal, CC units are more efficient than CT units, because CC units make use of the waste heat from one or more CTs to complete a second stage of electricity generation in an ST. This holds true at Polk 1, which currently operates as a CC unit. TECO projects that the average heat rate after conversion to a simple-cycle CT will be 10,653 Btu/kWh, compared to 8,770 Btu/kWh under the status quo.[52] Detailed data from the Company on the heat rate of the unit shows that across all load levels in both the summer and winter, the CT component of Polk 1 will have an improved heat rate post-conversion, but the heat rate of the CT alone will still be worse than the heat rate of the CC unit as a whole (Figure 6 and Figure 7).

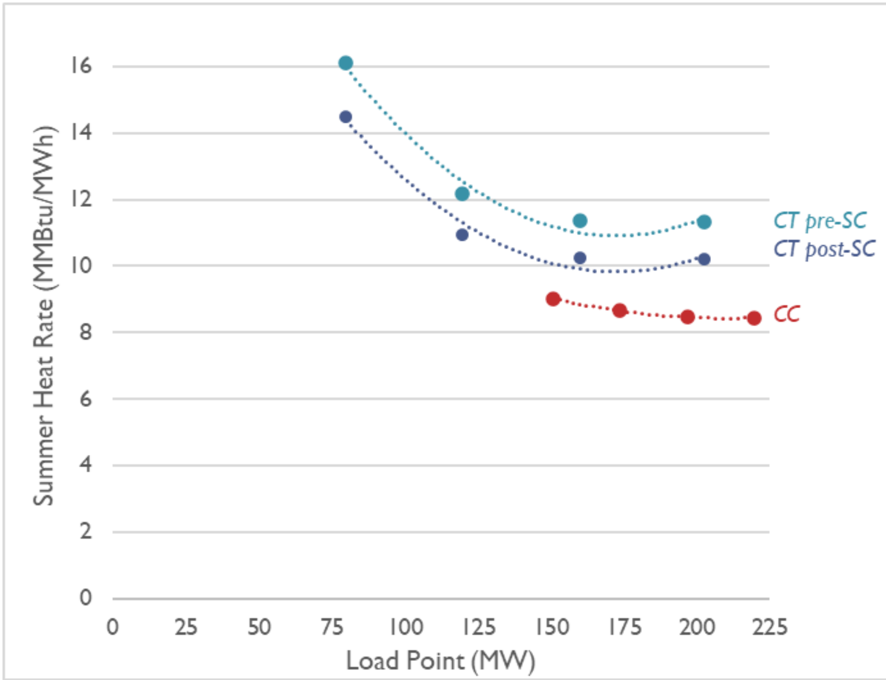
[52] Exhibit DG-3. TECO response to SC IRR 89 (j).

**Figure 6. Polk 1 winter heat rate**




*Source: TECO Response to SC POD 8, (BS 28863) Sierra Club 1st Set Quadratic Heat Rate Formula POD Q8.xlsx. CT is combustion turbine, SC is simple-cycle conversion, and CC is combined-cycle.*

**Figure 7. Polk 1 summer heat rate**




*Source: TECO Response to SC POD 8, (BS 28863) Sierra Club 1st Set Quadratic Heat Rate Formula POD Q8.xlsx. CT is combustion turbine, SC is simple-cycle conversion, and CC is combined-cycle.*

**Q What analysis has TECO provided to justify its claims that the Polk Flexibility Project is in the best interest of ratepayers?**

**A** TECO evaluated the costs and benefits of converting the unit to a CT relative to the current configuration and found that the conversion would provide $40 million in fuel benefits and a cumulative present value revenue requirement benefit of $166.9 million.[53] The Company did not consider other options, including retiring Polk 1 and replacing any needed capacity with alternatives. This is concerning because the unit has been only marginally economic in recent years and is projected to incur a net cost to ratepayers going forward. So even if the

[53] Direct Testimony of Aldazabal at 46.

conversion would provide benefits relative to the status quo, that doesn't mean that it would provide net benefits to ratepayers relative to the alternatives of early retirement or early retirement and replacement. TECO has provided no analysis evaluating alternatives or demonstrating that it is in the best interest of ratepayers to continue relying on Polk 1. The most recent retirement analysis that TECO conducted for Polk 1 was completed in the fall of 2022, before the environmental regulations described above went into effect. This analysis was done with the production cost model and evaluated a 2028 retirement date for Polk.[54]

**Q Do TECO's customers need the capacity or energy from Polk 1, or otherwise benefit from having Polk 1 online?**

**A** No. TECO repeatedly cites fuel diversity as a benefit of Polk 1 in attempting to justify maintaining the IG system at Polk. But as discussed above, fuel diversity does not justify maintaining an uneconomic asset, especially given the ongoing costs TECO will incur to maintain all the equipment at Polk 1. This is especially apparent when considering Polk's firm capacity is 2-3 percent of TECO's total firm winter capacity, and an even smaller percentage of its firm summer capacity. Even if Polk was operating at above its 5 percent capacity factor, it would still do very little to hedge against gas fuel price or supply risks, which would affect the majority of its generation fleet.

Retirement of the IG, as well as the ST and HRSG, would provide TECO with an easy opportunity to avoid unnecessary fixed operating costs and capital expenditures at this plant, in addition to avoiding the steep environmental compliance costs discussed above.

[54] Exhibit DG-2. TECO response to SC IRR 4.

**Q Does IGCC have a proven track record in the U.S. power sector that would justify preserving the gasifier block at Polk 1?**

A No. There are only three operational coal gasification plants in the entire U.S. power sector.[55] TECO noted that Polk 1 "is a one-of-a-kind installation because it is supplied fuel via the coal gasification process."[56] One reason the Company proposed the Polk 1 Flexibility Project is that GE, the Original Equipment Manufacturer ("OEM") of the turbine, no longer supports the turbine's combustion system.[57] Because of its bespoke design, maintaining the IGCC equipment at Polk will likely continue to be more costly and difficult than it would be for standardized generators types, where parts are still in circulation. Furthermore, it is telling that utilities across the country are constructing renewable energy to lower their energy costs, while only one coal gasification electricity generating plant has been successfully constructed in the United States since 2000.[58] This further underscores that generating syngas at Polk is unlikely to become economic in the future, and TECO—and its ratepayers—would be better off retiring the gasification equipment and focusing instead on adding clean energy to its system to replace Polk's relatively modest output.

**Q What do you recommend regarding Polk 1?**

A I recommend that TECO retires Polk 1—and at the very least, the IG technology, followed by the HRSG and ST technology—as soon as possible. The Company has not relied on Polk 1's ability to fuel switch, even when gas prices spiked in

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[55] These are Polk, Edwardsport in Indiana, and Wabash River in Indiana. The gasification equipment at a fourth plant, Kemper, was demolished in 2021 and the unit now runs on gas only.

[56] Direct testimony of Aldazabal at 45.

[57] *Id*.

[58] Exhibit DG-13. Schlissel, D. 2017. *Using Coal Gasification to Generate Electricity: A Multibillion-Dollar Failure*. Institute for Energy Economics and Financial Analysis.

recent years, and it has provided no legitimate justification for continuing to maintain the IG technology. Further, I recommend that the Commission not allow the CT conversion until the Company produces an analysis demonstrating that converting the unit to a CT is the lowest-cost option relative to retirement and replacement with alternatives, including clean energy resources. If the conversion is approved, TECO should be required to immediately retire the ST and HRSG equipment that will not be used to operate the unit as a simple-cycle CT—in addition to retiring the IG technology, which I recommend as a cost-effective measure across all scenarios.

## 5. TECO SEEKS TO RETAIN THE ABILITY TO OPERATE BIG BEND 4 ON COAL DESPITE THE UNIT PERFORMING POORLY IN RECENT YEARS

### *i. TECO has been operating Big Bend 4 on both coal and gas in recent years, and the unit has seen declining utilization and was uneconomic when it was operated*

**Q How has TECO been operating Big Bend 4 in recent years?**

A TECO has been operating this unit on both gas and coal (Table 4). In 2023, Big Bend 4 ran with a capacity factor of 21 percent on coal and 7 percent on gas.[59] In the first quarter of 2024 (through April), the unit ran with a 3 percent capacity factor on coal and 8 percent on gas.[60] Over the past five years, TECO operated the plant on coal the majority of the time—only in 2023 did it approach a 50/50 split,

[59] Exhibit DG-2. TECO response to SC IRR 46 (a).
[60] *Id*.

as measured by service hours.[61] On a net generation basis, gas still only accounted for around a quarter of Big Bend 4's output in 2023.

**Table 4. Big Bend 4 plant statistics operating on coal and gas**

| | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| **Net Capability (MW)** | | | | | |
| Coal | 438 | 392 | 425 | 425 | 425 |
| Gas | 188 | 170 | 157 | 418 | 413 |
| **Service Hours (hrs)** | | | | | |
| Coal | 3,973 | 3,337 | 4,850 | 5,575 | 3,404 |
| Gas | 681 | 1,278 | 2,367 | 1,355 | 3,331 |
| **Net Generation (MWh)** | | | | | |
| Coal | 1,214,307 | 909,110 | 1,357,954 | 1,336,581 | 769,413 |
| Gas | 83,516 | 143,651 | 274,144 | 83,267 | 263,553 |
| **Annual Capacity factor (%)** | | | | | |
| Coal | 32% | 26% | 36% | 36% | 21% |
| Gas | 5% | 10% | 20% | 2% | 7% |

*Source: TECO response to SC IRR 8, Attachment (BS28921) 2018-2023 GFP.xlsx.*

TECO reports that it is departing from this historical practice, and going forward, "the company plans to operate Big Bend 4 mostly on natural gas and expects to burn minimal amounts of coal to keep the solid fuel equipment viable."[62] In other words, TECO doesn't anticipate that burning coal will be economic, but it will still do so—at the expense of ratepayers—because it wants to maintain the solid fuel equipment. Burning coal at Big Bend 4 will be uneconomic because the unit's fuel costs are lower on gas, as well as its expected variable O&M costs ("VOM")—which are less than half the cost to operate on coal.[63] Burning coal

[61] Exhibit DG-7. TECO response to SC IRR 8, Attachment (BS 28921) 2018 - 2023 GFP.

[62] Exhibit DG-2. TECO response to SC IRR 46 (a).

[63] Exhibit DG-2. TECO response to SC IRR 46 (c).

will not even be necessary to maintain a firm fuel supply given that the Company has indicated that it has and will continue to have firm gas supply contracts.

**Q How has the unit's operational performance been recently?**

A As shown in Table 5, Big Bend 4 experienced a high outage rate in recent years, with a forced outage rate of between 8.7 percent and 31.6 percent over the past five years. TECO ratepayers will continue to be exposed to these outage risks as long as the Company continues to rely on the plant.

**Table 5. Big Bend 4 net equivalent forced outage rate (NEFOR)**

| | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| **Big Bend Unit 4** | 28.09% | 32.04% | 8.71% | 31.61% | 18.08% |

*Source: TECO response to SC IRR 8, Attachment (BS 28923) 2019 – 2023 Factor and Rates.*

**Q Please summarize the recent historical and projected utilization of Big Bend 4.**

A As shown in Figure 5, Big Bend's utilization has ranged between 28 and 44 percent over the past five years.[64] Going forward, TECO projects the plant will operate at between an 8.8 percent and a 17.6 percent capacity factor over the next decade.[65] This is a very low utilization rate for a baseload plant such as Big Bend 4.

**Q Describe the unit's financial performance in recent historical years.**

A As shown in Table 6, Big Bend has been uneconomic to operate since 2019 and shows net negative value in three of the past five years (based on fuel costs, O&M, capital expenditures, energy and capacity value). The years 2021 and 2022

[64] Exhibit DG-7. TECO response to SC IRR 8, Attachment (BS 28921) 2018 - 2023 GFP.
[65] TECO response to SC IRR 9, Attachment (BS 28927) Sierra Club 1st Set IRR Q9.

were exceptions when Big Bend 4 showed positive net value. However, these results were based on energy and gas market prices prompted by COVID and the war in Ukraine, which are rare and not expected to continue going forward.

**Table 6. Historical net value of Big Bend 4 ($2023 M) (2019-2023)**

| | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| **Big Bend 4** | ($38.9) | ($63.5) | $21.4 | $82.5 | ($29.1) |

*Source: Fuel costs from TECO response to SC IRR 8 d-g, Attachment (BS 28921) 2018 – 2023 GFP; energy revenues calculated using TECO response to SC IRR 30 (a) and (b); capacity value calculated from bilateral energy and capacity contracts SC Confidential ROG 1-25 (a-c); Capex from TECO response to SC IRR 8 (n), Attachment (BS 28920)2018 – 2023 Capital SC IRR8n; O&M from FERC Form 1 and TECO response to SC IRR 9.*

**Q Explain the methodology you used to develop this historical analysis.**

A I relied on Company data from TECO and public data to calculate the cost and revenues TECO incurred at Polk 1 between 2019 and 2023. I summed energy and capacity value to find total value. Because TECO is not located in an organized market, I relied on bilateral capacity contracts[66] that the Company provided for the past five years to calculate capacity value. I calculated energy value based on the Company's off-system energy sales and purchases[67] from 2019 to 2023 for each year, which were also provided by the Company.

I added the fuel costs, non-fuel O&M costs, and sustaining capital expenditures to get total unit costs. I used fuel costs[68] and capital expenditures[69] provided by the Company. For historical O&M costs (fixed and variable combined), TECO

[66] TECO response to Confidential SC IRR 25, Attachments ROG_1_25a-CONF_bates, ROG_1_25b_purchases-CONF_bates, ROG_1_25b-sales-CONF_bates, ROG_1_25c-CONF_bates.

[67] Exhibit DG-2. TECO response to SC IRR 30 (a) and (b).

[68] Exhibit DG-7. TECO response to SC IRR 8 (d-g), Attachment (BS 28921) 2018 - 2023 GFP.

[69] TECO response to SC IRR 8 (n), Attachment (BS 28920) 2018 - 2023 Capital SC IRR8n.

asserted it does not have historical fixed O&M ("FOM") and VOM data, so I relied on the FERC Form 1[70] for FOM and used TECO's projected VOM costs for the unit as a proxy for its historical costs.[71] I netted the unit costs and value to find the unit's historical net value (or cost) for each year.

**Q Does this analysis reflect system costs as they are allocated to ratepayers through the Company's revenue requirement?**

A No. This analysis is not intended to reflect the way costs are passed on to ratepayers over the lifespan of energy assets—but rather to provide a comparison of real-time expenses and revenues. Revenue requirements inherently require assumptions around the lifetime of assets/resources. Additionally, a substantial portion of resource costs are deferred until the future through capital and regulatory asset treatment. Therefore, poor near-term unit economics can be diluted or obscured by spreading out the losses over a longer period of time.

My analysis, on the other hand, is intended to provide a clear snapshot of how input revenues match output costs. It may be reasonable for expenses to exceed revenues in a single year (for example, when a large capital investment is made). But over a period of multiple years, expenses should not regularly exceed revenues. If they do, that is a strong indication that the unit is not operating economically.

[70] FERC Form 1.
[71] TECO response to SC IRR 9, Attachment (BS 29827) Sierra Club 1st Set IRR Q9.xlsx.

***ii. Based on TECO's data, Big Bend 4 is projected to continue to be uneconomic moving forward, especially when operated on coal***

**Q How is Big Bend 4 projected to perform going forward?**

A Going forward, TECO's own data suggests that Big Bend 4 will be very uneconomic to operate, and that the unit's costs will exceed its value from 2024 to 2033, as shown in Table 7 below. This is due in part to the low capacity factor at which the unit is projected to operate, as seen in Figure 5, coupled with the relatively high costs required to maintain a baseload plant. As discussed above, the unit shows record-low utilization and is projected to operate at capacity factors below 20 percent from 2024 to 2034. The potentially large capital investments required to meet various recently finalized federal environmental regulations, including the Section 111(d) standards for greenhouse gases and the ELG rule, will make the plant even more costly and uneconomic.

**Table 7: Projected net value of Big Bend 4 ($2023 M) (2024-2033)**

| Year | $2023 M |
|---|---|
| 2024 | ($6.1) |
| 2025 | ($1.9) |
| 2026 | ($6.6) |
| 2027 | ($10.5) |
| 2028 | ($5.6) |
| 2029 | $2.9 |
| 2030 | ($4.2) |
| 2031 | ($12.7) |
| 2032 | ($21.1) |
| 2033 | ($10.0) |

*Source: Fuel and VOM costs from TECO response to SC IRR 9, Attachment (BS 28927) Sierra Club 1st Set IRR Q9; FOM based on historical FOM from FERC form 1 net of projected VOM from TECO response to SC IRR 8 (which is use as a proxy for projected VOM); capex from TECO response to SC IRR 9, Attachment (BS 38292) 2024 – 2028 Capital SC IRR9m; energy value from*

*TECO Confidential response to SC 1-30(c-d), various attachments; capacity value from TECO Confidential response to SC 1-25b, various attachments.*

**Q How did you calculate the projected value of Big Bend 4?**

A As with the historical analysis presented above, I relied on Company projections for unit costs over the next ten years, supplemented by public data where no Company data was provided. I summed energy and capacity value to find total value. I relied on the same bilateral capacity contracts[72] that the Company provided for the past five years to calculate capacity value. I calculated energy value based on the Company's projection of off-system energy sales and purchases[73] from 2024 to 2034.

I added the fuel costs, non-fuel O&M costs, and sustaining capital expenditures to get total unit costs. I used fuel costs,[74] projected VOM costs,[75] and capital expenditures[76] provided by the Company. TECO did not provide FOM data, either projected or historical, for Big Bend 4, so I relied on the FERC Form 1[77] historical data for fixed O&M for the entire Big Bend plant and scaled it by MW to estimate the portion for just Unit 4. Because FERC Form 1 costs represent both FOM and VOM, I netted out the historical VOM to isolate just the FOM.

I then netted the unit costs and value to find the unit's historical net value (or cost) for each year.

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[72] TECO response to Confidential SC IRR 25, Attachments ROG_1_25a-CONF_bates, ROG_1_25b_purchases-CONF_bates, ROG_1_25b-sales-CONF_bates, ROG_1_25c-CONF_bates.

[73] TECO response to Confidential SC IRR 30, Attachments ROG_1_30c-CONF_bates, and ROG_1_30d-CONF_bates.

[74] TECO response to SC IRR 9, Attachment (BS 28927) Sierra Club 1st Set IRR Q9.

[75] *Id*.

[76] TECO response to SC IRR 9, Attachment (BS 38292) 2024 - 2028 Capital SC IRR9m.

[77] FERC Form 1.

**Q What analysis has the Company performed on the economics of continuing to operate Big Bend 4 on coal through 2040 to justify including its ongoing O&M and capital expenditures in rates?**

A Notably, the Company has not provided any analysis showing the continued reliance on Big Bend 4 is in the best interests of ratepayers. It argues that no analysis is needed because "that asset has numerous years of remaining useful life."[78] Despite projecting much higher dispatch costs for coal compared to gas,[79] TECO has not analyzed the feasibility or the cost of operating Big Bend 4 entirely on gas, claiming that "it is premature to incur significant costs to develop cost estimates and system impacts associated with repowering a unit with at least fifteen years of life left on it."[80]

This is a faulty line of reasoning on TECO's part. The Company should not make retirement decisions based on sunk costs, but rather based on the unit economics and the forward-going costs required to operate the unit. Units like Big Bend 4 that consistently yield negative net revenues should be retired and replaced with alternate sources of generation that can save ratepayers money immediately by incurring lower marginal costs than a coal plant. And there are alternative ways to address the undepreciated plant balance at Big Bend 4, such as through a regulatory asset or by using funding available under the EIR. These options will cost ratepayers substantially less than continuing to operate the plant, despite the availability of cheaper alternatives.

[78] Exhibit DG-2. TECO response to SC IRR 1.
[79] Exhibit DG-2. TECO response to SC IRR 46 (c).
[80] Exhibit DG-2. TECO response to SC IRR 40.

**Q What fixed costs are avoidable at Big Bend 4 with an earlier retirement?**

A Retirement would allow TECO to avoid unnecessary fixed operating costs and capital expenditures at this plant, including environmental compliance costs. In 2022, TECO incurred $17 million in sustaining capital costs at Big Bend 4, and the Company included a projected $7.5 million in sustaining capital costs for the unit in its test year spending.[81] TECO's own projections for Big Bend 4's capital expenditures over the next five years are low, working out to about $13 million in capex per year.[82] This is substantially lower than TECO's average Big Bend capex spending over the past five years, which was around $30 million per year.[83] TECO did not provide forecasted fixed O&M costs for Big Bend 4, stating in discovery that it does not have this data.[84] This is concerning, given that a forecast of forward-going costs is necessary to evaluate the economics of operating a plant. If TECO does not have a forecast of future O&M costs for a unit, then it can't be evaluating the forward-going economics of the unit and understanding what costs are avoidable with early retirement.

***iii. TECO could incur substantial costs to comply with new federal regulations at Big Bend 4 if it operates the plant on coal***

**Q Do any new federal greenhouse gas emissions rules impact the cost of TECO continuing to operate on coal at Big Bend Unit 4?**

A Yes. My understanding is that under the newly finalized greenhouse gas standards under Section 111 of the *Clean Air Act*, plants retiring after January 1, 2039 will

[81] Exhibit DG-2. TECO response to SC IRR 5.
[82] TECO response to SC IRR 9 (m), attachment (BS 38292) 2024 - 2028 Capital SC IRR9m.
[83] TECO response to SC IRR 8 (m), attachment (BS 28920) 2018 - 2023 Capital SC IRR8n.
[84] Exhibit DG-2. TECO response to SC IRR 9 (i).

have to meet a carbon emissions standard based on a standard of 90 percent capture of carbon dioxide by January 1, 2032. That means TECO's options at Big Bend Unit 4 are to:

- Maintain the stated 2040 retirement date and install CCS by January 1, 2032, achieving an 88.4 percent reduction in the unit's gross carbon dioxide emissions rate relative to its unit-specific baseline;
- Move up the retirement date to January 1, 2039, or earlier, and meet a medium-term standard based on 40 percent co-firing on natural gas by volume (equivalent to a 16 percent reduction in the unit's gross baseline carbon dioxide emission rate) starting January 1, 2030;
- Retire the unit before January 1, 2032, and avoid any compliance costs or requirements under this particular rule. However, operating Big Bend 4 past 2027 may still result in environmental compliance costs for TECO related to the MATs and ELG rules.

TECO itself noted that Big Bend 4 could comply with the Section 111 rule by retiring 1–2 years earlier than planned (prior to January 1, 2039, rather than in 2040) and that no major enhancements to the unit would be necessary under this approach.[85] But this would require that the Company co-fired on gas more than it has historically (or at least any time during the past five years) starting in 2030.

**Q What are the estimated compliance costs for Big Bend 4 to comply with EPA's ELG Rule?**

**A** The 2024 ELG rule strengthens the discharge standards for three types of wastewater produced by coal-fired units: flue gas desulfurization wastewater

[85] Exhibit DG-3. TECO response to SC IRR 88.

("FGD"), bottom ash transport water, and combustion residual leachate. EPA projects that Big Bend 4 is likely to have to invest in upgrades to meet new zero discharge FGD standards. They project these upgrades will cost $129 million in capital costs alone, with annual O&M costs of around $9 million.[86] Alarmingly, these costs remain the same across three different compliance options modeled by EPA in its technical memorandum attached to the final ELG rule.

TECO indicated that Big Bend 4 is already in compliance with the ELG rule, which regulates discharge to surface water, since it disposes wastewater into a deep injection well.[87] But this contradicts EPA's projections that ELG compliance would cost TECO $129 million at Big Bend 4.[88] Notably, TECO has not provided an analysis of how its deep injection wells at Big Bend will mitigate EPA's projected compliance costs for discharging FGD, nor has it disputed FGD discharge levels published by EPA.

**Q What are the estimated compliance costs for Big Bend 4 to comply with EPA's Mercury and Air Toxics Standards ("MATS") regulations?**

**A** TECO acknowledged that the MATS rule is applicable to Big Bend 4, but indicated that it expects no material additional compliance costs with the final MATS standards. Yet, in the unit-level regulatory impact analysis submitted

[86] Exhibit DG-9. EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Unit-Level Costs and Loadings Estimates for the 2024 Final Rule (DCN SE11756A1), April 22, 2024; Exhibit DG-10. EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule (DCN SE11756), April 22, 2024.

[87] Exhibit DG-2. TECO response to SC IRR 14.

[88] Exhibit DG-9. EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Unit-Level Costs and Loadings Estimates for the 2024 Final Rule (DCN SE11756A1), April 22, 2024.

along with the finalized 2024 MATS rule.[89] EPA lists Big Bend 4 in its catalog of impacted units and also identifies Big Bend's lowest achievable filterable particulate matter ("fPM") rate based on historical data as 0.00953 lb/MMBTU, which is just below the 0.01 lb/MMBTU threshold adopted in the final rule. If Big Bend 4's fPM rates push up above the 0.01 threshold, it will not be in compliance with the MATS rule, and the Company would have to install pollution controls by 2027 to comply. Operating Big Bend solely on gas would avoid any possibility of Big Bend 4 falling out of compliance with the MATS rule.

**Q What other options does TECO have for reducing the impact of operations at Big Bend 4?**

**A** TECO's reserve margin is substantially lower in the winter than in the summer. That means that the Company's resource needs are concentrated in the winter. Another option is to switch Big Bend 4 to seasonal operation, and only rely on it during the winter peak months. This is something that has been done by Xcel Energy in Minnesota for its coal plants. Utilities in Indiana and Missouri have also recently expressed interest in this option. In this event, although Big Bend 4's O&M costs and pollution would decrease in tandem with its capacity factor, it would still face the high environmental compliance costs described above, as those remain unaffected by seasonal operations.

Another option is to end the use of coal at the plant immediately and switch it to only operate on gas, in advance of an early retirement. Given that the Company has indicated that operation on gas is currently less costly than operation on coal,

[89] Exhibit DG-14. U.S. EPA. 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo), Attachment 1.

and that it is only burning coal to keep the solid fuel equipment viable,[90] such a switch is in line with the unit's economics.

## 6. TECO SHOULD EVALUATE RETIREMENT AND REPLACEMENT OPTIONS FOR ITS COAL PLANTS AND APPLY FOR EIR FUNDING TO FACILITATE THE COST-EFFECTIVE EARLIER RETIREMENT OF BIG BEND 4

### *i. TECO should evaluate replacement resources for its coal units at Polk and Big Bend*

**Q If TECO has sufficient capacity to meet its current summer and winter reserve margins, does that mean it should not consider any new clean energy resources?**

**A** No. Need is not just about having enough physical capacity on a system, but also the economics of operating existing generation relative to alternatives. TECO can and should regularly evaluate—as part of its resource planning exercises—whether it is more economical to get the energy and capacity it needs from its existing fossil resources, or to retire and replace them with clean energy alternatives. Prices of renewable energy resources have fallen substantially in recent years. Many utilities are selecting a combination of low-variable-cost renewables and flexible, dispatchable capacity as their preferred least-cost resource plan.

TECO should study the economics of maintaining an adequate, but not excessive, capacity position to serve its customers. Maintaining an appropriate capacity position for customers may require the sale, transfer, or retirement of some

[90] Exhibit DG-2. TECO response to SC IRR 46(a).

existing resources, as well as the procurement of additional resources that are more economical solutions to meeting current system needs. To support its study of resource economics, TECO should be proactive and test the market with requests for proposals to evaluate replacement resource options so it can procure lower-cost clean energy to replace its uneconomic coal plants.

**Q What risks does TECO expose its ratepayers to through continued reliance on coal, petcoke, and gas?**

A TECO's plan to continue relying heavily on gas, coal, and petcoke exposes ratepayers to fuel price volatility, to the cost of complying with future environmental regulations, and to potential grid crises from outages related to legacy fossil fuel infrastructure facing up against Tampa's hurricane season.

**Q Explain the risks posed to ratepayers by fuel price volatility.**

A Continued reliance on fossil gas subjects ratepayers to gas price volatility. TECO's portfolio got 82 percent of its generation from gas in 2023 and only 8 percent from solar PV.[91]

This level of reliance on gas is risky because when the market is constrained and prices spike, those costs are passed directly to ratepayers. For example, when DTE Electric Company in Michigan filed its 2022 Fuel Reconciliation Docket, it noted that gas spending was 74 percent higher than planned. These higher-than-expected prices resulted in large part from the Russian invasion of Ukraine, and European gas customers turning increasingly to U.S. gas. As a result, DTE is requesting to recover an additional $154 million for 2022 fuel costs alone.[92]

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[91] Exhibit DG-5. 2024 TYSP, Schedule 6.2.
[92] DTE Elec. Co. 2023. Exhibit *A-7.* Mich. Pub. Serv. Comm'n Docket No. E-21051. March 31, 2023.

Absent action from the Michigan Public Service Commission, DTE and its shareholders are not impacted by these gas price spikes—these costs are entirely passed on to ratepayers. The same phenomenon could happen just as easily in Florida or elsewhere in the Southeast. TECO should take this into account in planning its future resource mix. In fact, TECO's own historical fuel data shows that it experienced high gas costs in 2022 when gas prices spiked.[93]

**Q Is TECO aware of the risks posed by exposure to gas price volatility?**

A Yes, TECO recognizes the riskiness of its high level of exposure to gas price volatility, and stated in its most recent TYSP that it seeks to perform integrated resource planning in a "manner that reduces reliance on natural gas and its associated price volatility risk for customers."[94] However, the Company should re-think its approach to ensuring fuel diversity. TECO cites maintaining fuel diversity as a reason to maintain the capability for Polk 1 to burn petcoke[95] and Big Bend 4 to burn coal.[96] As I explain below, reliance on coal and petcoke poses many of the same risks as gas. TECO could more effectively protect its customers by procuring clean energy capacity, including solar PV, BESS, and wind. These resources are not subject to fuel price volatility, because they use no fuel, and they are not at risk of future environmental regulation, because they do not emit greenhouse gases or toxic pollutants. Moreover, the cost declines in the price of BESS means that solar PV and wind paired with battery storage can be utilized as a dispatchable resource.

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[93] Exhibit DG-2. TECO response to SC request IRR 8.
[94] Exhibit DG-5. 2024 TYSP at 2.
[95] Exhibit DG-3. TECO response to SC IRR 89(a).
[96] Exhibit DG-2. TECO response to SC IRR 40.

**Q Explain the risks posed to ratepayers from continued reliance on coal and petcoke assets.**

A The coal market has seen dramatic price volatility in some parts of the United States over the past few years.[97] There have also been labor challenges both at the mines and the railroad companies that transport the coal, as coal workers demand better pay and have more options in the labor market. Additionally, as more and more coal plants across the United States retire and the demand for coal contracts declines, there will be additional pressure on the coal industry. TECO itself has announced it is not renewing its long-term coal contracts,[98] further demonstrating the trend in declining coal contracts. The combination of declining demand and labor challenges could result in consolidation among coal companies and subsequently higher coal prices.[99]

Coal use was down in 2023 and never reached more than 20 percent of power market share (through October). This steady decline is novel because market share had been around 20 percent each month between 2020 and 2022, and prior to 2020, coal had never comprised less than a 20 percent market share in any month.[100] Additionally, as I discuss next, risks from increased environmental regulation could result in higher costs and higher risks for coal usage. Higher regulatory risk impacts not just resource planning economics, but also company

[97] U.S. Energy Information Administration, "Coal Markets." Available at https://www.eia.gov/coal/markets/.

[98] Exhibit DG-3. TECO response to SC IRR 79.

[99] Exhibit DG-15. Duke Energy, "Appendix F: Coal Retirement Analysis," 2023 Carolinas Resources Plan.

[100] Exhibit DG-16. Institute for Energy Economics and Financial Analysis, "Coal Use at U.S. Power Plants Continues Downward Spiral; Full Impact on Mines to be Felt in 2024," Nov. 2, 2023.

risk profiles, which can lead to downgraded credit ratings, and that can impact access to capital.

Additionally, breakdowns of parts and a lack of continued support from manufacturers based on the old age of coal plant technology can result in sustained outages and challenges in quickly repairing units and getting them back online.

**Q Explain the risks posed by future environmental regulations.**

A As discussed above, EPA recently finalized rules to regulate carbon dioxide emissions from new gas plants and existing coal plants, as well as mercury and air toxics emissions (including fine particulate matter) and effluent discharge. It is likely that additional environmental regulations will be issued, particularly ones that regulate emissions from existing gas plants. These regulations would continue to make it costlier and riskier to rely on gas resources.

**Q Explain the costs and risks of coal ash disposal.**

A For years, TECO deposited much of its coal ash in unlined ponds. Complying with EPA's recently updated stricter coal ash storage rule, called the Coal Combustion Residuals ("CCR") rule, could result in additional costs to ratepayers to line those unlined ponds and to construct and retrofit ponds to store coal ash that is disposed of in real time.[101] Indeed, TECO has acknowledged that it may have to remediate CCR surface impoundments and CCR management units as a

[101] Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments, 89 Fed. Reg. 38,950 (May 8, 2024).

result of the recently finalized updated CCR rule.[102]And there is already evidence of groundwater contamination from Big Bend 4's two unlined ponds.[103] Under federal law, TECO is required to remediate that contamination and prevent any further contamination associated with its current operations. This could incur significant costs, which would be imposed on TECO ratepayers and shareholders alike.[104]

**Q What replacement resource should TECO consider?**

A TECO should consider a range of low-cost clean energy resources to replace its coal plants, including solar PV, BESS, wind, energy efficiency, and demand response. The Company should be testing the market regularly and procuring solar PV, BESS, and other clean energy resources to economically displace energy and capacity from existing high-cost fossil resources.

**Q How much BESS and solar PV does TECO currently have on its system?**

A TECO currently has 1,252 MW of solar PV on its system,[105] which accounted for 8 percent of the Company's generation mix in 2023.[106] The Company currently has no BESS on its system. Going forward, TECO does plan to add 842 MW more in planned solar PV additions between 2024 and 2028, as well as 185 MW of BESS that will come online in the same timeframe (Table 8). Further out, TECO plans to add an additional 745 MW of solar PV between 2029 and 2033.

[102] Exhibit DG-2. TECO Response to SC IRR 14.
[103] Exhibit DG-17. Earthjustice, "Toxic Coal Ash in Florida: Addressing Coal Plants' Hazardous Legacy," May 3, 2023.
[104] Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments, 89 Fed. Reg. 38,950 (May 8, 2024).
[105] Exhibit DG-5. 2024 TYSP at 3.
[106] *Id*. at 1.

While it's encouraging that the Company plans to add some new solar PV and BESS, it is concerning that the quantities are so low—especially for BESS. Table 8 also shows TECO's projected construction costs for these resources.

**Table 8. TECO planned solar PV and battery capacity additions and construction costs**

| | Solar PV | | | Storage | | |
|---|---|---|---|---|---|---|
| | **Planned Capacity Additions (MW)** | **Projected Total Construction Cost ($M)** | **Projected cost per kW ($/kW)** | **Planned Capacity Additions (MW)** | **Projected Total Construction Cost ($M)** | **Projected cost per kW ($/kW)** |
| **2024** | 97.5 | $167 | $1,713 | 15 | $19 | $1,267 |
| **2025** | 149 | $244 | $1,638 | 100 | $143 | $1,430 |
| **2026** | 242 | $419 | $1,731 | 0 | $0 | |
| **2027** | 149 | $285 | $1,913 | 0 | $0 | |
| **2028** | 204 | $371 | $1,819 | 70 | $142 | $2,029 |
| **2029** | 149 | *TBD* | | 0 | *TBD* | |
| **2030** | 149 | *TBD* | | 0 | *TBD* | |
| **2031** | 149 | *TBD* | | 0 | *TBD* | |
| **2032** | 149 | *TBD* | | 0 | *TBD* | |
| **2033** | 149 | *TBD* | | 0 | *TBD* | |

*Source: TECO 2024 Site Plan, Schedule 8.1 and TECO response to SC IRR 91.*

***ii. TECO should apply for EIR funding under the IRA to finance clean energy replacement resources, and potentially also refinance undepreciated plant balances at Big Bend 4***

**Q What is the EIR program?**

**A** The EIR program, established under IRA, provides the DOE's LPO with around $250 billion in loan authority that it can deploy to "retool, repower, repurpose, or replace" fossil infrastructure.[107] The loans are available at just above the federal government's cost of borrowing, with repayment periods up to 30 years—which means they offer a cheap method of financing the undepreciated capital costs of a plant. The EIR's loans are even cheaper than financing the capital costs of coal plants by treating them as a regulatory asset.[108] Per statute, utilities are required to pass through the savings enabled under the EIR to their customers.[109]

The loans are intended to additionally finance investments in replacement generation capacity, distribution upgrades, or other investments that can help enable greenhouse gas emission reductions. And while the total loan amount is capped at 80 percent of the replacement project cost, my understanding is that the funding can be used to both lower the project costs for replacement resources and address legacy asset plant balances.[110]

**Q How does the EIR program provide value to ratepayers?**

A There are two main ways that the EIR program can provide value to ratepayers (assuming that the utility does not use debt from the program to alter its capital structure, i.e. debt-to-equity ratio): (1) by swapping federal LPO debt for utility debt, and (2) by providing capital utilities can use to refinance existing plant balances.

[107] Exhibit DG-18. U.S. Department of Energy, Loan Programs Office, Program Guidance for Title 17 Clean Energy Financing Program, May 19, 2023.
[108] *Id.* at 8.
[109] Id. at 28.
[110] Exhibit DG-19. C. Fong, D. Posner, and U. Veradarajan, "The Energy Infrastructure Reinvestment Program: Federal financing for an equitable, clean economy," RMI, February 16, 2024.

The first option can provide value to ratepayers if the utility itself does not have access to low-cost debt, but the benefits of using the loan in this way alone are not expected to be large. The more substantial benefits from an EIR loan are expected to stem from refinancing existing plant balances.[111] This addresses a critical barrier to retirement and can help accelerate unit retirements while reducing the economic burden on ratepayers relative to traditional financing mechanisms (and providing the utility with a level of certainty on cost recovery, which can ultimately improve its credit rating).

**Q Explain the swapping of federal LPO debt for utility debt.**

A LPO can provide debt to finance new clean energy resources. Here ratepayers benefit from the difference between the debt rate available from the LPO and the debt to which the Company would otherwise have access. The benefits of this option would have to outweigh the program's transaction costs, and may not, in themselves, be sufficient to warrant using this program.[112]

**Q Explain the EIR provision for refinancing remaining plant balances.**

A EIR loans provide capital that can be used to refinance the undepreciated balance of legacy fossil assets. While refinancing plant balance is not explicitly spelled out in existing guidance for the EIR program, and EIR applications cannot include funds for undepreciated plant balances, if the loan does not exceed the value of the clean energy replacement resources and the benefits are passed onto

[111] Exhibit DG-20. C. Fong, D. Posner, and U. Varadarajan, "Maximizing the value of the energy infrastructure reinvestment program for utility customers," RMI, May 24, 2024.

[112] RMI performed some calculations on the value this would provide and found that the benefits from trading LPO debt for utility debt are expected to be minimal.

ratepayers, utilities have the discretion to use the funds in this manner. Indeed, other utilities have confirmed that plant balance refinancing is allowed based on conversations with the LPO.[113]

To achieve this outcome, the plant balance would be transferred to a special purpose vehicle ("SPV"), removed from TECO's rate base (and balance sheet), and refinanced at the LPO debt rate. The Commission would have to approve a separate surcharge to repay the plant balance; and it should do so, because that would be a win-win for both the Company and ratepayers. Ratepayers would benefit because the federal LPO rate is lower than the utility's normal cost of capital, and the utility would benefit by removing a risky asset from its balance sheet. And the Commission would benefit because this would allow it to focus on approving the funding of resources that are needed to serve ratepayers. There would be a cost to create the SPV surcharge, but those costs would be outweighed by the benefits.

**Q What are the benefits of using EIR financing to address undepreciated balances?**

**A** There are multiple benefits of EIR financing, although the exact benefits accrued will vary based on the exact financing structure that a utility uses. EIR funding enables the following benefits:

- Removes the undepreciated plant balances from legacy assets from utility books. This is desirable because this is generally a low-quality, high-risk portion of a utility's rate base and is ultimately not desirable. This can

[113] *See, e.g.,* Iowa Utilities Board Docket RPU-2023-0002, Rebuttal Testimony of Christopher Boberg at 6.

improve utilities' credit ratings and result in more favorable financing terms for future projects.

- Enables the recycling of capital, which can in turn be made available to invest in new resources and projects.
- Facilitates repurposing of existing energy infrastructure, such as transmission, saving time and costs for ratepayers.
- Lowers costs for ratepayers by reducing the rate of return recovered on the undepreciated plant balance.
- Brings online new clean energy resources that can reduce costs and risks for ratepayers over the long term relative to continued reliance on fossil resources.

**Q Why is it important that TECO gets started on an EIR application now?**

**A** All projects that receive federal funding have to undergo a federal environmental review process under the National Environmental Policy Act ("NEPA"). This review process has historically been time-intensive, which is why the Biden administration recently finalized a rule to reform NEPA review process. Moreover, EIR is a rolling application and a number of utilities have already indicated their intent to apply for EIR funding.[114]

[114] Portland General Electric in Oregon, Consumers Energy in Michigan, Duke Energy in the Carolinas, and Alliant Energy in Wisconsin and Iowa.

**Q Has TECO applied for EIR funding or evaluated the potential to utilize funding from the EIR to finance replacement resources or refinance undepreciated plant balances?**

A No. TECO stated in discovery that it has not evaluated the potential use of the EIR program at any of its units,[115] nor has it communicated with DOE about the program.[116]

**Q What is your recommendation regarding TECO and EIR funding?**

A I recommend that TECO commit to locking in a retirement date for Big Bend 4 in its next rate case and submit an application for EIR financing as soon as possible, but in any event, before the program deadline in September 2026.

**Q Does this conclude your testimony?**

A Yes.

[115] Exhibit DG-2. TECO response to SC IRR 18.
[116] Exhibit DG-2. TECO response to SC IRR 19.

# Exhibit DG-1:

# Resume of Devi Glick

**Devi Glick,** Senior Principal

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## PROFESSIONAL EXPERIENCE

**Synapse Energy Economics Inc.**, Cambridge, MA. *Senior Principal*, May 2022 – Present; *Principal Associate*, June 2021 – May 2022; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

**Rocky Mountain Institute,** Basalt, CO. August 2012 – September 2017
*Senior Associate*

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.

- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

*Associate*

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

**The University of Michigan,** Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

**The Virginia Sea Grant at the Virginia Institute of Marine Science,** Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

**The Commission for Environmental Cooperation (NAFTA),** Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

**Congressman Tom Allen,** Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

## EDUCATION

**The University of Michigan**, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

**Middlebury College**, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

## PUBLICATIONS

Kwok, S., D. Glick, R. Anderson, T. Gyalmo. 2023. *Review of Southwestern Public Service Company 2023 Integrated Resource Plan*. Synapse Energy Economics for Sierra Club.

Kwok, S., J. Smith, D. Glick. 2023. *Review of Cleco Power's 2021 IRP Report.* Synapse Energy Economics for Sierra Club.

Addleton, I., D. Glick, R. Wilson. 2021. *Georgia Power's Uneconomic Coal Practices Cost Customers Millions*. Synapse Energy Economics for Sierra Club.

Glick, D., P. Eash-Gates, J. Hall, A. Takasugi. 2021. *A Clean Energy Future for MidAmerican and Iowa.* Synapse Energy Economics for Sierra Club, Iowa Environmental Council, and the Environmental Law and Policy Center.

Glick, D., S. Kwok. 2021 *Review of Southwestern Public Service Company's 2021 IRP and Tolk Analysis.* Synapse Energy Economics for Sierra Club.

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Glick, D. *2021. Synapse Comments and Surreply Comments to the Minnesota Public Utility Commission in response to Otter Tail Power's 2021 Compliance Filing* Docket E-999/CI-19-704. Synapse Energy Economics for Sierra Club.

Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

Eash-Gates, P., B. Fagan, D. Glick. 2020. *Alternatives to the Surry-Skiffes Creek 500 kV Transmission Line.* Synapse Energy Economics for the National Parks Conservation Association.

Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets.* Synapse Energy Economics for Climate Majority Project.

Glick, D., D. Bhandari, C. Roberto, T. Woolf. 2020. *Review of benefit-cost analysis for the EPA's proposed revisions to the 2015 Steam Electric Effluent Limitations Guidelines.* Synapse Energy Economics for Earthjustice and Environmental Integrity Project.

Glick, D., J. Frost, B. Biewald. 2020. *The Benefits of an All-Source RFP in Duke Energy Indiana's 2021 IRP Process.* Synapse Energy Economics for Energy Matters Community Coalition.

Camp, E., B. Fagan, J. Frost, N. Garner, D. Glick, A. Hopkins, A. Napoleon, K. Takahashi, D. White, M. Whited, R. Wilson. 2019. *Phase 2 Report on Muskrat Falls Project Rate Mitigation, Revision 1 – September 25, 2019.* Synapse Energy Economics for the Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Camp, E., A. Hopkins, D. Bhandari, N. Garner, A. Allison, N. Peluso, B. Havumaki, D. Glick. 2019. *The Future of Energy Storage in Colorado: Opportunities, Barriers, Analysis, and Policy Recommendations.* Synapse Energy Office for the Colorado Energy Office.

Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project*. Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Synapse Energy

Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet to and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

## TESTIMONY

**Iowa Utilities Board (RPU-2023-0002):** Surrebuttal Testimony of Devi Glick in re: Interstate Power and Light Company, Proposed Rate Increase. On behalf of Environmental Intervenors. June 3, 2024.

**Iowa Utilities Board (RPU-2023-0002):** Direct Testimony of Devi Glick in re: Interstate Power and Light Company, Proposed Rate Increase. On behalf of Environmental Intervenors. April 16, 2024.

**Michigan Public Service Commission (Case No. U-21051):** Direct Testimony of Devi Glick in the Matter of the application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-21050) for the 12 months ended December 31, 2022. On behalf of Michigan Environmental Council. March 8, 2024.

**Michigan Public Service Commission (Case No. U-21427):** Direct Testimony of Devi Glick in the matter of the Application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery plan and factors (2024). On behalf of Sierra Club and Citizens Utility Board of Michigan. March 4, 2024.

**Georgia Public Service Commission (Docket No. 55378):** Direct Testimony of Devi Glick and Lucy Metz in Re: Georgia Power Company's 2023 Integrated Resource Plan Update. On behalf of Sierra Club. February 15, 2024.

**Louisiana Public Service Commission (Docket No. U-36923):** Direct Testimony of Devi Glick in the Application of Cleco Power LLC for: (1) Implementation of changes in rates to be effective July 1, 2024; and (2) extension of existing formula rate plan. On behalf of Sierra Club. February 5, 2024.

**Public Service Commission of South Carolina (Docket No. 2023-154-E):** Supplemental Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. January 29, 2024.

**Public Service Commission of South Carolina (Docket No. 2023-154-E):** Surrebuttal Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. November 17, 2023.

**Public Utilities Commission of Ohio (Case No. 21-477-EL-RDR):** Direct Testimony of Devi Glick in the Matter of the OVEC Generation Purchase Rider Audits Required by 4928.148 for Duke Energy Ohio, Inc. the Dayton Power and Light Company, and AEP Ohio. On behalf of Union of Concerned Scientists and the Citizens Utility Board. October 10, 2023.

**Public Service Commission of South Carolina (Docket No. 2023-154-E):** Direct Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. September 22, 2023.

**Public Utilities Commission of Ohio (Case No. 20-165-EL-RDR):** Direct Testimony of Devi Glick in the matter of the review of the Reconciliation Rider of the Dayton Power and Light Company. On behalf of Office of the Ohio Consumers' Counsel. September 12, 2023.

**Virginia State Corporation Commission (Case No. PUR-2023-00066):** Direct Testimony of Devi Glick in re: Virginia Electric and Power Company's 2023 Integrated Resource Plan filing pursuant to Virginia Code to §56-597 *et seq.* On behalf of Sierra Club. August 8, 2023.

**Public Utility Commission of Texas (PUC Docket No. 54634):** Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. August 4, 2023

**Arizona Corporation Commission (Docket No. E-1345A-22-0144):** Surrebuttal Testimony of Devi Glick in the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of Sierra Club. July 26, 2023.

**Arizona Corporation Commission (Docket No. E-01345A-22-0144):** Direct Testimony of Devi Glick in the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of Sierra Club. June 5, 2023.

**Virginia State Corporation Commission (Case No. PUR-2023-00005):** Direct Testimony of Devi Glick in the Petition of Virginia Electric & Power Company for revision of rate adjustment clause, Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 23, 2023.

**New Mexico Public Regulation Commission (Case No, 22-00286-UT):** Direct Testimony of Devi Glick in the matter of Southwestern Public Service Company's application for: (1) Revisions of its retail rates under advance no. 312; (2) Authority to abandon the Plant X Unit 1, Plant X Unit 2, and Cunningham

Unit 1 Generating Stations and amend the abandonment date of the Tolk Generating Station; and (3) other associated relief. On behalf of Sierra Club. April 21, 2023.

**Michigan Public Service Commission (Case No. U-20805):** Direct Testimony of Devi Glick in the matter of the Application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ended December 31, 2021. On behalf of Michigan Attorney General. April 17, 2023.

**Michigan Public Service Commission (Case No. U-21261):** Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval to implement a Power Supply Cost Recovery Plan for the twelve months ending December 31, 2023. On Behalf of Sierra Club. March 23, 2023.

**New Mexico Public Regulation Commission (Case No. 19-00099-UT / 19-00348-UT)**: Direct Testimony of Devi Glick in the matter of El Paso Electric Company's Application for Approval of Long-Term Purchased Power Agreements with Hecate Energy Santa Teresa, LLC, Buena Vista Energy, LLC, and Canutillo Energy Center LLC. On Behalf of New Mexico Office of the Attorney General, January 23, 2023.

**Arizona Corporation Commission (Docket No. E-01933A-22-0107):** Direct Testimony of Devi Glick in the matter of the application of Tucson Electric Power Company for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of Tucson Electric Power Company devoted to its operations throughout the state of Arizona for related approvals. On Behalf of Sierra Club. January 11, 2023.

**New Mexico Public Regulation Commission (Case No. 22-00093-UT):** Direct Testimony of Devi Glick in the amended application for approval of El Paso Electric Company's 2022 renewable energy act plan pursuant to the renewable energy act and 17.9.572 NMAC, and sixth revised rate no. 38-RPS cost rider. On Behalf of New Mexico Office of the Attorney General, January 9, 2023.

**Iowa Utilities Board (Docket No. RPU-2022-0001):** Supplemental Direct and Rebuttal Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. November 21, 2022.

**Public Utility Commission of Texas (PUC Docket No. 53719):** Direct Testimony of Devi Glick in the application of Entergy Texas, Inc. for authority to change rates. On behalf of Sierra Club. October 26, 2022.

**Virginia State Corporation Commission (Case No. PUR-2022-00051):** Direct Testimony of Devi Glick in re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Virginia Code §56-597 *et seq*. On behalf of Sierra Club. September 2, 2022.

**Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130):** Surrebuttal Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. August 16, 2022.

**Iowa Utilities Board (Docket No. RPU-2022-0001):** Direct Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. July 29, 2022.

**Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130):** Direct Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. June 8, 2022.

**Virginia State Corporation Commission (Case No. PUR-2022-00006):** Direct Testimony of Devi Glick in the petition of Virginia Electric & Power Company for revision of rate adjustment clause: Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 24, 2022.

**Oklahoma Corporation Commission (Case No. PUD 202100164):** Direct Testimony of Devi Glick in the matter of the application of Oklahoma gas and electric company for an order of the Commission authorizing application to modify its rates, charges, and tariffs for retail electric service in Oklahoma. On behalf of Sierra Club. April 27, 2022.

**Public Utility Commission of Texas (PUC Docket No. 52485):** Direct Testimony of Devi Glick in the application of Southwestern Public Service Company to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. March 25, 2022.

**Public Utility Commission of Texas (PUC Docket No. 52487):** Direct Testimony of Devi Glick in the application of Entergy Texas Inc. to amend its certificate of convenience and necessity to construct Orange County Advanced Power Station. On behalf of Sierra Club. March 18, 2022.

**Michigan Public Service Commission (Case No. U-21052):** Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and Factors (2022). On Behalf of Sierra Club. March 9, 2022.

**Arkansas Public Service Commission (Docket No. 21-070-U):** Surrebuttal Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for approval of a general change in rate and tariffs. On behalf of Sierra Club. February 17, 2022.

**New Mexico Public Regulation Commission (Case No. 21-00200-UT):** Direct Testimony of Devi Glick in the Matter of the Southwestern Public Service Company's application to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. January 14, 2022.

**Public Utilities Commission of Ohio (Case No. 18-1004-EL-RDR):** Direct Testimony of Devi Glick in the Matter of the Review of the Power Purchase Agreement Rider of Ohio Power Company for 2018 and 2019. On behalf of the Office of the Ohio Consumer's Counsel. December 29, 2021.

**Arkansas Public Service Commission (Docket No. 21-070-U):** Direct Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs. On behalf of Sierra Club. December 7, 2021.

**Michigan Public Service Commission (Case No. U-20528):** Direct Testimony of Devi Glick in the matter of the Application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-20527) for the 12-month period ending December 31, 2020. On behalf of Michigan Environmental Council. November 23, 2021.

**Public Utilities Commission of Ohio (Case No. 20-167-EL-RDR):** Direct Testimony of Devi Glick in the Matter of the Review of the Reconciliation Rider of Duke Energy Ohio, Inc. On behalf of The Office of the Ohio Consumer's Counsel. October 26, 2021.

**Public Utilities Commission of Nevada (Docket No. 21-06001):** Phase III Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. October 6, 2021.

**Public Service Commission of South Carolina (Docket No, 2021-3-E):** Direct Testimony of Devi Glick in the matter of the annual review of base rates for fuel costs for Duke Energy Carolinas, LLC (for potential increase or decrease in fuel adjustment and gas adjustment). On behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy. September 10, 2021.

**North Carolina Utilities Commission (Docket No. E-2, Sub 1272):** Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

**Michigan Public Service Commission (Docket No. U-20530):** Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ending December 31, 2020. On behalf of the Michigan Attorney General. August 24, 2021.

**Public Utilities Commission of Nevada (Docket No. 21-06001):** Phase I Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

**North Carolina Utilities Commission (Docket No. E-7, Sub 1250):** Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

**Public Utility Commission of Texas (PUC Docket No. 51415):** Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

**Michigan Public Service Commission (Docket No. U-20804):** Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

**Public Utility Commission of Texas (PUC Docket No. 50997):** Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

**Michigan Public Service Commission (Docket No. U-20224):** Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan. On behalf of the Sierra Club. October 23, 2020.

**Public Service Commission of Wisconsin (Docket No. 3270-UR-123):** Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

**Public Service Commission of Wisconsin (Docket No. 6680-UR-122):** Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

**Public Service Commission of Wisconsin (Docket No. 3270-UR-123):** Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

**Public Service Commission of Wisconsin (Docket No. 6680-UR-122):** Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

**Indiana Utility Regulatory Commission (Cause No. 38707-FAC125):** Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

**Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1):** Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

**Indiana Utility Regulatory Commission (Cause No. 38707-FAC124):** Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

**Arizona Corporation Commission (Docket No. E-01933A-19-0028):** Reply to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

**Indiana Utility Regulatory Commission (Cause No. 38707-FAC123):** Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

**Public Utility Commission of Texas (PUC Docket No. 49831):** Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

**New Mexico Public Regulation Commission (Case No. 19-00170-UT):** Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

**Nova Scotia Utility and Review Board (Matter M09420):** Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

**New Mexico Public Regulation Commission (Case No. 19-00170-UT):** Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

**North Carolina Utilities Commission (Docket No. E-100, Sub 158):** Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

**State Corporation Commission of Virginia (Case No. PUR-2018-00195):** Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

**Connecticut Siting Council (Docket No. 470B):** Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

**Public Service Commission of South Carolina (Docket No. 2018-3-E):** Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

**Public Service Commission of South Carolina (Docket No. 2018-3-E):** Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

**Public Service Commission of South Carolina (Docket No. 2018-1-E):** Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

**Public Service Commission of South Carolina (Docket No. 2018-1-E):** Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

**Public Service Commission of South Carolina (Docket No. 2018-2-E):** Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

**Public Service Commission of South Carolina (Docket No. 2018-2-E):** Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. March 23, 2018.

*Resume updated June 2024*

# Exhibit DG-2:

# TECO response to Sierra Club 1st IRRs

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In re: Petition for Rate Increase by Tampa Electric Company | DOCKET NO. 20240026-EI |
| In re: Petition for approval of 2023 Depreciation and Dismantlement Study, by Tampa Electric Company | DOCKET NO. 20230139-EI |
| In re: Petition to implement 2024 Generation Base Rate Adjustment provisions in Paragraph 4 of the 2021 Stipulation and Settlement Agreement, by Tampa Electric Company | DOCKET NO. 20230090-EI<br><br>SERVED: May 16, 2024 |

**TAMPA ELECTRIC COMPANY'S ANSWERS TO**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES (NOS. 1-72)**

Pursuant to Rule 106.206, Florida Administrative Code, and Florida Rule of Civil Procedure 1.350, Tampa Electric Company ("Tampa Electric" or the "company"), hereby answers Sierra Club's First Set for Interrogatories (Nos. 1-72), served April 26, 2024 ("Sierra Club First ROG").

**General Objections**

1. Tampa Electric objects to each interrogatory in Sierra Club's First ROG ("Interrogatory") to the extent that it seeks information that is duplicative, not relevant to the subject matter of this docket, and is not reasonably calculated to lead to the discovery of admissible evidence.

2. Tampa Electric objects to each Interrogatory to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such Interrogatory. Tampa Electric will seek clarification from Sierra Club if an Interrogatory is not clear, but Tampa Electric will produce documents subject to, and without waiving, this objection.

3. Tampa Electric objects to each Interrogatory to the extent it requires Tampa Electric to produce information that is already in the public record before the Florida Public Service Commission ("FPSC" or the "Commission") or other public agency and available to Sierra Club through normal procedures or is readily accessible through legal search engines.

4. Tampa Electric objects to each Interrogatory to the extent that it calls for data or information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law. Tampa Electric will describe the nature of the privileged material, if any, in a privilege log that will accompany its responses.

5. Tampa Electric objects to producing paper copies on the grounds that doing so would be unduly burdensome. Tampa Electric has entered into an agreement with Sierra Club, governing discovery production and responses, and will serve its answers to the Interrogatories and related responsive documents to Sierra Club in electronic form via a SharePoint site to which Sierra Club have remote access.

6. Tampa Electric objects to each Request to the extent it requires the company to provide information that it believes is "proprietary confidential business information" as described in Section 366.093, Florida Statutes. Tampa Electric will provide such confidential information to Sierra Club in a designated confidential portion of the SharePoint site described above and subject to a Motion for Temporary Protective Order, Notice of Intent to Request Confidential Classification, and/or Request for Confidential Classification, as appropriate.

7. Tampa Electric objects to each Interrogatory, instruction, or definition in that purports to expand Tampa Electric's obligations under applicable law.

8. Tampa Electric objects to each Interrogatory to the extent it requests Tampa Electric to prepare information in a particular format or create data or information that it otherwise does not possess as unduly burdensome and as purporting to expand Tampa Electric's obligations under applicable law.

9. Subject to Section 366.093(1), Florida Statutes, Tampa Electric objects to any definition or Interrogatory that requests documents from persons or entities who are not parties to this proceeding, that seek information from affiliates unrelated to transactions or cost allocations involving Tampa Electric, or that are not otherwise subject to discovery under applicable rules.

10. Tampa Electric objects to any Interrogatory requiring the company to provide additional information beyond that obtained through a reasonable and diligent search.

**General Response**

Subject to and without waiving its general objections, which are incorporated by reference in each of its specific answers, Tampa Electric provides its answers to Sierra Club's First ROG by posting its answers on the Tampa Electric Discovery SharePoint site established for this docket (the "SharePoint") and as specified in its specific answers. Tampa Electric will serve its answers to the Commission staff by hand delivering a USB containing its answers to the Commission Clerk's office, and for Staff's purposes, the term "USB" should be substituted for "SharePoint" in the specific answers shown below.

The company's specific answers will identify interrogatories that call for answers that contain (a) information for which the company asserts a legal privilege and/or (b) "proprietary confidential business information" as defined in Section 366.093, Florida Statutes.

An answer that contains information for which the company asserts a legal privilege will be identified in the privilege log attached as Exhibit A.

An answer that contains information the company asserts to be "proprietary confidential business information" will be provided in the Confidential portion of the SharePoint subject to a request for confidential classification, motion for temporary protective order and/or a non-disclosure agreement.

## Specific Answers

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO.1**
**BATES PAGE(S): 28906**
**MAY 16, 2024**

**Topic: TECO's Coal Units**

**1.** Please provide a narrative description of the analysis, data, or information that TECO relies on to conclude that continued reliance on Big Bend Unit 4 and Polk Unit 1 is in the best interests of its ratepayers.

**ANSWER:**

Fuel diversity is an important element of any generation portfolio. Fuel diversity mitigates the company's risks from extreme weather events, fuel commodity price spikes and fuel delivery interruptions. Maintaining dual fuel capability on Big Bend Unit 4 and Polk Unit 1 provides flexibility and reliability to Tampa Electric's system and customers. Tampa Electric uses forward fuel curve projections to indicate which fuel would be most beneficial to customers to provide continued reliable and economic generation. Tampa Electric has not performed an analysis related to the continued reliance on Big Bend 4 as that asset has numerous years of remaining useful life.

An evaluation was performed on Polk Unit 1 and it was determined that converting Polk Unit 1 to a Simple Cycle unit is more cost effective to customers than an early retirement. The company provided its analysis of Polk Unit 1, which included an earlier retirement date scenario, in response to Sierra Club's First Request for Production of Documents, No. 5.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 2**
**BATES PAGE(S): 28907**
**MAY 16, 2024**

**2.** Please refer to Witness Aldazabal's testimony, pages 44-46, regarding the Polk 1 Flexibility project. Will TECO's conversion of the IGCC unit at Polk 1 into a simple cycle gas unit permanently retire the IGCC gasification technology at that unit?

a. Will TECO's conversion of the IGCC unit at Polk 1 into a simple cycle gas unit permanently retire any and all coal generation at Polk 1?

b. If the answer to either of these questions is no, please explain why not.

**ANSWER:**

No, the conversion of the IGCC unit into a simple cycle gas does not permanently retire the IGCC gasification technology.

a. No.

b. The conversion of Polk Unit 1 to simple cycle will provide more flexibility as the unit will be able to dispatch quicker to meet system demands. However, in the event that petcoke were to become more economic in the future, the company would be able to transition to Petcoke as a fuel source.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 3**
**BATES PAGE(S): 28908 - 28909**
**MAY 16, 2024**

**3.** Referring again to the Polk 1 Flexibility project described in Witness Aldazabal's testimony, please explain how Polk Unit 1 could be modified to operate on petcoke,as discussed on page 45.

a. Indicate whether operation on petcoke requires use of the IGCC technology.

b. Would modifying the unit to operate on petcoke require the installation of new technology?

c. Provide the estimated cost of the modification.

d. Provide the estimated outage time for the modification.

e. Would TECO need Commission approval in order to modify the unit to operate onpetcoke?

**ANSWER:**

a. Petcoke is a solid fuel, similar to coal. For petcoke to be used as a fuel for Polk Unit 1, petcoke must be converted from the solid state into a gaseous state (called synthetic natural gas, or syngas). That conversion process requires the use of the IGCC technology.

b. Depending on the timing of a future modification, new technology might be required. As mentioned in the direct testimony of Witness Aldazabal, GE (the OEM of the gas turbine) is no longer supporting the existing combustion system that enables syngas operations. The existing combustion system has reached the end of its useful life. To re-enable syngas operations, Tampa Electric would work with GE to select a new combustion system that allows syngas as a fuel type.

c. Because the timing of the modification and the technology selection is unknown, it is difficult to estimate the cost of a future modification. In addition to combustion system maintenance, other maintenance may be required to restore operation of the IGCC equipment, the HRSG equipment, and the steam turbine equipment.

d. The timeline to re-enable petcoke as a feed fuel is currently estimated at around one year. This timeline could be affected by market conditions at the time of the desired modification.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 3**
**BATES PAGE(S): 28908 - 28909**
**MAY 16, 2024**

e. No. Switching to petcoke as a fuel source at Polk Unit 1 would not require Commission approval.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 4**
**BATES PAGE(S): 28910**
**MAY 16, 2024**

**4.** For each retirement study or unit condition assessment provided in response to Sierra Club Document Production Request No. 6, provide the following:

a. State which modeling software was used to conduct the analysis.

b. State the date that the analysis was performed.

c. State whether the units were modeled with an economic (market) or self-commitment (must run) status for each year of the analysis

d. State the date of each forecast or projection used in the analysis.

e. State the regulation or rationale behind each retirement date(s) studied.

f. Identify all transmission grid updates or changes that would be needed to allow for the retirement of each of Big Bend Unit 4 and Polk Unit 1.

**ANSWER:**

Tampa Electric did not conduct a retirement study or unit condition assessment to study the value of continued operation of Big Bend Unit 4. The company provides its analysis of Polk Unit 1, which includes an earlier retirement date scenario, in response to Sierra Club's First Request for Production of Documents, No. 5.

a. Planning and Risk (PaR), a production costing model, was used to conduct the Polk 1 early retirement analysis.

b. The analysis was done in Fall 2022

c. All units were modeled with an economic commitment and dispatch.

d. The forecast or projection was done in Summer 2022

e. The company considered a 2028 retirement date in the analysis, which was selected because it was considered to be the earliest feasible retirement date for reserve margin purposes.

f. No transmission upgrades were identified for the analysis of the early retirement of Polk Unit 1.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 5**
**BATES PAGE(S): 28911**
**MAY 16, 2024**

**5.** For Polk IGGC and Big Bend Unit 4, please provide the following:

a. The amount for sustaining capital expenditures that TECO has included in test year rate base for each of Polk Unit 1 and Big Bend Unit 4.

a. For Polk, please separate capital spent on the IGCC from capital spent onall other parts of the plant.

b. For both Polk Unit 1 and Big Bend Unit 4, indicate which capital expenses are for environmental projects.

b. The amount of capital cost for sustaining capital expenditures that TECO included in the test year in its previous rate case.

a. For Polk, please separate capital spent on the IGCC from capital spent on all other parts of the plant.

b. For both Polk Unit 1 and Big Bend Unit 4, indicate which capital expenses are for environmental projects.

c. An explanation of the change in capital cost from the last rate case for each plant

**ANSWER:**
For the purpose answering this interrogatory, the company is providing information for Polk Unit 1, recognizing the fact that Polk Unit 1 is an Integrated Gas Combined Cycle (IGCC) unit. Capital expenditures devoted to Polk Unit 1 and Big Bend Unit 4 for 2022 and 2025 represent both actual and forecasted costs for reasonable and prudent capital expenditures to efficiently and effectively operate and maintain Polk Unit 1 and Big Bend Unit 4. Please see the table below for the answer to 5(a), 5(b), and 5(c).

| | Sustaining Capital | | | |
|---|---|---|---|---|
| | 2022 | 2025 | Variance | Explanation |
| Polk IGGC | $ 706,351 | $ 500,000 | $ 206,351 | Timing of maintenance costs |
| Polk 1 | $ 4,104,583 | $ 13,313,629 | $ (9,209,046) | Timing of Milestone payments on new CSA (Contractor Service Agreement) |
| Big Bend 4 | $ 17,055,843 | $ 7,528,452 | $ 9,527,391 | Reduced coal-fired generation and service hours. |
| | | | | |
| | Environmental | | | |
| | 2022 | 2025 | Variance | Explanation |
| Polk IGGC | $ - | $ - | $ - | |
| Polk 1 | $ - | $ - | $ - | |
| Big Bend 4 | $888,707.45 | $ - | $ 888,707.45 | Reducsed coal-fired generation and service hours |

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 6**
**BATES PAGE(S): 28912 - 28913**
**MAY 16, 2024**

**6.** For Big Bend Unit 4 and Polk Unit 1, please provide the following:

a. The amount of non-fuel operating & maintenance (O&M) costs included in the test year in this rate case.

b. The amount of non-fuel O&M costs included in the test year in the prior rate case.

c. An explanation of the change in non-fuel O&M cost from the last rate case.

**ANSWER:**

a. The amounts of non-fuel operating & maintenance (O&M) costs included in the test year in this rate case are:

| | |
|---|---|
| Big Bend Unit 4 | $12,472,909 |
| Polk Unit 1 | $ 9,685,047 |

The amounts above represent all O&M expense that is not recovered through a clause.

b. The amounts of non-fuel operating & maintenance (O&M) costs included in the test year in the prior rate case are:

| | |
|---|---|
| Big Bend Unit 4 | $18,399,660 |
| Polk Unit 1 | $10,125,856 |

The amounts above represent all O&M expense that is not recovered through a clause. The amounts shown above are the actual expenses for the year 2022.

c. The changes in the amounts of non-fuel operating & maintenance (O&M) costs from the last rate case are:

| | |
|---|---|
| Big Bend Unit 4 | $5,926,750 decrease in expense |
| Polk Unit 1 | $ 440,809 decrease in expense |

The amounts above represent all O&M expense that is not recovered through a clause.

The explanations of the changes above are:

| | |
|---|---|
| Big Bend Unit 4 | Reduced coal-fired generation and service hours |
| Polk Unit 1 | Reduced maintenance with steam turbine and HRSG in reserve standby and conversion to simple cycle operations |

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 7**
**BATES PAGE(S): 28914 - 28916**
**MAY 16, 2024**

**7.** For Big Bend Unit 4 and Polk ICGCC, please provide the remaining book value (plant balance) at the start of 2024 and the expected undepreciated book value for each year of the remaining operation life of each unit.

a. For Polk, please separate out the balance for the IGCC technology from the rest of the plant.

**ANSWER:**

a. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_7" for #7 Big Bend 4 Coal NBV recovery.xlsb by depreciation account for the Boiler, SCR and FGD equipment and #7 Polk 1 NBV recovery.xlsb with breakouts for CT, CCST=HRSG+ST, and IG=Gasifier equipment.

These files do not include any planned additions or retirements beyond 2023.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 8**
**BATES PAGE(S): 28917 - 28923**
**MAY 16, 2024**

**8.** For Big Bend Unit 4 and Polk Unit 1, please provide the following historical data for the years 2018-2023.

a. Installed capacity;

b. Unforced capacity;

c. Hourly generation (in MW);

d. Annual Generation (in MWh);

e. Capacity factor;

f. Equivalent Availability Factor (EAF);

g. Heat rate (average);

h. Forced or random outage rate;

i. Effective forced outage rate (EFORd);

j. Fixed O&M costs;

k. Non-fuel variable costs;

l. Fuel costs (by fuel type);

m. Any energy or capacity market revenue from bilateral or market sales; and

n. All historical capital expenditures (including environmental projects) since 2018 by year.

o. If these categories do not comprise all costs associated with these units, please explain and quantify the other costs of the units since 2018 by year.

**ANSWER:**

a. The Net Capacity for Big Bend Unit 4 is 442 MW Winter and 437 MW Summer. The Net Capacity for Polk Unit 1 is 220 MW for both Winter and Summer.

b. Tampa Electric does not calculate unforced capacity ratings.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 8**
**BATES PAGE(S): 28917 - 28923**
**MAY 16, 2024**

c. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_8" "2018 - 2023 Hourly Data.xlsx" for the hourly generation.

d. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_8" "2018 - 2023 GFP.xlsx" for the annual generation.

e. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_8" "2018 - 2023 GFP.xlsx" for the capacity factor.

f. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). S See attached in "ROG_1_8" "2018 - 2023 GFP.xlsx" for the equivalent availability factor.

g. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). S See attached in "ROG_1_8" "2018 - 2023 GFP.xlsx" for the heat rate.

h. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_8" "2019 - 2023 Factor and Rates" for the forced outage rate.

i. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_8" "2019 - 2023 Factor and Rates" for the forced outage rate.

j. Tampa Electric does not calculate or track historical fixed O&M,

k. Please see the table below for the non-fuel variable costs. Tampa Electric does not calculate or track historical non-fuel variable costs,

l. Please see the table below for fuel costs.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 8**
**BATES PAGE(S): 28917 - 28923**
**MAY 16, 2024**

| $/MMBtu | BB4 (coal) | BB4 (gas) | Polk1 (syngas) | Polk1 (gas) |
|---|---|---|---|---|
| 2018 | $ 3.24 | $ 4.07 | $ 2.40 | $ 4.07 |
| 2019 | $ 3.43 | $ 3.41 | N/A | $ 3.41 |
| 2020 | $ 3.46 | $ 2.90 | N/A | $ 2.90 |
| 2021 | $ 3.33 | $ 4.83 | N/A | $ 4.83 |
| 2022 | $ 3.35 | $ 8.32 | N/A | $ 8.32 |
| 2023 | $ 4.37 | $ 3.94 | N/A | $ 3.94 |

All values except 2018 Polk1 (syngas) taken from December A3 Schedules (Actual Period to Date)
Polk 1 (syngas) used August 2018 A4 Schedule; Polk1 did not run on solid fuel 2019-2023

m. Tampa Electric does not have any unit specific sales of capacity or energy from 2018 to 2023. Please see the company's answer to Interrogatory No. 25, below, for any system sales of capacity or energy.

n. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_8" "2018 - 2023 Capital SC IRR8n.xlsx" for all historical capital expenditures (including environmental projects) since 2018 by year.

o. Not applicable.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 9**
**BATES PAGE(S): 28924 - 28927**
**MAY 16, 2024**

**9.** For Big Bend Unit 4 and Polk Unit 1, please provide the following projected data for the years 2024-2034:

a. Installed capacity;

b. Unforced capacity;

c. Generation (in MWh);

d. Capacity factor;

e. Equivalent Availability Factor (EAF);

f. Heat rate (average);

g. Forced or random outage rate;

h. Effective forced outage rate (EFORd);

i. Fixed O&M costs;

j. Non-fuel variable costs;

k. Fuel costs (by fuel type);

l. Any energy or capacity market revenue from bilateral deal or market sales; and

m. All forecast capital expenditures (including environmental projects) by year.

n. If these categories do not comprise all costs associated with these units, please explain and quantify the other costs of the units by year.

**ANSWER:**

a. The Net Capacity for Big Bend Unit 4 is 442 MW Winter and 437 MW Summer. The forecasted Net Capacity after the Polk Unit 1 flexibility project is completed is expected to be 203 MW Winter and 190 MW Summer.

b. Tampa Electric does not calculate unforced capacity ratings.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 9**
**BATES PAGE(S): 28924 - 28927**
**MAY 16, 2024**

c. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_9" Sierra Club 1st Set IRR Q9.xlsx

d. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_9" Sierra Club 1st Set IRR Q9.xlsx

e. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_9" Sierra Club 1st Set IRR Q9.xlsx

f. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_9" Sierra Club 1st Set IRR Q9.xlsx

g. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_9" Sierra Club 1st Set IRR Q9.xlsx

h. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_9" Sierra Club 1st Set IRR Q9.xlsx

i. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_9" Sierra Club 1st Set IRR Q9.xlsx Tampa Electric does not have forecasted Fixed O&M costs for Big Bend Unit 4.

j. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_9" Sierra Club 1st Set IRR Q9.xlsx

k. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_9" Sierra Club 1st Set IRR Q9.xlsx

l. Tampa Electric does not have any unit specific sales of capacity or energy from 2024 to 2034. Please see the company's answer to Interrogatory No. 25, below, for any system sales of capacity or energy.

m. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_9" "2024

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 9**
**BATES PAGE(S): 28924 - 28927**
**MAY 16, 2024**

- 2028 Capital SC IRR9m.xlsx" All forecast capital expenditures (including environmental projects) by year. Tampa Electric capital planning goes out 5 years.

n. Not applicable.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 10**
**BATES PAGE(S): 28928**
**MAY 16, 2024**

**10.** Please provide a description of any major capital projects expected at Big Bend Unit 4 and Polk Unit 1 over the next ten years. Include information about expected timeline and cost.

**ANSWER:**

Please see below. Tampa Electric's capital planning goes out five years.

| Unit | Project | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|
| Big Bend 4 | BB4 D Booster Fan Reactor/VFD Insta | - | - | 3,000,000 | 3,000,000 | |
| Big Bend 4 | BB4 Intk Scrn 4A Course & Fine Mesh | | | 1,500,000 | - | 1,500,000 |
| Big Bend 4 | BB4 Stack pennguard liner addition | | - | - | 3,000,000 | |
| Big Bend 4 | Fly Ash Baghouse Replacement | - | - | 1,000,000 | 1,500,000 | |
| Big Bend 4 | FGD Limestone Unloading Building | | | 150,000 | 250,000 | 2,000,000 |
| Big Bend 4 | BB4 Structural Steel | - | - | - | 852,065 | 1,250,000 |
| Big Bend 4 | BB4 Swell Control Valve Addition | - | 1,933,489 | | | |
| Big Bend 4 | FGD Tower External Piping | | - | - | 750,000 | 1,000,000 |
| Big Bend 4 | BB4 Mark Vle Control Card Upgrd | | | 50,000 | 1,500,000 | |
| Big Bend 4 | BB4 Intake Scrn 4C FM&4B CoarseMesh | | | | 1,500,000 | |
| Big Bend 4 | BB4 Compressed Air Upgrades | 300,000 | 800,000 | | | |
| Big Bend 4 | BB4 C&D Booster Fan Cooler Rplmnts | | | 25,000 | 200,000 | 800,000 |
| Big Bend 4 | BB4 CWP Motor Replacement A | | | | 1,000,000 | |
| Polk 1 | Polk 1 Flexibility Project | 24,612,932 | 39,330,058 | | | |
| Polk 1 | Pk1 CSA Expense | | 10,713,631 | 900,930 | 926,863 | 952,797 |
| Polk 1 | PK CT1 Gen Breaker Replacement | | 1,000,000 | | | |

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 11**
**BATES PAGE(S): 28929 - 28931**
**MAY 16, 2024**

**11.** Please provide a list of all outages that occurred over the past 5 years at Big Bend Unit 4 and Polk Unit 1. Include the following:

a. Date and time outage began and ended;

b. Duration of outage;

c. Unit derating (in MW);

d. Whether it was forced or unforced;

e. Explanation for the outage; and

f. Replacement power costs.

**ANSWER:**

a. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See the attached in "ROG_1_11" "2018 - 2023 Outage Listing.xlsx" for the date and time of the outage begin and end. Refer to column 'G' and 'H'.

b. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_11" "2018 - 2023 Outage Listing.xlsx" for the outage duration. Refer to column 'I'.

c. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_11" "2018 - 2023 Outage Listing.xlsx" for unit derating. Refer to column 'M'.

d. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_11" "2018 - 2023 Outage Listing.xlsx" for outage type. Refer to column "F".

e. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached in "ROG_1_11" "2018 - 2023 Outage Listing.xlsx" for the explanation of the outage. Refer to column "K".

f. In addition to its general objections, which are incorporated herein by reference, Tampa Electric objects to this request on grounds that it is overbroad and unduly burdensome. At this time, the company does not have the capability to simulate every outage over the past five years since the forecasting tools are not configured to model historical events.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 12**
**BATES PAGE(S): 28932**
**MAY 16, 2024**

**12.** Regarding the Company's operation of the Big Bend Unit 4 and Polk Unit 1:

a) Provide a narrative of how TECO makes its unit commitment (that is, decisions to turn the plant on and off) and unit dispatch (that is, the decision to ramp the plant up or down) decisions. If there are any differences in decision-making processes by unit, please explain.

b) Indicate whether the Company conducts daily unit commitment analysis to determine how to commit and dispatch the plant.

**ANSWER:**

a. Tampa Electric economically commits and dispatches all of its units to minimize total costs to customers. This economic commitment and dispatch will occasionally be overridden by maintenance, transmission, environmental, or similar needs and constraints. With respect to dual fuel units like Big Bed Unit 4 and Polk Unit 1, those units are assumed to operate on natural gas since that has been predominantly the lower cost fuel for the last several years. However, Big Bend Unit 4 has been operated on coal when economic, for environmental needs, for logistical needs, and for natural gas supply and delivery limitations. Those decisions to operate on coal typically occur a few days to a few months in advance and apply for a week or more to allow for the coal operations to be stable and effective. Polk Unit 1 has not recently operated on a blend of petroleum coke and low sulfur coal because natural gas has been much more cost-effective and the time that would be required to operate on solid fuel.

b. Yes, Tampa Electric conducts daily analysis to decide how to commit and dispatch all of its units, including Big Bend Unit 4 and Polk Unit 1. However, whether to operate Big Bend Unit 4 or Polk Unit 1 on solid fuel is not part of the daily decision process since the lead time is more than same day or next day delivery.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 13**
**BATES PAGE(S): 28933**
**MAY 16, 2024**

**13.** Has TECO evaluated the revenue requirement of alternative depreciation schedules or regulatory treatment for either Big Bend Unit 4 or Polk Unit 1 including accelerated depreciation, creation of a regulatory asset, securitization, or similar financial structures?

a. If not, please explain why not.

**ANSWER:**

No. The company has not evaluated the revenue requirement of alternative depreciation schedules or regulatory treatment for either Big Bend Unit 4 or Polk Unit 1 including accelerated depreciation, creation of a regulatory asset, securitization, or similar financial structures.

a. In preparation of the instant depreciation study filing, the company evaluated whether the Big Bend 4 Coal and Polk Unit 1 assets would continue operating until their retirement date. That evaluation did not result in the identification of a need for alternative depreciation schedules or regulatory treatment. For perspective, in the 2020 depreciation study, the company revised the retirement date of the Big Bend Unit 4 Coal assets from 2050 to 2045; in the instant depreciation study, the company revised the retirement date from 2045 to 2040. In both the 2020 depreciation study and the instant study, the company maintained the 2036 retirement date assumption for Polk Unit 1.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 14**
**BATES PAGE(S): 28934 - 28935**
**MAY 16, 2024**

**Topic: Environmental Regulation and Policy**

**14.** Please provide a description of how any proposed or recently finalized federal environmental regulations may affect Big Bend Unit 4 and Polk Unit 1, including, but not limited to: the U.S. Environmental Protection Agency (EPA)'s Effluent Limitation Guidelines (ELG Rule);EPA's Mercury and Air Toxic Standards (MATS); EPA's regional haze standards; EPA's Good Neighbor rule; EPA's new Clean Air Act section 111 rule, which would limit greenhouse gas emissions from certain fossil fuel plants; and EPA's updated coal ash rule, which is anticipated to be released in early May 2024 and would likely require retrofitting or closure of legacy coal ash ponds.

a. How is the Company planning to comply with each new regulation, to the extent they are applicable to Big Bend Unit 4 and Polk Unit 1?

**ANSWER:**

Tampa Electric is well positioned to comply with the currently proposed and finalized federal environmental regulations relevant to Big Bend Unit 4 and Polk Unit 1.

The ELG Rule regulates discharges to surface water from operations associated with these units including flue gas desulfurization processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals, gasification processes, and flue gas mercury controls. Since both plants dispose any affected wastewaters into their respective deep injection wells rather than discharging to surface water, neither facility will be subject to the ELG Rule.

Since January 1, 2022, Polk Unit 1 is no longer subject to the MATS rule. The MATS rule is applicable to Big Bend Unit 4, and EPA recently finalized a lower emission limit for filterable particulate matter, required continuous monitoring, and limited startup criteria all to be implemented on a specific timeframe. Big Bend 4 has been performing within the current standards and is expected to meet the finalized lower limit with the required continuous monitoring system including the proposed startup criteria and is expected to continue performing in compliance with the final rules within the regulatory timeframes.

Big Bend Unit 4 is the only the Tampa Electric unit subject to the Regional Haze rules and is expected to remain in compliance with the rules as an "effectively controlled unit" pursuant to the Florida State Implementation Plan.

Florida emission units are not currently subject to EPA's Good Neighbor rule.

EPA issued a pre-publication version of the final Clean Air Act (CAA) 111 rule on April 24, 2024 and for Tampa Electric, only Big Bend Unit 4 is subject to the rules. The unit can comply using its current configuration based on the options described as the Best System of Emission reductions for existing coal units. A complete compliance strategy will be determined during the State Plan development process.

EPA's newest Coal Combustion Residuals ("CCR") rule would require Tampa Electric to evaluate the Big Bend site to identify any Legacy CCR Surface Impoundments ("LSI") or CCR Management Units ("CCRMU") and any potential regulatory requirements. (Note: LSI are excluded because Big Bend was operational as of the effective date of the original CCR Rule on October 19, 2015.) However, there is some potential for the presence of CCRMU, so an evaluation is required for these. All marketable, on-specification CCR produced by Big Bend Unit 4, are managed for beneficial use in either lined basins or enclosed buildings. Recycling rates for the previous seven years have averaged greater than 91 percent. Furthermore, there is no onsite disposal of CCR or storage of CCR in unlined basins.

a. Tampa Electric will comply with the ELG Rule by avoiding surface water discharges from the applicable operations by use of currently operating Underground Injection Control wells at each of the subject facilities.

Compliance with the new MATS standards will be achieved by using the existing Unit 4 Particulate Matter Continuous Emissions Monitoring System and optimization of current controls.

Compliance with the Regional Haze rule will be achieved by continued operation of Big Bend Unit 4 as an "effectively controlled unit." Compliance will be demonstrated using the existing $SO_2$ CEMS unit and optimization of current controls.

Compliance with the CAA 111 rule will be achieved with currently implemented controls deemed to be the Best System of Emission reductions and other compliance mechanisms to be developed as part of the State Plan.

A facility evaluation and compliance plan (if necessary based on the evaluation) for the new CCR rule will be developed according to the timeline described in the rule.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 15**
**BATES PAGE(S): 28936**
**MAY 16, 2024**

**15.** Please describe the impact that any of the federal rules identified in response to Interrogatory No. 14 above, as well as any Florida legislation or regulations governing environmental protection or pollution, will have Polk Unit 1 and/or Big Bend Unit 4 if such rule is fully implemented.

**ANSWER:**

Tampa Electric is well positioned to comply with currently proposed and finalized federal and state environmental regulations or legislation governing environmental protection or pollution relevant to Big Bend Unit 4 and Polk Unit 1. Based on the current design, operation and expected retirement date of these units, the planned retirement date of Big Bend Unit 4 would have to be accelerated by one year.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 16**
**BATES PAGE(S): 28937**
**MAY 16, 2024**

**16.** Please provide estimated compliance costs with each of the following for each unit and plant:

a. Carbon regulations (including Clean Air Act section 111 rule);

b. 2023 proposed rule for Steam Electric Power Generation Effluent Guidelines;

c. EPA updated Mercury Air Toxics (MATS) standards; and

d. Coal ash management regulations to store all waste in lined pits

**ANSWER:**

a. The costs are unknown. These costs will be determined as part of State Plan development.

b. No additional compliance costs are anticipated due to issuance of the final Steam Electric Power Generation Effluent Guidelines.

c. No material additional compliance costs are anticipated due to the issuance of the final MATS standards.

d. No additional compliance costs resulting from the stated activities.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 17**
**BATES PAGE(S): 28938**
**MAY 16, 2024**

**17.** If the Company does not have a plan for complying with EPA's new section 111 greenhouse gas rule, or with any other federal or state rule identified in response to Interrogatory Nos. 12 or 13, please explain why not, and please describe the impact that the greenhouse gas rule will have on the Company if it is fully implemented.

**ANSWER:**

As mentioned in the company's answers above, the company is well positioned to comply with these rules with minimal impact or cost. The final impact of the section 111 rule on existing coal units cannot be determined until the state implementation plan is determined, however even if implemented as issued by the EPA, the impact would be a one-year acceleration in the retirement date of Big Bend Unit 4.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 18**
**BATES PAGE(S): 28939**
**MAY 16, 2024**

**18.** Has TECO evaluated the potential to use the U.S. Department of Energy's Energy Infrastructure Reinvestment (EIR) loan program to facilitate and reduce the costs associated with early retirement and replacement of any of its existing or retired coal units?

**ANSWER:**

No. Tampa Electric has not evaluated the potential to use the U.S. Department of Energy's Energy Infrastructure Reinvestment ("EIR") loan program.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 19**
**BATES PAGE(S): 28940**
**MAY 16, 2024**

**19.** Has TECO communicated with the Department of Energy to discuss questions and opportunities associated with the EIR program, or solicited any technical advice for preparing an EIR application?

a. If so, please briefly describe the communication(s) and which generation unit(s) they applied to.

b. If not, please explain why not.

**ANSWER:**

No. Tampa Electric has not communicated with the Department of Energy ("DOE") to discuss questions and opportunities associated with the EIR program.

a. Not applicable.

b. The company has not communicated with the DOE to discuss questions or opportunities associated with the EIR program because the company has not evaluated the program.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 20**
**BATES PAGE(S): 28941**
**MAY 16, 2024**

**20.** Has TECO conducted any analyses on the costs that could be avoided through the EIR program?

a. If so, for which generation units has TECO undertaken these analyses?

b. Does TECO have any plans to apply for the EIR program?

**ANSWER:**

No. Tampa Electric has not conducted any analyses of costs that could be avoided through the EIR program.

a. Not applicable.

b. No, not at this time.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 21**
**BATES PAGE(S): 28942**
**MAY 16, 2024**

**21.** Regarding TECO's disposal of coal ash:

a. How much does TECO estimate it will cost to properly move all existing coal ash into lined basins?

b. How much does TECO estimate it will cost to properly dispose of new coal ash?

c. Has TECO calculated the incremental cost of disposing of coal ash in lined basins (relative to the cost of prior disposal methods) associated with the continued operation of Big Bend 4 and Polk Unit 1?

**ANSWER:**

a. Tampa Electric already manages all marketable, on-specification CCR for beneficial use in either lined basins or enclosed buildings. There is not an onsite disposal of CCR and therefore no need for CCR to be moved into lined basins.

b. All on-specification CCR are expected to be beneficially reused in commercial products such as cement and drywall, as is the current practice at the facility. Costs of offsite landfilling new unmarketable CCR should be immaterial and are determined by the established landfill tipping fees and transportation rates charged by Tampa Electric's waste vendors.

c. Tampa Electric has eliminated all onsite disposal of CCR and does not intend to dispose of CCR at either Big Bend Station or Polk Power Station at any time in the future. Therefore, there will be no incremental cost of disposal in lined basins.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 22**
**BATES PAGE(S): 28943 - 28944**
**MAY 16, 2024**

**Topic: New and Existing Energy Supply**

**22.** For each new generation facility for which the Company is requesting rate recovery in this rate case, please provide:

a. The generator size in MW;

b. the $/kW overnight capital cost of each generator; and

c. the expected $/kW-yr fixed operation and maintenance cost of each generator.

**ANSWER:**

a. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_22" Sierra Club 1st Set IRR Q22.xlsx

b. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_22" Sierra Club 1st Set IRR Q22.xlsx

c. Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_22" Sierra Club 1st Set IRR Q22.xlsx

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 23**
**BATES PAGE(S): 28945 - 28946**
**MAY 16, 2024**

**23.** For each owned or contracted generating resource added to TECO's portfolio from 2019 to 2024, provide the fuel type, capacity in MW, and Commercial Online Date. State whether each resource is owned or contracted.

**ANSWER:**

Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_23" Sierra Club 1st Set IRR Q23.xlsx

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 24**
**BATES PAGE(S): 28947 - 28949**
**MAY 16, 2024**

**24.** Please provide the Company's two most recent commodity (e.g., natural gas and coal), peak demand, and load forecasts. Indicate the date each forecast was completed.

**ANSWER:**

Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). Please see attached in "ROG_1_24" Fuel Price Forecast Sierra Club 1st IRR Q24.xlsx for the two most recent fuel forecasts. For the two most recent load forecasts, see attached Demand and Energy Forecast Sierra Club 1st IRR Q24.xlsx.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 25**
**BATES PAGE(S): 28950 - 28955**
**MAY 16, 2024**

**25.** Does the Company have bilateral capacity or energy contracts with third parties currently in place?

a. If so, please list each contract, its capacity in MW, the fuel type of any associated generator, the cost of the capacity in $/MW-year, and whether the capacity is considered firm capacity.

b. Provide a summary of all contracts in place between 2018-present.

c. Provide a summary of all contracts in place during the test year.

d. Provide a summary of all contracts that are planned to be in place between 2024-2030.

**ANSWER:**

Yes. Tampa has power purchase and sales contracts in place currently.

a. See the table attached in "ROG_1_25". Since the company's capacity payments for purchases are only seasonal (i.e., for a few months, not annual), the table shows the costs in $/kW-month instead of $/MW-year.

b. See the table attached in "CONF_ROG_1_25".

c. There are two executed contracts in place during the test year: the 18 MW non-firm sale to Seminole Electric Cooperative and the long-term, 18 MW firm purchase from the Pasco County waste-to-energy ("WTE") facility. The response to No. 25(b), above, lists these agreements. In addition, the company has 400 MW of unsecured capacity purchases planned in January and February 2025. These purchases are a placeholder in the event Tampa Electric purchases firm capacity as in recent years. The tables for this response do not include this unsecured purchase, but the average capacity cost for the 400 MW is $[redacted]/kW-mo, which equates to a total capacity cost of about $[redacted] for the two months.

d. The company always evaluates power purchase and sale opportunities that benefit customers. However, presently the only agreements planned to be in place for the year 2024 are the DEF and FMPA purchases and the 18 MW non-firm sale to Seminole Electric Cooperative. The agreements expected to be in place for the year 2025 are the 18 MW non-firm sale to Seminole Electric Cooperative, the 18 MW firm purchase from the Pasco County WTE facility, and the 400 MW of unsecured purchase noted in the response to No. 25(c), above. The planned agreements beyond 2025 are the 18 MW non-firm sale to Seminole Electric Cooperative and the 18 MW firm purchase from the Pasco County WTE facility.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 26**
**BATES PAGE(S): 28956 - 28957**
**MAY 16, 2024**

**26.** Does the Company regularly purchase or sell energy in any market other than the Southeast Energy Exchange Market (SEEM)? If so, please specify which hub(s) and How much energy was purchased at each hub during on-peak and off-peak hours in each month from 2019 through 2023.

**ANSWER:**

Yes. Tampa Electric executes power transactions inside Florida, at the FL/GA border and in SEEM. Please see the MWh transacted at each hub below.

Florida Hub Purchases (MWh)

| 2019 | On-Peak | Off-Peak | 2020 | On-Peak | Off-Peak | 2021 | On-Peak | Off-Peak |
|---|---|---|---|---|---|---|---|---|
| January | 6,507 | 2,000 | January | 5,225 | 2,021 | January | 151,597 | 4,920 |
| February | 4,643 | 1,450 | February | 4,775 | 2,688 | February | 61,721 | 16,929 |
| March | 33,794 | 1,830 | March | 6,252 | - | March | 86,553 | 1,200 |
| April | 41,750 | 960 | April | 139,180 | 4,500 | April | 121,812 | 100 |
| May | 39,190 | 330 | May | 329,643 | 5,875 | May | 270,735 | - |
| June | 208,651 | 225 | June | 297,552 | 9,000 | June | 290,904 | 125 |
| July | 208,092 | 500 | July | 299,827 | 13,840 | July | 315,397 | 300 |
| August | 207,861 | 150 | August | 298,233 | 10,089 | August | 310,164 | 1,320 |
| September | 194,660 | - | September | 277,376 | 10,115 | September | 288,814 | 225 |
| October | 191,070 | 50 | October | 288,753 | 9,300 | October | 304,659 | 936 |
| November | 38,793 | 1,698 | November | 240,800 | 4,600 | November | 77,785 | 2,315 |
| December | 3,534 | 844 | December | 153,196 | 13,946 | December | 13,647 | - |

Florida Hub Purchases (MWh)

| 2022 | On-Peak | Off-Peak | 2023 | On-Peak | Off-Peak |
|---|---|---|---|---|---|
| January | 22,815 | 55 | January | 17,125 | 4,101 |
| February | - | - | February | 3,200 | - |
| March | 20,349 | 7,025 | March | 51,216 | 300 |
| April | 9,108 | 200 | April | 161,818 | 300 |
| May | 220,572 | 8,160 | May | 202,439 | 1,203 |
| June | 264,096 | 4,500 | June | 124,843 | - |
| July | 309,977 | 5,928 | July | 151,011 | 21 |
| August | 281,657 | 13,400 | August | 180,511 | 6,531 |
| September | 316,481 | 10,353 | September | 292,243 | 36,722 |
| October | 233,119 | 7,477 | October | 139,790 | 150 |
| November | 120,017 | 4,150 | November | 68,275 | 100 |
| December | 38,741 | 5,249 | December | 18,010 | 600 |

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 26**
**BATES PAGE(S): 28956 - 28957**
**MAY 16, 2024**

FL/GA Border Hub Purchases (MWh)

| 2019 | On-Peak | Off-Peak | 2020 | On-Peak | Off-Peak | 2021 | On-Peak | Off-Peak |
|---|---|---|---|---|---|---|---|---|
| January | 2,429 | 732 | January | 800 | 320 | January | - | - |
| February | 1,070 | 590 | February | 1,600 | - | February | - | - |
| March | 6,133 | 750 | March | 5,420 | - | March | 1,054 | - |
| April | 2,269 | - | April | 4,992 | - | April | 400 | - |
| May | 3,825 | - | May | 2,439 | - | May | 4,200 | - |
| June | 6,635 | 375 | June | 10,051 | 300 | June | 2,700 | - |
| July | 2,750 | 100 | July | 2,350 | - | July | 7,850 | 150 |
| August | 5,654 | - | August | 1,519 | - | August | 7,327 | 100 |
| September | 1,441 | - | September | 50 | - | September | 560 | - |
| October | 4,251 | - | October | 2,650 | - | October | 4,500 | - |
| November | 5,351 | 2,000 | November | 3,788 | - | November | 1,106 | - |
| December | 275 | - | December | 925 | 800 | December | 250 | - |

FL/GA Border Hub Purchases (MWh)

| 2022 | On-Peak | Off-Peak | 2023 | On-Peak | Off-Peak |
|---|---|---|---|---|---|
| January | 100 | - | January | 200 | - |
| February | - | - | February | 900 | - |
| March | 28,523 | 11,000 | March | 19,475 | - |
| April | 905 | - | April | 29,912 | - |
| May | 680 | - | May | 4,375 | 175 |
| June | - | - | June | 6,890 | - |
| July | 200 | 16,640 | July | - | - |
| August | - | 3,600 | August | 13,224 | 5,836 |
| September | 20,277 | 14,576 | September | 28,349 | 2,154 |
| October | 5,040 | - | October | 4,046 | - |
| November | 30,199 | 160 | November | 1,950 | 100 |
| December | 5,750 | - | December | 100 | 100 |

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 27**
**BATES PAGE(S): 28958**
**MAY 16, 2024**

**27.** Does the Company purchase or sell energy in the SEEM?

a. If yes, please specify how much energy was purchased from SEEM during on-peak and off-peak hours in each month from 2023-present,

b. If no, explain why not.

c. How does TECO incorporate purchase from SEEM into its resource planning process?

d. Does TECO plan to use purchases from SEEM to meet any of its energy needs? If so, please provide an estimate of much capacity TECO plans to acquire from purchases from SEEM in order to meet its energy needs.

**ANSWER:**

a. Yes. Tampa Electric executes power transactions in SEEM. Please see the purchase MWh transacted in SEEM below.

SEEM Purchases (MWh)

| 2023 | On-Peak | Off-Peak | 2024 | On-Peak | Off-Peak |
|---|---|---|---|---|---|
| June | 10 | - | January | 1,281 | 1,082 |
| July | 420 | 2,106 | February | 266 | 202 |
| August | 143 | 1,071 | March | 534 | 651 |
| September | 255 | 981 | April | - | - |
| October | 96 | 144 | | | |
| November | - | - | | | |
| December | 158 | 432 | | | |

b. Not applicable.

c. SEEM is a 15-minute, bilateral market for non-firm energy. Tampa Electric does not incorporate SEEM purchases into its resource planning process due to the non-firm aspects of that market. Instead, Tampa Electric participates in the market for real-time optimization, making economic purchases (and sales) on an intra-hour basis.

d. No. Tampa Electric participates in that market for real-time optimization, making economic purchases (and sales) on an intra-hour basis.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 28**
**BATES PAGE(S): 28959**
**MAY 16, 2024**

**28.** Please provide the maximum price per MWh the Company paid for market or bilaterally purchased energy in each month from 2019 through 2023.

**ANSWER:**

Please see the table below for the maximum price per MWh paid for market or bilaterally purchased energy in each month from 2019 through 2023 below.

| Maximum purchase price per MWh | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2019 | $ | 2020 | $ | 2021 | $ | 2022 | $ | 2023 | $ |
| January | $ 197 | January | $ 52 | January | $ 35 | January | $ 60 | January | $ 150 |
| February | $ 55 | February | $ 48 | February | $ 194 | February | $ - | February | $ 63 |
| March | $ 78 | March | $ 89 | March | $ 200 | March | $ 130 | March | $ 90 |
| April | $ 120 | April | $ 75 | April | $ 65 | April | $ 145 | April | $ 70 |
| May | $ 100 | May | $ 70 | May | $ 250 | May | $ 280 | May | $ 89 |
| June | $ 90 | June | $ 55 | June | $ 60 | June | $ 155 | June | $ 75 |
| July | $ 77 | July | $ 85 | July | $ 75 | July | $ 145 | July | $ 71 |
| August | $ 60 | August | $ 68 | August | $ 115 | August | $ 160 | August | $ 125 |
| September | $ 75 | September | $ 60 | September | $ 112 | September | $ 205 | September | $ 110 |
| October | $ 375 | October | $ 64 | October | $ 125 | October | $ 135 | October | $ 70 |
| November | $ 130 | November | $ 64 | November | $ 80 | November | $ 170 | November | $ 200 |
| December | $ 50 | December | $ 88 | December | $ 78 | December | $ 250 | December | $ 65 |

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 29**
**BATES PAGE(S): 28960 - 28961**
**MAY 16, 2024**

**29.** Provide the maximum price per MW the Company paid for market or bilaterally purchased capacity in each month from 2019 through 2023.

**ANSWER:**

See the table attached in "CONF-ROG_1_29" for the requested information.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 30**
**BATES PAGE(S): 28962 - 28965**
**MAY 16, 2024**

**30.** Provide the following for TECO:

a. Total annual off system energy purchases in GWh and dollars since 2019;

b. Total annual off system energy sales in GWh and dollars since 2019;

c. Projected annual off system energy purchases in GWh and dollars from now through 2034; and

d. Projected annual off system energy sales in GWh and dollars from now through 2034.

**ANSWER:**

a. Please see the total annual off system energy purchases in GWh and dollars since 2019 below.

| Off system energy purchases | | |
|---|---|---|
| Year | GWh | Dollars |
| 2019 | 1,235 | $ 43,798,113 |
| 2020 | 2,465 | $ 71,366,888 |
| 2021 | 2,352 | $ 93,556,869 |
| 2022 | 2,041 | $ 137,475,445 |
| 2023 | 1,578 | $ 67,434,752 |

b. Please see the total annual off system energy sales in GWh and dollars since 2019 below.

| Off system energy sales | | |
|---|---|---|
| Year | GWh | Dollars |
| 2019 | 123 | $ 5,122,362 |
| 2020 | 38 | $ 1,371,651 |
| 2021 | 79 | $ 4,692,509 |
| 2022 | 369 | $ 37,190,880 |
| 2023 | 218 | $ 7,864,380 |

c. Tampa Electric lists its contracted purchases in its answer to Interrogatory to No. 25, above. The tables below contain the projected GWh and dollars for those agreements. The table in "CONF-ROG_1_30" also includes the previously mentioned 400 MW of unsecured purchases in January and February of 2025.

d. Tampa Electric lists its contracted sales in the company's answer to Interrogatory No. 25, above. See "CONF-ROG_1_30" for the projected GWh and dollars for those agreements.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 31**
**BATES PAGE(S): 28966 - 28967**
**MAY 16, 2024**

**Topic: Resource Planning and Resource Adequacy**

**31.** Please provide a load and resources table from now through 2034, or the furthest year TECO has available, showing the Company's projected peak demand and firm capacity available by year. List firm capacity by resource/fuel type. Include the Company's reserve margin in the table.

**ANSWER:**

Tampa Electric answers this subpart by producing records as allowed under Florida Rule of Civil Procedure 1.340(c). See attached "-ROG_1_31" for the Sierra Club 1st Set 2024 – 2033 Firm Generators and RM IRR Q31.xlsx

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 32**
**BATES PAGE(S): 28968**
**MAY 16, 2024**

**32.** Please provide a narrative explanation of how the Company calculates its available firm capacity for purposes of system planning. Does the Company include an estimate of firm capacity for variable renewable energy or storage resources?

**ANSWER:**

For traditional units, depending on the season, their entire net capability is available to be counted towards the firm reserve margin. The same can be said for energy storage capacity projects.

The projected summer firm capacity contributions for the solar range from approximately 56 percent to 1 percent[1] based on project timing and existing amount of solar on the system.

Solar photovoltaic ("PV") generation contributes to reliability through Reserve Margin and Fuel Diversity contributions, as further explained below.

<u>Reserve Margin</u>

Based on the expected solar generation profiles on the peak winter load day, solar PV output starts after the peak morning load in January. Solar PV has effectively a zero-capacity value for winter reserve margin. Based on the expected generation profiles on the summer peak load day, solar PV output is approximately 56 percent of its maximum capacity value for the hour during which peak firm retail load occurs, and further decreases when measured at the hour of peak firm retail load net solar, which is used for reserve margin calculations. While Tampa Electric's reserve margin is lowest in the winter and solar PV has zero value to winter reserve margin, solar PV provides fuel cost savings that justify the solar additions.

<u>Fuel Diversity</u>

Reliability is also dependent upon having fuel for the generating units at the time it is needed. Solar PV generation displaces natural gas generation and provides improved fuel reliability via energy diversity every hour that the sun is shining.

[1] For operating purposes, the utility's greatest "short" occurs at the peak of retail firm load net (less) solar generation. This is the hour used to determine utility reserve margin. Please see the company's response to LULAC's First Request for Production of Documents, No. 1 titled "FRCC 2023 TYSP Workshop (Page 19) .pptx" where the FRCC described the fact that while solar PV may be providing over 50 percent of its capacity value at the time of summer retail firm load peak, the greatest challenge to operating the system may occur around sunset when solar PV output declines faster than load declines.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 33**
**BATES PAGE(S): 28969**
**MAY 16, 2024**

**33.** Does the Company calculate capacity contribution, effective load carrying capacity, or another metric of firm capacity for its generators for planning purposes? Please provide that value for the Company's existing generators and any new generators included in this rate case.

**ANSWER:**

Tampa Electric's approach for determining when to add capacity is based on the Reserve Margin requirement that is consistent with the agreement that is outlined in Order No. PSC-99-2507-S-EU, issued on December 22, 1999, in Docket No. 19981890-EU.

Tampa Electric's reserve margin need is driven by the winter peak demand. Since solar PV has a zero firm capacity value to winter reserve margin, the addition of solar PV provides sufficient fuel cost savings to justify adding solar to the system.

For firm capacity values please refer to the company's answer to Interrogatory No. 31, above. Tampa Electric also answers this interrogatory by producing records as allowed under Florida Rule of Civil Procedure 1.340(c).

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 34**
**BATES PAGE(S): 28970**
**MAY 16, 2024**

**34**. Please provide a narrative explanation of how the Company ensures that it will have enough capacity to meet demand in the future while maintaining a cost-effective system for customers. Include answers to the following:

a. How frequently does the Company assess its resource adequacy?

b. How far into the future does the Company plan for resource adequacy?

c. What standard does the Company use? For example, is it a 1 day in 10 years standard or a different metric?

d. Does TECO use a planning reserve margin (PRM) when making resource decisions? If so, please provide the margin the company currently uses and a narrative explanation of how that PRM was determined to be appropriate for planning purposes.

e. What model or models does the Company use to assess resource adequacy?

**ANSWER:**

a. Every year the company assesses its resource adequacy as documented in the annual Ten-Year Site Plan.

b. The company plans for resource adequacy for 10 years.

c. The standard that drives the expansion plan is the 20 percent Reserve Margin.

d. The company evaluates new resource additions utilizing a minimum 20 percent firm reserve margin criteria with a minimum contribution of 7 percent supply-side resources.

   Tampa Electric's approach for calculating reserve margin is consistent with the agreement that is outlined in Order No. PSC-99-2507-S-EU, issued on December 22, 1999, in Docket No. 981890-EU.

e. The company uses the software PLEXOS to assess resource adequacy.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 35**
**BATES PAGE(S): 28971**
**MAY 16, 2024**

**35.** Please provide the Company's historical monthly peak (in MW) and monthly energy demand (in MWh) load data for the years 2019 through 2023.

**ANSWER:**

Please see the table below for the Company's history of monthly peaks [MW] and monthly energy [MWh] from 2019 through 2023.

**Tampa Electric Retail Peak Demand [MW]**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2019** | 3,091 | 3,094 | 3,129 | 3,505 | 4,153 | 4,298 | 4,073 | 4,111 | 4,101 | 3,672 | 3,309 | 2,765 |
| **2020** | 3,538 | 3,013 | 3,574 | 3,591 | 3,903 | 4,254 | 4,143 | 4,239 | 4,255 | 3,872 | 3,274 | 3,024 |
| **2021** | 2,905 | 3,415 | 3,467 | 3,636 | 4,069 | 4,057 | 4,211 | 4,393 | 3,968 | 3,961 | 2,924 | 2,941 |
| **2022** | 3,735 | 3,042 | 3,242 | 3,571 | 4,006 | 4,385 | 4,355 | 4,378 | 4,225 | 3,624 | 3,666 | 3,526 |
| **2023** | 3,347 | 3,273 | 3,585 | 3,678 | 3,912 | 4,318 | 4,312 | 4,669 | 4,194 | 3,801 | 3,440 | 2,982 |

**Tampa Electric Retail Net Energy for Load [MWh]**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2019** | 1,493,199 | 1,351,418 | 1,476,858 | 1,588,913 | 1,977,632 | 2,014,117 | 2,013,341 | 2,090,383 | 1,991,461 | 1,891,523 | 1,428,339 | 1,452,850 |
| **2020** | 1,494,237 | 1,423,018 | 1,635,768 | 1,588,403 | 1,786,106 | 2,013,109 | 2,128,174 | 2,097,403 | 1,942,105 | 1,879,965 | 1,539,290 | 1,528,756 |
| **2021** | 1,475,926 | 1,389,391 | 1,570,789 | 1,593,817 | 1,928,865 | 1,993,145 | 2,123,137 | 2,168,932 | 1,963,764 | 1,879,168 | 1,391,302 | 1,554,891 |
| **2022** | 1,571,865 | 1,398,763 | 1,604,587 | 1,660,188 | 1,991,905 | 2,099,025 | 2,225,845 | 2,213,429 | 1,897,148 | 1,733,821 | 1,577,919 | 1,597,626 |
| **2023** | 1,539,466 | 1,391,248 | 1,652,004 | 1,737,371 | 1,913,620 | 2,073,404 | 2,281,240 | 2,357,125 | 2,075,705 | 1,768,964 | 1,490,746 | 1,485,648 |

**Tampa Electric Retail Energy Sales [MWh]**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2019** | 1,409,524 | 1,410,848 | 1,397,135 | 1,381,922 | 1,647,400 | 1,893,748 | 1,925,283 | 1,867,967 | 2,005,923 | 1,810,565 | 1,654,921 | 1,378,330 |
| **2020** | 1,455,463 | 1,379,438 | 1,359,338 | 1,534,992 | 1,528,939 | 1,775,858 | 1,999,202 | 2,050,356 | 1,931,651 | 1,797,319 | 1,681,936 | 1,459,239 |
| **2021** | 1,538,558 | 1,376,994 | 1,370,567 | 1,490,208 | 1,639,372 | 1,886,573 | 1,898,127 | 1,992,304 | 2,057,363 | 1,846,646 | 1,550,796 | 1,445,136 |
| **2022** | 1,511,032 | 1,431,625 | 1,446,289 | 1,500,682 | 1,698,076 | 1,921,049 | 2,028,819 | 2,056,096 | 2,062,122 | 1,703,886 | 1,543,160 | 1,563,893 |
| **2023** | 1,562,832 | 1,397,242 | 1,460,715 | 1,591,084 | 1,684,991 | 1,825,937 | 2,105,681 | 2,117,954 | 2,199,565 | 1,849,238 | 1,525,035 | 1,470,427 |

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 36**
**BATES PAGE(S): 28972**
**MAY 16, 2024**

**36.** Please provide the Company's forecast monthly peak (in MW) and monthly demand (in MWh) from 2024 through 2034.

**ANSWER:**

Refer to the table below for the Company's forecast of monthly peaks [MW] and monthly energy [MWh] from 2024 through 2034.

**Tampa Electric Retail Peak Demand [MW]**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2024** | 4,513 | 3,520 | 3,561 | 3,682 | 4,034 | 4,331 | 4,326 | 4,384 | 4,230 | 3,844 | 3,396 | 3,873 |
| **2025** | 4,566 | 3,557 | 3,602 | 3,708 | 4,059 | 4,366 | 4,365 | 4,421 | 4,276 | 3,873 | 3,436 | 3,918 |
| **2026** | 4,625 | 3,601 | 3,648 | 3,738 | 4,089 | 4,404 | 4,409 | 4,461 | 4,324 | 3,905 | 3,478 | 3,966 |
| **2027** | 4,683 | 3,645 | 3,692 | 3,769 | 4,119 | 4,442 | 4,452 | 4,501 | 4,372 | 3,938 | 3,519 | 4,012 |
| **2028** | 4,739 | 3,690 | 3,736 | 3,800 | 4,150 | 4,481 | 4,495 | 4,542 | 4,420 | 3,971 | 3,560 | 4,057 |
| **2029** | 4,795 | 3,731 | 3,779 | 3,833 | 4,183 | 4,522 | 4,540 | 4,584 | 4,469 | 4,005 | 3,600 | 4,102 |
| **2030** | 4,850 | 3,773 | 3,822 | 3,867 | 4,216 | 4,562 | 4,585 | 4,626 | 4,518 | 4,040 | 3,639 | 4,146 |
| **2031** | 4,903 | 3,813 | 3,863 | 3,901 | 4,250 | 4,603 | 4,629 | 4,668 | 4,567 | 4,075 | 3,678 | 4,188 |
| **2032** | 4,954 | 3,856 | 3,904 | 3,936 | 4,284 | 4,643 | 4,674 | 4,710 | 4,615 | 4,111 | 3,716 | 4,230 |
| **2033** | 5,005 | 3,893 | 3,944 | 3,971 | 4,318 | 4,684 | 4,719 | 4,752 | 4,664 | 4,148 | 3,754 | 4,272 |
| **2034** | 5,055 | 3,932 | 3,984 | 4,007 | 4,353 | 4,725 | 4,764 | 4,795 | 4,713 | 4,185 | 3,791 | 4,313 |

**Tampa Electric Retail Net Energy for Load [MWh]**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2024** | 1,582,570 | 1,420,376 | 1,561,352 | 1,632,648 | 1,905,063 | 2,056,900 | 2,150,411 | 2,181,101 | 1,989,017 | 1,837,776 | 1,486,339 | 1,551,356 |
| **2025** | 1,594,022 | 1,427,455 | 1,569,836 | 1,641,217 | 1,916,504 | 2,073,092 | 2,168,298 | 2,199,424 | 2,006,945 | 1,853,244 | 1,498,641 | 1,564,423 |
| **2026** | 1,609,175 | 1,440,064 | 1,581,760 | 1,652,928 | 1,931,357 | 2,092,305 | 2,188,999 | 2,220,329 | 2,026,823 | 1,870,572 | 1,512,610 | 1,579,430 |
| **2027** | 1,624,512 | 1,452,892 | 1,594,035 | 1,664,799 | 1,946,184 | 2,111,194 | 2,209,337 | 2,240,939 | 2,046,401 | 1,887,912 | 1,526,809 | 1,594,818 |
| **2028** | 1,639,997 | 1,469,485 | 1,606,619 | 1,677,015 | 1,961,334 | 2,130,266 | 2,229,886 | 2,261,865 | 2,066,287 | 1,905,646 | 1,541,412 | 1,610,667 |
| **2029** | 1,656,964 | 1,480,153 | 1,620,994 | 1,691,080 | 1,978,511 | 2,151,057 | 2,252,151 | 2,284,462 | 2,087,535 | 1,924,841 | 1,557,290 | 1,627,851 |
| **2030** | 1,674,147 | 1,494,627 | 1,635,791 | 1,705,581 | 1,996,149 | 2,172,152 | 2,274,679 | 2,307,293 | 2,108,918 | 1,944,231 | 1,573,322 | 1,645,129 |
| **2031** | 1,691,515 | 1,509,222 | 1,650,985 | 1,720,597 | 2,014,440 | 2,193,822 | 2,297,881 | 2,330,846 | 2,130,847 | 1,964,227 | 1,589,839 | 1,662,799 |
| **2032** | 1,708,897 | 1,528,886 | 1,666,339 | 1,735,841 | 2,033,015 | 2,215,759 | 2,321,330 | 2,354,659 | 2,153,051 | 1,984,528 | 1,606,584 | 1,680,678 |
| **2033** | 1,727,010 | 1,539,111 | 1,682,809 | 1,752,332 | 2,052,949 | 2,238,807 | 2,345,858 | 2,379,589 | 2,176,205 | 2,005,893 | 1,624,229 | 1,699,448 |
| **2034** | 1,745,646 | 1,554,894 | 1,699,899 | 1,769,459 | 2,073,603 | 2,262,506 | 2,371,108 | 2,405,299 | 2,199,965 | 2,027,934 | 1,642,431 | 1,718,833 |

**Tampa Electric Retail Energy Sales [MWh]**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2024** | 1,549,330 | 1,431,380 | 1,402,381 | 1,478,416 | 1,642,445 | 1,899,071 | 2,005,223 | 1,997,793 | 2,042,574 | 1,826,039 | 1,567,594 | 1,472,678 |
| **2025** | 1,560,541 | 1,438,513 | 1,410,001 | 1,486,176 | 1,652,309 | 1,914,020 | 2,021,902 | 2,014,576 | 2,060,985 | 1,841,407 | 1,580,569 | 1,485,083 |
| **2026** | 1,575,376 | 1,451,220 | 1,420,712 | 1,496,781 | 1,665,114 | 1,931,759 | 2,041,205 | 2,033,723 | 2,081,398 | 1,858,625 | 1,595,302 | 1,499,328 |
| **2027** | 1,590,391 | 1,464,148 | 1,431,737 | 1,507,531 | 1,677,897 | 1,949,198 | 2,060,170 | 2,052,602 | 2,101,503 | 1,875,854 | 1,610,276 | 1,513,936 |
| **2028** | 1,605,550 | 1,480,869 | 1,443,040 | 1,518,593 | 1,690,959 | 1,966,807 | 2,079,332 | 2,071,769 | 2,121,925 | 1,893,474 | 1,625,678 | 1,528,981 |
| **2029** | 1,622,161 | 1,491,620 | 1,455,951 | 1,531,329 | 1,705,767 | 1,986,003 | 2,100,093 | 2,092,467 | 2,143,745 | 1,912,547 | 1,642,424 | 1,545,293 |
| **2030** | 1,638,983 | 1,506,207 | 1,469,241 | 1,544,460 | 1,720,974 | 2,005,479 | 2,121,100 | 2,113,379 | 2,165,704 | 1,931,814 | 1,659,332 | 1,561,695 |
| **2031** | 1,655,986 | 1,520,915 | 1,482,889 | 1,558,057 | 1,736,744 | 2,025,486 | 2,142,736 | 2,134,953 | 2,188,223 | 1,951,681 | 1,676,752 | 1,578,469 |
| **2032** | 1,673,003 | 1,540,731 | 1,496,679 | 1,571,862 | 1,752,758 | 2,045,740 | 2,164,602 | 2,156,764 | 2,211,025 | 1,971,853 | 1,694,413 | 1,595,442 |
| **2033** | 1,690,735 | 1,551,035 | 1,511,472 | 1,586,794 | 1,769,944 | 2,067,019 | 2,187,474 | 2,179,599 | 2,234,803 | 1,993,081 | 1,713,022 | 1,613,259 |
| **2034** | 1,708,980 | 1,566,940 | 1,526,822 | 1,602,303 | 1,787,751 | 2,088,900 | 2,211,019 | 2,203,148 | 2,259,203 | 2,014,981 | 1,732,219 | 1,631,661 |

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 37**
**BATES PAGE(S): 28973**
**MAY 16, 2024**

**37.** Has TECO assessed whether adding renewables or storage at the Big Bend Unit 4 or Polk Unit 1 sites could create benefits for customers, including reducing their electricity rates?

**ANSWER:**

Tampa Electric has constructed solar photovoltaic generation at property adjacent to Big Bend Station. The solar energy produced from these sites will create benefits for Tampa Electric's customers. Tampa Electric continues to seek property at Big Bend, at Polk, and throughout the Tampa Electric territory where cost-effective solar generation can be constructed and operated. The same is true for battery energy storage.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 38**
**BATES PAGE(S): 28974**
**MAY 16, 2024**

**38.** Has TECO evaluated the cost savings from retiring Polk Unit 1?

a. If so, please provide the results of this evaluation.

**ANSWER:**

a. Yes. The company will provide its analysis of Polk Unit 1, which includes an earlier retirement date scenario, in response to Sierra Club's Request for Production of Document, No. 5.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 39**
**BATES PAGE(S): 28975**
**MAY 16, 2024**

**39.** Has TECO evaluated the job and economic impacts of retiring Big Bend Unit 4 and Polk Unit 1 relative to the job and economic impacts of adopting alternative forms of generation?

**ANSWER:**

No. The retirement analysis for Polk Unit 1 does not include job and economic impact studies. There is not a retirement analysis for Big Bend Unit 4.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 40**
**BATES PAGE(S): 28976**
**MAY 16, 2024**

**40.** Witness Aldazabal testified that TECO replaced the Big Bend Unit 1 "boiler and coal processing equipment" with gas-powered combustion turbines. Has TECO considered the feasibility and/or costs of repowering Big Bend Unit 4 to permanently cease coal operations and operate entirely on gas or a different fuel source?

**ANSWER:**

No. Tampa Electric has not performed an analysis on repowering Big Bend 4 with gas-powered combustion turbines. Big Bend Unit 4 is currently dual fuel capable and can operate using coal or natural gas, providing fuel diversity for Tampa Electric's customers. Big Bend Unit 4 has numerous years remaining in both book life and operating life, so it is premature to incur significant costs to develop cost estimates and system impacts associated with repowering a unit with at least fifteen years of life left on it.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 41**
**BATES PAGE(S): 28977**
**MAY 16, 2024**

**41.** Witness Aldazabal opined that "the economic viability of coal for generating electricity will continue to erode, while the future will remain bright for renewable energy resources and storage capacity." In light of this observed trend, has TECO considered advancing the retirement dates of its two remaining coal-fired generation units, Big Bend Unit 4 and Polk Unit 1?

**ANSWER:**

The company has not considered advancing the retirement dates of these two generating units, other than the early retirement analysis for Polk Unit 1 which is provided in response to Sierra Club's Request for Production of Document, No. 5.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 42**
**BATES PAGE(S): 28978**
**MAY 16, 2024**

**42.** Similarly, Witness Stryker stated that TECO "could not prudently ignore the possibility that limits on greenhouse gas emissions would soon be imposed on the company's fossil fuel generation units." Has TECO assessed how a proposed rule limiting greenhouse gas emissions would affect the currently planned retirement dates of TECO's remaining coal units, Big Bend Unit 4 and Polk Unit 1?

a. If so, please share any results of such analysis.

**ANSWER:**

Yes. We performed a preliminary review of the Clean Air Act Section 111 rule EPA rule issued on April 25, 2024, and the only impact is that the retirement date of Big Bend Unit 4 would need to move up one year if the rule goes into effect as issued. There is no impact to Polk Unit 1's retirement date.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 43**
**BATES PAGE(S): 28979**
**MAY 16, 2024**

**43.** Witness Stryker discussed the $28.1 million that will be imposed on TECO's customers for experimental carbon capture and storage ("CCS") technology.

a. Is TECO considering implementing CCS at either Polk Unit 1 or Big Bend Unit 4?

b. If so, has TECO compared the costs of implementing CCS with the costs (and cost savings) of retiring those coal-fired plants?

**ANSWER:**

a. For clarification, witness Stryker describes CCS technology as well proven in his testimony, not as "experimental." The company is seeking only $18.2 million in cost recovery at this time and evaluating implementing CCS at Polk Unit 1, but not Big Bend Unit 4.

b. No. The company has not performed a cost-effectiveness analysis comparing implementing CCS on Polk Unit 1 with the costs of retiring the unit.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 44**
**BATES PAGE(S): 28980**
**MAY 16, 2024**

**44.** Witness Aponte calculates that the installation of 488.7 MW of solar in the coming years would "decrease carbon dioxide ('CO2') emissions by over 450 thousand tons per year and decrease nitrogen oxide ('NOX') and sulfur dioxide ('SO2') emissions by hundreds of tons."

a. Has TECO performed any calculations of the CO2, NOx, and SO2 emissions it would avoid by retiring its coal units, Polk Unit 1 and Big Bend Unit 4, earlier than their planned retirement dates?

b. How many CO2, NOx, and SO2 emissions would TECO avoid if it did not operate its coal units, Polk Unit 1 and Big Bend Unit 4, for one year?

c. Witness Collins stated that TECO's total annual emissions have decreased by 38% since 2017. Please provide any calculations TECO has made of the expected percentage emission reduction from advancing retirements of Polk Unit 1 and Big Bend Unit 4 ahead of their planned retirement dates.

**ANSWER:**

a. No. Tampa Electric has not performed an analysis of an early retirement of Big Bend Unit 4.

For Polk Unit 1, due to its small size, low capacity factor, and the necessary replacement capacity and energy, the reduction on the system's emissions assuming an earlier than planned retirement date is expected to be approximately 1 percent reduction on total $CO_2$.

b. If Tampa Electric did not operate Polk Unit 1 in all of 2025, the system $CO_2$ emissions would decline by 0.4 percent, $NO_x$ by 1.4 percent, and $SO_2$ by 0.06 percent of the total, however other generating resources would need to run to account for the lost generation. Tampa Electric has not performed any analysis of an early retirement of Big Bend Unit 4.

c. Please see the company's answer to subpart (a), above.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 45**
**BATES PAGE(S): 28981**
**MAY 16, 2024**

**45.** Witness Aldazabal also cites data showing its retirement of coal units has caused an improvement in its thermal efficiency, annual fuel expenses, and reliability. Please provide any calculations TECO has made of the expected decrease in its heat rate, annual net Equivalent Availability Factor (EAF), and fuel costs if it retires its two remaining coal units, Big Bend Unit 4 and Polk Unit 1, earlier than planned.

**ANSWER:**

Tampa Electric has not conducted any analysis that retires both Big Bend Unit 4 and Polk Unit 1 earlier than planned. It is worth noting that any retired capacity would have to be replaced to maintain the 20 percent reserve margin.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 46**
**BATES PAGE(S): 28982**
**MAY 16, 2024**

**46.** Witness Aldazabal stated that Big Bend Unit 4 has "dual fuel capability" and can be fired with both coal and natural gas.

a. How often does Big Bend Unit 4 run on gas as opposed to coal?

b. Has TECO calculated how much more pollution the plant produces when it runs on gas than on coal?

c. Has TECO calculated what the plant's operating costs are when it runs on gas, relative to coal?

**ANSWER:**

a. In 2023, Big Bend Unit 4 ran with a 21 percent capacity factor on coal and with a 7 percent capacity factor on natural gas. Through April of 2024, Big Bend Unit 4 had a capacity factor of 3 percent on coal and 8 percent on natural gas. The company will operate Big Bend Unit 4 using the most economic fuel type for customers, or on coal when natural gas deliveries are at risk. Currently, the company plans to operate Big Bend 4 mostly on natural gas and expects to burn minimal amounts of coal to keep the solid fuel equipment viable.

b. Yes, the company has performed that calculation. For $CO_2$, Big Bend Unit 4 is expected to produce 206 lb/MMBtu while on coal and 117 lb/MMBtu while running on gas. For $NO_x$, Big Bend Unit 4 is expected to produce 0.1 lb/MMBtu while on coal and 0.061 lb/MMBtu while running on gas. For $SO_2$, Big Bend Unit 4 is expected to produce 0.2 lb/MMBtu while on coal and 0.0006 lb/MMBtu while running on gas.

c. The expected operating costs for Big Bend Unit 4 to run on gas is approximately $3.24 per MWh and $8.79 per MWh to run on coal.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 47**
**BATES PAGE(S): 28983**
**MAY 16, 2024**

**47.** Witness Collins noted that, while inflation has raised costs for the Company, one way that TECO has kept its overall costs lower is by "transitioning from coal to natural gas." Has TECO performed any analysis of how much it would decrease its costs by retiring Big Bend Unit 4 and Polk Unit 1 earlier than planned?

a. If so, please provide the results of this analysis.

b. If not, please explain why not.

**ANSWER:**

a. Please see the company's answer to Interrogatory, No. 4, above. As stated in that response, early retirement of Polk Unit 1 is less cost-effective than operating the unit in simple-cycle mode.

b. Please see the company's answer to Interrogatory, No. 4, above. An early retirement of Big Bend Unit 4 has not been analyzed because of the system value provided by that unit. With its ability to operate on either coal or natural gas, it provides fuel resilience and fuel price economic opportunities. Additionally, that unit serves an important role in maintaining sufficient water temperature in the outlet canal during winter months as part of the Manatee Protection Plan. Lastly, the company's transmission and distribution system are built around the generation out of the Big Bend Station.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 48**
**BATES PAGE(S): 28984**
**MAY 16, 2024**

**48.** Turning to the Asset Optimization Mechanism described in Witness Heisey's testimony, does TECO have any environmental controls designed to reduce the pollution from its transportation of gas or coal?

a. The Asset Optimization Mechanism could involve the sale of gas or coal. Which entity(ies) might TECO sell this gas or coal to?

**ANSWER:**

Tampa Electric does not have any environmental controls to reduce pollution in any of its transportation agreements with natural gas pipelines, rail-based freight transportation or waterborne vessels. However, many of these companies may be implementing their own steps to reduce pollution and emissions across their transportation assets.

a. Tampa Electric executes gas and coal transactions with other investor-owned utilities, electric cooperatives, municipal utilities, energy marketers, suppliers and producers.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 49**
**BATES PAGE(S): 28985**
**MAY 16, 2024**

**49.** Witness Collins discussed renewable energy credit ("REC") sales, which have led to revenues for TECO's customers pursuant to the environmental cost recovery clause. How has the number of TECO's REC sales changed over time?

a. Could TECO increase its REC sales above their current volume?

b. If so, does TECO have any plans to increase its REC sales?

**ANSWER:**

Tampa Electric installed its first solar facility in 2016. It was a 1.4 MW facility located at Legoland with a commercial in-service date of December 2016. In calendar year 2017, the facility produced energy equivalent to 2,532 REC. Since that time, Tampa Electric's solar fleet has expanded to over 1,200 MW. Per Tampa Electric's 2024 Ten Year Site Plan, the company's solar forecast—and thus its REC production—have increased. Since 1 MWh of solar generation equals 1 REC, production increased from 2,532 REC in 2017 to an expected 2,471,000 REC in 2024 and 6,191,000 REC by the end of 2033. Tampa Electric began selling REC in the fall of 2023.

a. Yes. In future years, Tampa Electric could increase its REC sales volumes because the forecast is for the company's solar generation to increase, thus producing more REC.

b. Yes. Currently, Tampa Electric plans to continue selling generated REC into the voluntary market that are in excess of retail program needs.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 50**
**BATES PAGE(S): 28986**
**MAY 16, 2024**

**Topic: Renewable Generation**

**50.** Witness Stryker described the new solar installations that TECO is planning to bring online in the next few years. Does the Company have plans to install more solar projects after 2027?

a. If so, how many additional megawatts of solar is TECO considering installing?

b. How does TECO select potential solar projects?

**ANSWER:**

Yes, the company plans to install more solar projects.

a. The company has board approved plans to install an additional 353 MW going in service in 2027-2028 and preliminary plans to install an additional 745 MW going in service from 2029-2033 as shown in the company's 2024 ten-year site plan.

b. Please refer to witness Stryker's testimony page 10 lines 9-19.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 51**
**BATES PAGE(S): 28987**
**MAY 16, 2024**

**51.** Does TECO prioritize siting new solar projects in disadvantaged or lower-income communities?

a. If so, how does TECO define "disadvantaged communities" and/or "lower income communities"?

**ANSWER:**

No, we prioritize siting at the most cost-effective site for customers.

a. N/A

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 52**
**BATES PAGE(S): 28988**
**MAY 16, 2024**

**52.** How many of TECO's existing solar projects—and how many of TECO's solar projects that are planned as part of its current rate case—provide community solar?

a. Does TECO have a policy to promote community solar?

b. Does TECO require that a certain percentage of its solar installations be community solar as opposed to residential or utility-scale solar?

**ANSWER:**

Tampa Electric's community solar program is sourced from its solar generation portfolio. The program provides for up to 17.5 $MW_{ac}$ of capacity to be used for community solar to our customers.

a. In 2019, Tampa Electric launched a Shared Solar Program, called Sun Select, providing a choice for customers unable to install rooftop solar but prefer their energy generated from solar. Residential and small business customers can purchase locally generated solar power to match 25 percent, 50 percent or 100 percent of the electricity they use. Business and commercial customers can purchase solar in increments of 1,000 kWh. Sun Select participants pay a locked-in solar rate for the solar energy they purchase instead of paying the fuel charge for that portion of participants' electricity use.

b. No.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 53**
**BATES PAGE(S): 28989**
**MAY 16, 2024**

**53.** Witness Stryker mentioned that several of the planned solar sites have already received environmental resource permits. What is the average time that it takes solar sites to receive environmental resource permits?

a. Have any of TECO's applications for environmental resource permits been denied historically?

**ANSWER:**

Environmental Resource Permits have taken three to 10 months to receive after the application has been submitted for solar sites, with an average of six months.

a. Historically, Tampa Electric has not been denied an Environmental Resource Permit for solar sites.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 54**
**BATES PAGE(S): 28990**
**MAY 16, 2024**

**54.** Has TECO projected by how much the availability of production tax credits (PTCs), available under the federal Inflation Reduction Act (IRA), will increase the number of TECO customers that install solar and the cost-effectiveness of solar installations for TECO?

**ANSWER:**

No, Tampa Electric has not projected by how much the availability of production tax credits [PTC], available under the Federal Inflation Reduction Act [IRA], will increase the number of TECO customers that install solar.

However, Tampa Electric uses the Department of Energy's [DOE] Energy Information Administration's [EIA] Annual Energy Outlook [AEO2023] 2023 projections for customer-owned solar installation growth. The AEO2023 reflects the IRA adopted in August 2022 and the most likely tax credit uptake.

Tampa Electric has projected the availability of Production Tax Credits under the federal Inflation Reduction Act for eligible Tampa Electric installed solar assets. These projections are based on the amount of solar generation produced from the individual solar asset. This projection of Production Tax Credit was then deducted from the annual revenue requirement in the cost effectiveness analysis for each proposed solar project for a period of ten years from each project's in-service date.

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**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 55**
**BATES PAGE(S): 28991**
**MAY 16, 2024**

**55.** In the context of this rate case, has TECO considered pursuing any potential storage projects apart from the Future Energy Storage Capacity Projects?

a. If so, how many other potential projects did TECO consider?

b. How did TECO select the energy storage projects that it is proposing in this rate case?

c. Does TECO have plans to bring any other storage projects online after 2027?

i. If so, please list how many projects fall into this category and how many megawatts of power each project is estimated to produce.

**ANSWER:**

There is an additional 70 MW storage project in our 2024 ten-year site plan entering service in 2028.

a. The company only considered one, the project mentioned above

b. With the exception of the South Tampa Energy Storage project, all of the energy storage projects proposed in this rate case are co-located with existing solar facilities. The existing solar project locations were screened for sites that had adequate space available adjacent to the substation and adequate transmission capacity. Sites were further screened for locations that would have an added benefit of deferring necessary transmission upgrades associated with load growth.

c. Yes, there is an additional 70 MW storage project in our 2024 ten-year site plan entering service in 2028

i. See the company's response to (c), above.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 56**
**BATES PAGE(S): 28992**
**MAY 16, 2024**

**56.** Has TECO analyzed whether any areas in its service territory that the U.S. Department of Energy defines as "energy communities" are feasible sites for energy storage installations?

a. If so, what were the results of this analysis?

b. Do any of the sites where TECO is building its proposed energy storage projects qualify as "energy communities"?

**ANSWER:**

Yes, the company has performed an analysis on areas in its service territory.

a. The analysis showed the census tract where Big Bend Power Station is located, and adjacent census tracts are "energy communities"

b. Yes, the long duration energy storage project referenced on page 37 of witness Stryker's testimony qualifies. We are also evaluating sites for the additional 70 MW project in our ten-year site plan that would qualify, such as Big Bend Station.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 57**
**BATES PAGE(S): 28993**
**MAY 16, 2024**

**57**. Does the Company prioritize siting new energy storage projects in disadvantaged or lower-income communities?

**ANSWER:**

No, we prioritize siting at the most cost-effective site for customers.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 58**
**BATES PAGE(S): 28994**
**MAY 16, 2024**

**Topic: Federal Funding**

**58.** Has TECO applied for any funds available pursuant to the federal Infrastructure Investment & Jobs Act (IIJA) or IRA?

a. If so, please list which sources of federal funds TECO has applied for, and which, if any, it has received.

**ANSWER:**

Yes, please see Tampa Electric's answers to the OPC's Third Set of Interrogatories, Nos. 74-75, on bates numbered pages 18229-18233.

a. See above.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 59**
**BATES PAGE(S): 28995**
**MAY 16, 2024**

**59.** Does TECO have any programs in place to help its customers apply for and/or implement federal funding available under IIJA or IRA?

a. If so, please provide the names of these programs and describe what services they include.

**ANSWER:** No.

a. N/A

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 60**
**BATES PAGE(S): 28996**
**MAY 16, 2024**

**60.** How does TECO take into account, in its operations and/or resource planning processes, the cost savings in wind, solar, and energy storage production due to the changes to the production tax credit and investment tax credit structures under the IRA?

**ANSWER:**

As referenced in the company's response to the OPC's Third Set of Interrogatories, No. 74 (BS 18229-18231) and the OPC's Third Request for Production, No. 45, the solar production tax credit under the IRA provides an increased benefit to customers when compared with the investment tax credit option. In the resource planning process, these tax credits are modeled as part of the cost-effectiveness analysis demonstrating project benefits to customers. With regards to energy storage, the IRA enabled an investment tax credit for energy storage projects, whether they are co-located with and charged by solar facilities or not. This allows additional flexibility in selecting the sites for energy storage projects to provide optimized benefits to customers and the system.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 61**
**BATES PAGE(S): 28997**
**MAY 16, 2024**

**61.** Witness Aldazabal explains that the PTC, available under the IRA, improves the cost-effectiveness of solar projects. Did TECO evaluate whether any of the solar projects qualifying for the PTC would also be eligible for bonus tax credits, such as bonus tax credits for domestic content and energy communities?

a. If so, please provide the results of this evaluation.

b. If not, why has TECO not considered the feasibility of procuring domestic contentor siting the projects in energy communities?

**ANSWER:**

a. Yes, it was evaluated and determined that our solar projects qualifying for the PTC would qualify for the bonus tax credits. These projects meet prevailing wage and apprenticeship requirements but would not be eligible for bonus credits for domestic content and energy communities.

b. The company has, and continues to, consider the feasibility of procuring domestic content and siting the projects in energy communities. With regards to the domestic content bonus credit, a significant portion of the solar modules must be produced domestically to meet the cost percentage requirements on manufactured products. Our solar module supply contract for the 2024 and 2025 projects was executed prior to passage of the IRA and creation of the bonus credits. We began awarding solar module supply contracts for the 2026 projects in late 2023 and at the time the cost premium for qualifying panels was more than the incremental tax credit and the timing of availability was uncertain due to limited supply options. As it pertains to the energy community bonus tax credit, there was not land that was large enough and that was in buildable condition. This, coupled with the land being available at an appropriate cost due to it being an area of high population density disqualified us from the energy community bonus tax credits.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 62**
**BATES PAGE(S): 28998 - 28999**
**MAY 16, 2024**

**Topic: Electric Vehicle Charging Infrastructure**

**62.** Regarding TECO's investment in electric vehicle (EV) infrastructure:

a. Does TECO have an EV infrastructure investment plan? If yes, please provide the plan.

b. Has TECO included any EV infrastructure investment costs in its test year rates? If yes please outline what the costs are for.

c. Provide TECO's historical investments in EV infrastructure between 2019-2023.

**ANSWER:**

a. The company does not have an EV infrastructure investment plan. However, the company intends to finish EV charger installations under the current Commission-approved EV Charger Pilot Program through the end date of April 1, 2025. The company is also evaluating participant-funded voluntary customer programs to support residential and fleet customers that choose to install EV charging infrastructure and may file for approval of those programs at a later date.

b. Yes. EV infrastructure investment costs in the test year include electric vehicle charging infrastructure at the Bearss Operations Center and the Corporate Headquarters. It also includes nominal amounts for upgrading or replacing existing EV chargers at company-owned facilities.

c. Please see the table below for the requested information. The company does not have any information prior to 2021.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 62**
**BATES PAGE(S): 28998 - 28999**
**MAY 16, 2024**

| | Sum of 2020 | Sum of 2021 | Sum of 2022 | Sum of 2023 |
|---|---|---|---|---|
| Drive Smart EV Pilot | | $ 784,795 | $ 253,068 | $ 387,893 |
| EV Charger Upgrades (CE) | | | $ 12,367 | $ 53,741 |
| Fleet EV Charging | | | | $ 101,242 |
| Residential EV Charging | | | | $ 462,823 |
| **Grand Total** | | **$ 784,795** | **$ 265,435** | **$ 1,005,699** |

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 63**
**BATES PAGE(S): 29000**
**MAY 16, 2024**

**63.** Is TECO seeking any recovery for its EV pilot program, described in Docket No. 20240054, through this rate case as well?

a. Does TECO have plans to expand the offerings in its EV pilot program over the period from 2025 to 2027?

**ANSWER:**

Yes, a nominal amount of recovery for the existing pilot program assets is included in rate base.

a. No.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 64**
**BATES PAGE(S): 29001**
**MAY 16, 2024**

**64.** Please identify TECO's rate structures that are designed to facilitate off-peak charging by EVs and/or support vehicle-to-grid energy flow capacities.

**ANSWER:**

The company does not offer rate structures designed to facilitate off-peak charging by EV or to support vehicle-to-grid energy flow capabilities.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 65**
**BATES PAGE(S): 29002**
**MAY 16, 2024**

**65.** Does TECO have any policies that prioritize installing chargers in disadvantaged or lower-income communities?

**ANSWER:**

The company does not have policies that prioritize installing chargers in disadvantaged or lower-income communities.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 66**
**BATES PAGE(S): 29003**
**MAY 16, 2024**

**66.** Please identify any analysis and planning that TECO has performed in relation to the distribution system upgrades—such as line extensions and upgrades, bulk power transmission system upgrades, and transformer or substation upgrades—that will be needed to service high-speed charging or medium- and heavy-duty electric vehicle charging, including but not limited to chargers installed under the National Electric Vehicle Infrastructure (NEVI) and Charging and Fueling Infrastructure (CFI) programs.

a. Is TECO coordinating with its customers who are installing chargers to identify areas where line extensions are likely to be necessary?

**ANSWER:**

The company evaluates standard service requests from DC fast charging developers and/or large fleet customers when requested by individual customers.

a. Yes. Upon customer requests, the company will coordinate with Commercial and Industrial customers interested in installing chargers to identify any necessary expansions to the Tampa Electric system.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 67**
**BATES PAGE(S): 29004**
**MAY 16, 2024**

**67.** Please identify any of TECO programs or investments to inform and/or support eligible recipients of federal funds or awards under IIJA and IRA, including but not limited to the:

a. NEVI program;

b. CFI program;

c. U.S. Environmental Protection Agency (EPA)'s Clean School Bus program and Clean Heavy-Duty Vehicles program;

d. Federal Transit Administration's and/or Federal Highway Administration's Congestion Mitigation and Air Quality (CMAQ) program; Grants for Buses and Bus Facilities program; Low- or No-Emission (Low-No) programs; and Diesel Emission Reduction Act (DERA) program.

**ANSWER:**

a. The company does not have investments or programs to inform and/or support eligible recipients of federal funds or awards under the NEVI program.

b. The company does not have investments or programs to inform and/or support eligible recipients of federal funds or awards under the CFI program.

c. The company provided a letter of support for a Hillsborough County School District electric bus grant application under the EPA's Clean School Bus program. The grant was awarded to the District in early 2024.

d. The company has supported two Hillsborough Area Regional Transit Authority ("HART") electric bus grant applications. The application submitted under the Federal Transit Administration Section 5339(C) Low or No Emission Grant Program was not awarded. The application submitted by HART under the Federal Transit Administration Section 5339(B) Bus and Bus Facilities Grant Program was awarded in 2020.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 68**
**BATES PAGE(S): 29005**
**MAY 16, 2024**

**68.** Please identify:

a. The steps TECO has taken or will take to build out the distribution grid infrastructure needed to service potential recipients of NEVI funding, consistent with Florida's 2023 NEVI deployment plan.1

b. The costs of the grid upgrades needed to service those EV school buses;

c. Which entities are responsible for paying for those grid upgrades; and

d. The actual or estimated timeframes for (1) those grid upgrades, (2) the interconnection of the EV charging infrastructure, and (3) final energization.

**ANSWER:**

a. The company does not currently have requests from potential NEVI funding recipients and as such, does not currently have plans to build out the distribution grid.

b. The company provided a rough estimate of the costs to interconnect charging infrastructure in support of Hillsborough County School District's grant application under the U.S. Environmental Protection Agency (EPA)'s Clean School Bus program. Those costs were determined to be approximately $50,000 under the preliminary scope of the grant application.

c. The company uses prescribed calculations and procedures to determine the appropriate contribution in aid of construction ("CIAC") that will be the responsibility of customers interconnecting EV charging infrastructure.

d. The company does not have actual or estimated timeframes for grid upgrades, interconnection of EV charging infrastructure, and final energization for potential NEVI-funded projects.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 69**
**BATES PAGE(S): 29006**
**MAY 16, 2024**

**69.** Please identify or otherwise provide the estimated interconnection and energization timeframes for high-speed chargers, such as NEVI or CFI charging stations, that TECO did not address in response to question Number 56.

**ANSWER:**

Tampa Electric does not have mandated timeframes to complete the interconnection and energization for high-speed chargers. These requests will vary based on scale and scope of construction requirements for individual projects.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO. 70**
**BATES PAGE(S): 29007**
**MAY 16, 2024**

**70.** How does TECO forecast locations within its service territory where fleet electrification will be occurring?

a. Please provide any information on where on its distribution grid TECO anticipates fleet electrification occurring.

b. Does TECO have concrete plans to upgrade its distribution system at those locations?

c. If not, how does TECO plan to coordinate distribution grid upgrades with the electric vehicle charging infrastructure that will be brought on by customers with electric fleets, given that a lack of capacity on the distribution grid can be a bottleneck that prevents the charging—and therefore use—of electric fleets?

**ANSWER:**

a. The company does not have information available on prospective fleet electrifications within the service territory.

b. No.

c. Tampa Electric's annual distribution planning process provides a future five-year and 10-year look at system growth. These studies include load sensitivities which could include increased load related to electric vehicle charging infrastructure and may result in an expansion of the Tampa Electric distribution grid. Expansion plans of the Tampa Electric distribution grid would require firm customer commitment.

In addition, as needed upon request, the company coordinates with Commercial and Industrial customers interested in installing chargers to identify any necessary expansions to the Tampa Electric system.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO 71**
**BATES PAGE(S): 29008**
**MAY 16, 2024**

**71.** Does TECO provide any assistance to its customers in applying for federal funds for fleet electrification, such as by making customers aware of available federal funds or writing letters of support for customers' grant applications?

**ANSWER:**

Please see the company's answer to Interrogatory No. 67, above. The company considers writing letters of support for grant applications on a case-by-case basis.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S FIRST SET OF INTERROGATORIES**
**INTERROGATORY NO 72**
**BATES PAGE(S): 29009**
**MAY 16, 2024**

**72.** Does TECO have any programs for assisting its customers in using federal funds for fleet electrification, such as assisting customers in undertaking make-ready upgrades to enable the installation of chargers they are funding pursuant to a federal grant?

**ANSWER:**

The company does not have programs for assisting customers using federal funds for fleet electrification.

# AFFIDAVIT

**STATE OF FLORIDA )**
**)**
**COUNTY OF HILLSBOROUGH )**

Before me the undersigned authority personally appeared Jose Aponte, who deposed and said that he is Manager, Generation Planning, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 1st Set of Interrogatories (Nos. 4, 8, 12, 23. 31-34, 37-38, 40, 44, 46)

Dated at Tampa, Florida this 15 day of May, 2024.

______________________________

Sworn to and subscribed before me this 15 day of May, 2024.

Tyronda R. Nelson

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# A F F I D A V I T



**STATE OF FLORIDA )**
**)**
**COUNTY OF HILLSBOROUGH )**

Before me the undersigned authority personally appeared Lori Cifuentes who deposed and said that she is Director, Load Research and Forecasting, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by her and/or under her direction and supervision and are true and correct to the best of her information and belief.

Sierra Club's 1st Set of Interrogatories (No. 24)

Dated at Tampa, Florida this 14 day of May, 2024.

Sworn to and subscribed before me this 14 day of May, 2024.

Tyronda R. Nelson

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# AFFIDAVIT



**STATE OF FLORIDA** )
)
**COUNTY OF HILLSBOROUGH** )

Before me the undersigned authority personally appeared John Heisey, who deposed and said that he is Director, Origination and Trading, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 1st Set of Interrogatories (Nos. 24 – 29, 47, 48)

Dated at Tampa, Florida this 9th day of May, 2024.

______________________________

Sworn to and subscribed before me this 9th day of May, 2024.

Tyronda R. Nelson
______________________________

My Commission expires 7/10/2026

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

 **A F F I D A V I T** 

**STATE OF FLORIDA )**
**)**
**COUNTY OF HILLSBOROUGH )**

Before me the undersigned authority personally appeared Ashley Sizemore, who deposed and said that she is Director, Rates, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by her and/or under her direction and supervision and are true and correct to the best of her information and belief.

Sierra Club's 1st Set of Interrogatories (No. 30)

Dated at Tampa, Florida this 14th day of May, 2024.

Ashley Sizemore
_______________________________

Sworn to and subscribed before me this 14th day of May, 2024.

Tyronda R. Nelson
_______________________________

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# AFFIDAVIT

**STATE OF FLORIDA )**
**)**
**COUNTY OF HILLSBOROUGH )**

Before me the undersigned authority personally appeared Karen Sparkman, who deposed and said that she is Vice President, Customer Experience, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by her and/or under her direction and supervision and are true and correct to the best of her information and belief.

Sierra Club's 1st Set of Interrogatories (Nos. 59)

Dated at Tampa, Florida this 15 day of May, 2024.

Karen Sparkman

Sworn to and subscribed before me this 15 day of May, 2024.

Rebecca Lynn Maier

NOTARY PUBLIC STATE OF FLORIDA
REBECCA LYNN MAIER
MY COMMISSION # HH 350932
EXPIRES: March 25, 2027

My Commission expires 03/25/2027

# A F F I D A V I T



**STATE OF FLORIDA )**
**)**
**COUNTY OF HILLSBOROUGH )**

Before me the undersigned authority personally appeared Valerie Strickland, who deposed and said that she is Director Corporate Taxes, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by her and/or under her direction and supervision and are true and correct to the best of her information and belief.

Sierra Club's 1st Set of Interrogatories (No. 57)

Dated at Tampa, Florida this 13th day of May, 2024.

V Strickland
_______________________________

Sworn to and subscribed before me this 13th day of May, 2024.

Tyronda R. Nelson
_______________________________

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# A F F I D A V I T

**STATE OF FLORIDA )**
**)**
**COUNTY OF HILLSBOROUGH )**

Before me the undersigned authority personally appeared Jordan Williams, who deposed and said that he is Director, Pricing & Financial Analysis, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 1st Set of Interrogatories (Nos. 61-72)

Dated at Tampa, Florida this 15 day of May, 2024.

Jordan Williams
_______________________________

Sworn to and subscribed before me this 15 day of May, 2024.

Tyronda R. Nelson
_______________________________

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# AFFIDAVIT



**STATE OF FLORIDA )**
**)**
**COUNTY OF HILLSBOROUGH )**

Before me the undersigned authority personally appeared Kris Stryker, who deposed and said that he is Vice President, Clean Energy and Emerging Technology, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 1st Set of Interrogatories (Nos.18-20, 41, 42, 49-53, 54-58, 60)

Dated at Tampa, Florida this 9 day of May, 2024.

Kris Stryker
______________________________

Sworn to and subscribed before me this 9th day of May, 2024.

Tyronda R. Nelson
______________________________

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# A F F I D A V I T



**STATE OF FLORIDA )**
**)**
**COUNTY OF HILLSBOROUGH )**

Before me the undersigned authority personally appeared Carlos Aldazabal, who deposed and said that he is Vice President, Energy Supply, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 1st Set of Interrogatories (Nos.1-17, 21-40, 44-48, 55, 56)

Dated at Tampa, Florida this 9 day of May, 2024.

Carlos Aldazabal

Sworn to and subscribed before me this 9 day of May, 2024.

Tyronda R. Nelson

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

 **A F F I D A V I T** 

**STATE OF FLORIDA** )
)
**COUNTY OF HILLSBOROUGH** )

Before me the undersigned authority personally appeared Chip Whitworth, who deposed and said that he is Vice President, Electric Delivery, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 1st Set of Interrogatories (No. 57)

Dated at Tampa, Florida this 10 day of May, 2024.

______________________________

Sworn to and subscribed before me this 10 day of May, 2024.

Rebecca Lynn Maier

REBECCA LYNN MAIER
MY COMMISSION # HH 350932
EXPIRES: March 25, 2027

My Commission expires 03/25/2027

Dated this 16th day of May, 2024.

Respectfully submitted,

_______________________________

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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

**CERTIFICATE OF SERVICE**

I HEREBY CERTIFY that copies of the foregoing answers have been served by posting on a shared document site, hand delivery of a USB drive or by electronic mail on this 16th day of May, 2024 to the following:

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______________________________
ATTORNEY

# Exhibit DG-3:
# TECO response to Sierra Club 2nd IRRs

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In re: Petition for Rate Increase by Tampa Electric Company | DOCKET NO. 20240026-EI |
| In re: Petition for approval of 2023 Depreciation and Dismantlement Study, by Tampa Electric Company | DOCKET NO. 20230139-EI |
| In re: Petition to implement 2024 Generation Base Rate Adjustment provisions in Paragraph 4 of the 2021 Stipulation and Settlement Agreement, by Tampa Electric Company | DOCKET NO. 20230090-EI<br><br>SERVED: May 22, 2024 |

**TAMPA ELECTRIC COMPANY'S ANSWERS TO**
**SIERRA CLUB'S SECOND SET OF INTERROGATORIES (NOS. 73-91)**

Pursuant to Rule 106.206, Florida Administrative Code, and Florida Rule of Civil Procedure 1.350, Tampa Electric Company ("Tampa Electric" or the "company"), hereby answers Sierra Club's Second Set of Interrogatories (Nos. 73-91), served May 2, 2024 ("Sierra Club Second ROG").

**General Objections**

1. Tampa Electric objects to each interrogatory in Sierra Club's Second ROG ("Interrogatory") to the extent that it seeks information that is duplicative, not relevant to the subject matter of this docket, and is not reasonably calculated to lead to the discovery of admissible evidence.

2. Tampa Electric objects to each Interrogatory to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such Interrogatory. Tampa Electric will seek clarification from Sierra Club if an Interrogatory is not clear, but Tampa Electric will produce documents subject to, and without waiving, this objection.

3. Tampa Electric objects to each Interrogatory to the extent it requires Tampa Electric to produce information that is already in the public record before the Florida Public Service Commission ("FPSC" or the "Commission") or other public agency and available to Sierra Club through normal procedures or is readily accessible through legal search engines.

4. Tampa Electric objects to each Interrogatory to the extent that it calls for data or information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law. Tampa Electric will describe the nature of the privileged material, if any, in a privilege log that will accompany its responses.

5. Tampa Electric objects to producing paper copies on the grounds that doing so would be unduly burdensome. Tampa Electric has entered into an agreement with Sierra Club, governing discovery production and responses, and will serve its answers to the Interrogatories and related responsive documents to Sierra Club in electronic form via a SharePoint site to which Sierra Club has remote access.

6. Tampa Electric objects to each Interrogatory to the extent it requires the company to provide information that it believes is "proprietary confidential business information" as described in Section 366.093, Florida Statutes. Tampa Electric will provide such confidential information to Sierra Club in a designated confidential portion of the SharePoint site described above and subject to a Motion for Temporary Protective Order, Notice of Intent to Request Confidential Classification, and/or Request for Confidential Classification, as appropriate.

7. Tampa Electric objects to each Interrogatory, instruction, or definition in that purports to expand Tampa Electric's obligations under applicable law.

8. Tampa Electric objects to each Interrogatory to the extent it requests Tampa Electric to prepare information in a particular format or create data or information that it otherwise does not possess as unduly burdensome and as purporting to expand Tampa Electric's obligations under applicable law.

9. Subject to Section 366.093(1), Florida Statutes, Tampa Electric objects to any definition or Interrogatory that requests documents from persons or entities who are not parties to this proceeding, that seek information from affiliates unrelated to transactions or cost allocations involving Tampa Electric, or that are not otherwise subject to discovery under applicable rules.

10. Tampa Electric objects to any Interrogatory requiring the company to provide additional information beyond that obtained through a reasonable and diligent search.

**General Response**

Subject to and without waiving its general objections, which are incorporated by reference in each of its specific answers, Tampa Electric provides its answers to Sierra Club's Second ROG by posting its answers on the Tampa Electric Discovery SharePoint site established for this docket (the "SharePoint") and as specified in its specific answers. Tampa Electric will serve its answers to the Commission staff by hand delivering a USB containing its answers to the Commission Clerk's office, and for Staff's purposes, the term "USB" should be substituted for "SharePoint" in the specific answers shown below.

The company's specific answers will identify interrogatories that call for answers that contain (a) information for which the company asserts a legal privilege and/or (b) "proprietary confidential business information" as defined in Section 366.093, Florida Statutes.

An answer that contains information for which the company asserts a legal privilege will be identified in the privilege log attached as Exhibit A.

An answer that contains information the company asserts to be “proprietary confidential business information” will be provided in the Confidential portion of the SharePoint subject to a request for confidential classification, motion for temporary protective order and/or a non-disclosure agreement.

## Specific Answers

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S SECOND SET OF INTERROGATORIES**
**INTERROGATORY NO. 73**
**BATES PAGE(S): 30388**
**MAY 22, 2024**

**73.** Please provide a narrative description of how the Company factors interconnection costs into its resource planning and procurement decisions.

**ANSWER:**

The company factors interconnection costs into its resource planning and procurement decisions by including an estimate of such costs in the cost-effectiveness evaluation of future resource additions. The estimated costs are initially provided by the company's system planning department during the integrated resource planning process and subsequently refined as a project progresses through the required interconnection studies.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S SECOND SET OF INTERROGATORIES**
**INTERROGATORY NO. 74**
**BATES PAGE(S): 30389**
**MAY 22, 2024**

**74.** In addition to the material referenced in Sierra Club Document Production Request No. 20, please provide an explanation of whether and how interconnection costs are included in this rate case.

**ANSWER:**

The company has included interconnection costs as part of the total cost for Future Solar, Energy Storage Capacity, and South Tampa Resilience new resource additions in this rate case.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S SECOND SET OF INTERROGATORIES**
**INTERROGATORY NO. 75**
**BATES PAGE(S): 30390**
**MAY 22, 2024**

**75.** Please provide, in total dollars and dollars per MW, the annual transmission costs paid through the FERC Open Access Transmission Tariff (OATT), from 2021 through 2023, associated with:

a. Each of the solar resources included in this rate case, and

b. Each of the three most recent solar resources the Company procured before this rate case.

**ANSWER:**

a. There will be no transmission costs paid through the FERC Open Access Transmission Tariff ("OATT") since the proposed Future Solar sites are designated as company network resources.

b. No transmission costs were paid through the FERC OATT since the solar deployed between 2021 and 2023 were designated as company network resources.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S SECOND SET OF INTERROGATORIES**
**INTERROGATORY NO. 76**
**BATES PAGE(S): 30391**
**MAY 22, 2024**

**Topic: Capacity Contracts**

**76.** Please provide the price (in dollars) and quantity (in MW) of any bilateral capacity contracts sold by the Company for each year from 2019 through 2024.

**ANSWER:**

The company has one sale applicable to this period, and that sale is to Seminole Electric Cooperative. As noted in the company's answer to Sierra Club's First Set of Interrogatories, No. 25, the sale is for up to 18 MW; however, the service amount varies. The actual service amount has been 10 MW per month or less on average since 2019. The MW and capacity dollars for this agreement since 2019 are in the table below.

| Year | MW | Capacity Payment ($) | Description |
|---|---|---|---|
| **2019** | 10.0 | [redacted] | Average annual MW and total annual dollars (Actual) |
| **2020** | 8.3 | [redacted] | |
| **2021** | 7.4 | | |
| **2022** | 10.0 | | |
| **2023** | 6.0 | | |

| | | | |
|---|---|---|---|
| **2024** (Actual) | 6.5 | [redacted] | Average MW and total dollars January through April |
| **2024** (Forecast) | 6.0 | | Average MW and total dollars May through December |
| **2024** (Annual Estimate) | 6.2 | [redacted] | Average annual MW and total annual dollars (Actual + Forecast) |

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S SECOND SET OF INTERROGATORIES**
**INTERROGATORY NO. 77**
**BATES PAGE(S): 30392 - 30462**
**MAY 22, 2024**

**77.** Has the Company issued any requests for capacity contracts in the last five years?

a. If so, please provide price and quantity details about any offers the Company received.

**ANSWER:**

Yes. In the last five years, Tampa Electric has issued five requests for proposals ("RFP") to purchase firm capacity and two (2) RFP to sell firm capacity. The purchase RFP occurred once per year for the period 2019 through 2023. Tampa Electric has not issued a purchase RFP for capacity in 2024. The sale RFP occurred in 2022 and 2023. The company did not receive any firm offers through its sale RFP.

a. Please see the company's confidential attachment provided in folder CONF-ROG_2_77 for all offers received from 2019 through 2023 in purchase RFP.

**CONFIDENTIAL MATERIAL REDACTED**

**BATES STAMPED PAGES 30393 - 30462**

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S SECOND SET OF INTERROGATORIES**
**INTERROGATORY NO. 78**
**BATES PAGE(S): 30463**
**MAY 22, 2024**

**78.** Has the Company responded to any requests for capacity contracts in the last five years?

a. If so, please provide price and quantity details about any offers the Company made.

**ANSWER:**

No. The company has not submitted proposals to supply firm power in response to other entities' (e.g., cities or utilities) requests for capacity.

a. Not applicable.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S SECOND SET OF INTERROGATORIES**
**INTERROGATORY NO. 79**
**BATES PAGE(S): 30464 - 30465**
**MAY 22, 2024**

**79.** Please describe the types of agreements and transactions that provide fuel to Polk Unit 1 and Big Bend Unit 4.

a. If the Company has contracts with coal suppliers, please provide:

i. The contract duration;

ii. Quantity of coal per year;

iii. Price of coal in each year;

iv. Any minimum take quantity; and

v. Other important contractual agreements for each contract.

c. If the Company does not have contracts in place with suppliers, please describe the coal procurement process for the units, including where the coal is supplied from and the terms/requirements/parameters of purchasing the coal.

**ANSWER:**

Solid fuel burns have decreased over the past few years and the company does not project much solid fuel burn on either unit; therefore, Tampa Electric has transitioned to spot transactions for acquiring solid fuel and transportation. There are no agreements in place for solid fuel for Polk Unit 1 since no solid fuel has been burned in that unit since 2018. The current agreement for Big Bend Unit 4 is described below.

a. i. Tampa Electric has an agreement for delivered coal via barge (commodity and transport) from Knight Hawk Coal, LLC that ends on December 31, 2024.

ii. The contract quantity of coal in 2024 is 300,000 tons.

iii. The price of the delivered coal is $[redacted]/ton.

iv. Tampa Electric is obligated to take delivery of the remaining contracted tons.

v. The agreement with Knight Hawk Coal, LLC is a standard purchase agreement for delivered coal.

c. Any future solid fuel requirements, exceeding the 2024 Knight Hawk Coal, LLC agreement, will be purchased with spot market commodity and transportation agreements.

REDACTED

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S SECOND SET OF INTERROGATORIES**
**INTERROGATORY NO. 80**
**BATES PAGE(S): 30466**
**MAY 22, 2024**

**80.** Regarding TECO's long-term firm purchase power agreement with Pasco County, please provide the capacity and energy cost.

**ANSWER:**

There is no capacity cost. The pricing for the Pasco County agreement is an energy rate in $/MWh. The energy rates for the term are in the table below.

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|
| [redacted] | | | | | | | | | |

**81.** Regarding TECO's short-term firm capacity purchases during the winter of 2024 with MP, Orlando, and DEF:

d. Provide the cost, time period, and size of each purchase.

e. Indicate whether TECO plans to enter into any other short-term or long-term contracts between now and 2030.

**ANSWER:**

d. Please see Tampa Electric's answer to Sierra Club's First Set of Interrogatories, No. 25 for the cost, time period, and size of the FMPA, OUC, and DEF purchases.

e. Please see Tampa Electric's answer to Sierra Club's First Set of Interrogatories, No. 25. The company always evaluates power purchase and sale opportunities that benefit customers. Presently, the only agreements planned to be in place for the year 2024 are the DEF and FMPA purchases, an unsecured purchase for the winter of 2024/2025 and the 18 MW non-firm sale to Seminole Electric.

**Topic: TECO's Coal Units**

**82.** Please provide filterable particulate matter emissions on a lbs/MMBTU basis for Polk Unit 1 and Big Bend Unit 4 for the following time periods:

f. Actual emissions from 2018 through 2023, by the smallest recorded timeframe (e.g. days, months, years).

g. Projected emissions from 2024 through 2030, by the smallest recorded timeframe (e.g. days, months, years).

**ANSWER:**

f. The actual emissions are included in the following tables:

| Polk Unit 1 PM Emission Rates (lb/MMBtu) | | |
|---|---|---|
| Actuals | | |
| Year | lb/MMBtu | Averaging Period |
| 2018 | 0.0013 | 3, 1-hour runs |
| 2019 | No Monitoring | N/A |
| 2020 | 0.0019 | 3, 1-hour runs |
| 2021 | No Monitoring | N/A |
| 2022 | No Monitoring | N/A |
| 2023 | No Monitoring | N/A |

| Big Bend Unit 4 PM Emission Rates (lb/MMBtu) | | |
|---|---|---|
| Actuals | | |
| Year | lb/MMBtu | Averaging Period |
| 2018 | 0.0033 | Annual Average |
| 2019 | 0.0031 | Annual Average |
| 2020 | 0.0022 | Annual Average |
| 2021 | 0.0034 | Annual Average |
| 2022 | 0.0033 | Annual Average |
| 2023 | 0.0038 | Annual Average |

g. The projected emissions are included in the following tables.

| Polk Unit 1 PM Emission Rates (lb/MMBtu) | |
|---|---|
| Projections | |
| **Polk Unit 1** | **lb/MMBtu** |
| 2024 | 0.006 |
| 2025 | 0.006 |
| 2026 | 0.006 |
| 2027 | 0.006 |
| 2028 | 0.006 |
| 2029 | 0.006 |
| 2030 | 0.006 |

| Big Bend Unit 4 PM Emission Rates (lb/MMBtu) | |
|---|---|
| Projections | |
| **Year** | **lb/MMBtu** |
| 2024 | <0.01 |
| 2025 | <0.01 |
| 2026 | <0.01 |
| 2027 | <0.01 |
| 2028 | <0.01 |
| 2029 | <0.01 |
| 2030 | <0.01 |

**83.** Please provide a description of the types of costs included in "fossil dismantlement" and how the fossil dismantlement cost of a plant is determined and included in rate base.

h. Is this reserve reported in the reserve balance totals reported in the MFR for each plant or reported separately?

**ANSWER:**

A description of these types of costs is contained in the Direct Testimony of Witness Jeffrey Kopp Exhibit No. JK-1, Bates stamped page Nos. 37-47, section titled 3.0 Decommissioning Costs for a description of the types of costs included in "fossil dismantlement".

Pursuant to Florida Administrative Code Rule 25-6.04364 Electric Utilities Dismantlement Studies, the company has a dismantlement reserve embedded in the FERC Account 108 Accumulated Depreciation. Dismantlement studies are filed with the FPSC for approval of the annual dismantlement expense accrual per each plant and unit. The recognition of the dismantlement expense accrual results in a debit to expense and builds up an Account 108 reserve (credit balance) over time. After a unit is shutdown/retired, dismantling work commences, and the expenditure activities for cost of removal, net of salvage, are posted as a debit against the reserve. In a rate case, the fossil dismantlement costs of a plant that have been accumulated in Account 108 through a point in time are reflected as a 13-month average credit balance in the reserve, which has the effect of reducing rate base.

h. The dismantlement reserve is reported separately and can be seen on MFR Schedule B-09. It can be found under Account 10803 and is functionalized between production steam and other. The reserve details for each plant and unit are separately maintained as well. This information is all contained and reported in the 2023 Dismantlement Study, filed in this docket.

**84.** Please provide hourly generation from 2022 and 2023 for each of the Company's solar generators.

**ANSWER:**

Please see the folder ROG_2_84 for files titled: "2022 Hourly Solar Generation Data.xlsx" and "2023 Hourly Solar Generation Data.xlsx" for the 2022-2023 hourly generation for each of the solar generators.

**85.** Please provide 2023 capacity factors for each of the Company's solar generators.

**ANSWER:**

See the table below for the 2023 capacity factors for the solar generators.

| SOLAR SITES | 2023 NET CAPACITY FACTOR (%) |
|---|---|
| TIA SOLAR | 23.1 |
| BIG BEND I SOLAR | 13.5 |
| LEGOLAND SOLAR | 19.2 |
| PAYNE CREEK SOLAR | 18.6 |
| BALM SOLAR | 15.4 |
| LITHIA SOLAR | 19.4 |
| GRANGE HALL SOLAR | 17.9 |
| PEACE CREEK SOLAR | 18.9 |
| BONNIE MINE SOLAR | 16.4 |
| LAKE HANCOCK SOLAR | 20.8 |
| WIMAUMA SOLAR | 19.8 |
| LITTLE MANATEE RIVER SOLAR | 18.6 |
| DURRANCE SOLAR | 20.5 |
| ESA CANOPY SOLAR | 12.6 |
| MAGNOLIA SOLAR | 20.8 |
| JAMISON SOLAR | 18.9 |
| BIG BEND 2 SOLAR | 18.8 |
| MOUNTAIN VIEW SOLAR | 18.9 |
| LAUREL OAKS SOLAR | 22.8 |
| RIVERSIDE SOLAR | 23.3 |
| JUNIPER SOLAR | 11.5 |
| ALAFIA SOLAR | 12.1 |
| DOVER SOLAR | 9.1 |
| LAKE MABEL SOLAR | 10.5 |
| TOTAL SOLAR | 19.1 |

**86.** Please provide the Company's hourly load for 2023.

**ANSWER:**

Please see folder entitled ROG_2_86 for the 2023 hourly company load served.

**87.** For each new generation facility installed by the Company from 2020 through 2023, please provide:

a. The generator size in MW;

b. The $/kW overnight capital cost of each generator (include a separate line item for any investment tax credit (ITC) value); and

c. The expected $/kW-yr fixed operation and maintenance cost of each generator.

**ANSWER:**

a. Please see attached.

b. Please see attached.

c. Please see attached.

| Generator | Winter Net Capability (MW) | Commerical In Service Date | Costs (sans AFUDC) | $/kW Capital | ITC Capital | $/kW O&M |
|---|---|---|---|---|---|---|
| Little Manatee River Solar | 74.5 | 20-Feb | $105,247,935 | $1,413 | $28,644,713 | $25.00 |
| Wimauma Solar | 74.8 | 20-Apr | $108,487,581 | $1,450 | $25,631,652 | $15.00 |
| Durrance Solar | 60.0 | 21-Jan | $67,130,382 | $1,119 | $18,578,591 | $15.00 |
| Magnolia Solar | 74.5 | 21-Dec | $95,460,483 | $1,281 | $20,299,808 | $15.00 |
| Big Bend II Solar | 45.8 | 22-Jan | $63,396,810 | $1,384 | N/A | $15.00 |
| Big Bend Floating Solar | 1.0 | 22-Mar | $3,259,985 | $3,260 | N/A | $35.00 |
| Mountain View Solar | 54.6 | 22-Apr | $81,598,481 | $1,494 | N/A | $15.00 |
| Jamison Solar | 74.5 | 22-Apr | $106,462,003 | $1,429 | N/A | $15.00 |
| Big Bend Agrivoltaic Solar | 1.0 | 22-Jun | $2,031,882 | $2,032 | N/A | $35.00 |
| Laurel Oaks Solar | 61.2 | 22-Dec | $80,951,611 | $1,323 | N/A | $15.00 |
| Riverside Solar | 55.2 | 22-Dec | $80,012,558 | $1,450 | N/A | $15.00 |
| Juniper Solar | 70.0 | 23-Dec | $100,190,394 | $1,431 | N/A | $15.00 |
| Alafia Solar | 60.0 | 23-Dec | $86,234,650 | $1,437 | N/A | $15.00 |
| Lake Mabel Solar | 74.5 | 23-Dec | $104,780,618 | $1,406 | N/A | $15.00 |
| Dover Solar | 25.0 | 23-Dec | $43,807,256 | $1,752 | N/A | $15.00 |
| Big Bend CT 5[1] | 350.0 | 21-Dec | $156,645,063 | $448 | N/A | * |
| Big Bend CT 6[1] | 350.0 | 21-Dec | $155,931,433 | $446 | N/A | * |
| Big Bend 1 MOD | 1120.0 | 22-Dec | $425,637,139 | $380 | N/A | * |

Note: beginning in 2022, solar faciliaties qualified for the production tax credit which is more beneficial to customers. Please refer to OPC 3rd set IRR 74

Big Bend CT and Big bend 1 mod projects do not qualify for ITC

* Tampa Electric does not calculate unit specific forecasted fixed O&M costs for existing units.

**88.** TECO's 2024 Ten Year Site Plan (TYSP) has a 2040 retirement date for Big Bend Unit 4 and a 2026 retirement date for Polk Unit 1. How does EPA's April 25, 2024 announcement of its final greenhouse gas rules under section 111 of the Clean Air Act impact TECO's planned retirement dates for both units?

**ANSWER:**

The TYSP has a 2036 retirement date for Polk Unit 1, not 2026. Tampa Electric is reviewing the recently released final rule; however, final compliance impacts will be dependent upon the development of the State Implementation Plan by the Florida Department of Environmental Protection which has not been developed. Based on preliminary review, the new rule will have limited impact on Tampa Electric generating units. Big Bend Unit 4 is the only unit affected. As written, the rule would require Big Bend Unit 4 to retire in 2039 without major enhancements to the unit, instead of the current planned retirement date in 2040.

**89.** Please refer to the Direct Testimony of Company witness Aldazabal, pages 44-46, regarding the Polk 1 Flexibility project and plans to convert the unit back to combined cycle operation to run on petcoke.

a. Explain how TECO made the decision to maintain the option to operate on petcoke.

b. Indicate whether TECO evaluated the option of retiring the IGCC technology at Polk 1.

i. If no, explain why not.

c. What is the annual cost of maintaining the IGCC technology at Polk?

i. What costs could be avoided with its retirement? Please break out such costs by category and year.

d. Indicate when TECO last purchased petcoke for Polk or any other units.

i. Provide the quantity produced, price, and contract.

e. Provide TECO's forecasts of the price of petcoke between now and 2030.

f. Please indicate whether TECO has any projections or analysis that show the price of petcoke becoming more economic than natural gas.

g. If the price of natural gas goes up again in the future, how quickly does TECO anticipate being able to convert Polk back to a Combined Cycle system to burn petcoke?

i. What steps will TECO have to take to make such a conversion?

h. Does the EPA's announcement of the final greenhouse gas rule under section 111of the Clean Air Act impact TECO's consideration of the decision to maintain the option to operate the plant on petcoke?

i. Please explain.

ii. Does TECO anticipate that petcoke burning will require any additional environmental compliance costs? Please list these out. If not, please explain why.

i. Please provide documentation outlining all the claimed benefits from the conversion of Polk 1 to a simple-cycle combustion turbine.

j. Please provide Polk 1 unit's (a) current status quo and (b) projected post-conversion to simple-cycle combustion turbine costs and operations as follows:

   i. Operating cost;

   ii. Maintenance cycles;

   iii. Projected forced and unforced outage rates;

   iv. Start time;

   v. Ramping rate; and

   vi. Heat rate.

**ANSWER:**

a. Tampa Electric's reliance on natural gas as a fuel source is the primary consideration for maintaining future petcoke optionality. Removing petcoke as a fuel source would further limit fuel diversity and Tampa Electric's ability to manage customer cost in the case that natural gas price becomes uneconomical in comparison with petcoke.

b. As mentioned in Tampa Electric's response to Sierra Club's First Set of Interrogatories, No. 4, the company considered a 2028 early retirement date for the combined cycle portion of Polk Unit 1. The company did not perform any analyses on the early retirement of the IGCC technology such as the gasifier.

   i. IGCC optionality provides an element of fuel diversity and the ability to mitigate high fuel cost if natural gas prices become uneconomical.

c. Please see the table below for the requested information.

| IGCC | Annual Maintenance |
|---|---|
| Coal & Slurry Handling | $ 2,000 |
| Gasification Maintenance | $ 220,000 |
| Acid Plant Maintenance | $ 1,000 |
| Air Plant Maintenance | $ 37,000 |
| | $ 260,000 |

i. The annual preventative maintenance and corrosion control costs could be avoided with the IGCC technology's retirement. These amounts are listed in the chart above.

d. Tampa Electric last purchased petcoke on October 10, 2017.

i. The petcoke purchase was for up to 270,000 tons from Valero Marketing and Supply Company. The pricing was based on an index in the Pace Petroleum Coke Quarterly + $2.00/metric ton for delivery in 2018.

Please see attached.

e. Please see tables below.

| Polk Unit 1 | | | |
|---|---|---|---|
| **Years** | **Pet Coke ($/mmbtu)** | **Heat Rate (Btu/kWh)** | **Fuel Dispatch Rate ($/MWh)** |
| 2024 | 3.74 | 11.7 | 43.73 |
| 2025 | 3.64 | 11.7 | 42.64 |
| 2026 | 3.82 | 11.7 | 44.67 |
| 2027 | 4.18 | 11.7 | 48.90 |
| 2028 | 4.47 | 11.7 | 52.27 |
| 2029 | 4.62 | 11.7 | 54.00 |
| 2030 | 4.92 | 11.7 | 57.51 |

| Polk Unit 1 | | | |
|---|---|---|---|
| Years | Natural Gas ($/mmbtu) | Heat Rate (Btu/kWh) | Fuel Dispatch Rate ($/MWh) |
| 2024 | 3.85 | 8.4 | 32.35 |
| 2025 | 4.31 | 8.4 | 36.20 |
| 2026 | 4.55 | 8.4 | 38.24 |
| 2027 | 5.23 | 8.4 | 43.91 |
| 2028 | 5.82 | 8.4 | 48.89 |
| 2029 | 5.61 | 8.4 | 47.13 |
| 2030 | 5.40 | 8.4 | 45.35 |

f. Please see Tampa Electric's response to Sierra Club's Second Interrogatory No. 89e above.

g. As mentioned in Tampa Electric's answer to Sierra Club's First Set of Interrogatories, No. 3, the timeline to re-enable petcoke as a feed fuel is currently estimated at around one year. This timeline could be affected by market conditions at the time of the desired modification.

i. Converting back to petcoke requires the following major equipment to be in service and operational:

a) Gasification block which includes solid fuel processing, air separation unit, gasifier, and acid plant. This equipment has been on long-term standby for several years.

b) Steam cycle components which includes the HRSG, steam turbine, and condensate system. This equipment will be put into long term standby beginning in March 2025 with the simple cycle conversion.

c) Gas turbine components which includes the combustion system. This is no longer supported by the gas turbine OEM.

If a decision is made to restore operation on petcoke, parts (a), (b), and (c) equipment will need to be thoroughly assessed and made ready for safe operations. Restoring the unit to petcoke operations depends heavily on market conditions (supply chain), environmental agency response time, and the OEM's ability to qualify and procure combustion hardware.

As mentioned above, the timeline to restore gasification block equipment is approximately one year. The condition of the gasification block, acid plant, and air separation unit, along with all balance of plant equipment, will need to be inspected, assessed, and tested to determine suitability for service. In addition to the restoration process outlined above, environmental permit modifications will need to be evaluated, requested, and acquired from the regulating agency before petcoke operations can begin. The timeliness of permit modifications depends on the agencies involved and any public opposition to them.

h.

i. No, but the requirements of final greenhouse case rule under section 111 of the Clean Air Act would be considered in any future evaluation of which fuel is optimal for Polk Unit 1.

ii. Tampa Electric cannot anticipate whether or not there would be additional environmental costs resulting from burning petcoke until engaging in the required permitting processes.

i. Please see the attached.

j.

i. Please see the table below.

| Unit | VOM Operating Costs (2025$/MWh) | Projected Forced Outage Rate (%) | Ramping Up Rate (MW/min) | Heat Rate (Btu/KWh) |
|---|---|---|---|---|
| **Polk 1 Status Quo** | 6.13 | 3.1 | 15 | 8770 |
| **Polk 1 Projected Simple Cycle CT** | 5.59 | 2.4 | 15 | 10,653 |

ii. The current and projected impacts for maintenance cycles are described in detail below.

**<u>Current</u>**
The maintenance cycles are as follows:
For combustion inspections: every 8,000 fired hours.

For hot gas path hardware: 32,000 fired hours and will require a major outage at that interval.
For steam turbines: every 5 years.

**Simple Cycle**

Because of the projected high number of starts, major maintenance cycles will be based on starts and estimated to occur every 1,250 starts. This will equate to major maintenance outages occurring every 8 – 10 years. Minor inspection outages will occur annually.

iii. Please see the company's answer to 89(j)(i), above.

iv. The current and projected impacts for start time are described in detail below.

**Current**

Start time for the combined cycle power block on natural gas and from ambient conditions is about 8 hours. This time includes the start of combustion turbine to the full load operation of the combustion turbine and steam turbine.

**Simple Cycle**

Start time in simple cycle will be around 20 minutes from off-line to full load operation.

v. Please see ease see the company's answer to 89(j)(i), above.

vi. Please see ease see the company's answer to 89(j)(i), above.

TECO
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# LEGAL AGREEMENT OVERVIEW
**Required for approval of all legal documents**

| | |
|---|---|
| **DATE** | 11/28/2017 |
| **COMMERCIAL LEAD** | Martin Duff |
| **NAME OF CONTRACT** | Valero-18-SP1-DAT (the "Agreement") |
| **ANNEXES, SCHEDULES, ADDENDA** | Exhibit A – Quality Specifications<br>Exhibit B – Refinergy Delivery Terms<br>Exhibit C – n/a<br>Exhibit D – Marine Provisions<br>Exhibit E – Third Party Marine Terms |
| **SUPPLIER/COUNTERPARTY** | Valero Marketing and Supply Company ("Counterparty") |
| **EMERA LEGAL ENTITY** | Tampa Electric Company |
| **TERM OF CONTRACT** | Effective Date: 01/01/2018<br>Expiry Date: 12/31/2018<br>Tenor: 1 year<br>No evergreen provisions. |
| **SUBJECT OF CONTRACT**<br>Description of the nature of the transaction under the Contract and business consideration/legal risks. | Purchase of up to 270,000 tons 13,000 Btu petcoke DAT. Indexed contract + $2.00 adder per/metric ton. Moisture content price adjustment. |
| **KEY TERMS**<br>Explanation of key terms that differ or deviate from Emera's standard and any other items that may represent a business and/or legal risk to Emera (use more space on back if necessary). | Standard Form Used: n/a<br><br>MaterialChanges: n/a<br><br>Governing law is NY. |
| **NOTIONAL VALUE** | $0.00 – no minimum and index transaction |
| **AUTHORIZED SIGNATORY** | 1. Juan Villa<br>2. Frank Busot |
| **COUNTERPARTY CONTACT INFO** | Martin Tovar, 210-345-2288 |

| **ROUTING/REVIEW:** | | **DATE:** |
|---|---|---|
| Marty Duff<br>Commercial Lead | M Duff | 12/15/17 |
| Karen Bramley<br>Manager, Bulk Fuel | K Bramley | 12/15/17 |
| Matt Costa<br>Legal Department | [signature] | 12/15/17 |

*Routing: LAO must be signed by: (1) Commercial Lead (2) Legal (3) Credit & Risk Management and (4) other Commercial sponsors.*
*Fully executed contract to be scanned and uploaded to Sharepoint. Original copy to be filed.*

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# LEGAL AGREEMENT OVERVIEW
**Required for approval of all legal documents**

Adam Djak
Credit & Risk Management

12/12/17

*Routing: LAO must be signed by: (1) Commercial Lead (2) Legal (3) Credit & Risk Management and (4) other Commercial sponsors.*
*Fully executed contract to be scanned and uploaded to Sharepoint. Original copy to be filed.*

Valero Contract Number 40575173
TE contract number, Valero-18-SP1-PC-DAT

KB MW 1/12/18
2017

# PETCOKE SALES AGREEMENT

This Petcoke Sales Agreement (the "Agreement") is made and entered into on the 10th day of October, 2016 (the "Effective Date") by and between Valero Marketing and Supply Company ("Seller") and Tampa Electric Company ("Buyer"). Seller and Buyer shall sometimes be individually referred to as a "Party" and collectively as "Parties".

The Parties hereby agree as follows:

1 **SPECIAL TERMS.** For purposes of this Agreement, the following terms (the "Special Terms") shall have the respective meanings set forth below.

| | |
|---|---|
| Petcoke or Product: | Green delayed petroleum coke produced at the Refinery. |
| Quantity: | Up to 270,000 Wet Short Tons of Petcoke, to be delivered, per Section 9 of the Agreement, over the Term |
| Base Price: | The Base Price of Petcoke delivered in any calendar month hereunder will be the Pace Petroleum Coke Quarterly, Table 1 Green and Calcined Petroleum Coke Prices Export Markets, High Sulfur Green Coke Gulf Coast/Caribbean, Below 50 HGI high-point per wet metric ton for the month prior to the month of barge delivery at the Destination Port +$2.00. For example, if the Barge is placed at the Destination Port during October, 2016, the Pace report issued in October that reports September prices will apply. September 2016 high-point is $68. Price equals $70.00 per Metric Ton DAT Barge. All pricing is based on metric tons.<br>Notwithstanding the above, in no case shall the price of Petcoke fall below $2.00/ metric ton. |
| Payment Terms: | Payments shall be made by Buyer to Seller within thirty (30) calendar days following the delivery of Seller's invoice and Supporting Documents.<br><br>Invoices and Supporting Documents shall be addressed and delivered to Buyer at:<br><br>tesettlementfuels@tecoenergy.com |
| Term: | Commencing on January 01, 2018 (the "Commencement Date") and ending on December 31, 2018. |
| Refinery: | Valero St. Charles Refinery located in St. Charles, Louisiana |
| Delivery Terms: | Delivery will be DAT at the Buyer's Pile at the Destination Port (as defined below). |

Valero Contract Number 40575173
TE contract number, Valero-18-SP1-PC-DAT

| | |
|---|---|
| Destination Port: | The U.S. United Bulk Terminal ("UBT") located in Davant, Louisiana located at MP 53.7 lower Mississippi River. |
| Load Rates: | The load rates and other special delivery terms for the Refinery are set forth on Exhibit B attached hereto and incorporated herein for all purposes. |
| Intended Use: | The Petcoke purchased under this Agreement is intended to be used in Buyer's Polk Unit No. 1 or Buyer's Big Bend Power Plants (the "Power Plants"). |
| Other Terms and Conditions: | Seller is responsible for all charges associated with the unloading of river barges and also loading charges of Buyers Vessel both of which will be dealt with directly between Seller with UBT. Any storage charges incurred for Petcoke in Buyer's storage pile at UBT will be invoiced directly to Buyer by UBT. |
| Third Party Marine Terms: | The U.S. United Bulk Terminal Rules and Regulations dated April 1, 2015, as may be amended from time to time |
| Buyer's Address for Notice: | Tampa Electric Company<br>702 North Franklin Street<br>Tampa, Florida 33602<br>Attention: Brent Caldwell, Director<br>Fuels Department<br>Telephone: (813) 228-1509<br>Facsimile: (813) 228-1545 |
| With copy to: | Attention: Michelle Szekeres, Associate General Counsel<br>TECO Services, Inc.<br>Legal Services<br>Telephone: (813) 228-1429<br>Facsimile: (813) 228-1328<br><br>If applicable, the following Buyer contacts and their respective subject matter expertise are provided for convenience purposes only:<br><br>All Matters except invoices: Martin Duff, Fuels Origination<br>Tel: (813) 228-1596 |
| Exhibits and Conflict of Terms: | Exhibit A – Specifications<br>Exhibit B – Refinery Delivery Terms<br>Exhibit C – Not applicable<br>Exhibit D - Marine Provisions<br>Exhibit E - Third Party Marine Terms |

Valero Contract Number 40575173
TE contract number, Valero-18-SP1-PC-DAT

Any reference in this Agreement to the Special Terms shall mean and refer to the information and terms set forth in the Special Terms above. In the event of any conflict between the Special Terms and the other terms of this Agreement, the Special Terms shall control.

2 **DEFINITIONS.** The following definitions will apply to this Agreement.

(a) **"Affiliate"** means any entity that, directly or indirectly, controls, is controlled by, or is under common control with the referenced entity, including the referenced entity's parent. In this definition, "control" means the power to direct the management and policies of an entity, directly or indirectly, whether through the ownership of voting securities, by contract, or otherwise.

(b) **"Agreement"** means this Petcoke Sales Agreement, as such may be amended from time to time.

(c) **"Applicable Law"** means any and all federal, state, and local codes, constitutions, decrees, directives, laws, licenses, ordinances, injunctions, orders, permits, regulations, requirements, rules, and statutes applicable to the Parties or this Agreement which have been implemented, and are enforced, by any judicial, regulatory, or governmental authority, agency, body, commission, or department which have jurisdiction over the Parties or this Agreement or the subject matter hereof.

(d) **"ASTM"** means **ASTM** International, formerly known as the American Society for Testing and Materials.

(e) **"Business Day"** means a day on which banks are open for general commercial business in New York, New York.

(f) **"Buyer's Pile"** means the Petcoke pile provided by and designated by Seller at the Destination Port and placed at the disposal of the Buyer.

(g) **"Cargo"** means a shipment of Petcoke.

(h) **"DAT"** shall have the meaning ascribed to it in Incoterms 2010.

(i) **"Destination Port"** means the terminal identified in the Special Terms where the Petcoke is to be delivered hereunder.

(j) **"Effective Date"** is defined in the preamble of this Agreement.

(k) **"Force Majeure"** means any cause or event reasonably beyond the control of a Party, including (but without limiting the generality of such term): fires, earthquakes, lightning, floods, explosions, storms, adverse weather, landslides and other acts of natural calamity or acts of God; navigational accidents or maritime peril; vessel damage or loss; strikes, grievances, actions by or among workers or lock-outs (whether or not such labor difficulty could be settled by acceding to any demands of any such labor group of individuals and whether or not involving employees of Seller or Buyer); accidents at, closing of, or restrictions upon the use of mooring facilities, docks, ports, pipelines, harbors, railroads or other navigational or transportation mechanisms; disruption or breakdown of, explosions or accidents to wells, storage plants, terminals, machinery or other facilities; acts of war, hostilities (whether declared or undeclared), civil commotion, embargoes, blockades, terrorism, sabotage or acts of the public enemy; any act or omission of any governmental authority; good faith compliance with any order, request or directive of any governmental authority; curtailment, interference, failure or cessation of supplies (other than Petcoke unless there occurs a curtailment, reduction or interruption of Petcoke production at the Refinery) reasonably beyond the control of a Party; or any other cause reasonably beyond the control of a Party, whether similar or dissimilar to those above and whether foreseeable or unforeseeable, which, by the exercise of due diligence, such Party could not have been able to avoid or overcome. As it relates to Seller the term Force Majeure shall also include any accident, failure, defect or breakage of equipment or machinery, including without limitation the delayed petroleum coker units at the Refinery regardless of the cause of such accident, failure, defect or breakage; or any interruptions, outages or turnarounds at the Refinery. The term "Force Majeure" expressly excludes (i) a failure of performance of any Person other than the Parties, except to the extent that such failure was caused by an event that would otherwise satisfy the definition of Force Majeure under this Agreement, (ii) the loss of Buyer's market or any market conditions for the Petcoke that are unfavorable to Buyer, or (iii) a Party's inability to economically perform its obligations under this Agreement.

(l) "**Incoterms**" shall mean the 2010 edition of the trade terms published by the International Chamber of Commerce which shall apply to this Agreement to the extent that they do not conflict with the provisions of this Agreement.

(m) "**Interest Rate**" means an annual rate (based on a 360-day year) equal to the lesser of (i) two percent (2%) over the prime rate as published under "Money Rates" in the Wall Street Journal in effect at the close of the Business Day on which payment was due and (ii) the maximum rate permitted by Applicable Law.

(n) "**Laycan Window**" means the period (contract delivery date range) during which the Vessel nominated by or on behalf of Buyer or Seller under this Agreement is to present itself at the Load Port which except as otherwise expressly stated in the Special Terms shall be a 7 days period of time.

(o) "**Load Port**" means the terminal or other location as identified in the Special Terms where the Petcoke to be delivered hereunder is or will be loaded; provided that, for the avoidance of doubt, the term "Load Port" is used interchangeably with the term "Destination Port" throughout this Agreement.

(p) "**Marine Provisions**" mean the Valero Marketing and Supply Company Dry Bulk Marine Provisions, Effective September 1, 2014, a copy of which are attached as Exhibit D hereto and incorporated herein for all purposes. Seller reserves the right from time to time to amend, supplement, modify or revoke its Marine Provisions provided that (i) Seller provides Buyer with written notice of any such amendment, supplement, modification or revocation, (ii) such amendment, supplement, modification or revocation shall be uniformly applied to all of Seller's dry bulk marine customers who are purchasing Petcoke produced at the Refinery, and (iii) any amendment, supplement, modification or revocation shall not materially and adversely affect Buyer's rights and obligations under this Agreement.

(q) "**NOR**" means Notice of Readiness.

(r) "**Party**" means Buyer or Seller, and "**Parties**" means Buyer and Seller.

(s) "**Petcoke**" is defined in the Special Terms.

(t) "**Refinery**" means the refinery owned by Seller's Affiliate where the Petcoke is produced as identified in the Special Terms. If the Petcoke is produced at more than one Refinery, the term Refinery shall mean any one of the refineries identified in the Special Terms above and the term "**Refineries**" shall mean collectively, all of the refineries identified in the Special Terms.

(u) "**Seller**" is defined in the preamble of this Agreement, and includes its successors and assigns.

(v) "**Shipment Date**" means the date the Cargo is discharged into Buyer's Pile at the Destination Port.

(w) "**Specifications**" means the specifications for the Petcoke as produced at the Refinery which are set forth on Exhibit A attached hereto and incorporated herein for all purposes.

(x) "**Taxes**" means any and all foreign, federal, state and local taxes, duties, fees and charges of every description, including all motor fuel, excise, VAT, special fuel, environmental, spill, gross earnings or gross receipts and sales and use taxes, however designated, paid or incurred with respect to the purchase, storage, exchange, use, transportation, resale, importation or handling of the Petcoke; provided, however, that "Taxes" does not include: (i) any income withholding tax or tax imposed on or calculated based upon net profits, gross or net income, profit margin or gross receipts (excluding, for the avoidance of doubt, any transaction taxes that are based upon gross receipts, gross earnings or gross revenues received specifically from the sale of Petcoke); (ii) any tax measured by capital value or net worth, whether denominated as franchise taxes, doing business taxes, capital stock taxes or the like; (iii) business license or franchise taxes or registration fees; or (iv) any ad valorem or personal property taxes.

(y) "**Term**" has the meaning given such term in Section 3.

(z) "**Third Party Marine Terms**" has the meaning given such term in the Special Terms.

(aa) "**Wet Short Tons**" means 2,000 pounds avoirdupois weight, including moisture.

(bb) "**Wet Metric Tons**" means 2,204.6 pounds avoirdupois weight, including moisture.

3 **TERM**. The term of this Agreement (the "Term") shall begin on the Commencement Date and unless sooner terminated pursuant to any provision hereof shall continue for the time period specified in the Specific Terms.

4 **SALE OF PETCOKE**. Subject to the terms of this Agreement, Seller agrees to sell to Buyer and Buyer agrees to purchase from Seller the Petcoke in the Quantity identified in the Special Terms.

5 **PRODUCT AND QUALITY.** All Petcoke sold to Buyer hereunder shall (i) conform to the Specifications, (ii) be free from excess quantities of wood, metal, rock, wire, plastic and other similar impurities, and (iii) be delivered at a temperature not to exceed 140°F, as determined from analysis of samples taken from the Cargo at the point of title transfer. Except for the Specifications, Seller makes no representation as to the quality or specifications of the Petcoke produced and sold under this Agreement. The Parties specifically acknowledge that the Petcoke's characteristics and specifications can change depending on a particular Refinery's crude slate and operations and the particular Refinery operator shall have the sole and absolute discretion to run such crude slates and operate the Refinery as the particular Refinery operator deems appropriate without regard to any impact on the petcoke production. Notwithstanding anything contained herein to the contrary, the Petcoke shall consist only of petroleum coke produced from the Refinery's delayed petroleum coker unit. In the event that the characteristics and specifications of the Petcoke materially change such that Buyer is not able to use the Petcoke at its powerplant, Buyer may as its sole and exclusive remedy (subject to Section 14(e)), terminate this Agreement upon thirty (30) days written notice to Seller.

6 **PRICE.**

(a) Base Price. In consideration for the Petcoke, Buyer agrees to pay Seller the purchase price as reflected under the term Base Price in the Special Terms.

(b) Price Adjustment. The Base Price will be adjusted up or down based on 8.0% moisture, fractions pro rata according to the following formula: [(8.0 – Actual Moisture %) / 100 + 1] X Base Price = Total Purchase Price.

Example: (8.0 - 8.5) / 100 = -0.005
-0.005 + 1 = 0.995
0.995 X $27.00 = $26.87 per MT Invoice Price

7 **PAYMENT TERMS.**

(a) Payments. Seller shall invoice Buyer for all amounts that due Seller under this Agreement. Invoices and Supporting Documents received after 1:00 P.M. Eastern Prevailing Time (12:00 Noon Central Prevailing Time) shall be considered to be received on the next Business Day. All payments hereunder shall be made by wire transfer of immediately available funds to Seller pursuant to the payment terms set forth in the Special Terms without discount, deduction, withholding, offset or counterclaim in U.S. dollars to the bank and account designated by Seller.

(b) Supporting Documents. Seller shall provide the following supporting documentation to Buyer with each invoice (the "Supporting Documents"):

(i) Copy (ies) of Independent Inspector's report of loaded quantity and quality (may be presented as two separate documents) (facsimile acceptable).

(c) Interest and Costs. Any amount payable by a Party hereunder shall, if not paid when due, bear interest from the payment due date until, but excluding; the date payment is received by the other Party, at the Interest Rate. Each Party shall pay all the other Party's costs (including reasonable attorney's fees and court costs) of collecting past due payments.

(d) Disputed Invoices. If Buyer, in good faith, disputes the accuracy of the amount invoiced for Product delivered by Seller, Buyer shall pay the undisputed amount of the invoice and provide written notice stating the reasons why the invoice amount is incorrect, along with supporting documentation acceptable in industry practice. In the event the Parties are unable to resolve such dispute, either Party may pursue any remedy available at law or in equity to enforce its rights hereunder. In the event that it is determined or agreed that Buyer must or will pay the disputed amount then Buyer shall pay interest from and including the original payment due date until, but excluding, the date the disputed amount is received by Seller at the Interest Rate.

(e) Split Weekend Clause. If the payment due date falls on a Sunday, or on a Monday that is not a Business Day in the place where payment is to be made, payment shall be made in immediately available funds to Seller on the next Business Day after such payment due date. If the payment due date falls on a Saturday, or on a non-Business Day other than a Monday in the place where payment is to be made, payment shall be made in immediately available funds to Seller on the last Business Day prior to such payment due date.

## 8 CREDIT.

(a) Credit Approval. If Seller has reasonable grounds for insecurity as to the Buyer's creditworthiness or performance hereunder, Seller may, in its sole discretion require Buyer to (i) prepay Seller the full amount according to Seller's invoice for any Cargo of Petcoke by wire transfer of immediately available funds at least two (2) Business Days prior to the Laycan Window, (ii) post an irrevocable standby letter of credit that meets the requirements of Section 8(b), or (iii) provide some other form of credit support reasonably acceptable to Seller. In the event the above requirements have not been satisfied within the specified time limits, Seller shall have the option of terminating this Agreement and/or proceeding against Buyer for damages caused by Buyer's failure to perform. Seller's delivery or shipment of Petcoke hereunder prior to Buyer making payment or posting the letter of credit as provided above, shall not operate as a waiver of Seller's rights to immediately impose the credit support obligations under this Section or at any future time prevent Seller from promptly exercising any other option, right or remedy that it may have under the terms of this Agreement.

(b) Letter of Credit. In the event that Seller requires a letter of credit pursuant to Section 8(a), payment shall be covered by an irrevocable standby letter of credit to be issued and the original received by Seller not later than two (2) Business Days prior to each Laycan Window (or, in the case where a single letter of credit will cover multiple Cargos on the first Laycan Window), in a form acceptable to Seller, and issued by an A-rated bank acceptable to Seller. Such letter of credit shall be opened with sufficient value to cover the aggregate contractual volume plus ten percent (10%) times the aggregate price specified in Section 6 hereof. If at the time of executing the letter of credit the price is not fixed, the pricing clause set forth in Section 6 shall be quoted in the letter of credit and the letter of credit shall be opened with sufficient value to cover the aggregate contractual volume plus ten percent (10%) times a mutually agreed estimated price. If, after the price of a Cargo is fixed, the value of the letter of credit is not sufficient to cover the aggregate contractual volume plus ten percent (10%) times the aggregate price, then Seller may request that Buyer provide it with an amended letter of credit with sufficient value not later than the next Business Day following the date on which Seller requests the amended letter of credit.

All bank charges related to the letter of credit are for the account of Buyer. The letter of credit shall not expire until 30 days after the final invoice due date.

9 **DELIVERY.**

(a) All Petcoke sold hereunder shall be delivered to Buyer in the manner set forth in the Special Terms and pursuant to the Marine Provisions and any Third Party Marine Terms.

(b) Petcoke will be shipped ratably over the course of the Term.

(c) Nominated Vessels, including each Vessel to be used in cargo loading and discharging, must be mutually acceptable to all Parties. Such acceptance is not to be unreasonably withheld. The nominated Vessel will be required to be vetted by Seller's Marine Assurance Department and meet the general Vessel requirements of the Load Port, including published or posted terminal requirements. Acceptance of any Vessel shall not constitute a continuing acceptance of such Vessel for any subsequent loading.

(d) Seller shall provide the Buyer's Pile and the Buyer's Pile shall be sufficient to receive the Petcoke to be delivered pursuant to this Agreement. Any additional charges incurred by Buyer as result of Seller's failure to so provide the Buyer's Pile shall be for the account of Seller.

(e) The Parties acknowledge that (i) the Marine Provisions which are attached hereto shall apply to all deliveries by Vessel under the terms of this Agreement, and (ii) the Third Party Marine Terms shall apply to the Parties' use of the Load Port in connection with this Agreement. Buyer is responsible for any and all tariffs and other charges as outlined in the Third Party Marine Terms. In addition, Buyer or its Vessel Party (as that term is defined in the Dry Bulk Marine Provisions) shall be responsible for all wharfage fees, dockage fees, security fees and other service fees, duties and Taxes imposed upon the Vessel by the port or port authority (including, without limitation, charges for mooring, fresh water, steam, oil slops receipts, Tows and pilots, and fleeting costs, and taxes on freight). Should any of the above referenced fees be imposed upon Seller or to the extent Seller pays any of the above referenced fees, Buyer agrees to promptly reimburse Seller upon demand.

(f) The cost of freight for transportation beyond the Load Port shall be for Buyer's account and shall be paid directly by Buyer; provided that, for the avoidance of doubt, Seller shall be responsible for any fees imposed by UBT associated with the moving the Product from Buyer's Pile and loading the Product on Buyer's Vessel. The obligations of Seller in this respect shall survive the expiration or termination of this Agreement for a period of three years.

10 **TITLE AND RISK OF LOSS.** Title and risk of loss of a Cargo of Petcoke shall pass from Seller to Buyer at the Destination Port as the Product is discharged from Seller's Bargesinto Buyer's Pile. Buyer will assume all risk of loss once Petcoke is assigned to Buyer's Pile.

11 **REFINERY PRODUCTION.** Both Parties acknowledge and agree that the Petcoke sold pursuant to this Agreement is produced as a by-product of a Refinery operation. Notwithstanding anything in this Agreement to the contrary, if (i) a Refinery ceases to produce Petcoke, for any

reason or for no reason; (ii) there is a curtailment, reduction or interruption of Petcoke production at a Refinery, including without limitation, the Refinery's voluntary election to curtail, reduce or interrupt production of Petcoke; or (iii) there is a complete or partial shutdown of a Refinery, Seller and its Affiliates shall have no obligation or liability to sell or provide Petcoke to Buyer hereunder. Seller makes no representation, guarantee or warranty as to the quality or quantity of Petcoke which will be produced from the Refinery, as quality and quantity are likely to vary.

12 **ALLOCATION**. Notwithstanding the foregoing, if due to (i) an event of Force Majeure or (2) curtailment, reduction or interruption of Petcoke production at the Refinery (collectively a "Curtailment"), Valero does not have sufficient supplies of Product to meet its supply obligations under this Agreement and its other Product supply obligations, then Valero shall allocate Product to Buyer from its available supplies of Product on a basis which is fair and reasonable, including, but not limited to, the Buyer's purchase commitment pro rata with all other supply obligations to Valero's customers for Product from the Refinery existing at the time of the event of Force Majeure or Curtailment. Furthermore, this Agreement shall not be construed in any way to require Valero to purchase Product to supply any or all of the contract volume hereunder, except Product produced by the Refinery. In the event of a Curtailment, Seller shall not be obligated to purchase petcoke in the open or spot market or obtain petcoke from any of Seller's affiliates' refineries to supplement Seller's existing or contemplated availability of Product. In the event of a Curtailment, Valero upon the request of Buyer within fifteen (15) days following such Curtailment will, to the extent possible and subject to availability of petcoke at the Refinery, make-up any deficit amounts of Petcoke which were not otherwise available as a result of the Curtailment (the "Deficit Amount"). Seller shall have the right upon the approval of Buyer to add the Deficit Amount ratably to Shipments of Petcoke during the remainder of the term of this Agreement or extend the term of the Agreement up to six months for the sole purpose of providing the Deficit Amount of Petcoke to Buyer. The above notwithstanding, in no event shall the Deficit Amount exceed ten percent (10%) in the aggregate of total annual amount of Petcoke to be sold and delivered to Buyer under the terms of this Agreement. Notwithstanding the foregoing, Buyer reserves the right to reduce the amount of Petcoke it is obligated to purchase under this Agreement in the event that Buyer decides, in its sole discretion, to curtail or otherwise reduce the quantity of Petcoke burned at the Powerplant (collectively a "Reduction in Need"), provided however that a Reduction in Need shall not be available as a result of Buyer's ability to purchase petcoke at a lower price than the price of the Petcoke hereunder. A Reduction in Buyer's Needs shall be made ratably across all other commitments Buyer has made for Petcoke, and shall be effective upon thirty (30) days notice to Seller.

13 **TAXES.**

(a) Except as expressly set forth in the Special Terms above, Seller shall be liable for any and all Taxes with respect to the Petcoke delivered hereunder, the taxable incident of which occurs before the transfer of title to the Petcoke to Buyer, regardless of the character, method of calculation or measure of the levy or assessment. Buyer shall be liable for any and all Taxes with respect to the Petcoke delivered hereunder, the taxable incident of which occurs after the transfer of title to the Product to Buyer, regardless of the character, method of calculation or measure of the levy or assessment. Any and all Taxes the taxable incident of which is the transfer of title, regardless of the character, method of calculation or measure of the levy or assessment, shall be paid by the Party upon which the Tax is imposed by the applicable taxing authority.

(b) To the extent a Party ("X") is required by applicable law to pay or remit certain Taxes on behalf of the other Party ("Y") or X otherwise pays Taxes for which Y is liable under Applicable Law, Y shall reimburse X to the extent X paid such Taxes. Y's reimbursements of Taxes to X shall be grossed up as necessary to return to X, after payment of any Taxes thereon, the amount actually paid by X. A Party shall not be responsible for any penalties or interest related to the obligations of the Party in respect of Taxes to the extent such penalties or interest accrue based on the actions or inactions of the other Party.

(c) The importer of record shall be responsible for and shall pay all custom duties, import fees, environmental fund fees and other assessments pertaining to the importation of the Petcoke.

(d) If Buyer claims exemption from any of the aforesaid Taxes, then Buyer, in lieu of payment of or reimbursement of such Taxes to Seller, shall furnish Seller with a properly completed and executed exemption certificate in the form prescribed by the appropriate taxing authority. Buyer shall promptly notify Seller in writing of any change in the status of its exemption.

(e) If any ad valorem or personal property taxes are assessed against the Petcoke, the Party having title to the Petcoke at the time such tax liability is assessed shall be responsible for payment of such taxes.

14 **INSPECTION, QUANTITY AND QUALITY.**

(a) Measurements. All measurements and tests for quantity and quality shall be made in accordance with the most current ASTM standards. Should Buyer desire to inspect the loading, and/or sampling of a Cargo, Seller shall use reasonable efforts to obtain permission and approval for Buyer or its representative to conduct the inspection.

(b) Official Quantity. The official quantity of each Cargo of Petcoke sold hereunder shall be determined by a Barge draft survey performed by a mutually acceptable independent marine surveyor at the Load Port whose determinations shall be conclusive and binding upon both Parties, absent fraud or manifest error. If either Party should be dissatisfied with the weight determination, the Parties will use commercially reasonable efforts to find a suitable alternative method of weighing the Petcoke. Seller shall pay the cost of the independent surveyor. Buyer shall have the right to have a representative present at any and all times to observe the determination of weights.

(c) Quality Determination. Each Cargo of Petcoke sold hereunder shall be sampled by the most representative method possible on the loadout conveyor at the point of title transfer. Unless otherwise mutually agreed in writing, the sampling, sample preparation and analysis shall be performed by an independent laboratory (hereinafter called "Testing Lab"), mutually agreed to by both the Buyer and Seller according to the most current ASTM standards using the most reliable classification method and related procedures possible and the results shall be final and binding upon Buyer and Seller. In the event of breakdown, malfunction, or other inadequacy of sampling equipment not caused by the acts or omissions of Seller, Seller shall be entitled to use other sampling methods that are in accordance with then-current ASTM standards. Unless otherwise requested in writing by the Buyer, Seller shall cause one sample to be taken from each Cargo of Petcoke delivered hereunder.

(d) Analysis.

(i) The Testing Lab shall carefully prepare and process each sample in accordance with then-current ASTM methods, and shall divide each sample (other than the samples taken for size consist analysis) into three (3) or more splits, which shall be put into suitable airtight containers as applicable, properly sealed and labeled indicating, among other things, the identity of the Cargo.

(ii) Unless otherwise mutually agreed in writing, the Testing Lab to be used in connection with this Agreement shall be SGS, St. Rose, Louisiana. The first split shall be retained by the Testing Lab for short proximate analysis on the Cargo, as described below. The second split shall be identified as a "referee split" to be used for a referee analysis, if needed, and retained by the Testing Lab for a period of sixty (60) days from the date the sample was taken. The third split shall be retained by the Testing Lab for a period of thirty (30) days from the date the sample was taken, and shall be a spare sample and used if needed.

(iii) Promptly after the first split of each sample is obtained, the Testing Lab shall perform analyses of moisture, ash, sulfur, volatile matter, calorific value, Hargrove and grindability on such split in accordance with then-current ASTM methods. The results of such analyses shall determine the official per-Shipment measurements to be used in calculating the monthly weighted average analysis. Seller shall cause certified results to be delivered to Buyer by telecopy, telex or telephone within seventy-two (72) hours after completion of the barge loading, with an allowance of additional time to the extent barge loading was completed on a holiday or weekend. Except as provided below, the aforementioned analytical results shall be binding on the Buyer and the Seller.

(iv) After the end of each calendar month, Buyer shall calculate the mathematical weighted average of the results of the short proximate analyses taken on the first splits. The results of such calculation shall determine the official weighted monthly average of percentage ash, gross calorific value, percentage sulfur, percentage moisture, percentage volatile matter, and grindability. Except as provided below, the aforementioned analysis results shall be binding on the Buyer and the Seller for determining compliance with this Agreement.

(v) The cost of analyses shall be for the Seller's account, but copies of the results shall be forwarded by the Testing Lab to both Buyer and Seller, and to any other party requested by the Buyer and approved by Seller; Seller's approval will not be unreasonably withheld.

(vi) Either Party may request a referee analysis, should a disagreement as to the quality determined hereunder of any Cargo(s) of Petcoke arise within thirty (30) days after receipt of the Testing Lab's analysis. Upon such request, the corresponding referee split(s) shall be forwarded by the Testing Lab to a nationally recognized, independent testing laboratory, mutually agreed upon in writing by the Parties, for referee analysis using the same methods as described previously. The results of any such referee analysis shall override the results of the Testing Lab analysis and shall be final and binding on the Parties for all purposes herein. The cost of any such referee analysis shall be borne by the requesting Party.

(e) Remedies for Quality Deficiencies – Rejection and/or Termination.

(i) Buyer shall be entitled (but not obligated) to reject a Shipment, by tendering written demand (or verbal instructions followed by written confirmation) to Seller within forty-eight (48) hours of Buyer's receipt of the Testing Lab results, at the Destination Port or in route but prior to unloading from the transportation contractor's equipment, should the Testing Lab's analytical data indicate that such Shipment delivered hereunder fails to conform to any moisture, ash, gross calorific value, sulfur, volatile or grindability per-Cargo specification limits provided in Article 5. If Buyer rightfully rejects a Shipment while the Shipment is in Buyer's possession, Seller shall be obligated to promptly remove such Shipment. Except as provided by paragraph (b) below, any reasonable costs or expenses incurred in the inspection, receipt, transportation and storage of the rejected Shipment shall be for the account of Seller. The Parties shall in good faith decide if the rejected Shipment can and will be made up, taking into account among other things tonnage and availability. In the event that a referee analysis, if any, taken pursuant to this Article 14 hereof does not support the rejection of deliveries hereunder, said delivery shall be resumed and any missed deliveries shall be made up at Seller's option, but Buyer shall not be liable for damages or for reimbursing Seller-incurred expenses as a consequence of rejection of deliveries in reliance upon the Testing Lab results. Any costs or expenses incurred in the inspection, receipt, transportation and storage of such Shipment incurred by Buyer shall be for the account of Buyer.

(ii) Should the Testing Lab's analytical data indicate that the monthly weighted average delivered hereunder fails to conform to any of the quality specifications herein provided, Buyer and Seller shall promptly discuss a mutually satisfactory settlement. In the event Buyer and Seller fail to reach a mutually satisfactory settlement within 30 days after such settlement discussion commenced, upon written election of the Buyer this Agreement will terminate immediately without penalty to either Party.

(iii) Should the monthly weighted average Moisture Value exceed the maximum value of 8.0%, the invoiced weight of the relevant month's Shipments shall be adjusted downward to deduct for the moisture in excess of 8.0% prorata.

15 **CLAIMS.** Any and all claims either as to a shortage in quantity or quality shall be made by the claiming Party in writing to the other Party within 90 days after delivery and shall include documentation supporting the claim. If no such written notice of claim is received within 90 days after delivery of the Petcoke to the Buyer, the claim shall be deemed to have been waived.

16 **LAYTIME, DEMURRAGE AND LOAD RATES.**

(a) Laytime. Allowed laytime for any Vessel nominated under the Agreement shall be based on the load rate as set forth in the Special Terms. Laytime shall commence 12 hours after NOR has been tendered or commencement of loading, whichever is occurs first

(b) Demurrage. Demurrage shall be payable for each running hour and pro rata for each part of an hour that used laytime exceeds the allowed laytime. The demurrage rate shall be the rate set forth in the charter party terms for the Vessel. Dispatch is one-half of the demurrage rate.

(c) Load Rates. The minimum load rate for each Cargo shall be as set forth in the Special Terms.

17 **WARRANTY OF TITLE.** Seller represents and warrants to Buyer that as of the date of delivery of the Products hereunder, Seller has good title to the Petcoke sold and delivered, free and clear of any liens or encumbrances, other than taxes that are due by Buyer. OTHER THAN SELLER'S EXPRESS WARRANTIES SET FORTH IN THIS AGREEMENT, SELLER MAKES NO OTHER REPRESENTATION OR WARRANTY, WRITTEN OR ORAL, EXPRESS OR IMPLIED, INCLUDING ANY REPRESENTATION OR WARRANTY REGARDING MERCHANTABILITY, FITNESS OR SUITABILITY OF THE PETCOKE FOR ANY PARTICULAR PURPOSE, EVEN IF SUCH PURPOSE IS KNOWN TO SELLER.

18 **FORCE MAJEURE.**

(a) Affect of Force Majeure. Neither Party shall be liable to the other Party if it is rendered unable by an event of Force Majeure to perform in whole or in part any obligation or condition under this Agreement, for so long as the event of Force Majeure exists and to the extent that performance is prevented by the event of Force Majeure; provided, however, that the Party unable to perform shall use commercially reasonable efforts to avoid or remove the event of Force Majeure (provided, however, no Party shall be compelled to resolve any strikes, lockouts or other industrial disputes other than as it shall determine to be in its best interests). During the period that a Party's performance of its obligations under this Agreement has been suspended in whole or part by reason of an event of Force Majeure, the other Party likewise may suspend the performance of all or part of its obligations to the extent that such suspension is commercially reasonable, except for any payment and indemnification obligations arising prior to the occurrence of such Force Majeure event. No condition of force majeure shall operate to extend the terms of this Agreement.

(b) Notice. If the event of Force Majeure renders either Party unable, in whole or in part, to carry out its obligations under this Agreement, such Party (the "Notifying Party") must give the other Party (the "Noticed Party") notice and full particulars in writing as soon as practicable after the occurrence of the causes relied upon, or give notice by telephone and follow such notice with a written confirmation within forty-eight (48) hours.

(c) Termination. In the event that the period of suspension due to a Force Majeure event shall continue in excess of 30 days from the date that notice of such event is given, and so long as such event is continuing, the Party not affected by the Force Majeure event, in its sole discretion, may terminate such affected transaction by written notice to the other Party, and neither Party shall have any further liability to the other Party in respect of such transaction except for the rights and remedies previously accrued.

(d) In the event Buyer (or Buyer's contractor or agent) is unable to take delivery of or redeliver the Product to the Powerplant or to unload, accept or utilize the Product at the

Powerplant, in either case due to a Force Majeure, it is agreed that on Buyer's giving notice and full particulars of such Force Majeure to Seller, the obligations of Buyer shall be suspended from the date of receipt of such notice and for the continuance of any inability so caused, but for no longer period, and such cause shall, so far as possible, be remedied with all reasonable dispatch..

19 **DEFAULT.**

(a) Default by Seller. The failure by Seller to deliver Product in accordance with the terms and conditions of this Agreement (except where caused by Force Majeure, the result of a Curtailment as provided in Article 12 hereof, or a change in the specifications or characteristics of Petcoke as a result of the Refinery crude slate and operations as provided in Article 5 hereof) where such failure continues for a period of twenty (20) days after notice has been given by Buyer, shall constitute a default by Seller under the terms of this Agreement (a "Seller Event of Default"). Upon the occurrence of a Seller Event of Default Buyer shall be entitled to terminate and cancel this Agreement by giving one (1) business day's notice to Seller specifying the Seller Event of Default and Seller shall be liable to Buyer as damages for each ton of Product not delivered by reason of such Seller Event of Default an amount equal to the excess, if any, of (i) the Replacement Price (as defined below) for Product not delivered plus any increased transportation costs Buyer may incur; over (ii) the applicable price at the time of the cancellation of this Agreement for the Product not delivered plus transportation expenses saved as a result of cancellation or the Seller Event of Default. For purposes of the foregoing, the term "Replacement Price" means the price at which Buyer purchases (if at all) substitute Product in a commercially reasonable and good faith manner, of the same type, quality and in the same geographic region (Gulf Coast) as prescribed in this Agreement, or, absent such purchase, the prevailing market price as published as the Argus Index or Pace Index (or in a comparable industry publication if the Argus Index and Pace Index are no longer published) for such quantity of Product delivered to the Destination Port at the time of the cancellation.

(b) Default by Buyer. If Buyer (i) fails to schedule or accept all or any part of the quantity of Product to be delivered hereunder (unless excused by Force Majeure, the result of a Curtailment as provided in Article 12 hereof, or a change in the specifications or characteristics of Petcoke as a result of the Refinery crude slate and operations as provided in Article 5 hereof) and such failure continues for a period of twenty (20) days after notice has been given by Seller; or (ii) fails to pay for Product delivered hereunder and such failure continues for a period of five (5) days after notice has been given by Seller, Buyer shall be in default of this Agreement (a "Buyer Event of Default"). Upon a Buyer Event of Default, Seller may (i) withhold or suspend its performance under this Agreement (ii) without canceling or terminating the Agreement, proceed against Buyer for all sums owing to Seller hereunder; and/or (iii) with one (1) business day's notice to Buyer ("Cancellation Notice"), terminate this Agreement and liquidate and close out payment obligations then outstanding between the Parties under this Agreement in accordance with this Section 19.3(b). In the event of a termination of this Agreement by Seller hereunder, Buyer shall be liable to Seller for all unpaid invoices issued by Seller with respect to Shipments delivered prior to the effective date of termination specified in the Cancellation Notice, and (ii) the amount for each ton of Product not delivered by reason of such failure or termination an amount equal to the excess, if any, of (x) the applicable price at the time of the termination of this

Agreement for the Product not delivered plus any transportation expenses Seller may incur up to the Destination Port minus transportation expenses saved as a result of Buyer's breach; over (y) the Sales Price (as defined below). For purposes of the foregoing, the term "Sales Price" means the price at which Seller sells (if at all) into the market the Product not delivered pursuant to this Section 19.3(b) in a commercially reasonable and good faith manner, or, absent such sale, the prevailing market price as published as the Argus Index or Pace Index (or in a comparable industry publication if the Argus Index and Pace Index are no longer published) for such quantity of Product delivered to the Destination Port at the time of the cancellation.

(c) Liquidation and Close-Out. The Parties acknowledge that this Agreement is a "Forward Contract" as defined in the Bankruptcy Code [11 U.S.C. Sec. 101(25)]. If one Party (the "Defaulting Party") (i) shall voluntarily file a petition in bankruptcy, reorganization, or receivership or shall be forced by its creditors into bankruptcy, reorganization or receivership, (ii) becomes insolvent or incapable of paying its debts as they become due, or (iii) makes a general assignment for the benefit of creditors, the other Party (the "Liquidating Party") shall have the immediate right, exercisable in its sole discretion, to liquidate this Agreement and all other forward contracts as defined in the Bankruptcy Code then outstanding between the Parties (whether the Liquidating Party is Seller or Buyer thereunder) by closing out all such contracts at the then current market prices so that each contract being liquidated is terminated except for the settlement payment referred to below. The Liquidating Party shall calculate the difference, if any, between the price specified in each contract so liquidated, and the market price for the relevant commodity as of the date of liquidation (as published as the Argus Index or Pace Index, or in a comparable industry publication if the Argus Index and Pace Index are no longer published)), and aggregate or net such settlement payments, as appropriate, to a single liquidated amount. Payment of said settlement payment will be due and payable within one (1) Banking Day after reasonable notice of liquidation. The liquidation and close-out of this Agreement and all other forward contracts is in addition to any other rights and remedies which the other Party may have.

(d) Monetary Remedies. The remedies provided in Sections 19.3(a), 19.3(b) and 19.3(c) shall constitute the sole and exclusive monetary remedies of a non-defaulting Party in respect of an event of default attributable to the other Party, and the non-defaulting Party shall have no other monetary remedies in respect of any such event of default, except for claims under any indemnity obligations expressly set forth in this Agreement. Notwithstanding the foregoing, each Party retains the right to seek any equitable remedy to which it may be entitled. In the event of litigation brought by either Party to enforce its rights hereunder, the prevailing Party shall be entitled to reimbursement by the other Party of the prevailing Party's reasonable attorneys' fees and expenses of litigation. Upon the cancellation or termination of this Agreement becoming effective by reason of a Seller Event of Default under Section 19.3(a) Buyer Event of Default under Section 19.3(b) or an event of default under Section 19.3(c), the non-defaulting Party shall be excused and relieved of all further obligations and liabilities under this Agreement; provided, however, that no event of default or cancellation shall affect any of the rights or obligations of the Party not in default which have accrued before, or accrue as a result of, such event of default. Each Party hereby stipulates that the payment obligations set forth in this Section 19 are reasonable in light of the anticipated harm and the difficulty of estimation or calculation of actual damages and each Party waives the right to contest such payments as an unreasonable penalty or otherwise.

20 **INSURANCE**. During the term, Buyer shall cause to be maintained in full force and effect insurance policies as specifically defined in the Marine Provisions. Buyer will ensure that all insurance policies required hereunder are issued by insurance companies with an A.M. Best service rating of not less than a VII, with prompt notice of any alteration, cancellation or material change by endorsement of the coverage. The insurance policies required shall designate Seller as the loss payee or additional insured, whichever applies, and Buyer or its designee as the named insured. All such insurance policies shall also specifically state that Seller's parent, subsidiaries, agents, assigns, affiliates, employees, directors and officers are additional insureds or loss payee, as appropriate, as their interest may appear. All insurance policies shall contain a clause that the insurance is primary insurance and not excess over or contributory with any other valid, existing and applicable insurance carried by Seller,, its parent, subsidiaries and affiliates. With respect to all of the insurance provided for in this Section, Buyer hereby waives, and shall cause the insurer(s) to waive, any right of subrogation with respect to Seller, Seller's parent, subsidiaries, agents, assigns, affiliates, employees, directors and officers. Buyer will provide to Seller evidence that coverage has been renewed seven (7) days prior to the expiration date of the then effective insurance policies. Buyer shall obtain copies of Certificates of Insurance evidencing insurance required of the subcontractors performing any work under this Agreement and shall keep such documents available for inspection by Seller. Notwithstanding any contrary or conflicting provisions above, elsewhere in the Agreement, in Buyer's or its contractors' or subcontractors' insurance policies or Certificates of Insurance, or elsewhere, the additional insured status, primary relationship, and waivers of subrogation shall be solely as respects the risks for which Buyer has undertaken in the Agreement to provide defense and indemnity.

21 **INDEMNITY**.

(a) Seller hereby agrees to indemnify, defend and hold harmless Buyer, its Affiliates, officers, agents, directors, employees, successors and assigns from and against any and all claims, demands, suits, losses (including costs of defense and attorneys' fees), damages, causes of action and liability of every type and character without regard to amount ("Losses") to the extent caused by, arising out of or resulting from the negligence or willful misconduct of Seller, its Affiliates, officers, directors, employees or agents in the performance of this Agreement or any part thereof, except to the extent of the negligence or willful misconduct of Buyer or its Affiliates, officers, directors, employees, agents or contractors hereunder.

(b) Buyer hereby agrees to indemnify, defend and hold harmless Seller, its Affiliates, officers, agents, directors, employees, successors and assigns from and against any and all Losses to the extent caused by, arising out of or resulting from the negligence or willful misconduct of Buyer, its Affiliates, officers, directors, employees or agents, in the performance of this Agreement or any part thereof, except to the extent of the negligence or willful misconduct of Seller or its Affiliates, officers, directors, employees, agents or contractors hereunder.

22 **LIMITATION OF LIABILITY**. NOTWITHSTANDING ANYTHING TO THE CONTRARY CONTAINED IN THIS AGREEMENT, NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR ANY INDIRECT, INCIDENTAL OR CONSEQUENTIAL

LOSSES OR DAMAGES, SPECIAL OR PUNITIVE DAMAGES, OR FOR LOST PROFITS, WHICH ARISE OUT OF OR RELATE TO THIS AGREEMENT OR THE PERFORMANCE OR BREACH THEREOF WHETHER IN CONTRACT, TORT OR OTHERWISE, EXCEPT WITH RESPECT TO ANY SUCH DAMAGES OWED BY EITHER PARTY TO THE OTHER PARTY FOR PETCOKE DELIVERED HEREUNDER AND ANY THIRD PARTY CLAIMS COVERED BY THE INDEMNITY PROVISIONS IN THIS AGREEMENT (TO THE EXTENT SUCH DAMAGES ARE INCLUDED UNDER SUCH CLAIMS). **NOTWITHSTANDING ANY PROVISION IN THE AGREEMENT TO THE CONTRARY, BUYER'S AND SELLER'S LIABILITY WITH RESPECT TO THE AGREEMENT OR ANY ACTION IN CONNECTION HEREWITH, WHETHER IN CONTRACT, TORT OR OTHERWISE SHALL NOT EXCEED THE SUM OF SEVENTEEN MILLION, FIVE HUNDRED THOUSAND DOLLARS ($17,500,000).** Further, any actions to enforce any rights or obligations under this Agreement must be filed in court against the other party no later than one (1) year after the date on which the alleged breach of this Agreement occurred.

23 **EXPORTER OF RECORD.**

(a) Seller shall be the exporter of record. Each Party shall comply with United States laws and regulations concerning sanctioned and/or embargoed countries and the export of product from the United States. Buyer hereby agrees and represents and warrants to Seller that Petcoke obtained from Seller under this Agreement will not be traded with, sold or re-sold, or delivered or re-delivered to any country, territory, entity or individual in contravention of any laws or regulations concerning sanctioned and/or embargoed countries, entities and individuals administered or enforced by the U.S. Government, the United Nations Security Council, The European Union, Her Majesty's Treasury or the Canadian Government (the "Sanction Laws"). In the event, Seller discovers or in good faith has reason to believe that any cargo of Petcoke sold or to be sold hereunder is to be traded with, sold or re-sold, or delivered or re-delivered in violation of the Sanction Laws, Seller, in addition to any and all other remedies available at law or in equity for breach of Buyer's obligations under this Section 23, shall have the right to immediately terminate (or if the Petcoke has already been loaded on the Vessel immediately rescind and require Buyer to remove the Petcoke from the Vessel at its expense) the subject transaction or sale of Petcoke under this Agreement and terminate the Agreement. If Seller discovers or in good faith has reason to believe that any Cargo of Petcoke to be sold or sold hereunder is to be traded with, sold or re-sold, or delivered or re-delivered in violation of the Sanction Laws, Seller shall have no obligation to approve the Petcoke for export, and to the extent that it has already approved the Petcoke for export shall immediately rescind its approval of the Petcoke for export. If Seller terminates or rescinds the sale of Petcoke hereunder or terminates the Agreement pursuant to this Section 23, Buyer shall be responsible for all costs and expense incurred by Seller in connection with the removal (of Petcoke from the Vessel), transportation, storage and resale of the Petcoke hereunder.

(b) Buyer hereby agrees to protect, defend, indemnify and hold Seller and its Affiliates, other harmless from and against any and all Losses, sanctions, fines and penalties caused by, arising out of or resulting from Buyer's breach of the obligations, covenants, representations and warranties set forth in this Section 23, including any such Losses, sanctions, fines and penalties imposed on Seller or its Affiliates due to the transfer, sale or delivery of Petcoke in violation of the Sanction Laws.

24 **HAZARD WARNING RESPONSIBILITY**. With the other documents required hereunder, the Seller shall provide to the Buyer a Material Safety Data Sheet for each Product delivered hereunder. Buyer acknowledges that there may be hazards associated with the loading, unloading, transporting, handling or use of the Product sold hereunder, which may require that warning be communicated to or other precautionary action taken with all persons handling, coming into contact with, or in any way concerned with the Product sold hereunder. Buyer shall defend at its own expense, indemnify fully and hold harmless Seller and its parents, subsidiaries and affiliates and its and their agents, officers, directors, employees, representatives, successors and assigns from and against any and all liabilities; losses; damages; demands; claims; penalties; fines; actions; suits; legal, administrative or arbitration proceedings; judgments, orders, directives, injunctions, decrees or awards of any jurisdiction; costs and expenses (including, but not limited to, attorneys' fees and related costs) arising out of or in any manner related to Buyer's failure to provide Material Safety Data Sheet information in connection with the Product sold hereunder as provided above.

25 **DRAWBACK**. Seller reserves the right to claim, receive and retain drawbacks on imported duty-paid feedstocks used in the manufacture of the Petcoke which it delivers hereunder. Buyer shall on request execute proofs of exportation, drawback claim forms and assignments in favor of Seller to enable Seller to establish its drawback rights under applicable regulations.

26 **GENERAL PROVISIONS.**

(a) Audit. Each Party agrees to maintain books and records pertaining to the production, delivery and use of Product delivered under this contract. In the event (and only in the event) that either Party (i) asserts a claim or charge under this Agreement against the other Party based upon costs, expenses or damages incurred by such claiming Party, or (ii) asserts a claim, defense or excuse based upon the quality or condition of the Product or upon the performance of such Party or the occurrence of an event of Force Majeure, and a dispute arises regarding the accuracy of any statement, charge or computation made in relation thereto or on the validity of such claim, defense or excuse, the other Party shall have the right to audit any such books and records of the other Party pertaining to such claim, charge, defense or excuse as may be reasonably necessary to verify or challenge same, for a period of two (2) years after delivery/receipt of the Product during regular business hours so as not to disrupt the other Party's operations.

(b) Assignment. This Agreement shall not be assigned by either Party without the written consent of the other, which shall not be unreasonably withheld, except that Seller or Buyer may assign this Agreement without consent to any Affiliate, provided that any such assignment shall not release the assigning Party of any of its obligations hereunder and provided that the other Party is not prevented by any Applicable Law from doing business with the assignee. Notwithstanding any provision to the contrary, consent shall not be required if such assignment is in connection with the sale, transfer or conveyance by Buyer or Seller of all or substantially all of its assets, or in the case of Seller the sale, transfer or conveyance, whether directly or indirectly, of the Refinery. In the event consent is not required as set forth in the previous sentence, prior written notice of such assignment shall be provided to the other Party.

(c) Compliance with Laws. During the performance of this Agreement, each Party agrees to comply with all Applicable Laws.

(d) Commissions and Gifts. No director, officer, employee or agent of either Party shall give or receive any commission, fee, rebate, gift or entertainment of significant value or cost in connection with this Agreement. Further, neither Party shall make any commission, fee, rebate, gift or entertainment of significant value or cost to any governmental official or employee in connection with this Agreement.

(e) Governing Law and Jurisdiction. Any controversy, cause of action, dispute or claim arising out of, relating to, or in connection with this agreement, or the breach, termination or validity thereof, shall be governed by the substantive and procedural laws (excluding any conflict-of-laws, rules or principles which may refer the laws of the State of New York to the laws of another jurisdiction) of the State of New York. The parties specifically agree that the sole jurisdiction for any claims shall be in State or Federal courts having jurisdiction thereof located in the Borough of Manhattan, New York City. Without limiting the foregoing in any way, it is expressly understood and agreed that the United Nations Convention on Contracts for the International Sale of Goods shall not govern this transaction.

(f) No Waiver. No waiver of any right under this Agreement at any time will serve to waive of the same right at any future date.

(g) Amendment. No amendment to this Agreement will be effective unless made in writing and signed by an officer or other authorized representative of both Parties.

(h) Severability. If a provision of this Agreement is unenforceable under any Applicable Law, that provision will be enforced to the maximum extent permitted by Applicable Law. The remaining provisions of this Agreement will continue in full force and effect.

(i) Conflict of Interest. Neither Party will pay any commission, fee, or rebate to an employee of the other Party or favor an employee of the other Party with any gift or entertainment of significant value. The Parties hereto acknowledge and agree that Seller is not an agent or employee of Buyer but is independent of any managerial or other control or direction by Buyer in its work hereunder, and is free to perform, by such means and in such manner as Seller may choose, all work in pursuance of commitments hereunder.

(j) Entire Agreement. This Agreement, the Marine Provisions and if applicable the Third Party Marine Terms contain the entire agreement of the Parties pertaining to the subject matter of this Agreement. To the extent there is a conflict between this Agreement, the Marine Provisions and Third Party Marine Terms, the documents will govern in the following order of priority: (1) this Agreement, (2) the Third Party Marine Terms, and (3) the Marine Provisions.

(k) Succession. This Agreement shall inure to the benefit of and be binding upon the Parties hereto and their respective successors and permitted assigns. Nothing in this Agreement is intended to confer any rights or remedies on anyone other than a Party to this Agreement or the holder of a valid assignment of rights under this Agreement.

(l) Counterparts. This Agreement may be executed in counterparts, each of which shall be deemed an original for all purposes, and all of which together shall constitute one and the same document. Executed counterparts of this Agreement delivered via facsimile shall have the same validity, force and effect as originals.

27 **CONTACTS AND NOTICES.**

(a) For the Seller:

(i) The following contacts and their respective subject matter expertise are provided for convenience purposes only. All formal notices and communication required under this Agreement to Seller shall be in writing and delivered as set forth in 27(a)(ii) below:

| | | |
|---|---|---|
| Operational: | Deanna Lopez | Tel: (210) 345-3189<br>Fax: (210) 370-4159 |
| Contracts: | Martin Tovar | Tel: (210) 345-2288<br>Fax: (210) 345-2585 |
| Demurrage Department: | | Tel: (210) 345-2711<br>Fax: (210) 345-5932 |
| Credit: | Belinda Haecker | Tel : (210) 345-2064<br>Fax : (210) 345-2716 |
| Invoice: | Marsha Bradley | Tel : (210) 345-2445<br>Fax : (210) 444-8512 |

(ii) For required notices under this Agreement:

Executive Director, Petcoke Marketing
Valero Marketing and Supply Company
One Valero Way
San Antonio, Texas 78249
Telephone: (210) 345-2774
Facsimile: (210) 345-2585

(b) For the Buyer:

(i) All formal notices and communication required under this Agreement to Buyer shall be in writing and delivered as set forth in the Special Terms:

(c) Except as otherwise provided, all notices, consents, and other communications under this Agreement required to be in writing shall be deemed to have been duly given when (i) delivered in person, (ii) received by fax (with acknowledgement of receipt), (iii) received by the addressee if sent by express mail, Federal Express, or other express delivery service receipt requested), (iv) by email only in instances specifically provided for herein shall be deemed duly given immediately (with receipt confirmed) or (v) by any other means as the parties may agree from time to time, in each case to the appropriate address as designated by the Parties.

28 **EXCEPTIONS TO MARINE PROVISIONS.**

(a) Definitions.

(i) The term "General Terms and Conditions" shall have the same meaning as "General Provisions" as defined in the Special Provisions.

(ii) The term "Marine Provisions" shall have the same meaning as "Marine Provisions" defined in the Special Provisions.

(b) Vessel-Related Conditions.

(i) Vessel Party shall nominate Ocean Vessels acceptable to Terminal Party, such acceptance shall not be unreasonably withheld. For the avoidance of doubt, Terminal Party shall be entitled to reject Vessel Party's nominated Ocean Vessels if it does not pass Terminal Party's internal safety vetting procedures.

(ii) Notwithstanding Section III.F of the Marine Provisions, the Civil Liability Convention of 1969 shall not apply until and unless ratified by the United States.

(iii) Notwithstanding Section III.G of the Marine Provisions, breach of any warranties in Section III G does not entitle either Party to terminate the Agreement.

(iv) The reference to Oil Companies International Marine Forum Guidelines for the Control of Drugs and Alcohol Onboard Ship in Section III.H of the Marine Provisions is replaced with the United States Coast Guard guidelines or rules for the control of drugs and alcohol on board a Vessel..

(c) Wharf Damage; Indemnity. In lieu of Section IV.E of the Marine Provisions, the following provision shall apply:

THE VESSEL PARTY ASSUMES FULL RESPONSIBILITY FOR ANY LOSS, DESTRUCTION, OR DAMAGE SUSTAINED BY WHARVES, BERTHS, OR DOCKS OWNED OR MAINTAINED BY THE DESIGNATED SHORE FACILITIES IF AND TO THE EXTENT SUCH RESULTS FROM, ARISES OUT OF, OR IS CAUSED BY THE NEGLIGENT OR IMPROPER OPERATION OF ANY WATERBORNE CRAFT, EITHER OWNED, OPERATED, OR CHARTERED BY THE VESSEL PARTY, OR BEING OPERATED BY SUBCONTRACTORS OF THE VESSEL PARTY. THE VESSEL PARTY WILL FULLY AND COMPLETELY RELEASE, DEFEND (UPON THE REQUEST OF THE DESIGNATED SHORE FACILITIES), INDEMNIFY, AND HOLD SUCH SHORE FACILITIES, THE OWNER AND OPERATOR OF SUCH SHORE FACILITIES, AS WELL AS THE PARENT ENTITY, SUBSIDIARIES, AFFILIATES, OFFICERS, DIRECTORS, EMPLOYEES, AGENTS, CONTRACTORS, SUBCONTRACTORS, AND OTHER REPRESENTATIVES OF SUCH ENTITY OR ENTITIES, HARMLESS FROM AND AGAINST ANY SUCH DAMAGES, EXCEPT TO THE EXTENT CAUSED BY SHORE FACILITIES OR TERMINAL PARTY'S NEGLIGENCE OR WILLFUL MISCONDUCT. THIS PROVISION BETWEEN THE PARTIES IS WITHOUT PREJUDICE TO ANY OTHER RIGHTS, REMEDIES, CLAIMS, CAUSES OF ACTION, OR DEFENSES THERETO WHICH MAY EXIST.

(d) ISPS and MTSA.

(i) Notwithstanding the last sentence of Section IX.B.2 of the Marine Provisions, any delays, detentions, or loss of time in loading or unloading any portion of the Cargo as provided for under the Agreement as a direct or indirect result of the implementation and enforcement of the Maritime Security Regulations by or against the Terminal Party as set forth under this subsection IX.B.2 shall count as laytime or time on demurrage against Vessel Party to the extent determined.

(ii) Sections IX.A.5 and IX.B.4 of the Marine Provisions do not apply.

Valero Contract Number 40575173
TE contract number, Valero-18-SP1-PC-DAT

[Signature page to Petcoke Sales Agreement]

This Agreement is executed to be effective as of the date first written above.

Seller:

**VALERO MARKETING AND SUPPLY COMPANY**

By: Mark Williams
Name: MARK WILLIAMS
Title: EXECUTIVE DIRECTOR

Date of execution: 12/20/17

Approved Legal
CAB

Buyer:

**TAMPA ELECTRIC COMPANY**

By:
Name: Frank Busot
Title: Mg. Div., Fuels & Planning

Date of execution: 12/19/17

Buyer:

**TAMPA ELECTRIC COMPANY**

By:
Name: John Villa.
Title: Director Origination

Date of execution: 12/19/17

Valero Contract Number 40575173
TE contract number, Valero-18-SP1-PC-DAT

EXHIBIT A

SPECIFICATIONS

| ITEM | SPECIFICATIONS |
|---|---|
| % Moisture (AR) | Less than or equal to 12.0% on each Shipment. |
| | Less than or equal to 8.0% on a monthly weighted average basis. |
| % Ash (AR) | Less than or equal to 0.75% on each Shipment. |
| | Less than or equal to 0.50% on a monthly weighted average basis. |
| Calorific Value (AR BTU/lb) | Greater than or equal to 13,000 at 8.0% moisture on each Shipment. |
| | Greater than or equal to 13,700 at 8.0% moisture on a monthly weighted average basis. |
| % Sulfur (dry) | Less than or equal to 6.0 % on each Shipment. |
| | Less than or equal to 5.5% on a monthly weighted average basis. |
| % Volatile (dry) | Greater than 7.5% on each Shipment. |
| | Greater than 9.0% on a monthly weighted average basis. |
| Grindability | Greater than or equal to 35 HGI, per Shipment |
| Size | 3" X 0" |

Valero Contract Number 40575173
TE contract number, Valero-18-SP1-PC-DAT

EXHIBIT B

ST. CHARLES DELIVERY TERMS

Vessel nomination, arrival and loading shall be governed by the terms incorporated herein and made apart hereof, as well as the Third Party Marine Terms.

It is Buyer's responsibility to advise Seller of the estimated time of arrival ("ETA") of the vessel as soon as practicable after Buyer's knowledge of such ETA, and to keep Seller informed of any changes in the vessel ETA.

For vessels being loaded with a maximum of 35,000 metric tons, Seller guarantees to load said vessels at an average rate of 15,000 metric tons per day. For vessels being loaded with a minimum of 35,000 metric tons, Seller guarantees to load said vessels at an average rate of 20,000 metric tons per twenty-four hour weather working day, Saturdays, Sundays, and holidays included (SHINC), shall be excluded unless worked by UBT at its option.

Laytime to commence three (3) hours after written NOR is accepted confirming the vessel is ready in all respects, including customs, immigrations clearance, draft surveys, within its four (4) day window in accordance with the Terminal Rules and Regulations. The load guarantee is subject to the following:

(a) Time lost due to hold compaction excluded.
(b) Time lost due to draft survey excluded.
(c) If cargo is not available for loading due to Shipper's negligence, time waiting excluded.
(d) Delays caused by the vessel excluded.
(e) All cargo must be acceptable to load with P&I Club and ship master approval if applicable.
(f) Weather delays excluded.

All claims for UBT demurrage must be submitted in writing with supporting documentation within ninety (75) days of the performed service. Shipowner/Shipoperator invoice(s) and evidence of payment to shipowner are required in support.

Claims shall be sent by one or more of the following means:

a. E-mail address of Demurrage@Valero.com;
b. Facsimile number of (210) 345-5932;

Vessel Nomination and Arrival Clause

Buyer is to provide Seller, in writing, a ten (10) day laycan spread latest thirty (30) days prior to the date of the first day of the ten (10) day laycan spread. No later than fourteen (14) days from the date of the first day of the original ten (10) day laycan spread, Buyer is to identify in writing to Valero a four (4) day load window within such original ten (10) day laycan spread. In each case above, the written approval of UBT shall be required relative to the ten (10) day laycan and the four (4) day load window within the original ten (10) laycan.

Vessels that miss their assigned four (4) day window will be worked at the UBT's earliest convenience. In the event a vessel misses its ten (10) day laycan and/or four (4) day window, Seller's load rate guarantees shall commence when vessel is on berth, hatches open, and the vessel is ready in all respects to receive cargo.

# Valero Marketing and Supply Company
# Dry Bulk Marine Provisions Effective September 1, 2014
# "Exhibit B"

These Marine Provisions shall apply to the Agreement, and subsequent performance, between Buyer and Seller, for the purchase/sale/exchange and waterborne delivery of the Cargo set forth in the Agreement.

## I. Definitions (as used in these Marine Provisions)

**Agreement** – means and includes by reference herein the following documents in connection with each separate sale/purchase/exchange and waterborne delivery of Cargo entered into by and between Buyer and Seller: (A) the Special Provisions (including amendments thereto); (B) these Marine Provisions and attached appendices; and (C) Valero Marketing and Supply Company's General Terms and Conditions (latest edition).

**All Fast** – means the time during which the Vessel is completely moored, from the time gangway is down and secured (for all Vessels other than Inland Barges) at the Cargo Transfer Point.

**Bulk Carriers** - a ship constructed with a single deck and holds for the bulk carriage of loose dry cargo.

**Buyer** – refers to the person or entity that is obligated to buy the Cargo from Seller, or exchange the Cargo with Seller, under the terms of the Agreement.

**Cargo** – means any dry bulk or break-bulk material that is being sold, purchased, or exchanged by and between Buyer and Seller and delivered via Vessel under the terms of the Agreement.

**Cargo Quantity** – means the volume or quantity of the Cargo that is specified in the Special Provisions and either loaded or discharged at the Cargo Transfer Point.

**Cargo Transfer Point** – means the location specified in the Special Provisions to which these Marine Provisions are attached or incorporated by reference where custody of the Cargo is transferred from Seller to either Buyer or Buyer's designee.

**Charterer** – means the person or entity hiring the performing Vessel.

**CLC** – means Civil Liability Convention of 1969, as such has been amended from time to time.

**COC** – means Certification of Compliance.

**Customary Anchorage** – means the recognized anchorage area for or within the designated port for the Cargo Transfer Point that is specified in the Special Provisions.

**DHS** – means the United States Department of Homeland Security, including any successor department or agency.

**DOS** – means a Declaration of Security as provided for under the ISPS Code.

**Excess Insurance** - means Excess Pollution Liability Insurance.

**General Terms and Condition** – means, unless otherwise specified in the Special Provisions, Valero Marketing and Supply Company's General Terms and Conditions in effect as of the date of the Agreement.

**Inland Barge** – means a United States Coast Guard-approved or American Bureau of Shipping-inspected dry bulk cargo barge that is restricted to operations in the inland waterways of the United States.

**ISPS Code** refers to the International Code for Security of Ships and Port Facilities, as set forth in Title 33, C.F.R. Chapter I (Subchapter H) and relevant amendments to Chapter XI-2 of the International Convention for the Safety of Life at Sea, 1974 (SOLAS), as such may be amended from time to time.

**Laycan Window** – means the period during which the Vessel nominated by or on behalf of Buyer or Seller under the Agreement is to present itself at the Cargo Transfer Point, as established by the Special Provisions.

**Marine Incident** – means any incident or event outside normal Vessel operation that delays the Vessel for a period of three (3) or more hours including, but not limited to, spill, personal injury, fire, grounding, collision, allision, sinking, security issue, or significant media or governmental inquiry.

**Marine Provisions** – means these Marine Provisions as such may be amended, supplemented, or restated by Valero Marketing and Supply Company from time to time.

**Maritime Security Regulations** – means, collectively, the ISPS Code and the MTSA, and federal regulations promulgated pursuant thereto, if and when such are applicable.

**MTSA** – refers to the U.S. Maritime Transportation Security Act of 2002, as codified under 46 U.S.C., Chapter 701, as such may be amended from time to time.

**NOR** – means Notice of Readiness.

**Ocean Vessel** – means a United States Coast Guard-approved or American Bureau of Shipping-inspected dry bulk cargo vessel that is certified to operate in offshore waters.

**OPA** – means the (U.S.) Oil Pollution Act of 1990, as such many be amended from time to time.

**P&I Insurance** – means Protection and Indemnity Insurance.

**Parties** – means both Buyer and Seller.

**Party** – means either Buyer or Seller.

**Policy** – refers to any applicable drug and alcohol abuse policy.

**Seller** – refers to the person or entity that is obligated to sell the Cargo to, or exchange the Cargo with, Buyer under the terms of the Agreement.

**Shore Facilities** – means any refinery, terminal, storage, or port facility taking deliveries of the Cargo from, or making deliveries of the Cargo to a Vessel.

**Special Provisions** – means the fixture document that sets forth various contract terms, conditions, and provisions between a Buyer and Seller in connection with the sale/purchase/exchange of the Cargo via waterborne delivery including, without limitation, each of the following: (A) the name and business address of Buyer and Seller, (B) the transaction date of the Agreement, (C) the Agreement reference number, (D) a description of the Cargo being sold/purchased/exchanged and delivered under the Agreement, (E) the product specifications for the Cargo, (F) the volume/quantity of the Cargo being sold/purchased/exchanged and delivered under the Agreement, (G) the consideration, if any, to be provided for such Cargo, (H) the Cargo Transfer Point, (I) the delivery date(s)/window for such Cargo, (J) the measurement terms for such Cargo, (K) the payment terms for such Cargo, and/or (L) any other terms and conditions.

**Spot Chartered Equipment** – refers to when the owner of the Vessel places the Vessel and its crew at the disposal of the Charterer for a single voyage, with such owner being responsible for the operation of the Vessel.

**Spout Trimmed** – means distributed as evenly as practicable in the hold of a ship by use of existing mechanical ship loaders at the Port of Shipment without the use of labor or handling or leveling equipment on the ship

**Term (Time) Chartered Equipment** – refers to when the owner of the Vessel charters or leases the Vessel and its crew to the Charterer for a stipulated period of time; *provided, however*, under any such Term (Time) Charter, the Charterer pays for the bunkers and port charges in addition to the charter hire.

**Terminal Party** – refers to the Party naming the designated Shore Facilities that are to perform under the terms of the Agreement.

**Tow** - means any combination of tugs, push boats, or barges with the ability to function as a single unit.

**USCG** – means the United States Coast Guard.

**Vessel** - any Tow, Inland Barge, Ocean Vessel, or other marine vessel carrying the Cargo under the Agreement. References herein to "Vessel(s) Account" and responsibilities, duties, rights and liabilities of the "Vessel" are intended to include not only the Vessel itself, but also the owner, operator, Master, or agent of such Vessel, where applicable.

**Vessel Party** – refers to the Party nominating the Vessel which holds, takes custody of, or takes title to the Cargo under the terms of the Agreement.

## II. Conflicting Terms; Governing Provisions

The following documents, all of which are part of the Agreement, will govern in the following order of priority: (A) the Special Provisions (including amendments thereto); (B) these Marine Provisions; and (C) appendices attached to these Marine Provisions; and (D) Valero Marketing and Supply Corporation's General Terms and Conditions (latest edition).

In the event that one or more provisions of the Agreement are held unenforceable as a matter of law, the remainder of the governing provisions above remains in full force and effect.

## III. Vessel-Related Conditions

### A. Vessel Nomination & Acceptance

All Vessels nominated by the Vessel Party, including each Vessel to be used in connection with the loading or discharging of the Cargo under the Agreement, shall meet the applicable, general Vessel requirements of the designated Shore Facilities which shall receive or deliver such Cargo, including all applicable published or posted requirements. It is the responsibility and duty of the Vessel to contact the designated Shore Facilities in order to obtain any and all requirements related to berthing or docking at such facilities, and it is further the responsibility of the Vessel to comply with such requirements. At the request of the designated Shore Facilities or the Terminal Party, the nominated Vessel shall promptly complete a Vessel Questionnaire provided by such Shore Facilities or such Terminal Party. Acceptance of any Vessel by such Shore Facilities shall not constitute a continuing acceptance of such Vessel for any subsequent loading or discharging. Unless otherwise agreed to by the Parties, all deliveries and loadings of the Cargo in accordance with the terms and conditions of the Agreement shall be on or from a single voyage. Any damages incurred as a result of Vessel's failure to meet requirements of this Agreement, applicable regulations or port requirements are for Vessel Party's account.

Once a nominated Vessel is accepted by the designated Shore Facilities in order to receive or deliver the Cargo, the use of any other Vessel(s), carrying the Cargo under the Agreement shall only be permitted by prior, written mutual agreement, and all expense, risk of loss, or liability associated with such activity or activities shall be for the Vessel Party's account. Any written permission or consent of or by such Shore Facilities allowing the use of such other Vessel(s) shall not be unreasonably withheld, delayed, or conditioned.

B. <u>Eligibility</u>

The Vessel Party represents and warrants that (1) the nominated Vessel is, in all respects, eligible under and in compliance with all applicable laws, rules, and regulations including, without limitation, the Maritime Security Regulations, with respect to entering, docking, hoteling, loading, and unloading at or within the designated port or other places specified in the Agreement, and (2) at all times the Vessel shall have on board and readily available for inspection all certificates, security plans, declarations, records, and other documents required by applicable law for such service.

C. <u>Estimated Time of Arrival ("ETA")</u>

Upon acceptance of the Vessel nomination by the Terminal Party under the Agreement, either the Vessel or Vessel Party shall immediately advise the designated Shore Facilities and other Party(ies) to the Agreement of the Vessel's current position/location in terms of latitude and longitude, operational status, and ETA, by telex, facsimile, letter, telegram, electronic mail, or any other means which is deemed necessary or appropriate under applicable law, including the Maritime Security Regulations. The ETA shall be further promptly updated by telex, facsimile, letter, telegram, or electronic means as follows:

1. Upon leaving the last port before sailing to the designated Shore Facilities, or at least seven (7) days in advance of tendering NOR, whichever is more.

2. Where applicable, at 72, 48, 24, and 12 hours before the Vessel's expected arrival at the designated Shore Facilities specified in the Agreement; and

3. The Vessel shall promptly notify the designated Shore Facilities and Terminal Party of the new ETA if the ETA changes by plus or minus two (2) hours or more following the twelve (12) hour arrival notice.

Failure to comply with these ETA notifications may result in delays in the acceptance of the NOR by the designated Shore Facilities as outlined in Article V of these Marine Provisions, and consequent delays are for Vessel Party's account.

D. **Vessel Compliance with Shore Facilities Requirements**

Any Vessel that is not in compliance with the federal, state, or the designated Shore Facilities' applicable requirements with respect to any environmental, health, safety, financial responsibility, the Vessel's or such Shore Facilities' security, governmental security, or other liability concerns may not be permitted to dock or may be asked to vacate the berth at the designated Shore Facilities, and any resulting costs and/or delays shall be for the Vessel Party's Account.

Failure of any of a Vessel's safety or environmental systems, or the failure to possess or comply with the Vessel's own security plan, as mandated under applicable law, after initial acceptance by the designated Shore Facilities, is grounds for such facilities to immediately reject the Vessel, including notification to vacate the berth until either (1) suitable repairs are made in order to return the affected equipment to good working order, or (2) the Vessel and requirements for its crew are brought into compliance with its applicable security plan. Under such circumstances, the Vessel must be re-accepted by the designated Shore Facilities prior to the start or resumption of discharge or loading of the Cargo under the terms of the Agreement. Expenses incurred in making any such repairs or bringing the Vessel or its crew into compliance with the appropriate security plan shall be for the Vessel Party's Account, and delays resulting from said repairs shall not count as used laytime or as time on demurrage.

Vessel draft marks will be legible at all times. In the event, Vessel is accepted to load and draft marks are not legible, volume to be determined by belt scale quantities or draft survey quantities, whichever is greater.

E. **Legal and Regulatory Compliance**

The Vessel Party shall require the Vessel to comply with all applicable federal, state, and local laws, rules, and regulations including, but not limited to, all federal and state oil spill response plans and financial responsibility requirements, as well as the Maritime Security Regulations, if and where such are applicable. If the Vessel fails to comply with any such law, rule, or regulation, the Vessel may be required to leave the designated Shore Facilities promptly. Any delay due to the Vessel's non-compliance with such law, rule, or regulation shall not count as used laytime or as time on demurrage. All expenses, losses, and delays incurred to obtain or maintain the necessary certificates, Vessel security plan, declaration(s), response plan(s) shall be for the Vessel Party's Account and any delay resulting from the Vessel's non-compliance shall not count as used laytime or as time on demurrage. Damages incurred by Terminal Party as a result of the Vessel's non-compliance with such laws, rules, regulations, plans, and requirements are for Vessel Party's account.

F. **Pollution Prevention and Responsibility**

For the purpose of this Section F, the meaning of the term "Pollution Damage" shall include, without limitation, all damages which are compensable under the CLC, as well as any applicable U.S. federal, state, or local law, rule, or regulation.

1. In the event an escape, release, or discharge of the Cargo occurs from the Vessel and causes or threatens to cause Pollution Damage, the Vessel and Vessel Owner will promptly take whatever measures are necessary to prevent or mitigate such damage or remove the threat. The Vessel Party hereby authorizes the designated Shore Facilities, or its nominee, upon notice to the Vessel, to undertake, at the option of such Shore Facilities, such measures as are reasonably necessary to prevent or mitigate the Pollution Damage or remove the threat. Under such circumstances, the designated Shore Facilities or its nominee shall keep the Vessel advised of the measures intended to be taken. Any of the aforementioned measures shall be for the Vessel Party's Account, provided that if the designated Shore Facilities caused or contributed to such escape, release,

or discharge, the expense of the aforementioned measures shall be borne by the such facilities in proportion to its percentage of negligence in causing or contributing to the escape, release, or discharge. If the Vessel Party reasonably considers that said measures should be discontinued, the Vessel Party shall promptly notify the designated Shore Facilities or its nominee in writing and thereafter, such Shore Facilities or its nominee shall have no right to continue said measures at the Vessel Party's authority or expense unless directed to do so by a governmental entity, body, or agency having or purporting to have proper jurisdiction over (a) the Vessel or its crew, (b) the clean-up, remediation, mitigation, and/or disposal of any Pollution Damage, or (c) the repair, replacement, or removal of the designated Shore Facilities or any associated equipment being or needing to be undertaken. This provision shall be applicable only between the Parties and shall not affect any liability of the Vessel, it's owners or bareboat charterers to third parties including, but not limited to, any governmental entity, body, or agency.

2. The Vessel Party warrants that throughout the Vessel's service under the Agreement, the Vessel shall have on board the following certificates:

   a. Certificates issued pursuant to the CLC, and pursuant to the 1992 protocols to the CLC, if and as amended, as and when in force;
   b. Certificates issued pursuant to Section 1016(a) of OPA, and Section 108(a) of the Comprehensive Environmental Response, Compensation and Liability Act 1980, as amended in accordance with Part 138 of Coast Guard Regulations set forth in Title 33, U.S. Code of Federal Regulations; and
   c. Certificates issued or required by any state and/or local environmental regulatory agency, authority, or body which has proper jurisdiction over the operation of the designated Shore Facilities.

3. The Vessel Party shall be responsible for immediately notifying the Terminal Party of any Marine Incident. In addition to all other reporting requirements the Parties may have under the Agreement, all Parties are responsible for promptly notifying Valero Central Monitoring for each Marine Incident by calling 800-964-2210 (+1-210-736-2210). This monitoring system has been set up to accept calls twenty-four (24) hours per day, seven (7) days per week.

G. **Insurance**

The provisions set forth in this section shall be applicable only between the Parties and shall not affect any liability of the Vessel, its owners or bareboat charterers to third parties, including but not limited to, any governmental entity, body, or agency.

1. **Ocean Vessels**

The Vessel Party warrants that throughout the Vessel's service under the Agreement, the Vessel shall have full and valid P&I Insurance and valid Excess Insurance, as described below, with the P&I Insurance placed with a P&I club that is a member of the International Group of P&I Clubs. The P&I Insurance (including P&I U.S. surcharges and Excess Insurance) shall be at no additional cost to the Terminal Party.

The P&I Insurance must include coverage against liability for cargo loss/damage for the full value of the cargo. The P&I Insurance must also include coverage against liability for pollution, for the maximum available through the international group of P&I Clubs.

2. **Inland Barges**
The Vessel Party warrants that throughout the Vessel's service under the Agreement, each Vessel shall have full and valid insurance, including pollution liability insurance for an amount not less than:

a. 100 million U.S. dollars per incident for Vessels carrying a cargo of non-persistent oil as defined by OPA. This insurance shall be at no cost to the Terminal Party.
b. 200 million U.S. dollars per incident for the Vessels carrying a cargo of persistent oil as defined by OPA. This insurance shall be at no cost to the Terminal Party.

3. **Evidence of Insurance**
With respect to the requirements of subsections III.G.1 and III.G.2, above, if requested at any time during the Agreement, the Vessel Party shall promptly furnish to the Terminal Party reasonable evidence of such P&I Insurance, Excess Insurance, and any other required pollution liability insurance. The warranties set forth in subsections III.G.1 and III.G.2, above, are an essential part of the Agreement, and the obligations of the other Party under this Agreement are conditional on the truth and performance of such warranty. Any breach of the above referenced warranties shall entitle the other Party to whom any such warranty is given to terminate the Agreement and/or to recover damages allowable in law, admiralty, or equity.

H. **Drug and Alcohol**
The Vessel Party warrants that the Vessel shall have a Policy applicable to the Vessel which meets or exceeds the standards in the Oil Companies International Marine Forum Guidelines for the Control of Drugs and Alcohol Onboard Ship. Under the Policy, alcohol impairment shall be defined as a blood alcohol content of 40 mg/100 ml or greater; the appropriate seafarers to be tested shall be all Vessel officers; and the drug/alcohol testing and screening shall include unannounced testing in addition to routine medical examinations. An objective of the Policy must be that the frequency of the unannounced testing be adequate to act as an effective abuse deterrent, and that all officers be tested at least once a year through a combined program of unannounced testing and routine medical examinations. The Vessel Party further warrants that the Policy will remain in effect during the term of the Agreement and that the Vessel Party shall exercise due diligence to ensure compliance with the Policy. It is understood that an actual impairment or any test finding of impairment shall not in and of itself mean the Vessel Party has failed to exercise due diligence. Upon Terminal Party's request, Vessel Party shall provide Terminal Party with a copy of the Policy applicable to the Vessel. Absence of a Policy or failure to deliver a copy of the Policy within a reasonable time after Terminal Party's request, is grounds for Terminal Party to reject or withdraw acceptance of the Vessel.

I. **U.S. Customs and Border Protection**
The Vessel Party represents and warrants that the Vessel and any cargo discharges there from at the contract port and/or designated Shore Facilities shall fully comply with, and it possesses or shall timely secure and submit all necessary waivers required under, all applicable U.S. Customs and Border Protection rules and regulations in effect as of the date the Vessel berths at such Shore Facilities. Any delay resulting from the Vessel's non-compliance with such regulations shall not count as used laytime or as time on demurrage. The Vessel Party shall provide all information required for importation of the Cargo being sold/purchased/exchanged and delivered under the Agreement to the other Party at least five (5) business days prior to the Vessel's arrival at the designated Shore Facilities. Any delay resulting from lack of information required for importation of the

Cargo shall not count as used laytime or as time on demurrage unless such delay is the result of information required to be provided by such Shore Facilities hereunder.

J. **U.S. Department of Homeland Security; U.S. Coast Guard**
The Vessel Party represents and warrants that the Vessel shall fully comply with, or possess all necessary waivers, certificates, or other documents that are required under, each applicable law, rule, or regulation implemented and enforced by the DHS, the USCG, and any applicable port authority and/or the designated Shore Facilities including, without limitation, the Maritime Security Regulations, which is in effect when the Vessel (1) navigates within any waters that are subject to the jurisdiction of the United States, as well as (2) berths and remains All Fast at such Shore Facilities. Upon request, the Vessel Party shall promptly provide to the designated Shore Facilities and/or Terminal Party complete copies of all certificates, declarations, letters of approval or acknowledgment, and other compliance documentation (excluding the Vessel's security assessment and security plan) that are required under the Maritime Security Regulations. Any delay resulting from the Vessel's non-compliance shall not count as used laytime or as time on demurrage against the designated Shore Facilities or Terminal Party.

## IV. Related Conditions at Shore Facilities

A. **Berth Availability**
The designated Shore Facilities shall provide a berth for the nominated Vessel for normal Cargo transfer. All dockage and service fees, including mooring, fresh water, steam, and oil slops receipts, will be for the Vessel Party's Account. In addition, all duties and other charges on the Vessel, including, without limitation, those incurred for Tows and pilots, and other port costs, including fleeting, and taxes on freight, shall be for the Vessel Party's Account.

The designated Shore Facilities do not warrant the safety, draft, or clearance of public channels, fairways, approaches thereto, anchorages, or other publicly-maintained areas, either inside or outside the port area, where the Vessel may be directed. The designated Shore Facilities shall not be liable for any loss, damage, injury, or delay to the Vessel resulting from the use of such public waterways. If hold-in tugs are required for the Vessel, any charges for such hold-in tugs shall be for the Vessel Party's account.

B. **Vacating of Berth**
The designated Shore Facilities may order any Vessel to vacate its berth at such facilities if (1) it appears that the Vessel will not be able to complete loading or discharging of the Cargo, that has been sold/purchased/exchanged under the terms of the Agreement, within twenty-four (24) hours (pro-rata for part Cargo) of the Vessel's arrival in berth, or (2) the Vessel has entered such Shore Facilities, or docked/hotelled at the facilities, in violation of any applicable law, rule, or regulation. Unless mandated by the DHS, USCG, or any other law enforcement authority or agency having proper jurisdiction over the designated Shore Facilities, or the Vessel or its crew, the Vessel shall not be required to vacate a berth as a result of the inability to complete loading or discharging operations under this clause, unless that berth is needed to accommodate another Vessel. Upon the termination of loading or discharging operations, used laytime shall cease. After tendering NOR to recommence loading or discharging at the designated Shore Facilities in accordance with the Agreement, the Vessel shall be re-berthed in order of rotation, unless otherwise agreed by such Shore Facilities, and used laytime shall resume upon the recommencement of loading or discharging. Under any such circumstances, the expenses incurred for vacating the berth or re-berthing within the applicable Shore Facilities shall be for the Vessel Party's Account.

C. **Shifting of Vessels**

Vessel Party warrants that the designated Shore Facilities shall have the right to shift the Vessel from one berth to another within its facility, or to anchorage. Any expenses incurred in such shifting or anchoring of Vessel shall be for the account of the designated Shore Facilities, with the time consumed in shifting counted as used laytime or as time on demurrage.

Any expenses incurred where the shifting of the Vessel within a designated port is directed or mandated by any person, entity, or authority (included, but not limited to, the USCG, U.S. Customs Service, applicable port authority, or other government authority or agency having proper jurisdiction over either the Vessel or its crew) other than the designated Shore Facilities or Terminal Party shall be for the Vessel Party's Account. Any time consumed in shifting shall not be counted as used laytime or as time on demurrage.

D. **Terminal's Environmental/Safety Observer**

Vessel Party warrants that the designated Shore Facilities may, at its/their option, place an observer on board the Vessel to observe loading and/or discharging of the Cargo, and related operations, during the period the Vessel is in port. The responsibility and liability for any pollution, unsafe act, or violation of the requirements of such Shore Facilities remains with the Vessel and its master.

E. **Wharf Damage; Indemnity**

The Vessel Party assumes full responsibility for any loss, destruction, or damage sustained by wharves, berths, or docks owned or maintained by the designated Shore Facilities if and to the extent such results from, arises out of, or is caused by the negligent or improper operation of any waterborne craft, either owned, operated, or chartered by the Vessel Party, or being operated by subcontractors of the Vessel Party. The Vessel Party will fully and completely release, defend (upon the request of the designated Shore Facilities), indemnify, and hold such Shore Facilities, the owner and operator of such Shore Facilities, as well as the parent entity, subsidiaries, affiliates, officers, directors, employees, agents, contractors, subcontractors, and other representatives of such entity or entities, harmless from and against any such damages, even if caused by Shore Facilities or Terminal Party's negligence. This provision between the Parties is without prejudice to any other rights, remedies, claims, causes of action, or defenses thereto which may exist.

## V. Notice of Readiness ("NOR")

**Tendering a Valid NOR**

Notice of Readiness shall be in accordance with the regulations for the designated terminal described in the attached appendices.

If the designated terminal does not have in force its applicable terminal regulations, NOR shall tendered as per this section A below.

A. In the case of an Ocean Vessel to be loaded, issuance of the NOR shall mean that the Ocean Vessel has obtained all requisite governmental approvals, inspections and clearances, including, but not limited to, those required by the U.S. Customs Service and the Immigration and Naturalization Service, and is located at the Berth or Customary Anchorage, and is ready and suitable in all respects to receive the Cargo in all holds to be loaded and that the Buyer has determined that the Cargo is in a condition satisfactory to the Vessel Party and all regulatory authorities for shipment.

If NOR is tendered prior to meeting all of the above criteria, the date and effective time of the NOR will not be deemed tendered until said requirements have been met.

**VI. Laytime**

Laytime shall be in accordance with the regulations for the designated terminal described in the attached appendices.

If the designated terminal does not have in force terminal regulations addressing laytime, laytime shall be as per this section A-C below.

A. If the Ocean Vessel tenders NOR prior to the commencement of the applicable Laycan Window, laytime shall commence at 1200 hours on the date that the Laycan Window commences, or commencement of loading at the Designated Shore Facilities, whichever occurs first.
B. If the Ocean Vessel tenders NOR within the applicable Laycan Window, laytime shall commence upon the expiration of twelve (12) hours after NOR is tendered or at Commencement of loading at the Designated Shore Facilities, whichever occurs first.
C. If the Ocean Vessel tenders NOR after the end of the applicable Laycan Window, laytime shall commence at Commencement of loading at the Designated Shore Facilities.
D. If the Ocean Vessel tenders NOR and a Laycan Window has not been declared, laytime shall commence at Commencement of loading at the Designated Shore Facilities.

**VII. Loading Rate and Loading Procedure**

Loading rate and loading procedure shall be in accordance with the regulations for the designated terminal described in the attached appendices.

**VIII. Used Laytime Exclusions**

Laytime Exclusions shall be in accordance with the regulations for the designated terminal described in the attached appendices.

In addition to exclusions mentioned in these Marine Provisions and attached appendices, the following A-Q below shall not count as used laytime, nor as time on demurrage.

A. Any time on inward passage of the Vessel, including, but not limited to awaiting daylight, tide, tugs or pilot, weather, or channel closure and proceeding from the anchorage to the Shore Facilities until vessel is All Fast at berth.

B. Any delay preparing for and/or shifting the vessel at the berth specifically requested or caused by the vessel, vessel master, or other vessel representatives.

C Opening and closing of hatches at commencement and completion of loading.

D. Any time consumed in the breakdown, repairs or other causes attributable to the Vessel.

E. Any delay caused by strike, lockout, stoppage or restraint of labor involving the Terminal or the vessel personnel including the Master, officers and crew of the Vessel, or tugboats, or pilots.

F. Any delay caused by the Vessel Party's failure to comply with all financial and/or credit responsibilities of the Agreement.

G. Any delay due to prohibition of any cargo transfer at any time by the Vessel, Vessel Party, or the owner of the Vessel, or by any governmental agency or authority, unless such prohibition is caused by the failure of the designated Shore Facilities to comply with applicable laws, rules, or regulations.

H. Failure to have the required certificate of financial responsibility, or failure to be in compliance with applicable USCG regulations (or hold the necessary waiver if not in compliance), or the failure to have other legally required documentation, including the COC.

I. Awaiting applicable U.S. Customs and Immigration clearance and free pratique.

J. Force majeure events and conditions as outlined in the General Terms and Conditions.

K. Any delay at the designated ports of loading or discharging resulting from measures imposed by such port facility or by any relevant authority for purposes of port security, including but not limited to, measures imposed under any of the Maritime Security Regulations.

L. Delays due to weather and/or sea conditions shall include, but not be limited to, lightening, ice, fog, storm, wind, waves and/or swells;

M. Channel blockage and/or port closure associated with the designated Shore Facilities;

N. Breakdown or failure of equipment or machinery in or about the designated Shore Facilities;

O. Random security inspection pursuant to any of the Maritime Security Regulations.

P. Draft Surveys to include time before, during, and after loading, in excess of three (3) hours.

Q. Any other cause beyond the control of the Seller.

IX. <u>ISPS and MTSA</u>

A. **Vessel Party's Duties and Obligations**

1. Upon Terminal Party's request, Vessel Party shall promptly provide documentation to Terminal Party's reasonable satisfaction for the purpose of verifying that the Vessel nominated for the designated Shore Facilities under the terms of the Agreement is operating in compliance (a) with the applicable requirements of the ISPS Code, and (b) where any of the designated Shore Facilities are located within the United States or any of its territories or waters, with the applicable requirements of the MTSA.

2. As between Terminal Party and Vessel Party, Vessel Party shall be responsible for any delays, detentions, restriction of Vessel operations, denial of port entry, and expulsion from the port with respect to any non-compliance with any of the Maritime Security Regulations by the Vessel or the Vessel's owner/operator. Except where any of the designated Shore Facilities and/or its owner/operator has failed or refused to comply with the Maritime Security Regulations, any cost, expense, demurrage, loss, liability, fine, penalty, judgment, order, or assessment of any kind or nature which is actually incurred by either Vessel Party or Terminal Party and that is related to, or otherwise associated or connected with, the nominated Vessel and/or the Vessel's owner/operator in regard to the application and enforcement of the Maritime Security Regulations (including, without limitation, any and all costs and expenses which are necessary to review and/or verify applicable compliance documents, or impose any additional security and/or security measures on or in close proximity to the Vessel, its crew, operations, and/or Cargo as mandated by any federal, state, or local governmental authority, agency, or department which has the power to implement and enforce any of the Maritime Security Regulations) shall be for the account of the Vessel Party. Any delays, detentions, or loss of time in loading or unloading any portion of the Cargo as provided for under the Agreement as a direct or indirect result of the implementation and enforcement of the Maritime Security Regulations as set forth under this subsection IX.A.1 shall not count as used laytime or time on demurrage against Terminal Party.

3. Notwithstanding anything else provided for in this clause, Vessel Party's liability to the Terminal Party under the Agreement for any costs, losses, or expenses incurred by Terminal Party resulting from or associated with the failure, refusal, or inability of the Vessel and/or the Vessel's owner/operator to comply with any of the applicable requirements of the Maritime Security Regulations shall be limited to the payment of demurrage and any costs actually and necessarily incurred by the Terminal Party in accordance with the provisions of this Section IX.A.

4. Notwithstanding any prior acceptance of the nominated Vessel by Terminal Party, if at any time prior to the passing of risk of loss for and title to the Cargo covered by the Agreement, the nominated Vessel ceases to comply with the applicable requirements of the Maritime Security Regulations, then:

   a. Terminal Party shall have the right not to allow such nominated Vessel to dock at the designated Shore Facilities, and any demurrage resulting from such failure, refusal, or inability of the Vessel and/or the Vessel's owner/operator shall not be for the account of the Terminal Party; and

   b. Vessel Party shall be obliged to substitute such nominated Vessel with a Vessel complying with the applicable requirements of the Maritime Security Regulations.

5. Vessel Party shall exercise commercially reasonable efforts to ensure that the Vessel and the Vessel's owner/operator shall (a) reasonably cooperate with Terminal Party and the designated Shore Facilities in order to complete a DOS promptly after the execution of the Agreement, and (b) when required or requested, submit a fully executed copy of the DOS to the appropriate governmental or law enforcement authorities and Terminal Party prior to the Vessel's arrival at such Shore Facilities.

B. **Terminal Party's Duties and Obligations**

1. Upon Vessel Party's request, Terminal Party shall promptly provide documentation to Vessel Party's reasonable satisfaction for the purpose of verifying that any of the designated Shore Facilities and its owner/operator are operating in compliance with the applicable requirements of the Maritime Security Regulations.

2. As between Vessel Party and Terminal, Terminal Party shall be responsible for any delays, detentions, restriction of Vessel operations, denial of port entry, and expulsion of the Vessel from any of the designated Shore Facilities with respect to any non-compliance with any of the Maritime Security Regulations by such Shore Facilities and/or its owner/ operator. Except where the Vessel and/or vessel owner/operator has failed or refused to comply with the Maritime Security Regulations, any cost, expense, demurrage, loss, liability, fine, penalty, judgment, order, or assessment of any kind or nature which is incurred by either Vessel Party or Terminal Party and that is related to, or otherwise associated or connected with, any of the designated Shore Facilities and/or its owner/operator in regard to the application of the Maritime Security Regulations (including, without limitation, any and all costs and expenses which are necessary to review and/or verify applicable compliance documents, or impose any additional security and/or security measures on or in close proximity to such Shore Facilities as mandated by any federal, state, or local governmental authority, agency, or department which has the power to implement and enforce any of the Maritime Security Regulations) shall be for the account of the Terminal Party. Any delays, detentions, or loss of time in loading or unloading any portion of the Cargo as provided for under the Agreement as a direct or indirect result of the implementation and enforcement of the Maritime Security Regulations as set forth under this subsection IX.B.2 shall not count as laytime or time on demurrage against Vessel Party.

3. Notwithstanding anything else provided for in this clause, Terminal Party's liability to the Vessel Party under the Agreement for any costs, losses, or expenses incurred by Vessel Party resulting from or associated with the failure, refusal, or inability of any of the designated Shore Facilities and/or its owner/operator to comply with any of the applicable requirements of the Maritime Security Regulations shall be limited to the payment of demurrage and any cost(s) actually and necessarily incurred by the Terminal in accordance with the provisions of this Section IX.B.

4. Terminal Party shall exercise commercially reasonable efforts to ensure that the designated Shore Facilities and its owner/operator shall (a) reasonably cooperate with Vessel Party, the Vessel, and the Vessel's owner/operator in order to complete a DOS as provided for under the ISPS Code promptly after the execution of the Agreement, and (b) when required or requested, submit a fully executed copy of the DOS to the appropriate governmental or law enforcement authorities and Vessel Party prior to the Vessel's arrival at such Shore Facilities.

X. Demurrage and Despatch

Demurrage and Despatch does not apply to Inland Barges.

Demurrage shall be payable for each running hour and pro rata for each part of an hour that used laytime exceeds the allowed laytime.

A. Rate Determination (if not stated in the Special Provisions)

1. **Spot Chartered Equipment** – For spot chartered equipment that is used in connection with the Agreement, the rate shall be based on the rate specified in the Vessel's charter party. Despatch is to be 50% of demurrage.

2. **Term Chartered or Owned Equipment** – For term-chartered or owned equipment that is used in connection with the Agreement the demurrage and despatch rates shall be based on a mutually agreeable rate between the Parties. These rates reflect a daily hire rate, plus import fuel cost, and will be specified in the Vessel nomination and agreement indicated by the Vessel's acceptance. Despatch is to be 50% of demurrage.

B. Demurrage and Despatch Claims

1. **Claims Processing** - Demurrage claims arising at the designated Shore Facilities must be submitted in writing with supporting documentation within ninety (90) calendar days from the date after loading or discharging of the Cargo is completed. Claims shall be sent by one or more of the following means:

a. E-mail address of Demurrage@Valero.com;

b. Facsimile number of (210) 345-5932;

c. Courier Service to:
**Valero Marketing and Supply Company**
**Demurrage Department**
**One Valero Way**
**San Antonio, TX 78249-1112**

d. United States Postal Service to:
**Valero Marketing and Supply Company**
**Demurrage Department**
**P.O. Box 696000**
**San Antonio, TX 78269-6000**

Claims received after 1700 hours, New York City time, will be deemed to have been received on the next business day. If the claim and supporting documentation are not provided within the specified time, the claim will be deemed to be waived for all purposes. If a dispute arises as to the receipt of the demurrage claim within the ninety-day time deadline, written documentation of the receipt of the demurrage claim in question will be required before the claim will be considered.

No claims for special, indirect, incidental, exemplary, punitive, or consequential damages of any nature, including any loss of revenue, profit, or goodwill, shall be made by either party relating to demurrage.

2. **Documentation**

Claims shall include and laytime calculation of demurrage or despatch, copy of the Vessel's NOR, Vessel's statement of facts (SOF), charter party or nomination to verify demurrage rate, as well as such other supporting documentation as reasonably may be requested by the Terminal Party.

## XI. Other Items

Applicable Law – This Agreement shall be interpreted in accordance with the General Maritime Law of the United States, and Texas Law if and where U.S. General Maritime Law is not applicable, in either case, without regard to any choice of law rules. Notwithstanding anything to the contrary, the Agreement shall not be interpreted or applied so as to require either Party to do, or to refrain from doing, anything which would constitute a violation of any applicable U.S. Laws or Regulations. Venue for any dispute shall be the U.S. District Court for the Southern District of Texas, Houston Division. The prevailing party in any dispute hereunder is entitled to recover its reasonable costs, expenses and attorney's fees.

Interrogatory 89d



United Bulk Terminals

# TERMINAL RULES AND REGULATIONS

## UNITED BULK TERMINALS, DAVANT
## 14537 HIGHWAY 15
## DAVANT, LOUISIANA 70040

## EFFECTIVE: November 15, 2016

| Action | Name/Department | Title | Date | Initials |
|---|---|---|---|---|
| Preparation | Allen Newman | Logistics Superintendent | 10/19/2016 | AN |
| Approved | Brian Miles | Vice President of Sales | 10/19/2016 | BSM |
| Approved | Tyrone Williams | Operations Manager | 10/19/2016 | TW |

## Table of Contents

# 1 GENERAL RULES AND REGULATIONS

## 1.1 USE OF TERMINAL

Use of the United Bulk Terminals (sometimes hereinafter "United Bulk Terminals" or "Terminal") Terminal facilities and services covered by these Terminal Rules and Regulations shall constitute *evidence* of an agreement on the part of all Users of the Terminal to be covered by all the rules and regulations stated herein. Notwithstanding anything to the contrary herein, the rights of any User to utilize the Terminal facilities shall be subject to the prior approval of United Bulk Terminals.

## 1.2 AMENDMENTS

Amendments to these Terminal Rules and Regulations may be issued from time to time to cover changes. These Terminal Rules and Regulations are subject to change without notice. Any changes or revisions will be reflected in the online version of the Terminal Rules and Regulations which are available on the United Bulk Terminal's website:

www.unitedbulkterminals.com

## 1.3 INTERPRETATION

United Bulk Terminals shall be the sole judge as to the interpretation of these Terminal Rules and Regulations.

## 1.4 LOCAL AUTHORITY

The Terminal is within the jurisdiction of the Plaquemines Parish Port Harbor and Terminal District. Users of the Terminal are subject to the applicable rules and fees issued by the Plaquemines Parish Port Harbor and Terminal District, and are responsible for remitting any such fees directly to the Plaquemines Parish Port Harbor and Terminal District.

## 1.5 HOURS OF OPERATION

The Terminal operates twenty-four (24) hours a day, every day throughout the year except for Holidays.

## 1.6 SAFETY AND SECURITY

All Vessels are to furnish at all times while in Berth, safe ingress and egress.

When a Vessel is berthing at any of the Terminal facilities, the Master shall be solely responsible for the safety of the Vessel and her crew. Any Vessel in berth shall at all times maintain appropriate officers and crew aboard the Vessel in order to maintain an alert watch and respond to emergencies. Moreover, Terminal's written consent, as described more fully in Section 4.11, shall be obtained before any crew or any other individual will be allowed on any Terminal Facilities, docks and/or buoys.

a. The engineering plant and vessel trim must be maintained in a state of readiness to respond to emergency situations and to avoid delays in vacating the berth.

b. Guards must be installed to prevent ballast water from contacting personnel, equipment or the dock.

c. All personnel shall wear life jackets, hard hats and all generally accepted safety equipment and gear while on the docks at all times. It is Vessel Party's responsibility to provide life jackets, hard hats and all generally accepted safety equipment and gear. Vessel crew members shall adhere to this requirement when on the dock and when transiting the conveyor walkway system to and from the docks. Hazardous materials, substances or wastes, and cargoes which are of a highly flammable, radioactive, explosive, noxious or dangerous nature, or reactive to personnel, will not be provided with any service of any kind except under advance arrangement with United Bulk Terminals accompanied by full disclosure of the hazardous characteristics, risks and special handling requirements of such cargo and in such case negotiated rates and charges shall be applied. It is the responsibility of the Shipper or other person tendering cargo to the Terminal (1) to fully disclose in writing and in advance all of the cargo's characteristics, risks and special requirements applicable to its safe loading, unloading, handling and storage in bulk and (2) to obtain all necessary special permits or permissions required by the Captain of the Port, U.S.C.G., and/or other state or federal authorities in connection with the loading, unloading, handling and/or storage at United Bulk Terminals.

d. Simultaneous with the submission of the Berth Application, Users of Terminal facilities shall provide United Bulk Terminals with Material Safety Data Sheets on all commodities handled for their account.

e. In compliance with United States Coast Guard, Department of Homeland Security directives, 33 CFR 105, United Bulk Terminals has developed a Facility Security Plan ("FSP"). According to United Bulk Terminal's FSP, certain areas of the Terminal's landside facilities and all of United Bulk Terminal's berths and fleets are considered restricted areas. Any unauthorized entry into restricted areas is considered a "Breach of Security" and the proper authorities will be notified. Anyone or anything entering into the Terminal is subject to screening, inspection and/or search according to the Terminal's FSP. Failure to consent will result in denial or revocation of authorization to enter.

## 1.7 COMPLIANCE WITH LAWS AND REGULATIONS

Prior to coming into the Berth, all Vessels shall have fully complied with all applicable U.S. Coast Guard regulations and all applicable local, state and federal laws and regulations in effect while the Vessel is in Berth at the Terminal. In no event shall Loading or Unloading of an Ocean Vessel, as the case may be, occur until such time as such Ocean Vessel has been cleared by U.S. Customs. If any Vessel fails to comply with all such laws and regulations, the Terminal may order the Vessel to vacate the Berth. If the Vessel does not vacate the Berth when so ordered, the Vessel will be subject to, in addition to the liquidated damages provided for in Section 3.3, all costs (including, but not limited to, attorneys' fees) and expenses in connection with the moving of the Vessel, which costs and expenses (and liquidated damages) shall be for the account of and the full risk of the Vessel and the Vessel Party.

## 1.8 RESPONSIBILITY FOR VESSEL OR CARGO DAMAGE, PERSONAL INJURY OR DEATH, AND POLLUTION

United Bulk Terminals shall not be responsible for marine loss or damage to Cargo and/or Vessels including, but not limited to: (1) damage to Vessel parts or Cargo arising by reason of concealed or inadequately protected fastening, attachments, covers, and parts of the Vessel projecting into bulk Cargo; (2) damages incurred as a result of Vessel configuration; and/or (3) damage to Vessel's gear, equipment or structures caused by the nature, characteristics or quality of the Cargo being Loaded or Unloaded.

The Vessel Party shall have the duty to be fully familiar with the environmental rules and regulations and laws in respect to the type and levels of all discharge allowed in United States rivers, coastal waters and air and for fully abiding by said rules, regulations and laws. The Terminal will report any observed act which is suspected to be a violation of any such obligation, rule, regulation or law to the appropriate governmental authority.

The Loading and/or Unloading of Cargo shall be under the continuous direction and sole responsibility of the Master or authorized representative. The Loading/Unloading plan should be such that the Vessel is maintained in trim and the engine is in a condition that it could leave the dock on short notice (less than 20 minutes).

All Vessels and Users of the Terminal hereby agree to indemnify, defend and hold harmless United Bulk Terminals and all persons, firms or other entities which may manage, own or control the operations of said Terminal, and their officers, directors, agents, insurers, and Vessels (collectively with United Bulk Terminals, the "UBT Indemnitees") from and against any and all claims, actions, damages, liability or expense, including court costs and attorney's fees, in connection with the loss of life, bodily injury, disease, or any other injury of any type whatsoever, involving anyone, including Visitors, and damage, contamination or loss of property, including the User's Cargo, incident to or resulting from their use of the Terminal facilities.

Vessels shall not violate any air emission standards in the vicinity of United Bulk Terminals facilities.

Additionally, such obligation of Vessels and Users to indemnify, defend and hold harmless the UBT Indemnitees shall include, but not be limited to, loss, penalty, fine, clean-up costs, natural resource damage, remediation costs, removal costs, demurrage, administrative costs and any and all other costs and liabilities that arise directly or indirectly from pollution caused by (a) Vessel Party or other master or crew of the Vessel, whether in Loading and/or Unloading Cargo, or in the operation or management of the Vessel; or (b) a spill of the Cargo, fuel or any other pollutant of the Vessel or of any other party at any time while said Cargo, fuel, or pollutant is on board the Vessel or when said Cargo, fuel, or pollutant is within the care, custody or control of Vessel Party or those for whom Vessel Party is responsible except where such damages, losses, costs or liability are caused by the sole negligence of Terminal. In the event of a pollution event arising directly or indirectly out of services being performed at the Terminal, Vessel Party shall, and shall cause its representatives and insurers, to immediately:

a. Notify all local, state and federal authorities having jurisdiction of the pollution event.

b. Notify Terminal of all details of the pollution event.

c. Take all steps to eliminate the cause and/or source of the pollution.

d. Take all steps to clean up the pollution.

e. Take all steps required by law to restore the environment.

f. Take all steps to mitigate damages of Vessel Party, Terminal and third parties.

g. Promptly pay, and pay for, all fines, damages and losses of their parties, to the extent required by law, and for all costs and expenses of cleanup.

h. If necessary, advance or pay monies and funds required to be paid to the appropriate regulatory agencies.

i. Consult with Terminal and keep Terminal constantly informed of all steps taken and contemplated to comply with provisions of this paragraph.

j. Cooperate with Terminal in issuing statements to government authorities and media representatives.

Whether or not Vessel Party has complied with the provisions of the foregoing, Terminal may, but shall not be required to, take over and manage all prevention, cleanup and restoration activities, all without derogation or diminution of Vessel Party's obligations under these Terminal Rules and Regulations, and with full reservation to Terminal of all rights against the Vessel, Vessel Party or its insurers for reimbursement of costs, expenses and attorneys' fees. In such event, Vessel Party shall, cause its insurers and any subcontractors, to make available to Terminal all Vessels, personnel and equipment used or planned to be used in such prevention, cleanup and restoration efforts, all at the sole expense of Vessel Party.

In the event Terminal takes over and manages such prevention, cleanup and restoration efforts, such action shall not be deemed a waiver, or constitute an estoppel by Terminal or an admission of fault or responsibility on the part of Terminal. Terminal may, but is not required to, utilize its own and/or contracted personnel, vessels and equipment in such prevention, cleanup and restoration efforts, and may, at its discretion, allocate such resources as it, in its sole discretion, deems appropriate.

### 1.9 REMEDIES FOR ENFORCEMENT OF TERMINAL RULES AND REGULATIONS

United Bulk Terminals shall have all remedies available to it at law, in equity or under maritime law to enforce these Terminal Rules and Regulations, including, but not limited to, canceling a Vessel's Filing or ordering a Vessel from Berth. United Bulk Terminals shall also have all remedies available at law, in equity or under maritime law to collect liquidated damages, including, but not limited to, a maritime lien against the Vessel and cargo for such charges. In the event of any legal proceedings to enforce any provision of these Terminal Rules and Regulations, United Bulk Terminals shall be entitled to recover its expenses incurred in such proceedings, including, but not limited to, attorney's fees, court costs, expert witness fees and all other litigation expenses regardless of type.

### 1.10 SAFE BERTH

The master of the Ocean Vessel shall be solely responsible for determining if the depth of water (at any tide or river stage) is sufficient for the Vessel, the Terminal having no responsibility therefore and the Terminal shall not be deemed to warrant the safety of public channels, fairways, approaches thereto, anchorages or other publicly-maintained areas either inside or outside the port area where any Vessel may operate. Furthermore, the Terminal shall not be deemed to warrant the safety of any of the Berth's docks or midstream facilities, including the Terminal's mooring buoys.

### 1.11 ENTIRETY OF AGREEMENT

In the event of a conflict between these Terminal Rules and Regulations and any other agreement concerning the Vessel or the Cargo, the terms and conditions of these Terminal Rules and Regulations shall control. **Notwithstanding the foregoing, in the event of a conflict between these Terminal Rules and Regulations and any written agreement concerning the Vessel or the Cargo that is between Terminal and any of its customers (e.g. Bulk Cargo Transfer and Storage Agreement) ("Customer Contract"), the terms and conditions of the Customer Contract shall control.** In case any portion of any provision or any one or more of the provisions contained in these Terminal Rules and Regulations should be held or determined invalid, illegal, in conflict with a Customer Contract or unenforceable in any respect, the validity, legality and enforceability of the remaining portion of any such provision and the other remaining provisions or underlying rights and obligations referred to herein shall not in any way be affected, modified, or impaired thereby.

## 2 VESSEL FILING

### 2.1 NOMINATION AND FILING

#### a. NOMINATION

Nomination of the Ocean Vessel shall be furnished to the Terminal by facsimile transmittal ((504) 682-1388) or e-mail (ubt.taffic@unitedbulkterminals.com) between 7:30 a.m. and 4:00 p.m. Mondays thru Fridays, excluding Holidays, not earlier than thirty (30) days and not later than fourteen (14) days prior to the ETA of the Ocean Vessel.

Shipper is to provide Terminal, in writing, a ten (10) day laycan spread at least thirty (30) days prior to the date of the first day of the ten (10) day laycan spread. No later than fourteen (14) days from the date of the first day of the original ten (10) day laycan spread, Shipper is to identify in writing to Terminal a four (4) day load window within such original ten (10) day laycan spread. In each case mentioned above, the written approval of the Terminal shall be required relative to the ten (10) day laycan and the four (4) day load window within the original ten (10) day laycan.

Acceptance by Terminal of a Nomination of a Vessel shall be evidenced by Terminal's confirmation by facsimile or e-mail transmittal to the Vessel Party.

b. **FILING**

All Ocean Vessels, their owners, operators, charterers or agents which intend to utilize the facilities and services of the Terminal shall file by facsimile transmittal ((504) 682-1388) or e-mail ubt.traffic@unitedbulkterminals.com a Berth Application for an ETA with United Bulk Terminals. An executed original of the Berth Application must follow by U.S. Mail. The Berth Application sent by facsimile or e-mail must be received by the Terminal between 7:30 a.m. and 4:00 p.m. Mondays through Fridays, excluding Holidays, and no later than seven (7) days prior to the ETA of the Ocean Vessel.

Acceptance by Terminal of a Berth Application shall be evidenced by Terminal's issuance to the Vessel Party of a Berth Application Acceptance. Any Ocean Vessel arriving and submitting a Notice of Readiness, as defined below, prior to the date booked will be worked at the discretion of the Terminal; otherwise, the Ocean Vessel shall wait for the period set forth in the Berth Application Acceptance. Ocean Vessels arriving or submitting a Notice of Readiness after the ETA set forth in the Berth Application Acceptance similarly will be worked at the discretion of the Terminal.

With respect to river barges, the Vessel Party shall provide the following information not later than seven (7) days prior to the ETA of the river barges, listing with respect to each such river barge the individual barge numbers, tonnage, loading drafts, name of carrier, ETA and the type of Cargo carried or to be carried, which report shall be subsequently updated on the Monday of each week until such river barges are received into the Terminal Fleet. All Users and their river barges utilizing the facilities and services of the facilities and services of the Terminal shall be subject to and shall abide by the terms and conditions of the Terminal Rules and Regulations.

With respect to any ocean going vessel expected to arrive at the Terminal for the loading of export cargo, such vessel shall, no later than 3 working days after the departure from the Terminal, provide the Terminal with a full and correct freighted copy of the bill of lading including shipper, consignee and notify party(s). Any bill(s) of lading, mate's receipt or other shipping document issued in connection with the transportation of the cargo shall have no effect or control over the services to be provided by the Terminal, it being the intention of the parties that the Customer Contract and these Terminal Rules and Regulations shall contain all of the terms and conditions agreed upon by the parties. The terms and conditions as included in the Customer Contract and these Terminal Rules and Regulations shall control and supersede any terms and conditions contained in any bill of lading, mate's receipt or other shipping document.

## 2.2 NOTICE OF READINESS

In the case of an Ocean Vessel to be loaded, issuance of the Notice of Readiness shall mean that the Ocean Vessel (1) has obtained all requisite governmental approvals, inspections and clearances, including, but not limited to, those required by the U.S. Customs Service and the Immigration and Naturalization Service; and (2) is located at the Berth or Closest Available Anchorage (as defined in Section 2.5 below); and (3) is ready and suitable in all respects to receive the Cargo in all holds to be loaded; and (4) has confirmed with the Terminal that the Cargo to be loaded to Vessel is in storage at the Terminal or, if Cargo is to be direct transferred, is in barges in the Terminal's fleet; and (5) has determined that the Cargo is in a condition satisfactory to the Vessel Party and all regulatory authorities for shipment. Notice of Readiness shall be considered invalid unless the aforementioned five conditions are met. In addition, User specifically acknowledges that varying temperatures, moisture and weight changes and spontaneous combustion constitute inherent problems associated with the handling of coal, petroleum coke and other Cargo. Prior to Loading or Unloading, User's surveyor shall determine that the temperature, moisture and condition of the Cargo is satisfactory.

## 2.3 AGREEMENT TO BE BOUND

The issuance by the Terminal of the Berth Application Acceptance, Shipper's identification of a load window as set forth in Section 2.1.a above or the berthing of any Ocean Vessel at the Terminal, shall constitute a contract between United Bulk Terminal and the Ocean Vessel, her owners, operator(s), charterer(s) and agent(s) and any other Vessel Party (jointly and severally) to abide by the provisions of, and to be liable for the charges of whatsoever kind or nature in these Terminal Rules and Regulations.

## 2.4 CERTIFICATION FOR FILING

In the case of an Ocean Vessel, the following certificates and documents must be presented to file for a Berth at the Terminal. Facsimile transmissions, alone, will not be accepted.

a. Original Berth Application (the "Berth Application") signed by authorized representatives of the Vessel Party.

b. A copy of the Notice of Readiness executed by authorized representatives of the Vessel Party.

c. International tonnage certificate.

d. A proposed stowage plan which includes Cargo cubic capacity for any Ocean Vessel to be loaded and Loading sequence or the actual plan for Cargo to be unloaded including the Unloading sequence.

e. Additionally, should it be necessary for Vessel personnel or Visitors, including Vessel's agent, to leave or board the Vessel, twenty-four (24) hours prior written notification to Terminal must be provided and include a list of the: (a) name, (b) address, (c) telephone number and (d) reason for visit of each Visitor to the Vessel and Vessel Personnel leaving the Vessel. Each Visitor must have a form of identification acceptable to Terminal. Said list shall be supplemented as needed and furnished in advance of the visit to the Terminal in writing between 9:00 a.m. and 4:00 p.m. Mondays through Fridays and between 9:00 a.m. and 12:00 noon Saturdays, excluding Holidays as defined herein (the "Visitor List"). Any Vessel personnel leaving the ship shall be required to furnish the Terminal with a Crewman's Landing Permit – Form I-95 issued by the U.S. Immigration & Naturalization Service and a picture identification card.

## 2.5 CLOSEST AVAILABLE ANCHORAGE

Ocean Vessels filing a Berth Application to utilize the Terminal facilities normally will be required to anchor at Davant Anchorage (Mile 53.5-54.5 LDB), or the closest available anchorage to Davant, Louisiana.

Vessel Party acknowledges that any Vessel arriving at the Terminal with cargo on its deck may constitute a hazardous and unsafe condition, may be in violation of certain environmental compliance, regulations and laws and will render any Notice of Readiness invalid. Vessel Party agrees that if notified of such condition, it shall be the sole responsibility of Vessel Party to clean and remove any such product which renders the deck of any such Vessel hazardous to the safety of any person. Should Vessel Party fail to promptly clean and remove product from the deck of any such Vessel, the Terminal reserves the right, but not the obligation, to clean and remove the product from the Vessel's deck, which service will be solely for the account of the Vessel Party. Alternatively, Terminal may reject the Vessel and refuse to accept it at the Davant Anchorage. Any time used to clean and remove such product rendering the deck hazardous to the safety of any person shall not count against laytime.

Vessel Party shall coordinate and be solely responsible for all required inspections for cleanliness and compliance with all local, state and federal laws and regulations relative to the fitness of the Vessel. All run off reporting and other environmental compliance and reporting shall be Vessel Party's sole responsibility. Any EPA, regulatory or court imposed fines levied against Terminal as a result of Vessel Party's non-compliance and/or failure to report shall be for Vessel Party's account.

Whenever a Notice of Readiness has been issued, the Ocean Vessel shall be prepared to come to Berth and commence Loading or Unloading operations, as the case may be, upon three (3) hours notice. Upon assignment to a Berth, the Ocean Vessel shall remain prepared and be properly crewed to promptly carry out Cargo transfer operations within or between Terminal's Berths, and undock and vacate the Berth on order of the Terminal twenty-four (24) hours a day, seven (7) days a week, with any crew overtime being at the sole cost and expense of the Ocean Vessel. For purposes of these Terminal Rules and Regulations, "promptly" shall mean within thirty (30) minutes of notice being tendered by the Terminal.

In the event that the Ocean Vessel fails to comply with these requirements, Terminal management may, in its sole discretion, and without liability to anyone, bypass the subject Ocean Vessel. If the Ocean Vessel is ordered to Berth and a delay in delivery of the Ocean Vessel to Berth occurs in excess of three (3) hours from the time that the Ocean Vessel was ordered to Berth and such delay is due to circumstances or conditions within the control or due to the fault of the Ocean Vessel, its owner(s), operator(s), charterer(s), agent(s) or employee(s), then the Ocean Vessel, its owner(s), operator(s), charterer(s) and agent(s) shall be responsible, jointly and severally, for a dead Berth charge of $5,000 for each hour or fraction thereof until the Ocean Vessel is moored in Berth, regardless of intervening circumstances of any nature, which charge shall be assessed as liquidated damages.

### 2.6 BERTH ASSIGNMENT

Terminal operations may be scheduled at Terminal's Berths and in any combination thereof. Prior to the issuance of the particular Berth assignment, the Vessel Party must provide a guarantee acceptable to the Terminal regarding payment of Dockage fees as provided for in Appendix A.

### 2.7 REFILING

If any Ocean Vessel that has filed at Terminal is ordered to Berth by Terminal management and is unable or refuses to accept a Berth, due to any reason whatsoever, or otherwise fails to comply with these Terminal Rules and Regulations, the Terminal management may, at its sole discretion, cancel the Ocean Vessel's original filing. If filing is cancelled, the Ocean Vessel must refile and will be assigned a rotation in the Terminal lineup based on the new filing time.

## 3 LOADING AND UNLOADING

### 3.1 BERTHING AND SAFETY EQUIPMENT

Upon berthing, the Ocean Vessel shall immediately and at all times provide adequate lighting, equipment and appropriate officers and crew aboard to permit Loading or Unloading, as the case may be, of Cargo at any time of the day or night, including Saturdays, Sundays and Holidays. All Ocean Vessel officers and crews shall wear life jackets, safety glasses and hard hats while on the Terminal docks and when transiting the conveyor walkway system to and from the docks.

### 3.2 LINE HANDLING

The master and crew of every Vessel will provide assistance in handling lines and operating deck machinery. An English-speaking deck officer must be available to ensure timely response to directions of any representatives of the Terminal relative to handling of lines. Terminal representatives will position lines on the shoreside. Line handling for docking and undocking of Ocean Vessels in Berth and at the buoys, shall be assessed at the rate provided in Appendix A.

### 3.3 VACATING BERTH

Whenever an Ocean Vessel is unable or refuses to load or unload, or shift within or between anchorage sites, mid-stream transfer facilities, berths or docks, the Terminal management may order the Ocean Vessel to vacate the Berth after notice to vacate is delivered to the Ocean Vessel's master or agent. If an Ocean Vessel refuses or fails to vacate the Berth when ordered to vacate, United Bulk Terminal shall be entitled to charge and recover from Ocean Vessel and Vessel Party as liquidated damages the sum of $5,000.00 per hour (with partial hours prorated) beginning one hour after delivery of the notice to vacate and continuing as long as the Ocean Vessel remains in Berth, regardless of any intervening circumstances of any nature.

Furthermore, United Bulk Terminals reserves the right to order, at its sole discretion, any Ocean Vessel to vacate the Berth. Should the Ocean Vessel fail to vacate the Berth when so ordered, a charge of $5,000 per hour (with partial hours prorated) shall be assessed against the Ocean Vessel and Vessel Party as liquidated damages until the Ocean Vessel vacates the Berth, regardless of any intervening circumstances of any nature. If the Ocean Vessel does not vacate the Berth when so ordered, the Ocean Vessel will be subject to, in addition to the liquidated damages above, all costs, including but not limited to, attorney fees and expenses in connection with the moving of the Ocean Vessel, which costs and expenses (and liquidated damages) shall be for the account of and the full risk of the Ocean Vessel and Vessel Party.

### 3.4 VESSEL ROTATION

The Terminal management may alter the turn of Ocean Vessels for Loading or Unloading, when, in Terminal's sole judgment, it is in the best interest of Terminal operations.

### 3.5 CONTINUOUS READINESS

Assignment of Berth under these Terminal Rules and Regulations is predicated upon Ocean Vessel's continuous readiness twenty-four (24) hours a day, seven (7) days a week to receive or discharge Cargo at Terminal's full normal rate, throughout the entire time in Berth and compliance with the directions of Terminal management, including shifting within or between anchorage sites or Berths. Any delay in Loading or Unloading by the Ocean Vessel or refusal to follow directions of Terminal management, including an order to vacate the Berth, shall subject the Ocean Vessel and Vessel Party to a charge of $5,000 per hour (with partial hours prorated) of delay which shall be assessed as liquidated damages regardless of any intervening circumstances of any nature.

### 3.6 VACATING BERTH UPON COMPLETION OF LOADING/UNLOADING

Ocean Vessel shall vacate the Berth within one (1) hour of completion of Loading or Unloading. If an Ocean Vessel refuses or fails to vacate the Berth when ordered to vacate, United Bulk Terminal shall be entitled to charge and recover as liquidated damages from the Ocean Vessel and Vessel Party, the sum of $5,000 per hour (with partial hours prorated) beginning one hour after receipt of the notice to vacate and continuing until vacation of the Berth occurs regardless of any intervening circumstances of any nature. If the Ocean Vessel does not timely vacate the Berth, the Ocean Vessel will be subject to, in addition to the liquidated damages above, to all costs (including but not limited to attorney fees) and expenses in connection with the moving of the Ocean Vessel, which costs and expenses (and liquidated damages) shall be for the account of and the full risk of the Ocean Vessel and the Vessel Party.

### 3.7 WEATHER CONDITIONS

When, in the Terminal management's opinion, weather conditions threaten the safety of any moored or fleeted Vessel and/or the structural integrity of the Terminal facilities, transfer operations will be suspended and any Vessel moored or fleeted at the Berth shall vacate the Berth immediately when requested by the Terminal management to do so and until such time as weather conditions permit it to return (irrespective of whether the order by Terminal to vacate the Berth precedes any similar order to vacate issued by the Plaquemines Parish Port Harbor and Terminal District). If any Vessel does not leave the Berth within three (3) hours of being ordered to do so, all costs (including but not limited to attorney fees) and expenses in connection with the moving of the Vessel and mooring or fleeting of same, as the case may be, shall be for the account of and at the full risk of the Vessel and Vessel Party. In no event shall Terminal have any responsibility for any Vessel, including, but not limited to, the cost of moving a Vessel that is ordered to vacate the Berth for any reason provided in these Terminal Rules and Regulations. Any damage to the Terminal facilities or other equipment shall be the responsibility of the Vessel Party and Vessel. Any Vessel calling at the Terminal shall be subject to the written guidelines and procedures relative to hurricanes adopted by Terminal.

## 3.8 USE OF TUGS

When an Ocean Vessel is entering or leaving the Berth, United Bulk Terminals shall provide tugs, the cost of which as set forth in Appendix A shall be at the sole expense of and for the account of the Vessel and the Vessel Party without refund or credit against any charges due and owing the Terminal. If, in the opinion of the Terminal management, the weather or other conditions so warrant, each Ocean Vessel upon entering and leaving or lying at Berth (including shifting within the Berth) may be required to make use of additional tugs, depending on the size of the Ocean Vessel, which additional tugs shall be at the sole risk and expense of the Vessel and the Vessel Party. A one (1) hour waiting period from the call-out time is allowed. Any additional time will be invoiced at the current standby rate. If called out and not used, the current reporting fee will apply. Charges for towage services will be assessed to the Vessel by United Bulk Terminals.

## 3.9 MOORING OF BARGES

United Bulk Terminals operates a closed fleet. All Vessel Parties shall obtain the prior approval of United Bulk Terminals before their Vessels enter United Bulk Terminal's fleet/berth/docks/buoys. No less than twenty-four (24) hours advance notice of the foregoing shall be provided by Vessel Parties to United Bulk Terminal's Logistics Manager. If such approval by United Bulk Terminals is granted, all Vessels, Visitors, personnel, and passengers are required to comply with United Bulk Terminal's prescribed safety rules and personal protective equipment requirements and follow United Bulk Terminal's Facility Security Plan. United Bulk Terminal reserves the right to levy a user fee. Any User delivering river barges to the Terminal shall be responsible for mooring the barges in accordance with these Terminal Rules and Regulations and any other regulations promulgated by the Plaquemines Parish Port, Harbor and Terminal District and United States Coast Guard.

All river barges or other Vessels that User brings into the Terminal Fleet must be jointly inspected by officials of the United Bulk Terminals' customer or User and United Bulk Terminals prior to being placed in the Terminal Fleet (such joint inspection may sometimes be hereinafter referred to as the "Joint Inspection"). The Joint Inspection may include:

a. Check for water in all voids, including wing tanks, bow and stern compartments;
b. Inspect above water areas for signs of recent and/or major damage;
c. Inspect grain doors on covered barges to ensure that they are in the closed position;
d. Inspect deck fittings to ensure all are present;
e. Observe draft and trim of loaded barge(s) to determine that barge(s) are safe for fleeting; and
f. Inspect all deck areas and walkways for cargo or other debris that may impede the safety of personnel.

A river barge moored to another river barge, a mooring or spar barge, a vessel, a wharf, or a pier, will be secured as near as practicable to each abutting corner of the river barge being moored by:

a. Four part wire rope of at least 7/8" diameter with an eye at each end of the rope passed around the timberhead, cavel or button.

b. A mooring line of natural or synthetic fiber that has at least 75 percent of the breaking strength of four part 7/8" diameter wire rope; or

c. Fixed rigging that is equivalent to four part 7/8" diameter wire rope.

Any river barges arriving at the Terminal without lines, wire or stationary rigging meeting the requirements set forth above will not be accepted by the Terminal until such time as proper equipment is furnished. Upon arrival or departure from the Terminal, all Vessels are required to contact the Terminal harbor boats. The Terminal harbor boat operator in attendance shall have the right, although not the obligation, to determine if the river barges have been properly secured by the Vessel Party.

Vessel Party acknowledges that any river barge arriving at the Terminal with cargo on its deck may constitute a hazardous and unsafe condition. Vessel Party agrees that if notified of such condition, it shall be the sole responsibility of Vessel Party to clean and remove any such product which renders the deck of any such river barge hazardous to the safety of any person. Should Vessel Party fail to promptly clean and remove product from the deck of any such river barge, the Terminal reserves the right, but not the obligation, to clean and remove the product from the river barge's deck, which service will be solely for the account of the Vessel Party. Alternatively, Terminal may reject the river barge and refuse to accept it at the Terminal and in the fleet.

In the event User tenders a Vessel for placement into the Terminal Fleet which, based on United Bulk Terminals' sole discretion, is: (1) found to be in a leaking or otherwise damaged condition during the Joint Inspection whereby United Bulk Terminals believes such Vessel is not suitable or fit for fleeting, cargo handling operations and/or is otherwise unseaworthy; or (2) lacking adequate freeboard or otherwise improperly loaded with cargo such that fleeting operations and/or cargo handling operations may be unsafe, then United Bulk Terminals may refuse to accept such Vessel at the Terminal and in the fleet, or, alternatively, United Bulk Terminals may elect to "Conditionally Accept" such Vessel. In the event United Bulk Terminals agrees to "Conditionally Accept" a Vessel, United Bulk Terminals will provide notification to User by e-mail confirming United Bulk Terminals will accept the subject Vessel, but the acceptance of the Vessel shall be a "Conditional Acceptance." In the event United Bulk Terminals Conditionally Accepts a Vessel, the following allocation of risk, indemnity agreement and waiver of rights shall be in effect between the parties:

a. User shall be responsible for the leaking, damaged, lack of freeboard and/or improperly loaded condition of the Vessel resulting in the Conditional Acceptance of the Vessel by the Terminal, and User shall be responsible for any sinking, loss of and damage to the Vessel and its cargo, regardless of fault, and even when the Vessel is in the care, custody and/or control of United Bulk Terminals;

b. User shall be responsible for and shall assume all liability for damage and loss sustained to other property and for personal injury, illness and death claims which are caused in whole or in part by the Vessel's leaking, damaged, lack of freeboard and/or improperly loaded condition;

c. User shall defend (including the payment of attorney's fees, court costs and all litigation expenses regardless of type), indemnify and hold harmless the UBT Indemnitees from and against any and all claims for: (1) damage to and/or loss of the Vessel and its cargo, regardless of the cause or causes thereof; and (2) for all other personal injury, illness, death and property damage which is caused in whole or in part by the Vessel's leaking, damaged, lack of freeboard and/or improperly loaded condition; and

d. User hereby agrees that notice of the Vessel's leaking, damaged, lack of freeboard and/or improperly loaded condition resulting in such Vessel being Conditionally Accepted by United Bulk Terminals shall be considered "privity and knowledge" by the User of the Vessel's condition so as to waive any right the User may have to limit liability pursuant to the Shipowner's Limitation of Liability Act, 46 U.S.C. 30501, et. seq. In addition, User hereby agrees the Vessel is being handled at the Terminal pursuant to a "Personal Contract", and it is the intention of the User and United Bulk Terminals that User shall not be entitled to limit its liability to United Bulk Terminals in any respect under the afore-referenced Shipowner's Limitation of Liability Act.

Vessel Party shall coordinate and be solely responsible for all required inspections for cleanliness and compliance with all local, state and federal laws and regulations relative to the fitness of the river barge. All run off reporting and other environmental compliance and reporting shall be Vessel Party's sole responsibility. Any EPA, regulatory or court imposed fines levied against Terminal as a result of Vessel Party's non-compliance and/or failure to report shall be for Vessel Party's account.

## 3.10 BARGE RELEASE

Once Loading or Unloading of a river barge has been completed, as determined by Terminal personnel, the river barge must be picked up within seventy-two (72) hours of Terminal's transmittal of notice to the Vessel Party that the river barge must be removed. In the event that a river barge is not removed within the time limit, Terminal management may, at its sole election, arrange either to have the river barge shifted to a commercial barge fleet or fleeted at the Terminal, to the extent that fleeting space is available, at the sole risk and expense of the Vessel Party. If the Vessel Party has been instructed to pick up its river barges and removal of the river barges is not accomplished within seventy-two (72) hours, an additional charge above the normal fleeting will be assessed. The fee will be assessed until the river barges are removed, and shall be assessed in accordance with the fee provided in Appendix B. The Terminal will endeavor to send a facsimile or electronic transmittal for release of barges on a daily basis, but on days when Vessel Party does not receive such a notice, it is the Vessel Party's sole responsibility to check with the Terminal on status of barge loadings and unloadings. A Vessel Party's failure to receive facsimile or electronic transmittal notice of barge release will not result in the barge(s) remaining on placement.

## 3.11 STOWAGE

The Vessel Party shall be solely responsible for the stowage of the Cargo. Cargo shall be stowed within the Vessel only in areas where grabs and equipment spouts can reach, subject to Vessel design capability. Dozer work shall be provided to the Vessel Party at an additional charge agreed upon by the Terminal and Vessel Party prior to the Vessel coming into Berth. In any event, the loading sequence plan shall not exceed two (2) pass loadings and two (2) hold trims. United Bulk Terminal will allow each Vessel two (2) draft checks which are not to exceed a period of 30 minutes each. Any Vessel exceeding the allotted time for draft checks will also be assessed the detention fee of $5,000 per hour (with partial hours prorated).

Any Vessel which is required to shift/warp within the berth will be responsible for any/all expenses pertaining to shifting/warping, including, but not limited to, line handling, pilot, and tug(s). Furthermore, any time utilized for shifting/warping will not count against any laytime.

## 3.12 SUITABILITY OF CARGO

Users acknowledge that Terminal only provides transfer facilities and outside ground storage of the Cargo at the Terminal. The Terminal reserves the right, without any responsibility for any loss, damage, or demurrage that may arise, to refuse any Cargo because in the sole discretion of the Terminal, such Cargo is unmerchantable or in an unfit condition for Loading, Unloading, Storage, transfer or handling; or because of lack of space, facilities or equipment, or for any other reason based on the sole judgment of the Terminal. The Terminal shall not be responsible for any loss, damage or delay caused by varying temperatures, moisture and weight changes and/or spontaneous combustion of Cargo, frost, heating, flood, the elements, evaporation, natural shrinkage, wastage or decay or from insufficient notification, or from war, insurrection, Acts of God, or acts or failure to act of any Governmental entity, or for any consequences arising therefrom, or from concealed damage, leakage, variation in weights, or for losses in weights whether occurring while Cargo is in Storage or during Loading, Unloading or while otherwise being handled, or for failure to detect or remedy same. In addition, any extra time associated with the handling of wet Cargo will be deducted from laytime and demurrage calculations, and additional costs associated with the handling of wet Cargo will be billed to the Vessel Party.

### 3.13 VESSEL SUITABILITY

The Terminal reserves the right to refuse any Vessel considered unseaworthy due to damage, distribution of load, draft or lack of freeboard, lists or such other reason for which Terminal deems the Vessel not suitable for handling at the Terminal. The Vessel Party, at all times, shall remain responsible for the seaworthy condition of the Vessel. The berthing of any Ocean Vessel or delivery of any river barge to the Terminal shall constitute a warranty by the Vessel Party to United Bulk Terminals that there are no latent defects in the Ocean Vessel or river barge and that same is capable of either being loaded with the Cargo to be loaded by the Terminal or to be unloaded by the Terminal using the equipment normally employed by the Terminal. In no event shall the Terminal be responsible for the seaworthiness, maintenance, repair or service of Ocean Vessels coming into the Berth of the Terminal or river barges delivered to the Terminal, such responsibility being that of the Vessel Party. Notwithstanding the foregoing, should any Vessel develop any leaks, cracks or other conditions which, in the sole judgment of the Terminal, may result in damage to the Vessel and/or its Cargo, Vessel Party agrees to take whatever steps are necessary to protect the Vessel and/or its Cargo. Furthermore, in the event that any river barge develops any leaks, cracks, or other similar conditions, such river barge, at the election of Terminal, may remain in the Terminal Fleet subject to the agreement by the Vessel Party to provide a stand-by harbor tug for the duration of the river barge's stay at the Terminal for the purpose of tending to the river barge, the cost of which harbor tug shall be at the sole expense of the Vessel Party. In the event that the Terminal assists any river barge that is sinking or damaged as a result of any leaks, cracks or other similar conditions, the charges for such assistance shall be borne solely by the Vessel Party and Terminal shall have no responsibility for loss or damage to a river barge or Cargo occurring as a result of Terminal providing such assistance. In no event shall Terminal have any responsibility for inspecting any river barge nor shall Terminal have any liability if loss or damage to a river barge or Cargo occurs as a result of Terminal's failure to reject a river barge that has leaks, cracks or similar conditions, whether or not such conditions are latent or patent.

Notwithstanding anything to the contrary herein, the Terminal is a private terminal facility and is not a "marine terminal operator" as defined by the Shipping Act of 1984, as amended. Common carriers by water (such as liners), as defined by the Shipping Act of 1984, as amended, will not be accepted for Loading or Unloading at the Terminal. 46 U.S.C. App. Section 1702 (6) defines a common carrier as "a person holding itself out to the general public to provide transportation by water of passengers or cargo between the United States and a foreign country... except that the term does not include... ocean transportation by...ocean tramp...." Only Vessels engaged in private or contract carriage pursuant to private commercial arrangements will be accepted by the Terminal.

The standard Ocean Vessel acceptable for Loading is a gearless, bulk carrier, 750' LOA, 105' beam which can ballast to achieve an air draft of 54' 8" at river stage of 0' at Davant, Louisiana for Loading under traveling ship loader and 46' at a river stage of 0' for Loading at Terminal's stationary loader at Davant, Louisiana. The standard Ocean Vessel for Unloading is a gearless, bulk carrier, 750' LOA, 105' beam which can ballast to achieve an air draft of 57' at a river stage of 0'. Requests for exceptions to the foregoing shall be made at the time of Vessel filing and shall be subject to the sole discretion of the Terminal.

# 4 ADDITIONAL SERVICES, RATES AND CHARGES

## 4.1 CHARGES

United Bulk Terminals shall invoice all customers on inbound tons, whenever the initial handling of the Cargo occurs, e.g. (1) Cargo unloaded from a river barge direct to storage at the Terminal facilities or an Ocean Vessel shall be invoiced when cargo unloading occurs from the river barge, and (2) Cargo unloaded from an Ocean Vessel direct to storage at the Terminal facilities or another Vessel including a river barge shall be invoiced when cargo unloading occurs from the Ocean Vessel. United Bulk Terminals shall render invoices for services provided hereunder, including, but not limited to, those services as set forth in the Appendix, upon completion of said services and the User agrees to pay said invoices within ten (10) days from date of invoice. The invoice shall also contain reconciliation for Dockage charges which are to be secured with a deposit pursuant to Section 4.3 below. Any invoice that remains unpaid after ten (10) days from date of invoice shall earn interest, compounded at one and one-half (1-1/2%) percent per month or portion thereof or the maximum legal interest rate allowed under Louisiana law to the extent that a rate of one and one-half (1-1/2%) percent per month violates Louisiana laws. Any pending or alleged claims against United Bulk Terminal will not be allowed as an offset against outstanding or accrued charges until such claims have been agreed to by United Bulk Terminal in writing or legally established by court order.

The number of tons of Cargo to be invoiced by the Terminal shall be certified by a representative of the National Cargo Bureau or a mutually agreed surveyor who shall perform a displacement survey to determine the tonnage transferred either by barge or vessel. Such displacement survey shall be performed at the sole cost and expense of the User and it is agreed that copies of the certificate shall be concurrently submitted to the User and United Bulk Terminal.

Any charges for Liquidated Damages are due in full before the Vessel will be allowed to leave the Terminal. Moreover, Vessel Party agrees to waive any damages it may sustain resulting from any delay in Vessel leaving the Terminal because of Vessel Party's failure to pay or delay in paying Liquidated Damages.

Laycan Spread Cancellation Penalty and Window Cancellation Penalty charges assessed pursuant to Section 4.15 below will be invoiced by the Terminal following the close of the load window Vessel missed and will be due by Shipper within thirty (30) days from date of invoice. Window Cancellation Penalty charges are subject to the same interest and setoff terms and conditions as set forth in the first paragraph of this Section.

## 4.2 GROUND STORAGE OF CARGO

Terminal agrees to provide outside ground storage at the rate provided for in the applicable Customer Contract. Terminal shall not be responsible for spontaneous combustion or other damage to any stored Cargo. Upon request by the User, tractor work to shape, compact or periodically rearrange any stockpile in which the User's Cargo is stored will be provided, subject to such terms and conditions as mutually agreed upon by the Terminal and User. User agrees that the Terminal may also periodically groom Cargo stored at the Terminal so as to prevent spontaneous combustion. Terminal's grooming, shaping, compacting or rearranging of Cargo will in no way create any liability for the Terminal. If a condition of spontaneous Combustion or a significant rise in temperature should occur, User assumes full responsibility for all costs and damages thereby resulting; the responsibility of the Terminal being to promptly notify User of any such condition observed by Terminal and User being responsible to promptly advise and direct Terminal regarding the appropriate action necessary to extinguish any fires. If User fails to respond to such notice by Terminal or fails to promptly advise and direct

Terminal, then Terminal, at the sole cost and expense of User, may, but is not obligated, to take appropriate action to extinguish any fires caused thereby. All such actions undertaken by Terminal, whether under the direction of User or otherwise, shall be for User's account and will in no way create any liability for the Terminal.

Terminal shall not be responsible for loss or contamination or damage or destruction of any Cargo in its care, custody or control, whether in Storage or elsewhere. Furthermore, Terminal shall not be responsible for loss of calorific content or loss of weight of any Cargo transferred or stored at the Terminal. User specifically acknowledges that normal variances in the measurement of quantity and weight of cargo shipped in bulk exists and that the weights of Cargo determined by the National Cargo Bureau or a mutually agreed surveyor on behalf of User shall be used only for invoice purposes by the Terminal.

In no event shall the use of the Terminal Storage facilities be construed as a lease or sublease agreement between the Terminal and User.

## 4.3 DOCKAGE

Dockage fees calculated on the basis stated in Appendix A shall be assessed to any Vessel berthed at the Terminal or at any Terminal buoy system.

Prior to berthing, the Vessel Party will be required to deposit with United Bulk Terminals an amount sufficient to cover all estimated charges due, including dockage, tug assistance, line handling, crew boat services, facility security fee, facility user fees and any other supplemental fees levied by governmental agencies. United Bulk Terminals reserves the right to postpone Cargo operations until the full requested deposit has been received. Additional deposits may be required during the loading in the event actual charges incurred exceed any deposit(s) received. Cessation of operations will occur if actual charges incurred exceed total deposit(s) received, and any delays and costs and penalties associated created thereby shall be for Vessel Party's account.

## 4.4 RIVER BARGE FLEETING AND SHIFTING CHARGES

River barges fleeted and/or shifted at the Terminal shall be charged for the service by United Bulk Terminals at the rate provided in Appendix B.

## 4.5 RIVER BARGE COVER HANDLING

Any river barges requiring Terminal assistance in handling river barge covers shall be charged for the service at the rate provided in Appendix B.

## 4.6 DISCHARGING STACKED COVER RIVER BARGES

Any stacked cover river barges shall be discharged at the rate provided in Appendix B.

## 4.7 WATER

Water flow and access to water mains is limited. Arrangements for water shall be made with Terminal in advance of berthing the Vessel. Water, when available, will be furnished at the charge provided in Appendix A. Prior approval and coordination by Terminal management shall be required for water delivered by river barge.

## 4.8 BUNKERS

Absent the prior approval of the Terminal, no bunkers, diesel fuel or oils may be received by Ocean Vessels in Berth. To the extent the taking of bunkers hinders Terminal operations, the actual cost associated with any delay will be billed to the Vessel Party. Terminal reserves the right to assess a bunker fee if Vessel is allowed to accept a bunker barge while at berth.

## 4.9 REPAIRS

Once the Notice of Readiness has been tendered, no repairs that would impede the movement of the Vessel or that would interfere with Cargo transfer operations or affect safety shall be undertaken.

## 4.10 SAMPLING

Automatic mechanical sampling services are provided by an independent third party contractor and are available to the User at the Terminal at the sole cost and expense of the User. It is understood and agreed that Terminal shall not, under any circumstances, be responsible or liable for the sampling services or any lack thereof.

## 4.11 VISITORS AND DELIVERY OF VESSEL PROVISIONS

Absent the prior written consent of United Bulk Terminals, no Visitor or Visitors, including, but not limited to, any User, crew members, Shipper, river transportation operator, launch service operator, master, owner, charterer, operator or agent, shall be allowed access to any of the Terminal facilities, docks or buoys while any Vessel is moored or berthed at any such United Bulk Terminal facility, dock or buoy. The Terminal reserves the right to deny access to any Visitor or Visitors whom the Terminal, in its sole discretion, deems may result in injury, damage or loss to persons or property at the Terminal. Every person entering the Terminal facilities must sign in with the Terminal office before proceeding to any Vessel or Terminal building and shall furnish Terminal with identification acceptable to Terminal. Any person or vehicle that enters the Terminal facilities shall be subject to a search. Such Visitors, subject to the prior approval of the Terminal, may arrange for outside transportation for pickup and delivery at the Terminal. Approved Visitors may gain access to Vessels berthed at Berth No. 1 via United Bulk Terminal's crew boat service. Such access, however, shall require that the Visitor furnish twenty-four (24) hours prior written notification to the Terminal office of same. All Visitors must wear protective equipment, hard hats, safety glasses and life jackets. Delivery of provisions or stores to any Vessels berthed at the Terminal shall require the prior approval of the Terminal subject to a determination by the Terminal whether such activities will interfere with Cargo operations or Vessel arrivals, departures or shifting. The Vessel agent must be present when provisions are to be brought on to a Vessel. Any Visitor shall execute such releases and indemnity agreements as required by Terminal as a condition to being allowed access to the Terminal facilities.

## 4.12 SPECIAL CONTRACTS

Charges for services or items not specifically provided for in these Terminal Rules and Regulations shall be assessed pursuant to a separate contract with Terminal.

## 4.13 LIENS

All lawful charges made by or due to the Terminal shall constitute a lien in favor of the Terminal upon the Cargo and against any Vessel for such charges. It is understood and agreed that the Terminal shall have the right to retain possession of and/or relocate any Cargo within Terminal property if necessary to preserve and maintain its lien rights. Terminal shall have no liability to Vessel Party by retaining and/or relocating Cargo at the Terminal.

## 4.14 DEMURRAGE

United Bulk Terminals shall not be responsible for any demurrage or other damages for delay or loss of despatch time or any other damages incurred by any Vessel or Vessel Party or their Cargo for any cause, unless specifically agreed to in a separate written contract entered into between Vessel Party and United Bulk Terminal.

Moreover, United Bulk Terminals acknowledges the vessel chartering concept "once on demurrage, always on demurrage." However, United Bulk Terminal does not recognize this chartering provision as applying to any demurrage responsibility or liability on the part of United Bulk Terminals for a force majeure event or any other cause. Such language is a contractual issue between the vessel owner and charterer/customer. All layday deductions for United Bulk Terminal, including force majeure events, will apply regardless of whether the Vessel is already on demurrage and United Bulk Terminal will not be liable for reimbursement of such demurrage or cost of delays, including consequential damages.

All Vessel demurrage claims must be presented within three (3) months of the service provided by United Bulk Terminals and be accompanied by a supporting invoice and proof of payment of said demurrage. United Bulk Terminals shall have the right to conduct an independent audit of User's demurrage terms and original invoices. User shall pay to United Bulk Terminals despatch earned on services provided. Any demurrage claim presented after three (3) months of the performed service will be denied

## 4.15 LAYCAN SPREAD AND WINDOW CANCELLATION PENALTY

Shipper may cancel a scheduled laycan spread without penalty by providing written notice of such cancellation to Terminal at least twenty-one (21) days prior to the first day of the scheduled laycan spread. If Shipper cancels a laycan spread less than twenty-one days prior to the first day of such laycan spread, Terminal shall be entitled to a "Laycan Spread Cancellation Penalty" for Shipper's account. The Laycan Spread Cancellation Penalty is assessed per Vessel and is: (1) $17,500 for Vessels capable of Loading and/or Unloading only 50,000 metric tons or less of Cargo, or (2) $25,000 for Vessels capable of Loading and/or Unloading more than 50,000 metric tons of Cargo. If Shipper schedules a four (4) day loading window, it may cancel such scheduled loading window seven (7) days or more prior to the first day of the scheduled loading window and incur only the Laycan Spread Cancellation Penalty. If Shipper fails to cancel a scheduled loading window at least seven (7) days prior to the first day of the scheduled loading window, and Shipper does not execute load out to Vessel during that loading window, Terminal shall be entitled to a "Window Cancellation Penalty" for Shipper's account in place of the Laycan Spread Cancellation Penalty. The Window Cancellation Penalty is assessed per Vessel and is: (1) $35,000 for Vessels capable of Loading and/or Unloading only 50,000 metric tons or less of Cargo, or (2) $50,000 for Vessels capable of Loading and/or Unloading more than 50,000 metric tons of Cargo.

## 4.16 FORCE MAJEURE

Neither party shall be under any liability of any kind or nature whatsoever (other than obligations of such party to pay or expend money for services actually provided during a *Force Majeure* event) for any loss, damage, delay or failure in performance, including, but not limited to, demurrage, delay, damages, deterioration of quality, shrinkage in quantity and/or loss of cargo, in the event that it should fail or delay to perform its obligations hereunder where such failure is directly or indirectly, wholly or partly, caused by *Force Majeure* event.

The term *Force Majeure* includes the following regardless of whether foreseeable or not: war; civil commotion; government order; labor disputes; labor shortage; unforeseen mechanical and electrical breakdowns; strike or lockout; flood; river freeze up; inability to obtain fuel or power; fire; act of God; and/or resolution or order of government authority.

A *Force Majeure* event shall not excuse a party from performing unless such party shall give written notice to the other party promptly upon learning of such *Force Majeure*, but in no event later than thirty (30) days subsequent to such event. Information as to the cause of inability to perform, and probable extent thereof, shall be included in such notice and shall be updated periodically during the continuance of the *Force Majeure* event. Failure to give such notice and furnish such information promptly shall be deemed a waiver of all rights for such period of time during which notice was not given. Upon removal of the cause, shipment shall resume at the specified rate.

## 5 DEFINITIONS AND NOTES

**VESSEL.** The term "Vessel" or "Vessels" shall include any river barge, ocean-going barge, or Ocean Vessel.

**OCEAN VESSEL.** The term "Ocean Vessel" shall mean any Vessel, other than a river barge, that utilizes the services and facilities of the Terminal for the Loading, Unloading, Storage, handling or transfer of Cargo.

**CARGO.** The term "Cargo" shall include, but not be limited to, coal, petroleum coke, furnace coke, fertilizer, grain, steel related scrap products and other dry cargo.

**TERMINAL.** The term "Terminal" means the United Bulk Terminals' Terminal at Mile 55, AHP left descending bank, Lower Mississippi River, near Davant, Louisiana.

**HOLIDAYS.** The term "Holidays" includes Mardi Gras, Independence Day, Thanksgiving Day and Christmas Day. All guarantees are exclusive of Holidays.

**BERTH.** The term "Berth" or "Berths" means Terminal's docks and mid-stream transfer facilities including the Terminal's mooring buoys.

**USER OR USERS.** The terms "User" or "Users" shall include Vessel Party and all individuals or business entities, including all Ocean Vessels, river barges, trucks, railroad cars or other means of conveyance and/or equipment used by said individuals or business entities, which utilize the services and/or facilities of the Terminal.

**VESSEL PARTY.** The term "Vessel Party" or "Vessel Parties" means any party or parties owning, nominating or contracting with the Vessel, including, but not limited to, its agent(s), owner(s), operator(s) and/or charterer(s).

**SHIPPER.** The term "Shipper" shall include Vessel Party and all individuals and business entities which contract in writing directly with Terminal to utilize or intending to utilize the services and/or facilities of the Terminal (this definition in no way modifies the contractual relationship or duties created by the Agreement to be Bound (Section 2.3).

**STORAGE.** The term "Storage" shall mean the service of providing facilities for the outside storing of inbound or outbound Cargo.

**TERMINAL FLEET.** The term "Terminal Fleet" shall mean the United Bulk Terminals river barge upper and lower fleets at the Terminal.

**LOADING AND UNLOADING.** The terms "Loading" and "Unloading" shall mean the service of Loading or Unloading Cargo, as the case may be, between any place at the Terminal and railroad cars, trucks, Vessels, river barges or any other means of conveyance to or from the Terminal.

**VISITORS.** The terms "Visitors" or "Visitor" mean any individual or entity listed in the Visitor List and any other individual or entity that seeks access to the Terminal facilities or any Vessel berthed there, including, but not limited to, any surveyor.

# APPENDIX

## APPENDIX A - VESSEL FEE SCHEDULE

**(*All rates contained herein are in U.S. Dollars)**

### A.1 DOCKAGE

Rates as per the schedule below per gross registered ton shall be assessed for each full twenty-four (24) hour period (Not prorated). Time shall commence upon berthing and shall end at the Vessel's departure from the berth. The minimum dockage to be paid shall be $7,500.00. Vessel Party shall indicate the gross registered tonnage (Lloyd's) of the Vessel in the Berth Application. The daily dockage fee shall be calculated based on the dockage rate/GRT equivalent to the daily demurrage rate shown in the chart below.

**Proportional Vessel Dockage**

| Demurrage Rate/Day | Dockage Rate/GRT/Day |
|---|---|
| $0-$14,999 | 0.55 |
| $15,000-$24,999 | 0.60 |
| $25,000-$34,999 | 0.65 |
| $35,000-$44,999 | 0.70 |
| $45,000-$54,999 | 0.75 |
| $55,000-$64,999 | 0.80 |
| $65,000-$74,999 | 0.85 |
| $75,000-$84,999 | 0.90 |
| $85,000-$94,999 | 0.95 |
| $95,000-$104,999 | 1.00 |
| $105,000-$114,999 | 1.05 |
| $115,000-$124,999 | 1.10 |
| Every $10,000 Additional | 0.05 Additional |

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United Bulk Terminals

Terminal Rules And Regulations



**A.2 SECURITY FEE**

$1,250.00 per Vessel per day

**A.3 CREW BOAT SERVICE**

$1,500.00 per Vessel per day

**A.4 LINE HANDLING**

Main Docks or Buoys: $3,500.00

**A.5 WATER**

$500.00 per barge

**A.6 BUNKERING FEE**

$2,000.00 per barge

**A.7 ENVIRONMENTAL FEE**

$200.00 per day

**A.8 ASSIST TUGS**

United Bulk Terminals will provide all assist tugs for docking/undocking, shifting and holding operations. The cost of these services will be as follows:

1) Docking/Undocking

| | |
|---|---|
| Tug Charge | $3,212.00 per tug plus |
| Tonnage Charge | $31.00 per 1,000 GRT plus |
| Fuel Surcharge * | 1% for every $0.05 over $3.00/gal |

| | |
|---|---|
| 2) Shifting | $748.00 per hour per tug |
| 3) Holding | $748.00 per hour per tug |
| 4) Delays (Tug Stand-by) | $660.00 per hour per tug |
| 5) Reporting of tugs | $1,460.00 per tug |
| 6) Buoy Charge | $456.00 per tug |

**The fuel surcharge will be based on the lowest quoted fuel price on the 1st and 15th of each month from the greater New Orleans area and will be adjusted on those dates.*

## APPENDIX B - FLEET SERVICE RATES

### B.1 FLEETING

| | | |
|---|---|---|
| Dry Cargo, Open Hopper and Deck | Up to 200' x 35' | $55/day |
| Dry Cargo, Open Hopper and Deck | Over 200' x 35' | $85/day |
| Special Cargo – Equipment Barges – Towboats* | | $100/day |

**A watchman is required with all towboats*

### B.2 TUG SERVICE

| | |
|---|---|
| Tug Service (hourly rate with a one hour minimum) | $300 per hour |
| Tow Building | $300 per barge |
| Tow Building Assist (30 minute max per barge) | $150 per barge |
| Rigging Removal* – double-ups and additional rigging | $100 per barge |

**Picking up of loose rigging at the hourly tug rate*

### B.3 BARGE HANDLING

| | |
|---|---|
| Includes "in" charge, shift to dock, shift from dock and "out" charge | $850 per barge |
| Commercial barge handling – "in" charge and "out" charge | $425 per barge |
| Reload barge handling – shift to dock and shift from dock | $425 per barge |

### B.4 BARGE COVER FEES

| | |
|---|---|
| Stack or spread lift tops (steel or fiberglass) per operation | $2,000 per barge |
| Stack or spread roll tops per operation | $2,400 per barge |
| Roll barges with roll top covers per operation | $1,600 per barge |
| Cover productivity loss – barges unloading with stacked covers | $2,000 per barge |

### B.5 SHIFTING (all rates quoted each way)

| | |
|---|---|
| Shifting rates to/from IMT | $300per barge |
| Shifting rates to/from Turn Service Myrtle Grove | $300 per barge |
| Shifting rates to Cenex Harvest States | $500 per barge |
| Shifting rates to ConocoPhillips Alliance Refinery | $500 per barge |

**(Other shifting rates quoted upon request)**

### B.6 BARGE PUMPING SERVICES

Barge Pumping $150 (setup fee) plus 3 hr. minimum @ $80/hr. and $80/hr. each additional hour thereafter

### B.7 Additional Fleeting Charges

**FAILURE TO REMOVE BARGES.** For failure to timely remove river barges from terminal fleet, in accordance with Section 3.10, a charge of $150.00 per barge will be incurred.

**HIGH WATER PREMIUM.** When the Carrollton Gauge (New Orleans) reaches 12' or higher, a 25% high water premium will be added to all services.

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Terminal Rules And Regulations



**B.8** United Bulk Terminals Fuel Surcharge Policy

All barge shifting and hourly tug services are subject to the following fuel surcharge policy:

| Price | % | Price | % | Price | % | Price | % |
|---|---|---|---|---|---|---|---|
| $ 1.75 | 0.0 | $ 2.37 | 24.8 | $ 2.99 | 49.6 | $ 3.61 | 74.4 |
| $ 1.76 | 0.4 | $ 2.38 | 25.2 | $ 3.00 | 50.0 | $ 3.62 | 74.8 |
| $ 1.77 | 0.8 | $ 2.39 | 25.6 | $ 3.01 | 50.4 | $ 3.63 | 75.2 |
| $ 1.78 | 1.2 | $ 2.40 | 26.0 | $ 3.02 | 50.8 | $ 3.64 | 75.6 |
| $ 1.79 | 1.6 | $ 2.41 | 26.4 | $ 3.03 | 51.2 | $ 3.65 | 76.0 |
| $ 1.80 | 2.0 | $ 2.42 | 26.8 | $ 3.04 | 51.6 | $ 3.66 | 76.4 |
| $ 1.81 | 2.4 | $ 2.43 | 27.2 | $ 3.05 | 52.0 | $ 3.67 | 76.8 |
| $ 1.82 | 2.8 | $ 2.44 | 27.6 | $ 3.06 | 52.4 | $ 3.68 | 77.2 |
| $ 1.83 | 3.2 | $ 2.45 | 28.0 | $ 3.07 | 52.8 | $ 3.69 | 77.6 |
| $ 1.84 | 3.6 | $ 2.46 | 28.4 | $ 3.08 | 53.2 | $ 3.70 | 78.0 |
| $ 1.85 | 4.0 | $ 2.47 | 28.8 | $ 3.09 | 53.6 | $ 3.71 | 78.4 |
| $ 1.86 | 4.4 | $ 2.48 | 29.2 | $ 3.10 | 54.0 | $ 3.72 | 78.8 |
| $ 1.87 | 4.8 | $ 2.49 | 29.6 | $ 3.11 | 54.4 | $ 3.73 | 79.2 |
| $ 1.88 | 5.2 | $ 2.50 | 30.0 | $ 3.12 | 54.8 | $ 3.74 | 79.6 |
| $ 1.89 | 5.6 | $ 2.51 | 30.4 | $ 3.13 | 55.2 | $ 3.75 | 80.0 |
| $ 1.90 | 6.0 | $ 2.52 | 30.8 | $ 3.14 | 55.6 | $ 3.76 | 80.4 |
| $ 1.91 | 6.4 | $ 2.53 | 31.2 | $ 3.15 | 56.0 | $ 3.77 | 80.8 |
| $ 1.92 | 6.8 | $ 2.54 | 31.6 | $ 3.16 | 56.4 | $ 3.78 | 81.2 |
| $ 1.93 | 7.2 | $ 2.55 | 32.0 | $ 3.17 | 56.8 | $ 3.79 | 81.6 |
| $ 1.94 | 7.6 | $ 2.56 | 32.4 | $ 3.18 | 57.2 | $ 3.80 | 82.0 |
| $ 1.95 | 8.0 | $ 2.57 | 32.8 | $ 3.19 | 57.6 | $ 3.81 | 82.4 |
| $ 1.96 | 8.4 | $ 2.58 | 33.2 | $ 3.20 | 58.0 | $ 3.82 | 82.8 |
| $ 1.97 | 8.8 | $ 2.59 | 33.6 | $ 3.21 | 58.4 | $ 3.83 | 83.2 |
| $ 1.98 | 9.2 | $ 2.60 | 34.0 | $ 3.22 | 58.8 | $ 3.84 | 83.6 |
| $ 1.99 | 9.6 | $ 2.61 | 34.4 | $ 3.23 | 59.2 | $ 3.85 | 84.0 |
| $ 2.00 | 10.0 | $ 2.62 | 34.8 | $ 3.24 | 59.6 | $ 3.86 | 84.4 |
| $ 2.01 | 10.4 | $ 2.63 | 35.2 | $ 3.25 | 60.0 | $ 3.87 | 84.8 |
| $ 2.02 | 10.8 | $ 2.64 | 35.6 | $ 3.26 | 60.4 | $ 3.88 | 85.2 |
| $ 2.03 | 11.2 | $ 2.65 | 36.0 | $ 3.27 | 60.8 | $ 3.89 | 85.6 |
| $ 2.04 | 11.6 | $ 2.66 | 36.4 | $ 3.28 | 61.2 | $ 3.90 | 86.0 |
| $ 2.05 | 12.0 | $ 2.67 | 36.8 | $ 3.29 | 61.6 | $ 3.91 | 86.4 |
| $ 2.06 | 12.4 | $ 2.68 | 37.2 | $ 3.30 | 62.0 | $ 3.92 | 86.8 |
| $ 2.07 | 12.8 | $ 2.69 | 37.6 | $ 3.31 | 62.4 | $ 3.93 | 87.2 |
| $ 2.08 | 13.2 | $ 2.70 | 38.0 | $ 3.32 | 62.8 | $ 3.94 | 87.6 |
| $ 2.09 | 13.6 | $ 2.71 | 38.4 | $ 3.33 | 63.2 | $ 3.95 | 88.0 |
| $ 2.10 | 14.0 | $ 2.72 | 38.8 | $ 3.34 | 63.6 | $ 3.96 | 88.4 |
| $ 2.11 | 14.4 | $ 2.73 | 39.2 | $ 3.35 | 64.0 | $ 3.97 | 88.8 |
| $ 2.12 | 14.8 | $ 2.74 | 39.6 | $ 3.36 | 64.4 | $ 3.98 | 89.2 |
| $ 2.13 | 15.2 | $ 2.75 | 40.0 | $ 3.37 | 64.8 | $ 3.99 | 89.6 |
| $ 2.14 | 15.6 | $ 2.76 | 40.4 | $ 3.38 | 65.2 | $ 4.00 | 90.0 |
| $ 2.15 | 16.0 | $ 2.77 | 40.8 | $ 3.39 | 65.6 | $ 4.01 | 90.4 |
| $ 2.16 | 16.4 | $ 2.78 | 41.2 | $ 3.40 | 66.0 | $ 4.02 | 90.8 |
| $ 2.17 | 16.8 | $ 2.79 | 41.6 | $ 3.41 | 66.4 | $ 4.03 | 91.2 |
| $ 2.18 | 17.2 | $ 2.80 | 42.0 | $ 3.42 | 66.8 | $ 4.04 | 91.6 |
| $ 2.19 | 17.6 | $ 2.81 | 42.4 | $ 3.43 | 67.2 | $ 4.05 | 92.0 |
| $ 2.20 | 18.0 | $ 2.82 | 42.8 | $ 3.44 | 67.6 | $ 4.06 | 92.4 |
| $ 2.21 | 18.4 | $ 2.83 | 43.2 | $ 3.45 | 68.0 | $ 4.07 | 92.8 |

United Bulk Terminals Davant LLC
14537 Highway 15
Davant, Louisiana 70040
Facsimile: (504) 682-5678
E-mail:
ubt.traffic@unitedbulkterminals.com

United Bulk Terminals

Terminal Rules And Regulations



| | | | | | | | |
|---|---|---|---|---|---|---|---|
| $ 2.22 | 18.8 | $ 2.84 | 43.6 | $ 3.46 | 68.4 | $ 4.08 | 93.2 |
| $ 2.23 | 19.2 | $ 2.85 | 44.0 | $ 3.47 | 68.8 | $ 4.09 | 93.6 |
| $ 2.24 | 19.6 | $ 2.86 | 44.4 | $ 3.48 | 69.2 | $ 4.10 | 94.0 |
| $ 2.25 | 20.0 | $ 2.87 | 44.8 | $ 3.49 | 69.6 | $ 4.11 | 94.4 |
| $ 2.26 | 20.4 | $ 2.88 | 45.2 | $ 3.50 | 70.0 | $ 4.12 | 94.8 |
| $ 2.27 | 20.8 | $ 2.89 | 45.6 | $ 3.51 | 70.4 | $ 4.13 | 95.2 |
| $ 2.28 | 21.2 | $ 2.90 | 46.0 | $ 3.52 | 70.8 | $ 4.14 | 95.6 |
| $ 2.29 | 21.6 | $ 2.91 | 46.4 | $ 3.53 | 71.2 | $ 4.15 | 96.0 |
| $ 2.30 | 22.0 | $ 2.92 | 46.8 | $ 3.54 | 71.6 | $ 4.16 | 96.4 |
| $ 2.31 | 22.4 | $ 2.93 | 47.2 | $ 3.55 | 72.0 | $ 4.17 | 96.8 |
| $ 2.32 | 22.8 | $ 2.94 | 47.6 | $ 3.56 | 72.4 | $ 4.18 | 97.2 |
| $ 2.33 | 23.2 | $ 2.95 | 48.0 | $ 3.57 | 72.8 | $ 4.19 | 97.6 |
| $ 2.34 | 23.6 | $ 2.96 | 48.4 | $ 3.58 | 73.2 | $ 4.20 | 98.0 |
| $ 2.35 | 24.0 | $ 2.97 | 48.8 | $ 3.59 | 73.6 | $ 4.21 | 98.4 |
| $ 2.36 | 24.4 | $ 2.98 | 49.2 | $ 3.60 | 74.0 | $ 4.22 | 98.8 |

## APPENDIX C - CONTACTS

**United Bulk Terminals Davant LLC**
**14537 HWY 15**
**Davant, Louisiana, 70040**

**Dispatchers (24 hrs.)**
504-333-7400 – Main line
504-682-5678 - Fax
504-784-1263 - Cell
ubt.traffic@unitedbulkterminals.com

**Allen Newman**
Logistics Superintendent (7am to 4pm, Monday - Friday)
504-333-7360 – Office
504-682-5678 – Fax
504-416-9279 – Cell
Allen.Newman@unitedbulkterminals.com

**Tyrone Williams**
Operations Manager (7am to 4pm, Monday - Friday)
504-333-7318 - Office
504-319-4362 - Cell
Tyrone.Williams@unitedbulkterminals.com

**Rickey Rosser**
Operations Superintendent (7am to 4pm, Monday - Friday)
504-333-7338 - Office
504-202-8566 - Cell
Rickey.Rosser@unitedbulkterminals.com

## APPENDIX D - BERTH APPLICATION

### BERTH APPLICATION

Application is hereby made by facsimile or e-mail, with an executed original to follow by U.S. Mail at the addresses below, this ______ day of ________________, ______ for assignment and use of the terminal facilities at United Bulk Terminals for the M/V ____________________ on or about ________________, ______ for loading/discharge in accordance with the United Bulk Terminals Rules and Regulations made a part hereof and attached hereto as Exhibit "A".

PARTICULARS OF VESSEL (if known, otherwise to be provided not less than 72 hours prior to Vessel coming to the Berth):

Vessel: M/V ______________________________

Gross Registered Tons:__________________ Dead Weight: ______________________

Length:______________________________ Breadth:__________________________

Maximum Depth Loaded: ________________ Air Draft: __________________________

Previous Port: _____________________ Previous Cargo: ______________________

Cargo Destination_______________________________________________________

Max air draft: Traveling loader – 54' 8" at zero river stage / Stationary loader – 46' at zero river stage.

Will vessel bunker: YES / NO If so, how many barges:_________ (must get terminal approval)

Total M/T's to load or unload: ______________________________________________

Hold Stowage:

Hold #1__________________ Hold #2 _________________ Hold #3 __________________

Hold #4__________________ Hold #5 _________________ Hold #6 __________________

Hold #7__________________ Hold #8 _________________ Hold #9 __________________

Hold Load Rotation (**max 2 load passes, 2 holds to trim**):

1)______________ 2)______________ 3)______________ 4)______________

5)______________ 6)______________ 7)______________ 8)______________

9)______________ 10)______________ 11)______________ 12)______________

13)______________ 14)______________ 15)______________ 16)______________

17)______________ 18)______________ Trim 1) __________ Trim 2) __________

APPLICANT AGREES:

1. Application for berth is hereby made on behalf of Vessel, its agent(s), owner(s) and/or operator(s) and/or charterer(s) and that payment of applicable charges for said Vessel will be made to United Bulk Terminals as required in the United Bulk Terminals Rules and Regulations.

| United Bulk Terminals Davant LLC<br>14537 Highway 15<br>Davant, Louisiana 70040<br>Facsimile: (504) 682-5678<br>E-mail:<br>ubt.traffic@unitedbulkterminals.com | United Bulk Terminals<br>**Terminal Rules And Regulations** | Document: TRR-002<br>Version: 1<br>Page: 29 of 29<br>Prepared by: A. Newman |
|---|---|---|

2. Has in its possession a current copy of the United Bulk Terminals Rules and Regulations and stipulates that the Vessel, its agent(s), owner(s) and/or operator(s) and/or charterer(s) are bound by and agree to abide by all provisions of the United Bulk Terminals Rules and Regulations.

3. Berthing tug(s), shifting tug(s) and disembarking tug(s), will be arranged prior to the Vessel coming to the Berth and, to the extent required beyond those normally furnished by United Bulk Terminals, shifting tug(s) also will be arranged prior to the Vessel coming to the Berth.

4. Warrants that the Vessel shall fully comply with all applicable U.S. Coast Guard regulations and local, state and federal environmental laws and regulations in effect as of the date Vessel gives the Notice of Readiness.

5. Will furnish United Bulk Terminals with the International Tonnage Certificate and the proposed stowage plan; including cargo capacity, for Cargo to be loaded or actual stowage plan for Cargo to be unloaded, prior to the Vessel coming to the Berth.

6. Will furnish United Bulk Terminals with Notice of Readiness signed by the charterer or his agent, prior to commencement of Loading or Unloading.

7. Warrants that the Vessel does not constitute a "common carrier" within the meaning of 46 U.S.C. App. 1702(6) and 46 U.S.C. 801 and is a private or contract carrier.

8. WARRANTS THAT HE/SHE HAS AUTHORITY TO EXECUTE THIS BERTH APPLICATION ON BEHALF OF THE VESSEL, ITS AGENT(S), OWNER(S) AND/OR OPERATOR(S) AND/OR CHARTERER(S); THAT APPLICANT HAS RECEIVED, READ AND UNDERSTANDS THE PROVISIONS OF THE UNITED BULK TERMINAL, L.L.C. RULES AND REGULATIONS AND IS EMPOWERED TO BIND THE VESSEL, ITS AGENT(S), OWNER(S) AND/OR OPERATOR(S) AND/OR CHARTERER(S) TO THE TERMS OF THE UNITED BULK TERMINAL, L.L.C. RULES AND REGULATIONS AND THE BERTH APPLICATION.

____________________________
REQUESTED BY

____________________________
AUTHORIZED SIGNATURE

____________________________
TITLE

____________________________
DATE

# Value Proposition - Summary of Project Benefits

Polk 1 operating in simple-cycle mode:

- Defers extensive capital investment in HRSG and ST
- Lowers customer fuel costs by eliminating combine-cycle operational limitations
- Provides operational flexibility needed by current system
- 2.6+ Fuel System can burn up to 20% hydrogen

HRSG and ST are maintained in long-term standby reserve:

- Reactivated if fuel prices dictate
- Reactivated if system needs dictate
- Reactivated if Hydrogen, Carbon-capture, Syngas, or other opportunity arises

**90.** Please refer to the Direct Testimony of Company witness Aldazabal, pages 44-46, regarding TECO's plans to convert Polk 1 into a simple cycle gas turbine.

a. What components of Polk Unit 1 that are currently in use for operation will not be used once the unit is converted to a simple cycle turbine?

b. What components of Polk Unit 1 that are currently in use for operation will be retired once the unit is converted to a simple cycle turbine?

c. If there are components that are not going to be used and are also not going to be retired, please explain why.

d. What is the remaining plant balance on parts that are not going to be used and not going to be retired after the conversion?

i. Please provide remaining plant balance by part

e. How quickly can TECO switch between operations on gas and operations on coal when the IGCC is operational?

f. How long would it take to remove the IGCC from reserve and bring it back online?

g. How quickly will TECO be able to switch between operation on gas and operation on petcoke with the combustion turbine?

h. Please confirm that the steam turbine is currently not in use at Polk. If not, please explain.

i. Please confirm that Polk 1's heat recovery steam generators (HRSG) will not be used once Polk 1 is converted to a simple cycle combustion turbine. If not, please explain.

**ANSWER:**

a. Once the conversion is complete, the equipment associated with combined cycle mode will no longer be in operation. This includes existing equipment such as the HRSG, steam turbine, and associated piping, pumps, and instrumentation.

b. As mentioned in testimony, the existing gas turbine combustion system is no longer supported by the OEM. The existing combustion system will be retired and replaced by current technology.

c. Tampa Electric reviewed all available options and determined that adding simple cycle capability and performing a gas turbine upgrade to the latest technology was the best option for customers. This maintains the option for future combined cycle operations of Polk Unit 1. The retirement of the combined cycle equipment at this time would decrease the future flexibility of Polk Unit 1.

d. This detailed, by parts analysis, has not been performed. An analysis was provided in response to Sierra Club's First Set of Interrogatories No. 7 regarding Polk Unit 1 net book values remaining for the CT, CCST and Gasifier equipment.

e. When the IGCC is operational, the swap from natural gas to petcoke fuel is part of the normal startup of the IGCC process. Start-up of the IGCC takes about 24 hours. Swapping from petcoke to natural gas can be done in a few hours.

f. Please see the company's answer to Interrogatory No. 89(g), above.

g. Please see the company's answer to Interrogatory No. 90(f), above.

h. This is incorrect. Currently, the steam turbine is available for combined cycle operations. Upon completion of the Polk 1 Simple Cycle Project, the steam turbine will be put into reserve standby.

i. This is correct. Once Polk Unit 1 Simple Cycle Project is completed, the HRSG will be placed into reserve standby.

**Topic: Renewable Generation**

**91.** TECO's 2024 TYSP indicates that the Company plans to add 1,500 GW of incremental solar PV generation between 2024 and 2033 and 185 MW of battery storage (BESS).

a. How much of this solar is coming online during the test year?

b. How much BESS is coming online during the test year?

c. What is the price TECO paid for the solar PV and BESS that is coming online during the test year and what is the cost included in rate base?

i. Please include a breakdown of costs by individual projects.

d. How much solar and BESS is coming online between now and 2030, and what is the cost?

i. Please include a breakdown of costs by project/source type where possible.

**ANSWER:**

a. 149 MW is coming on-line in the 2025 test year.

b. 100 MW is coming on-line in the 2025 test year.

c. Please see table below; Rate Base Cost is the 13-month average net book value:

| Project Name | In-Service Date | Total Construction Cost (2017-2029) | 2025 Rate Base (13-mo avg NBV) |
|---|---|---|---|
| Duette Solar | 12/01/2025 | $122.7 million | $9.4 million |
| Cottonmouth Solar | 12/01/2025 | $121.3 million | $8.8 million |
| Lake Mabel Energy Storage | 04/01/2025 | $57.5 million | $37.6 million |
| Wimauma Energy Storage | 02/01/2025 | $52.9 million | $40.0 million |
| South Tampa Energy Storage | 04/01/2025 | $32.5 million | $20.2 million |

d. Based on the current ten-year site plan, 991 MW of solar and 185 MW of energy storage will be installed between now and January 1, 2030. The costs for the solar projects to be constructed in 2029 have not been finalized but are expected to be approximately $1,650/kW.

| Year | Project | In-Service Date | Type | Total Construction Cost (2017-2029) |
|---|---|---|---|---|
| 2024 | Dover Energy Storage | 09/01/2024 | Storage | $19.4 million |
| 2024 | English Creek Solar | 12/01/2024 | Solar | $53.3 million |
| 2024 | Bullfrog Creek Solar | 12/01/2024 | Solar | $113.7 million |
| 2025 | Duette Solar | 12/01/2025 | Solar | $122.7 million |
| 2025 | Cottonmouth Solar | 12/01/2025 | Solar | $121.3 million |
| 2025 | Lake Mabel Energy Storage | 04/01/2025 | Storage | $57.5 million |
| 2025 | Wimauma Energy Storage | 02/01/2025 | Storage | $52.9 million |
| 2025 | South Tampa Energy Storage | 04/01/2025 | Storage | $32.5 million |
| 2026 | Big Four Solar | 05/01/2026 | Solar | $116.6 million |
| 2026 | Farmland Solar | 12/01/2026 | Solar | $106.3 million |
| 2026 | Brewster Solar | 12/01/2026 | Solar | $61.3 million |
| 2026 | Wimauma 3 Solar | 12/01/2026 | Solar | $135.0 million |
| 2027 | Clear Springs 1 Solar | 12/01/2027 | Solar | $134.3 million |
| 2027 | Future Solar 1 | 12/01/2027 | Solar | $150.3 million |
| 2028 | Future Battery Storage 1 | 12/01/2028 | Storage | $141.8 million |
| 2028 | Clear Springs II Solar | 12/01/2028 | Solar | $136.9 million |
| 2028 | Mattaniah Solar | 12/01/2028 | Solar | $95.2 million |
| 2028 | Future Solar 2 | 12/01/2028 | Solar | $138.5 million |
| 2029 | Future Solar 3 | TBD | Solar | TBD |

# A F F I D A V I T

**STATE OF FLORIDA** )
)
**COUNTY OF HILLSBOROUGH** )

Before me the undersigned authority personally appeared Carlos Aldazabal, who deposed and said that he is Vice President, Energy Supply, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 2nd Set of Interrogatories (Nos.76-82, 84, 85, 87-90)

Dated at Tampa, Florida this 14 day of May, 2024.

Carlos Aldazabal

Sworn to and subscribed before me this 14 day of May, 2024.

Tyronda R. Nelson

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# A F F I D A V I T

**STATE OF FLORIDA** )
)
**COUNTY OF HILLSBOROUGH** )

Before me the undersigned authority personally appeared Jose Aponte, who deposed and said that he is Manager, Generation Planning, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 2nd Set of Interrogatories (Nos. 73, 74, 85)

Dated at Tampa, Florida this 15 day of May, 2024.

Jose Aponte

Sworn to and subscribed before me this 15 day of May, 2024.

Tyronda R. Nelson

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# A F F I D A V I T

STATE OF FLORIDA )
)
COUNTY OF HILLSBOROUGH )

Before me the undersigned authority personally appeared Jeff Chronister, who deposed and said that he is Vice President, Finance, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 2nd Set of Interrogatories (No. 83)

Dated at Tampa, Florida this 14 day of May, 2024.

______________________________

Sworn to and subscribed before me this 14 day of May, 2024.

Tyronda R. Nelson

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# A F F I D A V I T

**STATE OF FLORIDA )**
**)**
**COUNTY OF HILLSBOROUGH )**

Before me the undersigned authority personally appeared Lori Cifuentes who deposed and said that she is Director, Load Research and Forecasting, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by her and/or under her direction and supervision and are true and correct to the best of her information and belief.

Sierra Club's 2nd Set of Interrogatories (No. 86)

Dated at Tampa, Florida this 14 day of May, 2024.

Sworn to and subscribed before me this 14 day of May, 2024.

Tyronda R. Nelson

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# A F F I D A V I T

**STATE OF FLORIDA** )
)
**COUNTY OF HILLSBOROUGH** )

Before me the undersigned authority personally appeared John Heisey, who deposed and said that he is Director, Origination and Trading, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 2nd Set of Interrogatories (Nos. 76 - 81, 89)

Dated at Tampa, Florida this 14th day of May, 2024.

______________________________

Sworn to and subscribed before me this 14th day of May, 2024.

Tyronda R. Nelson
______________________________

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# A F F I D A V I T

**STATE OF FLORIDA** )
)
**COUNTY OF HILLSBOROUGH** )

Before me the undersigned authority personally appeared Kris Stryker, who deposed and said that he is Vice President, Clean Energy and Emerging Technology, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 2nd Set of Interrogatories (No. 84, 91)

Dated at Tampa, Florida this 14 day of May, 2024.

_______________________________

Sworn to and subscribed before me this 14 day of May, 2024.

_______________________________

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

# A F F I D A V I T

STATE OF FLORIDA )
)
COUNTY OF HILLSBOROUGH )

Before me the undersigned authority personally appeared Chip Whitworth, who deposed and said that he is Vice President, Electric Delivery, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 2nd Set of Interrogatories (No. 75)

Dated at Tampa, Florida this 10 day of May, 2024.

[signature]

Sworn to and subscribed before me this 10 day of May, 2024.

Rebecca Lynn Maier

NOTARY PUBLIC STATE OF FLORIDA
REBECCA LYNN MAIER
MY COMMISSION # HH 350932
EXPIRES: March 25, 2027

My Commission expires 03/25/2027

# A F F I D A V I T

**STATE OF FLORIDA** )
)
**COUNTY OF HILLSBOROUGH** )

Before me the undersigned authority personally appeared Jordan Williams, who deposed and said that he is Director, Pricing & Financial Analysis, Tampa Electric Company, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 2nd Set of Interrogatories (No. 75)

Dated at Tampa, Florida this 15 day of May, 2024.

Jordan Williams

Sworn to and subscribed before me this 15 day of May, 2024.

Tyronda R. Nelson

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

Dated this 22nd day of May, 2024.

Respectfully submitted,


J. JEFFRY WAHLEN
jwahlen@ausley.com
MALCOLM N. MEANS
mmeans@ausley.com
VIRGINIA L. PONDER
vponder@ausley.com
Ausley McMullen
Post Office Box 391
Tallahassee, Florida 32302
(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

## CERTIFICATE OF SERVICE

I HEREBY CERTIFY that electronic copies of the foregoing answers have been served by posting on a shared document site, hand delivery of a USB drive or by electronic mail on this 22nd day of May 2024 to the following:

Adria Harper
Carlos Marquez
Timothy Sparks
Daniel Dose
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ddose@psc.state.fl.us
discovery-gcl@psc.state.fl.us

Walt Trierweiler
Patricia Christensen
Octavio Ponce
Charles Rehwinkel
Office of Public Counsel
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(212) 284-8021
hlochan@earthjustice.org
flcaseupdates@earthjustice.org

ATTORNEY

# Exhibit DG-4:

# TECO response to Sierra Club 3rd IRRs

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In re: Petition for Rate Increase by Tampa Electric Company | DOCKET NO. 20240026-EI |
| In re: Petition for approval of 2023 Depreciation and Dismantlement Study, by Tampa Electric Company | DOCKET NO. 20230139-EI |
| In re: Petition to implement 2024 Generation Base Rate Adjustment provisions in Paragraph 4 of the 2021 Stipulation and Settlement Agreement, by Tampa Electric Company | DOCKET NO. 20230090-EI<br><br>SERVED: May 30, 2024 |

**TAMPA ELECTRIC COMPANY'S ANSWERS TO**
**SIERRA CLUB'S THIRD SET OF INTERROGATORIES (NOS. 92-95)**

Pursuant to Rule 106.206, Florida Administrative Code, and Florida Rule of Civil Procedure 1.350, Tampa Electric Company ("Tampa Electric" or the "company"), hereby answers Sierra Club's Third Set of Interrogatories (Nos. 92-95), served May 10, 2024 ("Sierra Club's Third ROG").

**General Objections**

1. Tampa Electric objects to each interrogatory in Sierra Club's Third ROG ("Interrogatory") to the extent that it seeks information that is duplicative, not relevant to the subject matter of this docket, and is not reasonably calculated to lead to the discovery of admissible evidence.

2. Tampa Electric objects to each Interrogatory to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such Interrogatory. Tampa Electric will seek clarification from Sierra Club if an Interrogatory is not clear, but Tampa Electric will produce documents subject to, and without waiving, this objection.

3. Tampa Electric objects to each Interrogatory to the extent it requires Tampa Electric to produce information that is already in the public record before the Florida Public Service Commission ("FPSC" or the "Commission") or other public agency and available to Sierra Club through normal procedures or is readily accessible through legal search engines.

4. Tampa Electric objects to each Interrogatory to the extent that it calls for data or information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law. Tampa Electric will describe the nature of the privileged material, if any, in a privilege log that will accompany its responses.

5. Tampa Electric objects to producing paper copies on the grounds that doing so would be unduly burdensome. Tampa Electric has entered into an agreement with Sierra Club, governing discovery production and responses, and will serve its answers to the Interrogatories and related responsive documents to Sierra Club in electronic form via a SharePoint site to which Sierra Club have remote access.

6. Tampa Electric objects to each Request to the extent it requires the company to provide information that it believes is "proprietary confidential business information" as described in Section 366.093, Florida Statutes. Tampa Electric will provide such confidential information to Sierra Club in a designated confidential portion of the SharePoint site described above and subject to a Motion for Temporary Protective Order, Notice of Intent to Request Confidential Classification, and/or Request for Confidential Classification, as appropriate.

7. Tampa Electric objects to each Interrogatory, instruction, or definition in that purports to expand Tampa Electric's obligations under applicable law.

8. Tampa Electric objects to each Interrogatory to the extent it requests Tampa Electric to prepare information in a particular format or create data or information that it otherwise does not possess as unduly burdensome and as purporting to expand Tampa Electric's obligations under applicable law.

9. Subject to Section 366.093(1), Florida Statutes, Tampa Electric objects to any definition or Interrogatory that requests documents from persons or entities who are not parties to this proceeding, that seek information from affiliates unrelated to transactions or cost allocations involving Tampa Electric, or that are not otherwise subject to discovery under applicable rules.

10. Tampa Electric objects to any Interrogatory requiring the company to provide additional information beyond that obtained through a reasonable and diligent search.

**General Response**

Subject to and without waiving its general objections, which are incorporated by reference in each of its specific answers, Tampa Electric provides its answers to Sierra Club's Third ROG by posting its answers on the Tampa Electric Discovery SharePoint site established for this docket (the "SharePoint") and as specified in its specific answers. Tampa Electric will serve its answers to the Commission staff by hand delivering a USB containing its answers to the Commission Clerk's office, and for Staff's purposes, the term "USB" should be substituted for "SharePoint" in the specific answers shown below.

The company's specific answers will identify interrogatories that call for answers that contain (a) information for which the company asserts a legal privilege and/or (b) "proprietary confidential business information" as defined in Section 366.093, Florida Statutes.

An answer that contains information for which the company asserts a legal privilege will be identified in the privilege log attached as Exhibit A.

An answer that contains information the company asserts to be “proprietary confidential business information” will be provided in the Confidential portion of the SharePoint subject to a request for confidential classification, motion for temporary protective order and/or a non-disclosure agreement.

## Specific Answers

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S THIRD SET OF INTERROGATORIES**
**INTERROGATORY NO. 92**
**BATES PAGE(S): 37951**
**MAY 30, 2024**

**92.** Regarding the Polk Unit 1 IGCC's ability to operate on both coal and gas:

a. What is TECO's strategy for deciding when to switch between coal and gas at Polk Unit 1?

b. Please explain why TECO did not switch Polk Unit 1 back to combusting coal in 2022, when natural gas prices spiked.

c. Did TECO consider switching the IGCC unit back to operating on coal in 2022? Please explain.

**ANSWER:**

a. Natural gas has been the economic fuel on Polk Unit 1 for a few years. Should petcoke become more economic than natural gas and a decision is made to use petcoke, the company would need approximately one year to restore petcoke operation on Polk Unit 1. Once petcoke operation is restored on Polk Unit 1, switching fuels can be done in a short period of time, similar to fuel switching at Big Bend Unit 4.

b. Given the lead time of approximately one year to restore operation on petcoke at Polk Unit 1, the decision needed to be made in 2021. In 2021, natural gas was the economic fuel choice for Polk Unit 1 in 2022, based on our fuel forecast.

c. No. Please see the company's answer to Interrogatory 92(b), above.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S THIRD SET OF INTERROGATORIES**
**INTERROGATORY NO. 93**
**BATES PAGE(S): 37952**
**MAY 30, 2024**

**93.** What is involved in switching Polk Unit 1 between coal and gas right now (prior to the proposed CT conversion described in Witness Aldazabal's testimony)?

a. Please explain the steps and provide the cost and timeline required.

**ANSWER:**

Converting the unit back to petcoke would generally involve the following major equipment, steps, and timeline.

Major equipment involved includes the gasification block, which includes the solid fuel processing system, air separation unit, gasifier, acid plant, slag handling, and balance of plant ancillary equipment.

The timeline to restore gasification block equipment is estimated to be at least one year, due to the engineering assessment, full equipment restoration, environmental permitting, and operationally preparing the unit to burn petcoke. The first step in the restoration process would be to assess the condition of the gasification block, acid plant, and air separation unit, along with all balance of plant equipment. This is done through an inspection, as well as testing to determine suitability for service. In addition to the restoration process outlined above, the second step is the environmental permit modifications will need to be evaluated, requested, and acquired from the regulating agency before petcoke operations could resume. The timeliness of permit modifications depends on the agencies involved and any public opposition.

If the forward price curve showed it was economic to switch back to petcoke, the company would need to perform an engineering assessment of the gasification system and balance of plant to determine the costs to safely burn petcoke. Polk Unit 1 has not burned petcoke since 2018.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S THIRD SET OF INTERROGATORIES**
**INTERROGATORY NO. 94**
**BATES PAGE(S): 37953**
**MAY 30, 2024**

**94.** Did TECO evaluate the costs or benefits of the Polk Unit 1 conversion to a simple cycle relative to the costs or benefits of retiring the Unit and replacing it with alternatives?

**ANSWER:**

Yes. Tampa Electric has evaluated the cost effectiveness of retiring components of Polk Unit One earlier than planned. However, the company did not evaluate the retirement of the gasifier in order to maintain fuel diversity. Out of the options evaluated, the Polk 1 Flexibility project demonstrated the most savings to customers. This project will allow for faster starts, and lower turndowns, which will allow Tampa Electric to better optimize our lower cost system assets. In addition, this project will also improve the unit's heat rate, which, along with the added flexibility, will allow for fuel cost savings. Additional benefits include reduction to sustaining capital and operations and maintenance costs while enhancing system reliability.

**TAMPA ELECTRIC COMPANY**
**DOCKET NO. 20240026-EI**
**SIERRA CLUB'S THIRD SET OF INTERROGATORIES**
**INTERROGATORY NO. 95**
**BATES PAGE(S): 37954**
**MAY 30, 2024**

**95.** Please refer to the direct testimony of Company witness Aldazabal on page 46 regarding the expected improved heat rate of Polk Unit 1 as a CT.

a. Provide the current heat rate of Polk Unit 1.

b. Provide the expected heat rate if Polk Unit 1 is converted to a CT.

c. Provide the heat rate expected if Polk Unit 1 runs on petcoke in the future. Please provide all iterations and explanations of those iterations if the heat rate varies based on petcoke usage.

**ANSWER:**

a. The current heat rate of Polk Unit 1 in combined-cycle configuration is 10,514 Btu/kWh.

b. Upon completion of the Polk 1 Flexibility project, the expected gross heat rate 10,064 btu/kWh HHV. This assumes 100 percent output operating at 59 percent relative humidity and an ambient temperature of 59 degrees Fahrenheit.

c. The expected heat rate if Polk Unit 1 runs on petcoke, on a net basis, would be 11,740 Btu/kWh. This represents the average combined cycle heat rate of the unit during calendar 2018. The petcoke usage of Polk Unit 1 was kept close to an 80 to 85 percent blend of petcoke to low sulfur coal.

There are notable changes to the net heat rate of Polk Unit 1 on natural gas versus coal. Coal operation involves large amounts of parasitic load, more than 60 MW. The parasitic load while on natural gas operation is much smaller in comparison, closer to 15 MW.

# A F F I D A V I T



**STATE OF FLORIDA** )<br>
)<br>
**COUNTY OF HILLSBOROUGH** )

Before me the undersigned authority personally appeared Carlos Aldazabal, who deposed and said that he is Vice President, Energy Supply, and Tampa Electric's answers to the interrogatories specified below were prepared by him and/or under his direction and supervision and are true and correct to the best of his information and belief.

Sierra Club's 3rd Set of Interrogatories (Nos. 92 - 95)

Dated at Tampa, Florida this 14 day of May, 2024.

Carlos Aldazabal

Sworn to and subscribed before me this 14 day of May, 2024.

Tyronda R. Nelson

Notary Public State of Florida
Tyronda R Nelson
My Commission HH 285797
Expires 7/10/2026

My Commission expires 7/10/2026

Dated this 30th day of May, 2024.

Respectfully submitted,

______________________________

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ATTORNEYS FOR TAMPA ELECTRIC COMPANY

## CERTIFICATE OF SERVICE

I HEREBY CERTIFY that electronic copies of the foregoing answers have been served by posting on a shared document site, hand delivery of a USB drive or by electronic mail on this 30th day of May 2024 to the following:

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ATTORNEY

# Exhibit DG-5:

# TECO Ten-Year Site Plan,

# January 2024 – December 2033

TAMPA ELECTRIC COMPANY
UNDOCKETED: REVIEW OF
TYSP'S FIRST DATA REQUEST
REQUEST NO. 1
BATES PAGE(S): 1-108
FILED: APRIL 1, 2024

TAMPA ELECTRIC COMPANY
UNDOCKETED: REVIEW OF TYSP'S
FIRST DATA REQUEST
REQUEST NO. 1
BATES PAGE(S): 1-108
FILED: APRIL 1, 2024

Tampa Electric Company

# Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2024 to December 2033

*April 1, 2024*

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# TABLE OF CONTENTS

# LIST OF SCHEDULES & TABLES

# LIST OF FIGURES

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# GLOSSARY OF TERMS

## CODE IDENTIFICATION SHEET

| | | | |
|---|---|---|---|
| Unit Type: | BA | = | Battery Storage |
| | CC | = | Combined Cycle |
| | CT | = | Combustion Turbine |
| | D | = | Diesel |
| | FS | = | Fossil Steam |
| | GT | = | Gas Turbine (includes jet engine design) |
| | HRSG | = | Heat Recovery Steam Generator |
| | IC | = | Internal Combustion |
| | IGCC | = | Integrated Gasification Combined Cycle |
| | PV | = | Photovoltaic |
| | ST | = | Steam Turbine |
| Unit Status: | LTRS | = | Long-Term Reserve Stand-By |
| | OP | = | Operating (In commercial operation) |
| | OT | = | Other |
| | P | = | Planned |
| | T | = | Regulatory Approval Received |
| | U | = | Under Construction, less than or equal to 50 percent complete |
| | V | = | Under Construction, more than 50 percent complete |
| | RT | = | Planned Retirement |
| Fuel Type: | BIT | = | Bituminous Coal |
| | RFO | = | Residual Fuel Oil (Heavy - #6 Oil) |
| | DFO | = | Distillate Fuel Oil (Light - #2 Oil) |
| | NG | = | Natural Gas |
| | PC | = | Petroleum Coke |
| | WH | = | Waste Heat |
| | BIO | = | Biomass |
| | SOLAR | = | Solar Energy |
| Environmental: | FQ | = | Fuel Quality |
| | LS | = | Low Sulfur |
| | SCR | = | Selective Catalytic Reduction |
| Transportation: | PL | = | Pipeline |
| | RR | = | Railroad |
| | TK | = | Truck |
| | WA | = | Water |
| Other: | EV | = | Electric Vehicle(s) |
| | NA | = | Not Applicable |

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# Executive Summary

Tampa Electric Company's (TEC or the company) 2024 Ten-Year Site Plan (TYSP or Plan) features plans to enhance electric generating and storage capability to meet projected incremental resource needs for 2024 through 2033. This Plan provides the Florida Public Service Commission (FPSC) assurances that TEC will have cost effective options to ensure the delivery of adequate, safe, environmentally responsible, and reliable power to its customers.

TEC's systems and facilities for generating electricity have evolved over time to embrace new technologies, environmental considerations, public policy changes, and the economics of electric generation. The company transitioned from oil generation to coal after the oil embargos of the 1970s and from coal to gas as environmental concerns about coal increased and the price of gas decreased.

The company added its first 600 MW of solar generation beginning in 2017 and added another 595 MW beginning in 2021, in both instances based on regulatory agreements approved by the FPSC. About eight percent of the energy we generated in 2023 came from the sun, and we expect our solar generation to be approximately 13 percent by the end of 2024.

The company recently completed its modernization project at Big Bend Station. The company retired Big Bend Unit 2 and Unit 3, refurbished the Big Bend Unit 1 steam turbine and generator, and replaced the Unit 1 boiler and coal processing equipment with two new, highly efficient General Electric 7HA.02 combustion turbines and associated heat recovery steam generators. These changes improved our system reliability and operating flexibility, reduced fuel costs, increased the combined winter generating capacity of Units 1 and 2 from approximately 800 MW to 1,120 MW, and reduced their combined heat rates from over 10,500 Btu/kWh to about 6,300 Btu/kWh – a 40 percent efficiency gain.

The fuel efficiency of our combined generating system has improved by 20 percent since 2017. These changes, along with other improvements and the addition of solar generation, have significantly reduced customers' fuel costs, along with reducing annual emissions by about 38 percent since 2017.

The company is diligently and thoughtfully planning to improve the safety, reliability, and resilience of our electric system and improve efficiency in all areas of our operations - especially the generating efficiency of our existing power plants. The company plans to meet the power needs of its customers through additional resources and will do so in a cost-effective way.

We are continuing to transform our energy supply system as reflected by the projects in this document, which include:

1. Adding 1.5 GW of incremental solar generation to promote fuel diversity, protect customers from fuel price volatility, and lower fuel costs on customers' bills. These additions will bring our total committed solar capacity to nearly 2,800 MW or approximately 34% of our total summer installed capacity by the end of the study horizon.

2. Installing a small distributed energy project that will help the company avoid costly transmission system upgrades, increase system resilience, reduce line losses, provide peaking capacity and fuel savings, and support national security as part of our South Tampa Resilience Project.

3. Constructing approximately 185 MW of energy storage capacity as the most cost-effective means to maintain reserve margins and provide additional resilience in the event of extreme weather events. This energy storage will allow us to serve customers with lower-cost energy during peaks, thereby reducing our reliance on fuels purchased from sources beyond Florida.

These resource additions are based on TEC's Integrated Resource Planning (IRP) process, which incorporates an ongoing evaluation of demand-side and supply-side resources on a comparable and consistent basis to satisfy future demand and energy requirements in a cost-effective, reliable, and environmentally responsible manner that reduces reliance on natural gas and its associated price volatility risk for customers.

TEC is also committed to pursuing cost-effective improvements on the existing generating fleet. In 2024, Bayside Unit 2 will undergo advanced hardware upgrades to improve efficiency, generating capacity, and operational flexibility to its four (4) CTs. We also have plans to modify existing power plants (Polk Fuel Diversity Project and Polk one simple cycle conversion) to improve performance, increase fuel resilience, reduce sustaining capital and operations and maintenance costs, increase generating fleet flexibility, and enhance system reliability.

Tampa Electric Company's current and planned generating and storage resources will meet operating reserve requirements under normal peak demand scenarios. The reserve margin provides operating flexibility in the case of unplanned outages and deviations to load from colder than normal (or hotter than normal) weather. However, temperatures that vary significantly from those used to prepare this plan would result in the need to employ mitigations under extreme weather conditions such as switching to alternate fuels, making full use of demand response, pursuing purchase power agreements and potentially interrupting customers.

The portfolio of resource additions presented in this TYSP will operate in concert to provide cost savings, price stability, and reliability benefits for customers and will enhance our system's operational flexibility, energy diversity, and resiliency.

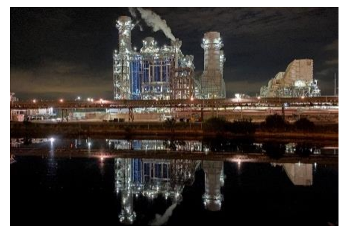
# Chapter I

## DESCRIPTION OF EXISTING FACILITIES

TEC has three (3) central generating stations that include steam units, combined cycle units, combustion turbine peaking units, and an integrated coal gasification combined cycle (IGCC) unit. Additionally, TEC has numerous solar facilities.

**Big Bend Power Station**

Big Bend Station is composed of one (1) combined cycle unit, Unit 1, which utilizes two (2) natural gas fueled combustion turbines that supply waste heat for reuse by the Unit 1 steam turbine via two (2) heat recovery steam generators (HRSGs). Big Bend also has one (1) steam unit, Big Bend Unit 4. The steam unit is equipped with desulfurization scrubbers, electrostatic precipitators, and Selective Catalytic Reduction air pollution control systems. Big Bend Unit 4 can be fired with coal and natural gas. Big Bend CT 4 is a natural gas aero-derivative combustion turbine.



**H.L. Culbreath "Bayside" Power Station**

The Bayside station consists of two (2) natural gas-fired combined cycle units and four (4) aero derivative combustion turbines. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) HRSGs and one (1) steam turbine. Bayside Unit 2 utilizes four (4) combustion turbines, four (4) HRSGs and one (1) steam turbine. Bayside 3, 4, 5, and 6 are four (4) natural gas fired aero-derivative combustion turbines.

**Polk Power Station**

Polk Unit 1 is a dual fuel natural gas / IGCC unit consisting of one (1) combustion turbine, one (1) HSRG, and one (1) steam turbine. Polk 2 Combined Cycle utilizes four (4) natural gas-fired combustion turbines, four (4) HRSGs and one (1) steam turbine. Two (2) of the combustion turbines can also be fired with distillate oil.

**Solar**

As of December 31, 2023, TEC owns 1,252 $MW_{AC}$ of solar throughout our territory. It consists of primarily single axis tracking PV solar array sites throughout Hillsborough, Pasco, and Polk counties, and several large-scale, fixed-tilt systems on rooftops, carports, and ground mount. Tampa Electric also has a 1.0 $MW_{AC}$ floating solar project located at Big Bend Power Station, and an integrated renewable energy system, consisting of solar PV carports that charge commercial-sized batteries, which re-charge the company's growing EV fleet.

TAMPA ELECTRIC COMPANY
UNDOCKETED: REVIEW OF TYSP'S
FIRST DATA REQUEST
REQUEST NO. 1
BATES PAGE(S): 1-108
FILED: APRIL 1, 2024

**Schedule 1**
**Existing Generating Facilities**
**As of December 31, 2023**

| (1) Plant Name | (2) Unit No. | (3) Location | (4) Unit Type | (5) Fuel Pri | (6) Fuel Alt | (7) Fuel Transport Pri | (8) Fuel Transport Alt | (9) Alt Fuel Days | (10) Commercial In-Service Mo/Yr | (11) Expected Retirement Mo/Yr | (12) Gen. Max. Nameplate kW | (13) Net Capability Summer MW | (14) Net Capability Winter MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Big Bend** | | **Hillsborough Co.** | | | | | | | | | | | |
| | **1** | | CC | NG | NA | PL | NA | NA | 12/22 | ** | 1,241,100 | 1,055 | 1,120 |
| | **4** | | ST | NG | BIT | PL | WA/RR | NA | 02/85 | 01/40 | 486,000 | 437 | 442 |
| | **CT 4** | | GT | NG | NA | PL | NA | NA | 08/09 | ** | 69,900 | 56 | 61 |
| **Big Bend Total [4]** | | | | | | | | | | | **1,797,000** | **1,548** | **1,623** |
| **Bayside** | | **Hillsborough Co.** | | | | | | | | | | | |
| | **1** | | CC | NG | NA | PL | NA | NA | 04/03 | 04/38 | 914,000 | 749 | 847 |
| | **2** | | CC | NG | NA | PL | NA | NA | 01/04 | 01/39 | 1,205,100 | 929 | 1,047 |
| | **3** | | GT | NG | NA | PL | NA | NA | 07/09 | ** | 69,900 | 56 | 61 |
| | **4** | | GT | NG | NA | PL | NA | NA | 07/09 | ** | 69,900 | 56 | 61 |
| | **5** | | GT | NG | NA | PL | NA | NA | 04/09 | ** | 69,900 | 56 | 61 |
| | **6** | | GT | NG | NA | PL | NA | NA | 04/09 | ** | 69,900 | 56 | 61 |
| **Bayside Total** | | | | | | | | | | | **2,398,699** | **1,902** | **2,138** |
| **Polk** | | **Polk Co.** | | | | | | | | | | | |
| | **1** | | IGCC | NG | PC/BIT | PL | WA/TK | * | 09/96 | 09/36 | 326,299 | 220 | 220 |
| | **2** | | CC | NG | DFO | PL | TK | * | 01/17 | ** | 1,216,080 | 1,061 | 1,200 |
| **Polk Total** | | | | | | | | | | | **1,542,379** | **1,281** | **1,420** |
| **TIA** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 12/15 | ** | 1,600 | 1.6 | 1.6 |
| **LEGOLAND®** | **1** | **Polk Co.** | PV | SOLAR | NA | NA | NA | NA | 12/16 | ** | 1,400 | 1.4 | 1.4 |
| **Big Bend Solar [1]** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 02/17 | ** | 19,800 | 19.8 | 19.8 |
| **Payne Creek Solar** | **1** | **Polk Co.** | PV | SOLAR | NA | NA | NA | NA | 09/18 | ** | 70,300 | 70.3 | 70.3 |
| **Balm Solar** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 09/18 | ** | 74,400 | 74.4 | 74.4 |
| **Lithia Solar** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 01/19 | ** | 74,500 | 74.5 | 74.5 |
| **Grange Hall Solar** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 01/19 | ** | 61,100 | 61.1 | 61.1 |
| **Bonnie Mine Solar** | **1** | **Polk Co.** | PV | SOLAR | NA | NA | NA | NA | 01/19 | ** | 37,500 | 37.5 | 37.5 |
| **Peace Creek Solar** | **1** | **Polk Co.** | PV | SOLAR | NA | NA | NA | NA | 03/19 | ** | 55,400 | 55.4 | 55.4 |
| **Lake Hancock Solar** | **1** | **Polk Co.** | PV | SOLAR | NA | NA | NA | NA | 04/19 | ** | 49,500 | 49.5 | 49.5 |
| **Little Manatee River Solar** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 02/20 | ** | 74,500 | 74.5 | 74.5 |
| **Wimauma Solar** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 04/20 | ** | 74,800 | 74.8 | 74.8 |
| **Durrance Solar** | **1** | **Polk Co.** | PV | SOLAR | NA | NA | NA | NA | 01/21 | ** | 60,000 | 60.0 | 60.0 |
| **Magnolia Solar** | **1** | **Polk Co.** | PV | SOLAR | NA | NA | NA | NA | 12/21 | ** | 74,500 | 74.5 | 74.5 |
| **Big Bend II Solar** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 01/22 | ** | 45,800 | 45.8 | 45.8 |
| **Big Bend Floating Solar** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 03/22 | ** | 1,000 | 1.0 | 1.0 |
| **Mountain View Solar** | **1** | **Pasco Co.** | PV | SOLAR | NA | NA | NA | NA | 04/22 | ** | 54,600 | 54.6 | 54.6 |
| **Jamison Solar** | **1** | **Polk Co.** | PV | SOLAR | NA | NA | NA | NA | 04/22 | ** | 74,500 | 74.5 | 74.5 |
| **Big Bend Agrivoltaic** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 06/22 | ** | 1,000 | 1.0 | 1.0 |
| **Laurel Oaks Solar** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 12/22 | ** | 61,200 | 61.2 | 61.2 |
| **Riverside Solar** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 12/22 | ** | 55,200 | 55.2 | 55.2 |
| **Juniper Solar** | **1** | **Pasco Co.** | PV | SOLAR | NA | NA | NA | NA | 12/23 | ** | 70,000 | 70.0 | 70.0 |
| **Alafia Solar** | **1** | **Polk Co.** | PV | SOLAR | NA | NA | NA | NA | 12/23 | ** | 60,000 | 60.0 | 60.0 |
| **Lake Mabel Solar** | **1** | **Polk Co.** | PV | SOLAR | NA | NA | NA | NA | 12/23 | ** | 74,500 | 74.5 | 74.5 |
| **Dover Solar** | **1** | **Hillsborough Co.** | PV | SOLAR | NA | NA | NA | NA | 12/23 | ** | 25,000 | 25.0 | 25.0 |
| **Solar Total [2, 3]** | | | | | | | | | | | **1,252,100** | **1,252** | **1,252** |
| | | | | | | | | | | | **TOTAL** | **5,983** | **6,433** |

**Notes:**

* Limited by environmental permit.

** Undetermined.

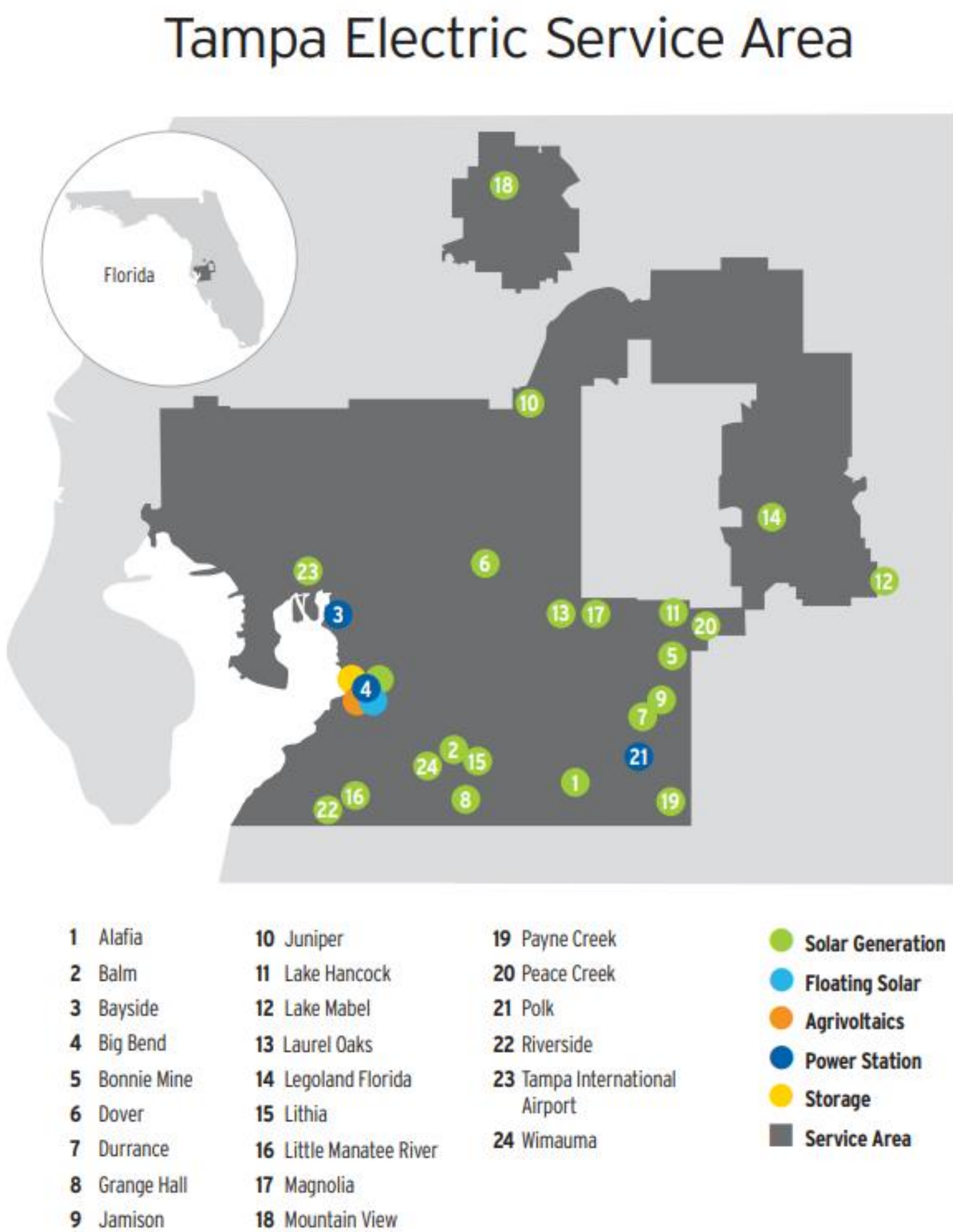
1 The 12.6 MW Big Bend Battery was integrated into the solar site at Big Bend in December 2019.

2 Rating for Solar units are nameplate.

3 Utility owned solar/battery less than 1 MW not included.

4 Big Bend 3 retired 4/23 with a Gen Max. nameplate capacity of 445,500 kW and a Summer and Winter Net Capacity of 395 MW and 400 MW respectively.

**Figure I-I: Tampa Electric Service Area Map**



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# Chapter II

## TAMPA ELECTRIC COMPANY FORECASTING METHODOLOGY

The customer, demand and energy forecasts are the foundation from which the IRP is developed. Recognizing their importance, TEC employs proven methodologies for carrying out this function. The primary objective of this procedure is to blend proven statistical techniques with practical forecasting experience to provide a projection that represents the highest probability of occurrence.

This chapter is devoted to describing TEC's forecasting methodologies and the major assumptions utilized in developing the 2024-2033 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the years 2024-2033.

### RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2024-2033 customer, demand, and energy forecasts. This software allows a platform for the development of more dynamic and fully integrated models.

In addition, TEC uses MetrixLT, which integrates with MetrixND, to develop multiple-year forecasts of energy usage at the hourly level. This tool allows the annual or monthly forecasts in MetrixND to be combined with hourly load shape data to develop a long-term "bottom-up" forecast.

TEC's retail customer, demand and energy forecasts are the result of eight separate forecasting analyses:

1. Economic Analysis
2. Customer Multiregression Model
3. Energy Multiregression Model
4. Peak Demand Multiregression Model
5. Phosphate Demand and Energy Analysis
6. Customer-Owned Photovoltaic (PV)
7. Electric Vehicle Charging (EV)
8. Conservation, Load Management and Cogeneration Programs

The MetrixND models are the company's most sophisticated and primary load forecasting models. The phosphate demand and energy are forecasted separately and then combined in the final forecast, as well as the lighting forecast energy and effects of customer-owned photovoltaic (PV) and electric vehicle (EV) related energy and demand. Likewise, the effects of TEC's conservation, load management, and cogeneration programs are incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

### 1. *Economic Analysis*

The economic assumptions used in the forecast models are derived from forecasts from Moody's Analytics and the University of Florida's Bureau of Economic and Business Research (BEBR).

See the "Base Case Forecast Assumptions" section of this chapter for an explanation of the most significant economic inputs to the MetrixND models.

### 2. *Customer Multiregression Model*

The customer multiregression forecasting model is a twelve-equation model. The primary economic drivers in the customer forecast models are population estimates, new construction, and employment growth. Below is a description of the models used for the five-customer classes.

- ***Residential Customer Model (Equation #1):*** Customer projections are a function of regional population due to the strong correlation that exists between regional population and historical changes in service area customers.

- ***Commercial Customer Model:*** Total commercial customers include commercial customers plus construction service customers; therefore, two models are used to forecast total commercial customers:

    - The <u>Commercial Customer Model</u> ***(Equation #2)*** is a function of commercial employment and a time trend variable. An increase in employment signals growth in additional services, restaurants, and retail establishments.

    - Projections of permits in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the <u>Construction Service Model</u> ***(Equation #3)*** projects the number of customers as a function of new construction permits.

- ***Industrial Customer Model (Non-Phosphate):*** *Non-phosphate industrial customers include four rate classes modeled individually: General Service, General Service Demand, General Service Large Demand and Standby Large Demand.*

    - The <u>General Service Customer Model</u> ***(Equation #4)*** is a function of Hillsborough County commercial employment.

    - The <u>General Service Demand Customer Model</u> ***(Equation #5)*** is a function of Hillsborough County manufacturing employment.

    - The <u>General Service Large Demand Customer Model</u> ***(Equation #6)*** is a function of recent trends.

- The Standby Large Demand Customer Model ***(Equation #7)*** is a function of recent trends.

- ***Industrial Phosphate Customers:*** Customer counts seldom change within this industry; however, actual counts are tracked for any changes and phosphate accounts are individually surveyed annually to reflect any known future changes.

- ***Public Authority Customer Model:*** Customer projections are based on the recent growth trends in the governmental sector and are modeled individually for five rate classes: Residential Service, General Service, General Service Demand, General Service Large Demand and Standby Large Demand. ***(Equations #8 through #12)***

- ***Street & Highway Lighting Customers:*** Customer projections are based on recent growth trends in the sector and provided exogenously by the Lighting Growth department, subject matter experts who are familiar with industry dynamics and changing lighting technologies which can drive new customer growth.

### *3. Energy Multiregression Model*

The energy multiregression forecasting model is also a twelve-equation model. All these equations represent average usage per customer (kWh/customer), except for the construction services which represent total energy (kWh) sales. The average usage models interact with the customer models to arrive at total sales for each class.

The energy models are based on a Statistically Adjusted End-Use (SAE) framework. SAE entails specifying end-use variables, such as heating, cooling, and base use appliance/equipment, and incorporating these variables into regression models. This approach allows the models to capture long-term structural changes that end-use models are known for, while also performing well in the short-term, as do econometric regression models.

- ***Residential Energy Model (Equation #1)****:* The residential forecast model is made up of three major components: (1) end-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements; (2) changes in the economy such as household income, household size, and the price of electricity; and (3) weather variables, which serve to allocate the seasonal impacts of weather throughout the year. The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment (XHeat y,m), cooling equipment (XCool y,m), and other equipment (XOther y,m). The XHeat, XCool, and XOther variables are defined as a product of an annual equipment index and a monthly usage multiplier.

$$\text{Average Usage}_{y,m} = (\text{XHeat}_{y,m} + \text{XCool}_{y,m} + \text{XOther}_{y,m})$$

Where:

$$\text{XHeat}_{y,m} = \text{HeatEquipIndex}_{y} \times \text{HeatUse}_{y,m}$$
$$\text{XCool}_{y,m} = \text{CoolEquipIndex}_{y} \times \text{CoolUse}_{y,m}$$
$$\text{XOtherUse}_{y,m} = \text{OtherEquipIndex}_{y} \times \text{OtherUse}_{y,m}$$

The annual equipment variables (HeatEquipIndex, CoolEquipIndex, OtherEquipIndex) are defined as a weighted average across equipment types multiplied by equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations and operating efficiencies. The weights are defined by the estimated energy use per household for each equipment type in the base year.

Where:

$$\textbf{HeatEquipIndex} = \sum_{Tech.} \text{Weight} \times \left( \frac{\text{Saturation}_{y} \; / \; \text{Efficiency}_{y}}{\text{Saturation}_{base\,y} \; / \; \text{Efficiency}_{base\,y}} \right)$$

$$\textbf{CoolEquipIndex} = \sum_{Tech.} \text{Weight} \times \left( \frac{\text{Saturation}_{y} \; / \; \text{Efficiency}_{y}}{\text{Saturation}_{base\,y} \; / \; \text{Efficiency}_{base\,y}} \right)$$

$$\textbf{OtherEquipIndex} = \sum_{Tech.} \text{Weight} \times \left( \frac{\text{Saturation}_{y} \; / \; \text{Efficiency}_{y}}{\text{Saturation}_{base\,y} \; / \; \text{Efficiency}_{base\,y}} \right)$$

Next, the monthly usage multiplier or utilization variables (HeatUse, CoolUse, OtherUse) are defined using economic and weather variables. A customer's monthly usage level is impacted by several factors, including weather, household size, income levels, electricity prices and the number of days in the billing cycle. The degree-day variables allocate the seasonal impacts of weather throughout the year, while the remaining variables capture changes in the economy.

$$\textbf{HeatUse}_{y,m} = \left( \frac{\text{Price}_{y,m}}{\text{Price}_{base\,y,m}} \right)^{-.10} \times \left( \frac{\text{HH Income}_{y,m}}{\text{HH Income}_{base\,y,m}} \right)^{.17} \times \left( \frac{\text{HH Size}_{y,m}}{\text{HH Size}_{base\,y,m}} \right)^{.15} \times \left( \frac{\text{HDD}_{y,m}}{\text{Normal HDD}} \right)$$

$$\textbf{CoolUse}_{y,m} = \left( \frac{\text{Price}_{y,m}}{\text{Price}_{base\,y,m}} \right)^{-.10} \times \left( \frac{\text{HH Income}_{y,m}}{\text{HH Income}_{base\,y,m}} \right)^{.17} \times \left( \frac{\text{HH Size}_{y,m}}{\text{HH Size}_{base\,y,m}} \right)^{.15} \times \left( \frac{\text{CDD}_{y,m}}{\text{Normal CDD}} \right)$$

$$\textbf{OtherUse}_{y,m} = \left( \frac{\text{Price}_{y,m}}{\text{Price}_{base\,y,m}} \right)^{-.10} \times \left( \frac{\text{HH Income}_{y,m}}{\text{HH Income}_{base\,y,m}} \right)^{.17} \times \left( \frac{\text{HH Size}_{y,m}}{\text{HH Size}_{base\,y,m}} \right)^{.15} \times \left( \frac{\text{Billing Days}_{y,m}}{\text{Billing Days}_{base\,y,m}} \right)$$

The SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels and gives estimates of weather sensitivities that vary over time and trend adjustments.

- ***Commercial Energy Model:*** total commercial energy sales include commercial sales plus construction service sales; therefore, two equations are used to forecast total commercial energy sales.
  - Commercial Energy Model ***(Equation #2)***: The model framework for the commercial sector is the same as the residential model. It also has three major components and utilizes the SAE model framework. The differences lie in the type of end-use equipment and in the economic variables used. The end-use equipment variables are based on commercial appliance/equipment

saturation and efficiency assumptions. The economic drivers in the commercial model are commercial productivity measured in terms of dollar output and the price of electricity for the commercial sector. The third component, weather variables, is the same as in the residential model.

- Construction Service Energy Model ***(Equation #3)***: This model is a subset of the total commercial sector and is a small percentage of the total commercial sector. Although small, it is still a component that must be included. A simple regression model is used with the drivers being construction service customer growth, projections of construction permits, along with the number of days billed, and cooling and heating degree-days.

- ***Industrial Energy Model (Non-Phosphate):*** *Non-phosphate industrial energy includes four rate classes modeled individually: General Service, General Service Demand, General Service Large Demand and Standby Large Demand.*

  - The General Service Energy Model ***(Equation #4)*** utilizes the same SAE model framework as the commercial energy model. The weather component is consistent with the residential and commercial models.

  - The General Service Demand Energy Model ***(Equation #5)*** is based on manufacturing output, the price of electricity in the industrial sector, cooling degree-days and number of days billed. Unlike the previous models discussed; heating load does not impact this sector.

  - The General Service Large Demand Energy Model ***(Equation #6)*** is based on cooling degree-days and seasonal trends.

  - The Standby Large Demand Energy Model ***(Equation #7)*** is based on cooling degree-days and seasonal trends.

- ***Public Authority Sector Energy Model:*** The governmental sector is modeled individually for five rate classes: Residential Service, General Service, General Service Demand, General Service Large Demand, and Standby Large Demand.

  - The Residential Service Energy Model ***(Equation #8)*** is based on the residential equipment saturation and efficiency assumptions used in the residential model.

  - The General Service Energy Model ***(Equation #9)*** is based on the same commercial equipment saturation and efficiency assumptions used in the commercial model. The economic component is based on government sector productivity and the price of electricity in this sector. Weather variables are consistent with the residential and commercial models.

  - The General Service Demand Energy Model ***(Equation #10)*** is a function of cooling and heating degree-days.

  - The General Service Large Demand Energy Model **(Equation #11)** is based on cooling degree-days.

  - The Standby Large Demand Energy Model ***(Equation #12)*** is based on seasonal trends.

- ***Street & Highway Lighting Sector Energy:*** Street and highway lighting is not weather sensitive; therefore, it is a simple calculation. Street and highway lighting energy consumption is a function of energy (kWh) ratings by fixture type times the number of projected lighting fixtures. This information is provided exogenously by the Lighting Growth department, subject matter experts who are familiar with industry dynamics and changing lighting technologies which can drive changes in energy projections. The street and highway lighting forecast reflects the impacts of the company's LED lighting program.

The twelve energy models described above, plus the incremental effects of customer-owned rooftop solar [PV], electric vehicle [EV] charging and conservation related energy, along with an exogenous lighting, and phosphate forecast, are added together to arrive at the total retail energy sales forecast. See sections 5 – 8 below for details. A line loss factor is applied to the energy sales forecast to produce the retail net energy for load forecast (RNEL).

In summary, the SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels, gives estimates of weather sensitivity that varies over time, and estimates trend adjustments.

### *4. Peak Demand Multiregression Model*

After the retail net energy for load forecast is complete, it is integrated into the peak demand model as an independent variable along with weather variables. The energy variable represents the long-term economic and appliance trend impacts. To stabilize the peak demand data series and improve model accuracy, the volatility of the industrial phosphate load is removed. To further stabilize the data, the peak demand models project on a per customer basis.

The weather variables provide the monthly seasonality to the peaks. The weather variables used are heating and cooling degree-days based on the following: temperature at the time of the peak, 24-hour average on the day of the peak and the day prior to the peak. By incorporating the day prior to the peak, the model is accounting for the fact that cold/heat buildup contributes to determining the peak day.

The non-phosphate per customer kW forecast is multiplied by the final customer forecast. This result is then aggregated with a phosphate-coincident peak forecast and adjusted for the incremental effects of customer-owned PV, EV charging, and conservation related demand to arrive at the final projected peak demand.

### *5. Phosphate Demand and Energy Analysis*

TEC phosphate customers are relatively few, which has allowed the company's Commercial and Industrial Business Development Department to obtain detailed knowledge of industry developments including:

- Knowledge of expansion and close-out plans
- Familiarity with historical and projected trends
- Personal contact with industry personnel
- Governmental legislation
- Familiarity with worldwide demand for phosphate products

This department's familiarity with industry dynamics and their close working relationship with phosphate and other company representatives were used to form the basis for a survey of the phosphate customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecasts are based. Further input is provided by individual customer trend analysis and discussions with industry experts.

***6. Customer-Owned Solar (PV)***

Customer-owned solar forecasts are based on the historical number of PV installations and the average size of the PV systems installed in the service area. From this historical data, future penetration levels of PVs are based on assumptions used by the Energy Information Administration's (EIA) for the South Atlantic region. It is assumed Tampa Electric will no longer have to serve this portion of PV customers' load; therefore, the energy sales forecast is adjusted downward to incorporate the loss of this load.

***7. Electric Vehicle (EV) Charging***

The electric vehicle charging forecast process begins with an estimate of the number of EVs operating in Tampa Electric's service area. Future penetration levels of EVs are based on assumptions used by the Energy Information Administration's (EIA) for the South Atlantic region. The demand and energy consumption associated with EV charging is based on several assumptions including the average number of miles driven in a year, the weighted average battery size of seven common EV models sold within the service area and the number of charges per year.

***8. Conservation, Load Management and Cogeneration Programs***

Conservation and Load Management demand and energy savings are forecasted for each individual program. The savings are based on a forecast of the annual number of new participants, estimated annual average energy savings per participant and estimated summer and winter average demand savings per participant. The individual forecasts are aggregated and represent the cumulative amount of Demand Side Management (DSM) savings throughout the forecast horizon.

TEC retail demand and energy forecasts are adjusted downward to reflect the incremental demand and energy savings of these DSM programs.

TEC has developed conservation, load management and cogeneration programs to achieve five major objectives:

1. Defer expansion, particularly production plant construction.
2. Reduce marginal fuel cost by managing energy usage during higher fuel cost periods.
3. Provide customers with some ability to control energy usage and decrease energy costs.
4. Pursue the cost-effective accomplishment of the FPSC ten-year demand and energy conservation goals for the residential and commercial/industrial sectors.
5. Achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act (FEECA).

In 2023, Tampa Electric continued operating within the FPSC approved 2020-2029 DSM Plan which consists of one renewable program, one research and development program, 15 residential and 20 commercial DSM

Programs which support the approved FPSC goals which are reasonable, beneficial, and cost-effective to all customers as required by the FEECA. Also in 2023, the company continued the process with all the other FEECA utilities to start the development of the technical potential study which will support the 2025-2034 DSM Plan projected to be filed in the spring of 2024. The following is a list that briefly describes the company's DSM programs:

1. Energy Audits - a "how to" information and analysis guide for customers. Six types of audits are available to Tampa Electric customers; four types are for residential customers and two types are for commercial/industrial customers.

2. Residential Ceiling Insulation – a rebate program that encourages existing residential customers to install additional ceiling insulation in existing homes.

3. Residential Duct Repair – a rebate program that encourages residential customers to repair leaky duct work of central air conditioning systems in existing homes.

4. Energy and Renewable Education, Awareness and Agency Outreach - a program that provides opportunities for engaging and educating groups of customers, students on energy-efficiency and conservation in an organized setting and electric vehicles at participating high schools. Participants are provided with an energy savings kit which includes energy saving devices and supporting information appropriate for the audience.

5. Energy Star for New Multi-Family Residences - a rebate program that encourages the construction of new multi-family residences to meet the requirements to achieve the ENERGY STAR certified apartments and condominium label.

6. Energy Star for New Homes - a rebate program that encourages residential customers to construct residential dwellings that qualify for the Energy Star Award by achieving efficiency levels greater than current Florida building code baseline practices.

7. Energy Star Pool Pumps - a rebate program that encourages residential customers to install Energy Star rated pool pumps in existing homes.

8. Energy Star Thermostats - a rebate program that encourages residential customers to install Energy Star rated thermostats in existing homes.

9. Residential Heating and Cooling – a rebate program that encourages residential customers to install high-efficiency residential heating and cooling equipment in existing homes.

10. Neighborhood Weatherization – a program that provides for the installation of energy efficient measures for qualified low-income customers.

11. Prime Time Plus – a program that reduces weather-sensitive loads through direct load control of residential customers HVAC, water heating and pool pumps. This program uses the company's advanced metering infrastructure ("AMI") system.

12. Residential Price Responsive Load Management (Energy Planner) – a program that reduces weather-sensitive loads through an innovative price responsive rate used to encourage residential customers to

make behavioral or equipment usages changes by pre-programming HVAC, water heating and pool pumps.

13. Residential Window Replacement – a rebate program that encourages existing residential customers to install window upgrades in existing homes.

14. Commercial Chiller – a rebate program that encourages commercial and industrial customers to install high efficiency chiller equipment.

15. Cogeneration – an incentive program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, meet their own electrical requirements and/or sell their surplus to the company.

16. Conservation Value – a rebate program that encourages commercial and industrial customers to invest in energy efficiency and conservation measures not sanctioned by other commercial programs.

17. Commercial Cooling – a rebate program that encourages commercial and industrial customers to install high efficiency direct expansion commercial air conditioning cooling equipment.

18. Demand Response – a turn-key incentive program for commercial and industrial customers to reduce their demand for electricity in response to market signals.

19. Commercial Facility Energy Management System – a rebate program that encourages commercial and industrial customers to install high efficiency energy management systems.

20. Industrial Load Management – an incentive program whereby large industrial customers allow for the interruption of their facility or portions of their facility electrical load.

21. Street and Outdoor Lighting Conversion – A program that converts Tampa Electric's metal halide and high-pressure sodium street and outdoor lighting to energy efficient light emitting diode (LED) technology to reduce energy consumption and Tampa Electric's peak demand. Tampa Electric will recover the remaining unamortized costs in rate base with the eligible non-LED luminaires. The company completed this conversion program in 2023.

22. Lighting Conditioned Space – a rebate program that encourages commercial and industrial customers to invest in more efficient lighting technologies in existing conditioned areas of commercial and industrial facilities.

23. Lighting Non-Conditioned Space – a rebate program that encourages commercial and industrial customers to invest in more efficient lighting technologies in existing non-conditioned areas of commercial and industrial facilities.

24. Lighting Occupancy Sensors – a rebate program that encourages commercial and industrial customers to install occupancy sensors to control commercial lighting systems.

25. Commercial Load Management – an incentive program that encourages commercial and industrial customers to allow for the control of weather-sensitive heating, cooling, and water heating systems to reduce the associated weather sensitive peak.

26. Commercial Smart Thermostat - a rebate program that encourages commercial and industrial customers to install smart thermostats.

27. Standby Generator – an incentive program designed to utilize the emergency generation capacity of commercial/industrial facilities to reduce weather sensitive peak demand.

28. Variable Frequency Drive Control for Compressors - a rebate program that encourages commercial and industrial customers to install variable frequency drives on refrigerant or compressed air systems.

29. Commercial Water Heating – a rebate program that encourages commercial and industrial customers to install high efficiency water heating systems.

30. Integrated Renewable Energy System – a five-year pilot program to study and understand the potential opportunities and interactions of a fully integrated renewable energy system that contains a photovoltaic system, batteries, car charging and industrial truck charging.

31. Conservation Research and Development (R&D) – a program that allows for the exploration of DSM measures that have insufficient data on the cost-effectiveness of the measure and the potential impact to Tampa Electric and its ratepayers.

The programs listed above were developed to meet FPSC demand and energy goals established in Docket No. 20190021-EG, Order No. PSC-2019-0509-FOF-EU, Issued November 26, 2019. The 2023 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

TEC developed a Monitoring and Evaluation (M&E) plan in response to FPSC requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources.

The M&E plan has its focus on two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give TEC insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

**TABLE III-1**
**Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals**
Savings at the Generator

**Residential**

| | Winter Peak MW Reduction | | | Summer Peak MW Reduction | | | GWh Energy Reduction | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Total Achieved | Commission Approved Goal | % Variance | Total Achieved | Commission Approved Goal | % Variance | Total Achieved | Commission Approved Goal | % Variance |
| 2015 | 12.3 | 2.6 | 473.1% | 10.8 | 1.1 | 981.8% | 21.2 | 1.8 | 1,177.8% |
| 2016 | 7.7 | 4.1 | 187.8% | 5.1 | 1.6 | 318.8% | 13.2 | 3.5 | 377.1% |
| 2017 | 6.9 | 5.2 | 132.7% | 4.7 | 2.2 | 213.6% | 14.9 | 4.8 | 310.4% |
| 2018 | 8.0 | 6.5 | 123.0% | 5.6 | 2.7 | 205.7% | 17.1 | 6.1 | 280.3% |
| 2019 | 8.3 | 7.6 | 108.8% | 5.7 | 3.1 | 184.5% | 16.8 | 6.9 | 243.2% |
| 2020 | 3.5 | 7.6 | 45.5% | 2.6 | 3.3 | 78.2% | 8.9 | 7.4 | 120.3% |
| 2021 | 4.5 | 8.0 | 55.8% | 6.4 | 3.3 | 194.2% | 16.4 | 7.7 | 213.1% |
| 2022 | 9.5 | 7.4 | 127.8% | 11.1 | 3.0 | 369.8% | 30.4 | 6.9 | 441.0% |
| 2023 | 10.3 | 6.8 | 151.2% | 12.5 | 2.9 | 429.5% | 29.6 | 6.3 | 469.9% |
| 2024 | | 6.1 | | | 2.5 | | | 5.5 | |

**Commercial/Industrial**

| | Winter Peak MW Reduction | | | Summer Peak MW Reduction | | | GWh Energy Reduction | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Total Achieved | Commission Approved Goal | % Variance | Total Achieved | Commission Approved Goal | % Variance | Total Achieved | Commission Approved Goal | % Variance |
| 2015 | 8.1 | 1.2 | 675.0% | 11.7 | 1.7 | 688.2% | 12.5 | 3.9 | 320.5% |
| 2016 | 2.9 | 1.3 | 223.1% | 4.4 | 2.5 | 176.0% | 17.8 | 6.0 | 296.7% |
| 2017 | 9.2 | 1.6 | 575.0% | 10.4 | 2.7 | 385.2% | 30.2 | 8.0 | 377.5% |
| 2018 | 13.0 | 1.7 | 767.1% | 15.0 | 3.3 | 453.6% | 33.7 | 9.2 | 365.9% |
| 2019 | 22.4 | 1.6 | 1401.9% | 29.2 | 3.3 | 885.9% | 74.6 | 9.9 | 753.4% |
| 2020 | 10.4 | 1.7 | 612.5% | 11.8 | 3.5 | 336.0% | 26.1 | 10.3 | 253.3% |
| 2021 | 4.7 | 1.9 | 246.2% | 5.6 | 3.6 | 156.8% | 20.4 | 10.4 | 196.1% |
| 2022 | 7.1 | 1.9 | 376.0% | 12.3 | 3.3 | 372.2% | 26.6 | 10.2 | 261.2% |
| 2023 | 7.2 | 1.8 | 398.1% | 8.1 | 3.5 | 232.1% | 30.3 | 9.9 | 305.6% |
| 2024 | | 1.7 | | | 3.2 | | | 9.6 | |

**Combined Total**

| | Winter Peak MW Reduction | | | Summer Peak MW Reduction | | | GWh Energy Reduction | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Total Achieved | Commission Approved Goal | % Variance | Total Achieved | Commission Approved Goal | % Variance | Total Achieved | Commission Approved Goal | % Variance |
| 2015 | 20.4 | 3.8 | 536.8% | 22.5 | 2.8 | 803.6% | 33.7 | 5.7 | 591.2% |
| 2016 | 10.6 | 5.4 | 196.3% | 9.5 | 4.1 | 231.7% | 31.0 | 9.5 | 326.3% |
| 2017 | 16.1 | 6.8 | 236.8% | 15.1 | 4.9 | 308.2% | 45.1 | 12.8 | 352.3% |
| 2018 | 21.0 | 8.2 | 256.5% | 20.5 | 6.0 | 342.1% | 50.8 | 15.3 | 331.8% |
| 2019 | 30.7 | 9.2 | 333.7% | 35.0 | 6.4 | 546.2% | 91.4 | 16.8 | 543.9% |
| 2020 | 13.9 | 9.3 | 149.1% | 14.3 | 6.8 | 210.9% | 35.0 | 17.7 | 197.7% |
| 2021 | 9.1 | 9.9 | 92.3% | 12.1 | 6.9 | 174.7% | 36.8 | 18.1 | 203.3% |
| 2022 | 16.6 | 9.3 | 178.5% | 23.4 | 6.3 | 371.0% | 57.1 | 17.1 | 333.8% |
| 2023 | 17.4 | 8.6 | 202.9% | 20.6 | 6.4 | 321.6% | 59.9 | 16.2 | 369.5% |
| 2024 | | 7.8 | | | 5.7 | | | 15.1 | |

## BASE CASE FORECAST ASSUMPTIONS

## RETAIL LOAD

Numerous assumptions are inputs to the MetrixND models, of which the more significant ones are listed below.

1. Population and Households
2. Commercial, Industrial and Governmental Employment
3. Commercial, Industrial and Governmental Output
4. Real Household Income
5. Price of Electricity
6. Appliance Efficiency Standards
7. Weather

### *1. Population and Households*

Florida and Hillsborough County population forecasts are the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Moody's Analytics supply population projections for Hillsborough County and Florida comparisons. BEBR's population growth for Hillsborough County was used to project future growth patterns in residential customers from 2024-2033. The average annual population growth rate is expected to be 1.5%.

### *2. Commercial, Industrial and Governmental Employment*

Commercial, industrial, and governmental employment assumptions are utilized in computing the number of customers in their respective sectors. Over the next ten years (2024-2033), employment is assumed to rise at a 1.2% average annual rate within Hillsborough County. Moody's Analytics supplies employment projections for the non-residential models.

### *3. Commercial, Industrial and Governmental Output*

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Output for the entire employment sector within Hillsborough County is assumed to rise at a 3.4% average annual rate from 2024-2033. Moody's Analytics supplies output projections.

### *4. Real Household Income*

Moody's Analytics supplies the assumptions for Hillsborough County's real household income growth. During 2024-2033, real household income for Hillsborough County is expected to increase at a 1.3% average annual rate.

### *5. Price of Electricity*

Forecasts for the price of electricity by customer class are supplied by TEC's Regulatory Affairs Department.

***6. Appliance Efficiency Standards***

Another factor influencing energy consumption is the movement toward more efficient appliances such as heat pumps, refrigerators, lighting, and other household appliances. The forces behind this development include market pressures for greater energy-saving devices, legislation, rules, and the appliance efficiency standards enacted by the state and federal governments. Also influencing energy consumption is the customer saturation levels of appliances. The saturation trend for heating appliances is increasing through time; however, overall electricity consumption declines over time as less efficient heating technologies (room heating and furnaces) are replaced with more efficient technologies (heat pumps). Similarly, cooling equipment saturation will continue to increase, but be offset by heat pump and central air conditioning efficiency gains.

Improvements in the efficiency of other non-weather-related appliances also help to lower electricity consumption. Although there is an increasing saturation trend of electronic equipment and appliances in households throughout the forecast period, it does not offset the efficiency gains from lighting and appliances.

***7. Weather***

The weather assumptions are the most difficult to project. Therefore, historical data is the major determinant in developing temperature profiles. For example, monthly profiles used in calculating energy consumption are based on twenty years of historical data. The temperature profiles used in projecting the winter and summer system peak are based on an examination of the minimum and maximum temperatures for the past twenty years plus the temperatures on peak days for the past twenty years. Monte Carlo simulations are performed to estimate weather probabilities.

## HIGH AND LOW SCENARIO FORECAST ASSUMPTIONS

The base case scenario is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy scenarios represent alternatives to the company's base case outlook. Compared to the base case, the expected economic growth rates are 0.5 percent higher in the high scenario and 0.5 percent lower in the low scenario.

## HISTORY AND FORECAST OF ENERGY USE

A history and forecast of energy consumption by customer classification are shown in Schedules 2.1 - 2.3 in Chapter IV.

***1. Retail Energy***

For 2024-2033, retail energy sales are projected to rise at a 0.9% annual rate. The primary contributor to growth is the residential class increasing at an annual rate of 1.2%.

***2. Wholesale Energy***

TEC has no scheduled firm wholesale power sales currently.

## HISTORY AND FORECAST OF PEAK LOADS

Historical, base, high, and low scenario forecasts of peak loads for the summer and winter seasons are presented in Schedules 3.1 and 3.2, respectively. For the period of 2024-2033, TEC's base retail firm peak demand is expected to increase at an average annual rate of 0.9% in the summer and 1.2% in the winter.

# Chapter III

## INTEGRATED RESOURCE PLANNING PROCESSES

TEC's IRP process is designed to evaluate demand-side and supply-side resources on a comparable and consistent basis to satisfy future demand and energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders.

The process incorporates a reliability analysis to determine timing of future needs and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. Initially, a demand and energy forecast is developed which excludes incremental energy efficiency and conservation programs. This forecast is used to identify the basis for the next potential avoided unit(s), and becomes the baseline used to perform a comprehensive cost effectiveness analysis of these programs based on the following Commission approved tests: the Rate Impact Measure test (RIM), the Total Resource Cost test (TRC), and the Participants Cost test (PCT). Using the FPSC's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are also used in this analysis. All measures that pass the RIM and PCT tests in the energy efficiency and demand response analysis are considered for utility program adoption.

Each adopted measure is quantified into its coincident summer and winter peak kW reduction contribution and its annual kWh savings and is reflected in the demand and energy forecast. TEC evaluates and reports energy efficiency and demand response measures that comports with Rule 25-17.008, F.A.C., the FPSC's prescribed cost-effectiveness methodology.

Once this comprehensive analysis is complete and the cost-effective energy efficiency and conservation programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the energy efficiency and conservation programs and supply-side resources.

Generating supply side resources to be considered are determined through an alternative technology screening analysis, which is designed to determine the economic viability of a wide range of generating technologies for the TEC service area. The technologies that pass the screening are included in a supply-side analysis that examines various supply-side alternatives for meeting future system requirements.

TEC uses a long- term planning computer model developed by Energy Exemplar, PLEXOS, to evaluate supply-side resources. PLEXOS utilizes a mixed integer linear program (MILP) to develop an estimate of the timing and type of supply-side resources for generation additions that would economically meet the system demand and energy requirements. The objective function of the MILP is to compare all feasible combinations of generating unit additions, satisfy the specified reliability criteria, and determine the schedule and addition with the lowest total system cost.

Detailed cost analyses for each of the top ranked resource plans are performed using the Energy Exemplar's PLEXOS production cost model. The capital expenditures, including interconnection costs and incremental fuel transportation associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources in our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total cumulative present value of revenue requirements for each alternative plan.

The result of the IRP process provides Tampa Electric's customers with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment, while positioning Tampa Electric for a lower carbon future. To meet the expected system demand and energy requirements and cost-effectively maintain system reliability, the company's expansion plan includes the following:

- Enhancements of existing assets
- Completion of solar PV through 2023, in accordance with the 2021 Rate Case Settlement
- Additional future utility-scale solar, battery storage, and reciprocating engines beyond 2024 until the end of the study period

The Bayside Unit 1 advanced hardware improvements to its existing CTs was completed and placed in service in 2023. Bayside Unit 2 advanced hardware improvements to its existing CTs will be operational in 2024.

The remainder of the expansion plan presented in this Ten-Year Site Plan will meet growing customer needs with the addition of energy resources distributed throughout our territory. In addition to enhancements to the existing assets and the utility-scale solar, battery storage and reciprocating engines will be added to meet customer demand growth and provide operational flexibility and system resiliency to better serve our customers. The detailed expansion plan is shown in Schedule 8.1.

TEC will continue to assess competitive purchase power agreements and DSM programs that may replace or delay the scheduled units. Such optimizations must achieve the overall objective of providing reliable power in a cost-effective manner.

## FINANCIAL ASSUMPTIONS

TEC makes numerous financial assumptions as part of the preparation for its TYSP process. These assumptions are based on the current financial status of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code 25-6, an amount for AFUDC is recorded by the company during the construction phase of each capital project that meets the requirements. This rate is approved by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.
- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the TYSP.
- The financing cost rates reflect the incremental cost of capital associated with each of the sources of long-term financing.
- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.

- Depreciation represents the annual cost to amortize the total original investment in a plant over its useful life less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the TYSP represents the average expected life for that type of asset.

## FUEL FORECAST

TEC forecasts base case fuel commodity prices for natural gas, coal, and oil by analyzing current market prices and price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, S&P Global, U.S. Energy Information Administration, and Coaldesk, LLC Publications. For natural gas, coal and oil prices, the company produces both high and low fuel price projections, which represent alternative forecasts to the company's base case outlook.

## TEC RENEWABLE RESOURCES AND STORAGE TECHNOLOGY INITIATIVES

### *1. Renewable Energy Initiatives and Customer Programs*

In September 2017, TEC announced plans to build 600 $MW_{AC}$ of new solar PV generating capacity from 2018 through January 2021, which is enough electricity to power more than 100,000 homes. The actual design and completion of these projects resulted in 632 $MW_{AC}$ and combined with 23 $MW_{AC}$ from three smaller projects built prior to 2018, created a total of 655 $MW_{AC}$ of solar capacity. In February 2020, the Company announced plans to build an additional 597 $MW_{AC}$ of new cost-effective, utility-scale solar PV generating capacity from 2021 through the end of 2023 for a total of 1,252 $MW_{AC}$. By the end of 2024, Tampa Electric will have about 1,350 $MW_{AC}$ of solar power – enough energy to power more than 214,000 homes – or approximately 13 percent of TEC's energy produced by the sun.

The company's proposed solar expansion helps lower electricity costs. These cost-effective projects also help serve increased customer load while reducing the impact of fuel price fluctuations on the customers' bill due to the zero-fuel cost generation. The additional utility-scale solar will help moderate fuel price volatility, increase fuel diversity, reduce reliance on natural gas, and has little to no water requirements for operations. In addition, with the passage of the Inflation Reduction Act, the federal government is providing additional tax incentives which will also benefit customers.

Beyond 2024 there is an additional 1,489 $MW_{AC}$ of solar PV generating capacity shown in this TYSP that is in the planning and analysis phase and requires further development. In sum, TEC would have over 2,800 $MW_{AC}$ of solar capacity by the end of the study horizon, which means approximately 27 percent of our energy will come from the sun.

Since 2006, TEC implemented the Renewable Energy Program which offers residential, commercial, and industrial customers the opportunity to purchase 200 kWh renewable energy "blocks" for their home or business. In 2009, TEC added a new feature to the program which allows residential, commercial, and industrial customers the opportunity to purchase renewable energy in one-time blocks to power a specific event. This enables a family, business, or venue to make a statement about their commitment to the environment and to renewable energy. Through December 2023, TEC's Renewable Energy Program has 1,082 customers purchasing over 1,924 blocks of renewable energy each month and there have been over 5,600 one-time blocks purchased since program inception.

The company's renewable generation portfolio is a mix of various technologies and renewable generation sources, including both large utility scale solar PV sites and smaller, company-owned community sited PV arrays that provide ample solar energy for the Renewable Energy Block Program. The smaller, community-sited PV arrays are currently installed at Middleton High school, the Manatee Viewing Center, Zoo Tampa at Lowry Park, the Florida Aquarium, LEGOLAND Florida's Imagination Zone, the Museum of Science and Industry (MOSI), and Meachum Urban Farm. The newest array is located at an organic farm and store open to the public in downtown Tampa, featuring solar with battery storage and a charging station for visitor use. The Renewable Energy Program installations are strategically located throughout the community and are designed to educate students and the public on the benefits of renewable energy. Educational signage touts the advantages of solar energy and interactive displays provide hands-on experience to engage visitors' interest in clean, renewable technologies.

The Florida Conservation and Technology Center (FCTC) located south of Big Bend Station is a collaborative partnership with the Florida Aquarium and Florida Fish & Wildlife to develop and educate students and the public on water and energy conservation technologies, marine science development and clean energy demonstrations. The FCTC site includes the TEC Manatee Viewing Center, the Center for Conservation, and the TEC Clean Energy Center (CEC). The CEC has a flexible rooftop adhesive PV array, a dual axis tracking PV Smart Flower array, and a fixed tilt solar canopy array. The FCTC also includes a vertical axis Be-Wind wind turbine, a vanadium flow battery and a supercapacitor based energy storage system. A 1 $MW_{AC}$ floating solar pilot project at FCTC began operations in 2022. It integrates solar panels onto floats and will analyze the benefits of bi-facial solar panels capabilities to increase the output created from reflected light onto the reverse side of the solar panels. The data collected and lessons learned will inform future applications over open water reservoirs and demonstrate that floating solar has the potential to decrease the evaporation of water. A 1 $MW_{AC}$ agrivoltaics pilot project at FCTC was also completed in 2022. The project was designed to combine renewable energy with agriculture by positioning elevated solar panels in wider rows with plants or crops planted between the rows of solar panels. This will provide farmable acreage to balance the community attrition of acreage due to development. Agrivoltaics applications have the potential to lower the operating costs of large utility scale solar sites by sharing viable land with agricultural interests.

By Order No. PSC-2019-0215-TRF-EI, the Commission approved Tampa Electric Company's (TECO or utility) Shared Solar Tariff (SSR-1 tariff). The SSR-1 tariff provides residential and commercial customers with the option to purchase energy produced from a TECO-owned solar generation facility to replace all or a portion of their monthly energy consumption. Participants are charged a Shared Solar Charge of $0.063 per kilowatt-hour while the fuel kWh is removed for the subscribed portion. The SSR-1 tariff became effective on June 25, 2019, after TECO completed programming its billing system to administer the SSR-1 tariff. Tampa Electric Company launched the Sun Select program on June 26, 2019, making 17.5 $MW_{AC}$ of solar generation available to its customers via the SSR-1 tariff.

### *2. Storage Technology Initiatives*

Battery storage projects will help maintain the required winter capacity reserve margin as peak load grows with increased customers. Additionally, battery storage provides fuel savings for customers through energy arbitrage, where energy is stored during off-peak hours when electricity prices are cheapest and used during on-peak hours when electricity prices are highest. Other added benefits include the potential deferral or avoidance of future transmission and distribution investments by eliminating an otherwise necessary upgrade by locating an energy source close to a high load area.

In 2018, Tampa Electric began interconnecting customer-owned battery storage. As of December 31, 2023, there are 1,083 customers interconnected with 9.90 MW DC storage capacity.

### *3. Electric Vehicle Initiatives*

The upward trajectory of customer adoption of Electric Vehicles (EV) continues, and this trend is expected to persist into the foreseeable future. Florida continually ranks second in the nation for the number of EVs sold, and TEC is forecasting a nearly 30% average annual growth rate in the number of EVs within our service area through 2030. Given the ongoing enhancements in battery technology and cost efficiencies, increased access to public charging infrastructure, and greater consumer choice in the types of EVs offered by major automakers, forecasts show EV adoption will continue to grow.

Most recently, in 2021, the FPSC approved TEC's Drive Smart℠ EV charging pilot, which allows for the installation of up to 200 Level 2 (240V) and up to four Direct Current Fast Charging (DCFC) stations across the service territory. The 4-year pilot will help to increase driver confidence by expanding access to EV charging, while also providing valuable data to support proper grid planning. The pilot has seen significant interest from customers with nearly 750 ports being applied for. In 2020, TEC received FPSC approval for a variance to CIAC Rule No. 25-6.064, F.A.C. when primary line extensions are required to serve high-power DCFC locations. Through this variance, TEC can extend the revenue period used in determining customer CIAC, from 5 years to 10 years. By doing so, the economics for charging station developers should significantly improve, particularly as charging needs expand to more rural areas and underserved communities. To educate future Electric Vehicle (EV) drivers, TEC introduced a high school driver education program as an enhancement of the company's ongoing Energy Education and Awareness conservation program. TEC not only provided funding for the EVs, but also installed the necessary EV chargers and helped to develop curriculum used in the classrooms.

Through these activities, as well as increased customer engagement, TEC is learning valuable information to support the needs of specific market segments, particularly multi-family residential properties and commercial fleets. The high concentration of EVs at these locations requires extensive planning for both the customer and utility infrastructure needed to provide adequate charging while minimizing grid impacts. As EV adoption continues to increase, smart grid enhancements, smart charging infrastructure and innovative customer programs will be necessary to help manage the potential effects of EV charging on our grid, in a way that benefits all TEC customers.

## GENERATING UNIT PERFORMANCE ASSUMPTIONS

TEC's generating unit performance assumptions are used to evaluate long-range system operating costs associated with integrated resource plans. Generating units are characterized by several different performance parameters. These parameters include capacity, heat rate, unit derations, planned maintenance days, and unplanned outage rates.

The unit performance projections are based on historical data trends, engineering judgment, time since last planned outage, and recent equipment performance. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on a repetitive pattern.

The forecasted outage schedule is based on unit-specific maintenance needs, material lead-time, labor availability, and the need to supply our customers with power in the most economical manner. Unplanned outage rates are projected based on an average of three years of historical data, future expectations, and any necessary adjustments to account for current unit conditions.

## GENERATION RELIABILITY CRITERIA

### *1. Reserve Margin*

TEC calculates reserve margin in two ways to measure reliability of the generating system. The company utilizes a minimum 20 percent firm reserve margin with a minimum contribution of 7 percent supply-side resources. TEC's approach to calculating percent reserves are consistent with the agreement that is outlined in the Commission approved Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, issued December 22, 1999. The calculation of the minimum 20 percent firm reserve margin employs an industry accepted method of using total available generating capacity and firm purchased power capacity (capacity less planned maintenance and solar capacity unavailable at the time of peak demand) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100. Capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from TEC's available capacity.

TEC's supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the firm peak demand and interruptible and load management loads.

***2. Winter Reliability Assessment***

Tampa Electric Company's current and expected resources meet operating reserve requirements under normal peak demand scenarios. The reserve margin provides operating flexibility in the case of unplanned outages and deviations to load from colder than normal (or hotter than normal) weather. However, temperatures that vary significantly from those used to prepare this plan would result in the need to employ operating mitigation under these extreme conditions. These mitigations could include changes to unit dispatch to enhance reliability, switching to alternate fuels, making full use of demand response, pursuing purchase power agreements, and potentially interrupting customers to maintain grid stability. The company has reviewed and updated its freeze protection plans for each of its generation stations and implemented measures to mitigate equipment failure during these extreme temperatures. Refer to schedule 7.2.1 to see how a 2-degree change in temperatures can impact winter reserve margins.

## SUPPLY-SIDE RESOURCES PROCUREMENT PROCESS

TEC uses wholesale power market opportunities to enhance and optimize its system. Prospective suppliers of supply-side resources are identified in accordance with established policies and procedures. Competitive bid evaluations are used in developing award recommendations to management. Fuel, fuel transportation, transmission availability, transmission cost, environmental requirements, ancillary services, and balancing requirements are considered as part of evaluating future supply-side resources.

This process allows for future supply-side resources to be supplied from self-build, purchased power, or asset purchases. Consistent with company practice, bidders are encouraged to propose incentive arrangements that promote development and implementation of cost savings and process-improvement recommendations.

## TRANSMISSION PLANNING - CONSTRAINTS AND IMPACTS

The TEC transmission system supports the reliable delivery of required capacity and energy to TEC's retail and wholesale customers. Transmission Planning studies are performed annually to evaluate the performance of the TEC transmission system with the results of the studies varying due to refinements in load projections, planning criteria, generation plans and operating flexibility. This involves the use of steady-state load flow, short circuit and transient stability programs to model various contingency situations, 3-Phase Fault and Single Line-Ground Fault analysis that may occur to determine if the TEC transmission system meets the reliability criteria. Simulations of normal system conditions, as well as single and select multiple contingency events, are performed during system peak and off-peak load levels, and summer and/or winter conditions.

Based on existing studies (ex: internal expansion, joint utility, operating, Florida Reliability Coordinating Council (FRCC) Long Range Study, FRCC Planning and Extreme Events Stability Analysis, FRCC Summer Assessment, FRCC Winter Assessment and other miscellaneous studies) and TEC's current transmission construction program, TEC anticipates no transmission constraints that violate the criteria as described in the Transmission Planning Reliability Criteria section of this document.

## TRANSMISSION PLANNING RELIABILITY CRITERIA

### *1. Transmission*

TEC developed the transmission planning reliability criteria, as described in the FERC Form 715 filing, to assess and test the strength and limits of the transmission system, while meeting the load responsibility and being able to move bulk power between and among other electric systems. TEC has adopted the transmission planning criteria outlined in the FRCC's *FRCC Regional Transmission Planning Process*. The FRCC's transmission planning criteria are consistent with the North American Electric Reliability Corporation (NERC) Reliability Standards.

In general, the NERC Reliability Standards state the transmission system will remain stable, within the applicable thermal and voltage rating limits, without cascading outages, under normal, single and select multiple contingency conditions. In addition to the FRCC criteria, TEC utilizes company-specific planning criteria for normal system operation and contingency operation, along with a Facility Rating Methodology and Facility Interconnection Requirements document available at https://www.oasis.oati.com/TEC/index.html.

The transmission planning reliability criteria are used as guidelines for proposing transmission system expansion and/or improvement projects, however they are not absolute rules for system expansion. These criteria are used to alert planners of potential transmission system capacity limitations. Engineering analysis is used in all stages of the planning process to weigh the impact of system deficiencies, the likelihood of the triggering contingency, and the viability of any operating options. Only by carefully researching each potential planning criteria violation can a final evaluation of available transmission capacity be made.

### *2. Available Transmission Transfer Capability (ATC) Criteria*

TEC adheres to the ATC calculation methodology described in the Attachment C of the Tampa Electric Company *Open Access Transmission Tariff FERC Electric Tariff*, Fourth Revised Volume No. 4 document, accessible at https://www.oasis.oati.com/woa/docs/TEC/TECdocs/Tariff_Fourth_Revised_Volume_No._4_effective_5-1-23.pdf as well as the principles contained in the NERC Reliability Standards relating to ATC calculations. Members of the FRCC, including TEC, have formed the Florida Transmission Capability Determination Group in an effort to provide ATC values to the regional electric market that are transparent, coordinated, timely and accurate.

## TRANSMISSION SYSTEM PLANNING ASSESSMENT PRACTICES

TEC's transmission system planning assessment practices are developed according to the TEC and NERC Reliability Standards to ensure a reliable system is planned that demonstrates adequacy within TEC's footprint to meet present and future system needs. The Reliability Standards require that the TEC transmission system be planned such that it will remain stable within the applicable facility ratings and voltage rating limits and without cascading outages under normal system conditions, as well as single and select multiple contingency events.

TEC performs transmission studies independently, collaboratively with other utilities, and as part of the FRCC to determine if the system meets the criteria. The studies involve the use of steady-state power flows, transient stability analyses, short circuit assessments and various other assessments to ensure adequate system performance.

### *1. Base Case Operating Conditions*

The TEC transmission system can support peak and off-peak system load levels while meeting the criteria as described in the Transmission Planning Reliability Criteria section of this document.

***2. Single Contingency Planning Criteria***

The TEC transmission system is designed to support any single event outage of a transmission circuit, autotransformer, generator, or shunt device (including FRCC studies of Category P1 and P2-1 events) at a variety of load levels while meeting the criteria as described in the Transmission Planning Reliability Criteria section of this document.

***3. Multiple Contingency Planning Criteria***

Select double contingencies (including FRCC studies of Category P2-2 through P7 events) involving two or more Bulk Electric System (BES) transmission system elements out of service are analyzed at a variety of load levels. The TEC transmission system is designed such that double contingencies meet the criteria as described in the Transmission Planning Reliability Standards Criteria section of this document.

***4. Transmission Construction and Upgrade Plans***

A specific list of the proposed directly associated transmission construction projects corresponding with the proposed generating facilities can be found in Chapter V, Schedule 10. This list represents the latest BES transmission construction related to the generation expansion on Schedule 8.1 and 9. However, due to the timing of this document in relationship to the company's internal planning schedule, this plan may change in the future. The current transmission construction and upgrade plan for the planning horizon does not require any electric utility system lines to be certified under the Transmission Line Siting Act (403.52-403.536, F.S.).

## ENERGY EFFICIENCY, CONSERVATION, AND ENERGY SAVINGS DURABILITY

TEC ensures that DSM programs the company offers are directly monitorable and yield measurable results. The achievements and durability of energy savings from the company's conservation and load management programs is validated by several methods. First, TEC has established a monitoring and evaluation process where historical analysis validates the energy savings. These include:

- Periodic system load reduction analysis for price responsive load management (Energy Planner), Commercial industrial load management and Commercial demand response to confirm and verify the accuracy of TEC's load reduction estimation formulas.
- Billing energy usage and demand analysis of participants in certain energy efficiency and conservation programs as compared to control groups.
- Analysis of DOE2 modeling of various program participants.
- End-use monitoring and evaluation of projects and programs.
- Specific metering of loads under control to determine the actual demand and energy savings in commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response.

Second, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Specifically, those programs that promote the installation of energy-efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, wall insulation, window replacements, air distribution system repairs, DX commercial cooling units, chiller replacements, and water heating replacements) have program standards that require the new equipment to be installed in a permanent manner thus ensuring their durability.

# Chapter IV

## FORECAST OF ELECTRIC POWER, DEMAND AND ENERGY CONSUMPTION

Tables in Schedules 2 through 4 reflect three different levels of load forecasting: base case, high case, and low case. The expansion plan is developed using the base case load forecast and is reflected on Schedules 5 through 9. This forecast band best represents the current economic conditions and the long-term impacts to TEC's service territory.

Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 3.1: History and Forecast of Summer Peak Demand (Base, High & Low)

Schedule 3.2: History and Forecast of Winter Peak Demand (Base, High & Low)

Schedule 3.3: History and Forecast of Annual Net Energy for Load (Base, High & Low)

Schedule 4: Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month (Base, High & Low)

Schedule 5: History and Forecast of Fuel Requirements

Schedule 6.1: History and Forecast of Net Energy for Load by Fuel Source in GWh

Schedule 6.2: History and Forecast of Net Energy for Load by Fuel Source as a Percent

## Schedule 2.1

### History and Forecast of Energy Consumption and Number of Customers by Customer Class
### Base Case

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|
| | Rural and Residential | | | | | Commercial | | |
| Year | Hillsborough County Population | Members Per Household | GWH | Customers* | Average KWH Consumption Per Customer | GWH | Customers* | Average KWH Consumption Per Customer |
| | 1,301,887 | 2.6 | 8,656 | 623,846 | 13,875 | 6,142 | 72,647 | 84,548 |
| **2015** | 1,325,563 | 2.6 | 9,045 | 635,403 | 14,235 | 6,301 | 73,556 | 85,658 |
| **2016** | 1,352,797 | 2.6 | 9,187 | 646,221 | 14,217 | 6,310 | 74,313 | 84,911 |
| **2017** | 1,379,302 | 2.6 | 9,029 | 659,387 | 13,693 | 6,362 | 74,998 | 84,830 |
| **2018** | 1,408,864 | 2.6 | 9,418 | 670,517 | 14,046 | 6,266 | 74,895 | 83,664 |
| **2019** | 1,444,870 | 2.6 | 9,584 | 685,122 | 13,989 | 6,239 | 76,038 | 82,057 |
| **2020** | 1,459,762 | 2.6 | 10,122 | 698,493 | 14,491 | 6,058 | 76,790 | 78,890 |
| **2021** | 1,490,374 | 2.6 | 9,941 | 713,135 | 13,940 | 6,144 | 78,115 | 78,653 |
| **2022** | 1,520,529 | 2.6 | 10,109 | 729,334 | 13,861 | 6,300 | 79,610 | 79,131 |
| **2023** | 1,541,531 | 2.6 | 10,307 | 742,575 | 13,880 | 6,462 | 80,622 | 80,154 |
| **2024** | 1,569,983 | 2.6 | 10,200 | 755,744 | 13,497 | 6,289 | 81,520 | 77,145 |
| **2025** | 1,597,332 | 2.5 | 10,299 | 768,913 | 13,395 | 6,351 | 82,465 | 77,013 |
| **2026** | 1,624,239 | 2.5 | 10,413 | 781,870 | 13,318 | 6,415 | 83,413 | 76,907 |
| **2027** | 1,650,693 | 2.5 | 10,534 | 794,608 | 13,257 | 6,470 | 84,369 | 76,687 |
| **2028** | 1,676,455 | 2.5 | 10,662 | 807,013 | 13,212 | 6,524 | 85,342 | 76,451 |
| **2029** | 1,701,455 | 2.5 | 10,801 | 819,051 | 13,187 | 6,579 | 86,323 | 76,218 |
| **2030** | 1,725,605 | 2.5 | 10,948 | 830,679 | 13,179 | 6,634 | 87,304 | 75,982 |
| **2031** | 1,748,484 | 2.5 | 11,096 | 841,697 | 13,183 | 6,691 | 88,287 | 75,792 |
| **2032** | 1,770,488 | 2.5 | 11,249 | 852,292 | 13,198 | 6,752 | 89,270 | 75,641 |
| **2033** | 1,791,686 | 2.4 | 11,403 | 862,499 | 13,221 | 6,813 | 90,256 | 75,484 |

**Notes:**
December 31, 2023 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

**Schedule 2.1**

**History and Forecast of Energy Consumption and Number of Customers by Customer Class**
**High Case**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|
| | Rural and Residential | | | | | Commercial | | |
| Year | Hillsborough County Population | Members Per Household | GWH | Customers* | Average KWH Consumption Per Customer | GWH | Customers* | Average KWH Consumption Per Customer |
| 2024 | 1,585,472 | 2.6 | 10,261 | 759,455 | 13,511 | 6,292 | 81,539 | 77,164 |
| 2025 | 1,621,017 | 2.6 | 10,421 | 776,487 | 13,421 | 6,356 | 82,504 | 77,039 |
| 2026 | 1,656,429 | 2.6 | 10,598 | 793,455 | 13,357 | 6,422 | 83,472 | 76,942 |
| 2027 | 1,691,690 | 2.6 | 10,785 | 810,351 | 13,309 | 6,480 | 84,447 | 76,729 |
| 2028 | 1,726,550 | 2.6 | 10,982 | 827,055 | 13,278 | 6,536 | 85,443 | 76,499 |
| 2029 | 1,760,929 | 2.6 | 11,191 | 843,528 | 13,267 | 6,594 | 86,445 | 76,274 |
| 2030 | 1,794,728 | 2.6 | 11,410 | 859,723 | 13,272 | 6,650 | 87,449 | 76,046 |
| 2031 | 1,827,498 | 2.6 | 11,633 | 875,425 | 13,289 | 6,711 | 88,455 | 75,864 |
| 2032 | 1,859,633 | 2.6 | 11,863 | 890,823 | 13,317 | 6,774 | 89,462 | 75,719 |
| 2033 | 1,891,196 | 2.6 | 12,096 | 905,947 | 13,352 | 6,837 | 90,473 | 75,570 |

**Notes:**
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

**Schedule 2.1**

**History and Forecast of Energy Consumption and Number of Customers by Customer Class**
**Low Case**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|
| | Rural and Residential | | | | | Commercial | | |
| Year | Hillsborough County Population | Members Per Household | GWH | Customers* | Average KWH Consumption Per Customer | GWH | Customers* | Average KWH Consumption Per Customer |
| 2024 | 1,554,570 | 2.5 | 10,140 | 752,032 | 13,483 | 6,286 | 81,502 | 77,127 |
| 2025 | 1,573,878 | 2.5 | 10,178 | 761,375 | 13,368 | 6,346 | 82,428 | 76,985 |
| 2026 | 1,592,521 | 2.5 | 10,229 | 770,397 | 13,278 | 6,408 | 83,356 | 76,873 |
| 2027 | 1,610,496 | 2.4 | 10,287 | 779,095 | 13,204 | 6,460 | 84,291 | 76,645 |
| 2028 | 1,627,578 | 2.4 | 10,350 | 787,362 | 13,146 | 6,513 | 85,244 | 76,402 |
| 2029 | 1,643,710 | 2.4 | 10,423 | 795,168 | 13,107 | 6,565 | 86,203 | 76,162 |
| 2030 | 1,658,822 | 2.4 | 10,502 | 802,481 | 13,086 | 6,617 | 87,163 | 75,919 |
| 2031 | 1,672,522 | 2.4 | 10,581 | 809,111 | 13,077 | 6,673 | 88,124 | 75,722 |
| 2032 | 1,685,208 | 2.3 | 10,663 | 815,249 | 13,080 | 6,731 | 89,085 | 75,562 |
| 2033 | 1,696,958 | 2.3 | 10,746 | 820,935 | 13,090 | 6,789 | 90,048 | 75,398 |

**Notes:**
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

## Schedule 2.2

### History and Forecast of Energy Consumption and Number of Customers by Customer Class
### Base Case

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|
| | Industrial | | | | | | |
| Year | GWH | Customers* | Average KWH Consumption Per Customer | Railroads and Railways GWH | Street & Highway Lighting GWH ** | Other Sales to Public Authorities GWH | Total Sales to Ultimate Consumers GWH |
| **2014** | 1,901 | 1,572 | 1,208,831 | 0 | 75 | 1,752 | 18,526 |
| **2015** | 1,870 | 1,586 | 1,179,087 | 0 | 77 | 1,714 | 19,006 |
| **2016** | 1,928 | 1,616 | 1,193,504 | 0 | 78 | 1,730 | 19,234 |
| **2017** | 2,024 | 1,608 | 1,259,094 | 0 | 0 | 1,771 | 19,186 |
| **2018** | 2,014 | 1,588 | 1,268,262 | 0 | 0 | 1,933 | 19,631 |
| **2019** | 2,021 | 1,516 | 1,332,913 | 0 | 0 | 1,939 | 19,783 |
| **2020** | 1,891 | 1,408 | 1,342,642 | 0 | 0 | 1,883 | 19,954 |
| **2021** | 2,122 | 1,382 | 1,535,835 | 0 | 0 | 1,886 | 20,093 |
| **2022** | 2,111 | 1,357 | 1,556,126 | 0 | 0 | 1,947 | 20,467 |
| **2023** | 2,082 | 1,330 | 1,565,053 | 0 | 0 | 1,939 | 20,791 |
| **2024** | 1,856 | 1,327 | 1,398,511 | 0 | 0 | 1,970 | 20,315 |
| **2025** | 1,837 | 1,325 | 1,386,481 | 0 | 0 | 1,979 | 20,466 |
| **2026** | 1,834 | 1,323 | 1,386,313 | 0 | 0 | 1,989 | 20,651 |
| **2027** | 1,833 | 1,322 | 1,387,137 | 0 | 0 | 1,998 | 20,835 |
| **2028** | 1,833 | 1,320 | 1,388,348 | 0 | 0 | 2,008 | 21,027 |
| **2029** | 1,832 | 1,319 | 1,389,525 | 0 | 0 | 2,017 | 21,229 |
| **2030** | 1,831 | 1,317 | 1,389,863 | 0 | 0 | 2,026 | 21,438 |
| **2031** | 1,830 | 1,316 | 1,390,405 | 0 | 0 | 2,036 | 21,653 |
| **2032** | 1,829 | 1,315 | 1,390,860 | 0 | 0 | 2,045 | 21,875 |
| **2033** | 1,828 | 1,314 | 1,391,549 | 0 | 0 | 2,055 | 22,098 |

**Notes:**
December 31, 2023 Status
*Average of end-of-month customers for the calendar year.
**Sales shown for Street and Highway Lighting from 2017 forward are now included with Other Sales to Public Authorities.
Values shown may be affected due to rounding.

**Schedule 2.2**

**History and Forecast of Energy Consumption and Number of Customers by Customer Class**
**High Case**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|
| | Industrial | | | | Street & | Other Sales | Total Sales |
| | | | Average KWH | Railroads | Highway | to Public | to Ultimate |
| | | | Consumption | and Railways | Lighting | Authorities | Consumers |
| Year | GWH | Customers* | Per Customer | GWH | GWH ** | GWH | GWH |
| 2024 | 1,856 | 1,327 | 1,398,711 | 0 | 0 | 1,970 | 20,379 |
| 2025 | 1,837 | 1,325 | 1,386,061 | 0 | 0 | 1,979 | 20,593 |
| 2026 | 1,834 | 1,323 | 1,386,195 | 0 | 0 | 1,989 | 20,844 |
| 2027 | 1,833 | 1,322 | 1,386,648 | 0 | 0 | 1,998 | 21,096 |
| 2028 | 1,833 | 1,320 | 1,388,487 | 0 | 0 | 2,008 | 21,359 |
| 2029 | 1,832 | 1,319 | 1,389,182 | 0 | 0 | 2,017 | 21,634 |
| 2030 | 1,831 | 1,317 | 1,390,211 | 0 | 0 | 2,027 | 21,918 |
| 2031 | 1,830 | 1,316 | 1,390,421 | 0 | 0 | 2,036 | 22,209 |
| 2032 | 1,829 | 1,315 | 1,390,665 | 0 | 0 | 2,045 | 22,511 |
| 2033 | 1,828 | 1,314 | 1,391,083 | 0 | 0 | 2,055 | 22,816 |

**Notes:**
*Average of end-of-month customers for the calendar year.
**Sales for Street and Highway Lighting from 2017 forward are now included with Other Sales to Public Authorities.
Values shown may be affected due to rounding.

**Schedule 2.2**

**History and Forecast of Energy Consumption and Number of Customers by Customer Class Low Case**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|
| | Industrial | | | | Street & | Other Sales | Total Sales |
| | | | Average KWH Consumption | Railroads and Railways | Highway Lighting | to Public Authorities | to Ultimate Consumers |
| Year | GWH | Customers* | Per Customer | GWH | GWH ** | GWH | GWH |
| **2024** | 1,856 | 1,327 | 1,398,711 | 0 | 0 | 1,970 | 20,251 |
| **2025** | 1,837 | 1,325 | 1,386,061 | 0 | 0 | 1,979 | 20,340 |
| **2026** | 1,834 | 1,323 | 1,386,195 | 0 | 0 | 1,989 | 20,460 |
| **2027** | 1,833 | 1,322 | 1,386,648 | 0 | 0 | 1,998 | 20,579 |
| **2028** | 1,833 | 1,320 | 1,388,487 | 0 | 0 | 2,007 | 20,703 |
| **2029** | 1,832 | 1,319 | 1,389,182 | 0 | 0 | 2,017 | 20,837 |
| **2030** | 1,831 | 1,317 | 1,390,211 | 0 | 0 | 2,026 | 20,976 |
| **2031** | 1,830 | 1,316 | 1,390,421 | 0 | 0 | 2,035 | 21,119 |
| **2032** | 1,829 | 1,315 | 1,390,665 | 0 | 0 | 2,045 | 21,268 |
| **2033** | 1,828 | 1,314 | 1,391,083 | 0 | 0 | 2,054 | 21,417 |

**Notes:**
*Average of end-of-month customers for the calendar year.
**Sales for Street and Highway Lighting from 2017 forward are now included with Other Sales to Public Authorities.
Values shown may be affected due to rounding.

## Schedule 2.3

### History and Forecast of Energy Consumption and Number of Customers by Customer Class
### Base Case

| (1) Year | (2) Sales for * Resale GWH | (3) Utility Use ** & Losses GWH | (4) Net Energy *** for Load GWH | (5) Other **** Customers | (6) Total **** Customers |
|---|---|---|---|---|---|
| **2014** | 0 | 789 | 19,315 | 8,095 | 706,161 |
| **2015** | 0 | 1,098 | 20,105 | 8,168 | 718,713 |
| **2016** | 9 | 930 | 20,173 | 8,353 | 730,503 |
| **2017** | 2 | 1,110 | 20,298 | 8,698 | 744,690 |
| **2018** | 0 | 1,031 | 20,662 | 9,254 | 756,254 |
| **2019** | 0 | 986 | 20,770 | 9,283 | 771,960 |
| **2020** | 0 | 1,101 | 21,055 | 9,356 | 786,047 |
| **2021** | 0 | 940 | 21,033 | 9,418 | 802,049 |
| **2022** | 0 | 1,105 | 21,572 | 9,466 | 819,766 |
| **2023** | 0 | 976 | 21,767 | 9,616 | 834,144 |
| **2024** | 0 | 1,040 | 21,355 | 9,668 | 848,259 |
| **2025** | 0 | 1,047 | 21,513 | 9,740 | 862,443 |
| **2026** | 0 | 1,056 | 21,706 | 9,810 | 876,416 |
| **2027** | 0 | 1,065 | 21,900 | 9,879 | 890,177 |
| **2028** | 0 | 1,074 | 22,100 | 9,947 | 903,622 |
| **2029** | 0 | 1,083 | 22,313 | 10,015 | 916,774 |
| **2030** | 0 | 1,094 | 22,532 | 10,082 | 929,450 |
| **2031** | 0 | 1,104 | 22,757 | 10,149 | 941,516 |
| **2032** | 0 | 1,115 | 22,990 | 10,217 | 953,161 |
| **2033** | 0 | 1,126 | 23,224 | 10,284 | 954,069 |

**Notes:**
December 31, 2023 Status
*Includes sales to St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
RCID contract from 2016 to 2017.
**Utility Use and Losses include accrued sales.
***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
****Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

**Schedule 2.3**

**History and Forecast of Energy Consumption and Number of Customers by Customer Class High Case**

| (1) Year | (2) Sales for Resale GWH | (3) Utility Use * & Losses GWH | (4) Net Energy ** for Load GWH | (5) Other *** Customers | (6) Total *** Customers |
|---|---|---|---|---|---|
| **2024** | 0 | 1,043 | 21,422 | 9,668 | 851,989 |
| **2025** | 0 | 1,054 | 21,647 | 9,740 | 870,056 |
| **2026** | 0 | 1,065 | 21,909 | 9,810 | 888,060 |
| **2027** | 0 | 1,078 | 22,174 | 9,879 | 905,999 |
| **2028** | 0 | 1,090 | 22,449 | 9,947 | 923,765 |
| **2029** | 0 | 1,104 | 22,738 | 10,015 | 941,307 |
| **2030** | 0 | 1,118 | 23,036 | 10,082 | 958,571 |
| **2031** | 0 | 1,133 | 23,342 | 10,149 | 975,345 |
| **2032** | 0 | 1,147 | 23,658 | 10,217 | 991,817 |
| **2033** | 0 | 1,163 | 23,979 | 10,284 | 1,008,018 |

**Notes:**
*Utility Use and Losses include accrued sales.
**Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
***Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

## Schedule 2.3

### History and Forecast of Energy Consumption and Number of Customers by Customer Class
### Low Case

| (1) Year | (2) Sales for Resale GWH | (3) Utility Use * & Losses GWH | (4) Net Energy ** for Load GWH | (5) Other *** Customers | (6) Total *** Customers |
|---|---|---|---|---|---|
| 2024 | 0 | 1,037 | 21,288 | 9,668 | 844,529 |
| 2025 | 0 | 1,040 | 21,380 | 9,740 | 854,868 |
| 2026 | 0 | 1,046 | 21,506 | 9,810 | 864,886 |
| 2027 | 0 | 1,051 | 21,630 | 9,879 | 874,587 |
| 2028 | 0 | 1,057 | 21,760 | 9,947 | 883,873 |
| 2029 | 0 | 1,063 | 21,900 | 10,015 | 892,705 |
| 2030 | 0 | 1,070 | 22,046 | 10,082 | 901,043 |
| 2031 | 0 | 1,076 | 22,195 | 10,149 | 908,700 |
| 2032 | 0 | 1,083 | 22,351 | 10,217 | 915,866 |
| 2033 | 0 | 1,091 | 22,508 | 10,284 | 922,581 |

**Notes:**

*Utility Use and Losses include accrued sales.
**Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
***Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

## Schedule 3.1

### History and Forecast of Summer Peak Demand (MW)
### Base Case

| (1) Year | (2) Total * | (3) Wholesale** | (4) Retail * | (5) Interruptible | (6) Residential Load Management | (7) Residential Conservation*** | (8) Comm./Ind. Load Management | (9) Comm./Ind. Conservation | (10) Net Firm Demand |
|---|---|---|---|---|---|---|---|---|---|
| **2014** | 4,275 | 0 | 4,275 | 170 | 36 | 132 | 96 | 84 | 3,757 |
| **2015** | 4,248 | 0 | 4,248 | 111 | 21 | 142 | 102 | 88 | 3,784 |
| **2016** | 4,401 | 15 | 4,386 | 138 | 0 | 149 | 101 | 92 | 3,907 |
| **2017** | 4,372 | 5 | 4,367 | 110 | 0 | 154 | 100 | 98 | 3,905 |
| **2018** | 4,289 | 0 | 4,289 | 125 | 0 | 159 | 101 | 106 | 3,798 |
| **2019** | 4,591 | 0 | 4,591 | 122 | 0 | 165 | 101 | 125 | 4,079 |
| **2020** | 4,573 | 0 | 4,573 | 113 | 0 | 169 | 104 | 135 | 4,053 |
| **2021** | 4,713 | 0 | 4,713 | 187 | 0 | 174 | 105 | 139 | 4,108 |
| **2022** | 4,772 | 0 | 4,772 | 204 | 0 | 183 | 106 | 148 | 4,131 |
| **2023** | 5,017 | 0 | 5,017 | 178 | 0 | 194 | 106 | 153 | 4,385 |
| **2024** | 4,762 | 0 | 4,762 | 135 | 0 | 211 | 106 | 166 | 4,143 |
| **2025** | 4,823 | 0 | 4,823 | 133 | 0 | 228 | 106 | 174 | 4,182 |
| **2026** | 4,890 | 0 | 4,890 | 133 | 0 | 247 | 106 | 182 | 4,222 |
| **2027** | 4,959 | 0 | 4,959 | 133 | 0 | 268 | 107 | 190 | 4,261 |
| **2028** | 5,029 | 0 | 5,029 | 133 | 0 | 290 | 107 | 198 | 4,302 |
| **2029** | 5,101 | 0 | 5,101 | 134 | 0 | 312 | 107 | 205 | 4,343 |
| **2030** | 5,173 | 0 | 5,173 | 134 | 0 | 333 | 107 | 213 | 4,385 |
| **2031** | 5,244 | 0 | 5,244 | 134 | 0 | 355 | 107 | 221 | 4,427 |
| **2032** | 5,316 | 0 | 5,316 | 134 | 0 | 377 | 107 | 229 | 4,469 |
| **2033** | 5,387 | 0 | 5,387 | 134 | 0 | 399 | 107 | 237 | 4,511 |

**Notes:**
December 31, 2023 Status
2016, 2018, 2020, 2022 and 2023 Net Firm Demand is not coincident with system peak.
**Notes prior to 2024**
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
***Includes Energy Planner program.
Values shown may be affected due to rounding.

**Schedule 3.1**

**Forecast of Summer Peak Demand (MW)**
**High Case**

| (1) Year | (2) Total * | (3) Wholesale | (4) Retail * | (5) Interruptible | (6) Residential Load Management | (7) Residential Conservation** | (8) Comm./Ind. Load Management | (9) Comm./Ind. Conservation | (10) Net Firm Demand |
|---|---|---|---|---|---|---|---|---|---|
| **2024** | 4,778 | 0 | 4,778 | 135 | 0 | 211 | 106 | 166 | 4,159 |
| **2025** | 4,856 | 0 | 4,856 | 133 | 0 | 228 | 106 | 174 | 4,215 |
| **2026** | 4,941 | 0 | 4,941 | 133 | 0 | 247 | 106 | 182 | 4,272 |
| **2027** | 5,028 | 0 | 5,028 | 133 | 0 | 268 | 107 | 190 | 4,330 |
| **2028** | 5,116 | 0 | 5,116 | 133 | 0 | 290 | 107 | 198 | 4,389 |
| **2029** | 5,209 | 0 | 5,209 | 134 | 0 | 312 | 107 | 205 | 4,451 |
| **2030** | 5,299 | 0 | 5,299 | 134 | 0 | 333 | 107 | 213 | 4,512 |
| **2031** | 5,392 | 0 | 5,392 | 134 | 0 | 355 | 107 | 221 | 4,575 |
| **2032** | 5,484 | 0 | 5,484 | 134 | 0 | 377 | 107 | 229 | 4,637 |
| **2033** | 5,578 | 0 | 5,578 | 134 | 0 | 399 | 107 | 237 | 4,701 |

**Notes:**
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
Values shown may be affected due to rounding.

**Schedule 3.1**

**Forecast of Summer Peak Demand (MW)**
**Low Case**

| (1) Year | (2) Total * | (3) Wholesale | (4) Retail * | (5) Interruptible | (6) Residential Load Management | (7) Residential Conservation** | (8) Comm./Ind. Load Management | (9) Comm./Ind. Conservation | (10) Net Firm Demand |
|---|---|---|---|---|---|---|---|---|---|
| 2024 | 4,746 | 0 | 4,746 | 135 | 0 | 211 | 106 | 166 | 4,127 |
| 2025 | 4,790 | 0 | 4,790 | 133 | 0 | 228 | 106 | 174 | 4,149 |
| 2026 | 4,840 | 0 | 4,840 | 133 | 0 | 247 | 106 | 182 | 4,171 |
| 2027 | 4,892 | 0 | 4,892 | 133 | 0 | 268 | 107 | 190 | 4,194 |
| 2028 | 4,943 | 0 | 4,943 | 133 | 0 | 290 | 107 | 198 | 4,216 |
| 2029 | 4,998 | 0 | 4,998 | 134 | 0 | 312 | 107 | 205 | 4,240 |
| 2030 | 5,050 | 0 | 5,050 | 134 | 0 | 333 | 107 | 213 | 4,263 |
| 2031 | 5,103 | 0 | 5,103 | 134 | 0 | 355 | 107 | 221 | 4,286 |
| 2032 | 5,154 | 0 | 5,154 | 134 | 0 | 377 | 107 | 229 | 4,307 |
| 2033 | 5,207 | 0 | 5,207 | 134 | 0 | 399 | 107 | 237 | 4,330 |

**Notes:**
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
Values shown may be affected due to rounding.

## Schedule 3.2

### History and Forecast of Winter Peak Demand (MW)
### Base Case

| (1) Year | (2) Total * | (3) Wholesale ** | (4) Retail * | (5) Interruptible | (6) Residential Load Management | (7) Residential Conservation*** | (8) Comm./Ind. Load Management | (9) Comm./Ind. Conservation | (10) Net Firm Demand |
|---|---|---|---|---|---|---|---|---|---|
| **2013/14** | 3,880 | 0 | 3,880 | 61 | 64 | 512 | 100 | 64 | 3,079 |
| **2014/15** | 4,202 | 0 | 4,202 | 79 | 47 | 521 | 99 | 65 | 3,390 |
| **2015/16** | 4,034 | 0 | 4,034 | 145 | 21 | 533 | 98 | 67 | 3,171 |
| **2016/17** | 3,748 | 0 | 3,748 | 137 | 0 | 541 | 95 | 70 | 2,905 |
| **2017/18** | 4,670 | 0 | 4,670 | 66 | 0 | 548 | 96 | 77 | 3,883 |
| **2018/19** | 3,913 | 0 | 3,913 | 104 | 0 | 556 | 95 | 88 | 3,071 |
| **2019/20** | 4,238 | 0 | 4,238 | 140 | 0 | 564 | 98 | 99 | 3,336 |
| **2020/21** | 4,151 | 0 | 4,151 | 132 | 0 | 568 | 102 | 103 | 3,247 |
| **2021/22** | 4,414 | 0 | 4,414 | 158 | 0 | 572 | 104 | 108 | 3,473 |
| **2022/23** | 4,396 | 0 | 4,396 | 217 | 0 | 582 | 105 | 113 | 3,380 |
| **2023/24** | 5,229 | 0 | 5,229 | 116 | 0 | 596 | 105 | 120 | 4,292 |
| **2024/25** | 5,302 | 0 | 5,302 | 115 | 0 | 610 | 106 | 126 | 4,345 |
| **2025/26** | 5,383 | 0 | 5,383 | 115 | 0 | 626 | 106 | 132 | 4,404 |
| **2026/27** | 5,463 | 0 | 5,463 | 115 | 0 | 643 | 107 | 138 | 4,461 |
| **2027/28** | 5,544 | 0 | 5,544 | 115 | 0 | 661 | 107 | 143 | 4,517 |
| **2028/29** | 5,624 | 0 | 5,624 | 115 | 0 | 680 | 108 | 149 | 4,572 |
| **2029/30** | 5,703 | 0 | 5,703 | 115 | 0 | 699 | 109 | 155 | 4,626 |
| **2030/31** | 5,781 | 0 | 5,781 | 115 | 0 | 717 | 109 | 161 | 4,679 |
| **2031/32** | 5,856 | 0 | 5,856 | 115 | 0 | 736 | 110 | 166 | 4,729 |
| **2032/33** | 5,931 | 0 | 5,931 | 115 | 0 | 754 | 110 | 172 | 4,780 |

**Notes:**

December 31, 2023 Status
2015/2016 , 2020/2021, 2022/2023 Net Firm Demand is not coincident with system peak.
**Notes prior to 2024**
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
***Includes energy planner program.
Values shown may be affected due to rounding.

**Schedule 3.2**

**Forecast of Winter Peak Demand (MW)**
**High Case**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
|---|---|---|---|---|---|---|---|---|---|
| Year | Total * | Wholesale | Retail * | Interruptible | Residential Load Management | Residential Conservation** | Comm./Ind. Load Management | Comm./Ind. Conservation | Net Firm Demand |
| 2023/24 | 5,247 | 0 | 5,247 | 116 | 0 | 596 | 105 | 120 | 4,310 |
| 2024/25 | 5,338 | 0 | 5,338 | 115 | 0 | 610 | 106 | 126 | 4,381 |
| 2025/26 | 5,437 | 0 | 5,437 | 115 | 0 | 626 | 106 | 132 | 4,457 |
| 2026/27 | 5,535 | 0 | 5,535 | 115 | 0 | 643 | 107 | 138 | 4,533 |
| 2027/28 | 5,636 | 0 | 5,636 | 115 | 0 | 661 | 107 | 143 | 4,608 |
| 2028/29 | 5,736 | 0 | 5,736 | 115 | 0 | 680 | 108 | 149 | 4,684 |
| 2029/30 | 5,835 | 0 | 5,835 | 115 | 0 | 699 | 109 | 155 | 4,758 |
| 2030/31 | 5,933 | 0 | 5,933 | 115 | 0 | 717 | 109 | 161 | 4,831 |
| 2031/32 | 6,031 | 0 | 6,031 | 115 | 0 | 736 | 110 | 166 | 4,904 |
| 2032/33 | 6,129 | 0 | 6,129 | 115 | 0 | 754 | 110 | 172 | 4,977 |

**Notes:**
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
Values shown may be affected due to rounding.

**Schedule 3.2**

**Forecast of Winter Peak Demand (MW)**
**Low Case**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
|---|---|---|---|---|---|---|---|---|---|
| Year | Total * | Wholesale | Retail * | Interruptible | Residential Load Management | Residential Conservation** | Comm./Ind. Load Management | Comm./Ind. Conservation | Net Firm Demand |
| 2023/24 | 5,210 | 0 | 5,210 | 116 | 0 | 596 | 105 | 120 | 4,273 |
| 2024/25 | 5,266 | 0 | 5,266 | 115 | 0 | 610 | 106 | 126 | 4,309 |
| 2025/26 | 5,330 | 0 | 5,330 | 115 | 0 | 626 | 106 | 132 | 4,350 |
| 2026/27 | 5,391 | 0 | 5,391 | 115 | 0 | 643 | 107 | 138 | 4,389 |
| 2027/28 | 5,454 | 0 | 5,454 | 115 | 0 | 661 | 107 | 143 | 4,426 |
| 2028/29 | 5,515 | 0 | 5,515 | 115 | 0 | 680 | 108 | 149 | 4,463 |
| 2029/30 | 5,575 | 0 | 5,575 | 115 | 0 | 699 | 109 | 155 | 4,498 |
| 2030/31 | 5,632 | 0 | 5,632 | 115 | 0 | 717 | 109 | 161 | 4,530 |
| 2031/32 | 5,688 | 0 | 5,688 | 115 | 0 | 736 | 110 | 166 | 4,561 |
| 2032/33 | 5,742 | 0 | 5,742 | 115 | 0 | 754 | 110 | 172 | 4,590 |

**Notes:**
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
Values shown may be affected due to rounding.

## Schedule 3.3

### History and Forecast of Annual Net Energy for Load (GWh)
### Base Case

| (1) Year | (2) Total* | (3) Residential Conservation** | (4) Comm./Ind. Conservation | (5) Retail | (6) Wholesale *** | (7) Utility Use & Losses | (8) Net Energy for Load | (9) Load **** Factor % |
|---|---|---|---|---|---|---|---|---|
| **2014** | 19,376 | 544 | 306 | 18,526 | 0 | 789 | 19,315 | 54.3 |
| **2015** | 19,888 | 565 | 316 | 19,006 | 0 | 1,098 | 20,105 | 57.1 |
| **2016** | 20,149 | 584 | 330 | 19,234 | 9 | 930 | 20,173 | 55.2 |
| **2017** | 20,137 | 598 | 353 | 19,186 | 2 | 1,110 | 20,298 | 56.2 |
| **2018** | 20,634 | 614 | 388 | 19,631 | 0 | 1,031 | 20,662 | 58.1 |
| **2019** | 20,863 | 631 | 449 | 19,783 | 0 | 986 | 20,770 | 55.2 |
| **2020** | 21,085 | 644 | 487 | 19,954 | 0 | 1,101 | 21,055 | 56.2 |
| **2021** | 21,256 | 656 | 508 | 20,093 | 0 | 940 | 21,033 | 54.7 |
| **2022** | 21,676 | 679 | 530 | 20,467 | 0 | 1,105 | 21,572 | 55.5 |
| **2023** | 22,059 | 709 | 560 | 20,791 | 0 | 976 | 21,767 | 53.2 |
| **2024** | 21,626 | 735 | 576 | 20,315 | 0 | 1,040 | 21,355 | 53.9 |
| **2025** | 21,826 | 763 | 597 | 20,466 | 0 | 1,047 | 21,513 | 53.8 |
| **2026** | 22,062 | 793 | 619 | 20,651 | 0 | 1,056 | 21,706 | 53.6 |
| **2027** | 22,300 | 824 | 641 | 20,835 | 0 | 1,065 | 21,900 | 53.4 |
| **2028** | 22,545 | 856 | 662 | 21,027 | 0 | 1,074 | 22,100 | 53.1 |
| **2029** | 22,801 | 888 | 684 | 21,229 | 0 | 1,083 | 22,313 | 53.1 |
| **2030** | 23,063 | 919 | 706 | 21,438 | 0 | 1,094 | 22,532 | 53.0 |
| **2031** | 23,331 | 951 | 727 | 21,653 | 0 | 1,104 | 22,757 | 53.0 |
| **2032** | 23,606 | 982 | 749 | 21,875 | 0 | 1,115 | 22,990 | 52.8 |
| **2033** | 23,883 | 1,014 | 771 | 22,098 | 0 | 1,126 | 23,224 | 53.0 |

**Notes:**
December 31, 2023 Status
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
***Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
****Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

**Schedule 3.3**

**Forecast of Annual Net Energy for Load (GWh)**
**High Case**

| (1) Year | (2) Total* | (3) Residential Conservation** | (4) Comm./Ind. Conservation | (5) Retail | (6) Wholesale | (7) Utility Use & Losses | (8) Net Energy for Load | (9) Load *** Factor % |
|---|---|---|---|---|---|---|---|---|
| **2024** | 21,689 | 735 | 576 | 20,379 | 0 | 1,044 | 21,422 | 53.8 |
| **2025** | 21,954 | 763 | 597 | 20,593 | 0 | 1,054 | 21,647 | 53.7 |
| **2026** | 22,256 | 793 | 619 | 20,844 | 0 | 1,066 | 21,909 | 53.5 |
| **2027** | 22,562 | 824 | 641 | 21,096 | 0 | 1,078 | 22,174 | 53.2 |
| **2028** | 22,877 | 856 | 662 | 21,359 | 0 | 1,090 | 22,449 | 52.9 |
| **2029** | 23,205 | 888 | 684 | 21,634 | 0 | 1,104 | 22,738 | 52.9 |
| **2030** | 23,543 | 919 | 706 | 21,918 | 0 | 1,118 | 23,036 | 52.8 |
| **2031** | 23,888 | 951 | 727 | 22,209 | 0 | 1,132 | 23,342 | 52.7 |
| **2032** | 24,242 | 982 | 749 | 22,511 | 0 | 1,147 | 23,658 | 52.5 |
| **2033** | 24,601 | 1014 | 771 | 22,816 | 0 | 1,162 | 23,978 | 52.6 |

**Notes:**
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

## Schedule 3.3

### Forecast of Annual Net Energy for Load (GWh)
### Low Case

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|
| Year | Total* | Residential Conservation** | Comm./Ind. Conservation | Retail | Wholesale | Utility Use & Losses | Net Energy for Load | Load *** Factor % |
| **2024** | 21,562 | 735 | 576 | 20,251 | 0 | 1,036 | 21,288 | 53.9 |
| **2025** | 21,700 | 763 | 597 | 20,340 | 0 | 1,040 | 21,380 | 53.9 |
| **2026** | 21,872 | 793 | 619 | 20,460 | 0 | 1,046 | 21,506 | 53.7 |
| **2027** | 22,044 | 824 | 641 | 20,579 | 0 | 1,051 | 21,630 | 53.6 |
| **2028** | 22,222 | 856 | 662 | 20,703 | 0 | 1,057 | 21,760 | 53.3 |
| **2029** | 22,409 | 888 | 684 | 20,837 | 0 | 1,063 | 21,900 | 53.4 |
| **2030** | 22,601 | 919 | 706 | 20,976 | 0 | 1,070 | 22,046 | 53.3 |
| **2031** | 22,797 | 951 | 727 | 21,119 | 0 | 1,077 | 22,195 | 53.3 |
| **2032** | 23,000 | 982 | 749 | 21,268 | 0 | 1,083 | 22,352 | 53.2 |
| **2033** | 23,202 | 1,014 | 771 | 21,417 | 0 | 1,091 | 22,509 | 53.4 |

**Notes:**
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

**Schedule 4**
**Base Case**

**Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|
| | 2023 Actual | | 2024 Forecast | | 2025 Forecast | |
| Month | Peak Demand * MW | NEL ** GWH | Peak Demand * MW | NEL ** GWH | Peak Demand * MW | NEL ** GWH |
| January | 3,347 | 1,539 | 4,513 | 1,583 | 4,566 | 1,594 |
| February | 3,273 | 1,391 | 3,520 | 1,420 | 3,557 | 1,427 |
| March | 3,585 | 1,652 | 3,561 | 1,561 | 3,602 | 1,570 |
| April | 3,678 | 1,737 | 3,682 | 1,633 | 3,708 | 1,641 |
| May | 3,912 | 1,914 | 4,034 | 1,905 | 4,059 | 1,917 |
| June | 4,318 | 2,073 | 4,331 | 2,057 | 4,366 | 2,073 |
| July | 4,312 | 2,281 | 4,326 | 2,150 | 4,365 | 2,168 |
| August | 4,669 | 2,357 | 4,384 | 2,181 | 4,421 | 2,199 |
| September | 4,194 | 2,076 | 4,230 | 1,989 | 4,276 | 2,007 |
| October | 3,801 | 1,769 | 3,844 | 1,838 | 3,873 | 1,853 |
| November | 3,440 | 1,491 | 3,396 | 1,486 | 3,436 | 1,499 |
| December | 2,982 | 1,486 | 3,873 | 1,551 | 3,918 | 1,564 |
| TOTAL | | 21,767 | | 21,355 | | 21,513 |

**Notes:**
December 31, 2023 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
**Values shown may be affected due to rounding.

**Schedule 4**
**High Case**

**Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|
| | 2023 Actual | | 2024 Forecast | | 2025 Forecast | |
| Month | Peak Demand * MW | NEL ** GWH | Peak Demand * MW | NEL ** GWH | Peak Demand * MW | NEL ** GWH |
| January | 3,347 | 1,539 | 4,532 | 1,587 | 4,602 | 1,604 |
| February | 3,273 | 1,391 | 3,533 | 1,425 | 3,583 | 1,436 |
| March | 3,585 | 1,652 | 3,575 | 1,566 | 3,629 | 1,579 |
| April | 3,678 | 1,737 | 3,696 | 1,637 | 3,735 | 1,651 |
| May | 3,912 | 1,914 | 4,049 | 1,911 | 4,090 | 1,928 |
| June | 4,318 | 2,073 | 4,348 | 2,064 | 4,399 | 2,087 |
| July | 4,312 | 2,281 | 4,342 | 2,158 | 4,398 | 2,183 |
| August | 4,669 | 2,357 | 4,400 | 2,188 | 4,454 | 2,214 |
| September | 4,194 | 2,076 | 4,246 | 1,996 | 4,307 | 2,020 |
| October | 3,801 | 1,769 | 3,858 | 1,844 | 3,901 | 1,865 |
| November | 3,440 | 1,491 | 3,407 | 1,491 | 3,460 | 1,507 |
| December | 2,982 | 1,486 | 3,886 | 1,556 | 3,946 | 1,573 |
| TOTAL | | 21,767 | | 21,422 | | 21,647 |

**Notes:**
December 31, 2023 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
**Values shown may be affected due to rounding.

**Schedule 4**
**Low Case**

**Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|
| | 2023 Actual | | 2024 Forecast | | 2025 Forecast | |
| Month | Peak Demand * MW | NEL ** GWH | Peak Demand * MW | NEL ** GWH | Peak Demand * MW | NEL ** GWH |
| January | 3,347 | 1,539 | 4,495 | 1,578 | 4,530 | 1,584 |
| February | 3,273 | 1,391 | 3,506 | 1,416 | 3,530 | 1,419 |
| March | 3,585 | 1,652 | 3,548 | 1,557 | 3,576 | 1,561 |
| April | 3,678 | 1,737 | 3,669 | 1,628 | 3,680 | 1,632 |
| May | 3,912 | 1,914 | 4,019 | 1,899 | 4,029 | 1,905 |
| June | 4,318 | 2,073 | 4,315 | 2,050 | 4,333 | 2,060 |
| July | 4,312 | 2,281 | 4,309 | 2,143 | 4,333 | 2,154 |
| August | 4,669 | 2,357 | 4,368 | 2,174 | 4,388 | 2,185 |
| September | 4,194 | 2,076 | 4,215 | 1,982 | 4,244 | 1,994 |
| October | 3,801 | 1,769 | 3,831 | 1,832 | 3,846 | 1,841 |
| November | 3,440 | 1,491 | 3,385 | 1,482 | 3,413 | 1,490 |
| December | 2,982 | 1,486 | 3,860 | 1,547 | 3,891 | 1,555 |
| TOTAL | | 21,767 | | 21,289 | | 21,380 |

**Notes:**
December 31, 2023 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
**Values shown may be affected due to rounding.

## Schedule 5

### History and Forecast of Fuel Requirements
### Base Case Forecast Basis

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fuel Requirements | Unit | Actual 2022 | Actual 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
| (1) | Nuclear | Trillion BTU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (2) | Coal | 1000 Ton | 652 | 367 | 177 | 102 | 110 | 101 | 103 | 110 | 109 | 85 | 74 | 72 |
| (3) | Residual | 1000 BBL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (4) | ST | 1000 BBL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (5) | CC | 1000 BBL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (6) | GT | 1000 BBL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (7) | D | 1000 BBL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (8) | Distillate | 1000 BBL | 19 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (9) | ST | 1000 BBL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (10) | CC | 1000 BBL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (11) | GT | 1000 BBL | 19 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (12) | D | 1000 BBL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (13) | Natural Gas | 1000 MCF | 124,914 | 126,239 | 126,127 | 123,369 | 121,463 | 118,851 | 118,161 | 116,001 | 115,651 | 116,221 | 116,636 | 115,210 |
| (14) | ST | 1000 MCF | 6,892 | 5,295 | 3,280 | 1,675 | 2,658 | 2,232 | 4,228 | 1,910 | 2,767 | 5,963 | 6,261 | 6,259 |
| (15) | CC | 1000 MCF | 105,985 | 120,717 | 122,286 | 120,513 | 117,050 | 115,017 | 112,094 | 112,425 | 109,494 | 107,023 | 107,582 | 106,070 |
| (16) | GT | 1000 MCF | 12,036 | 227 | 561 | 1,181 | 1,755 | 1,602 | 1,839 | 1,666 | 3,390 | 3,235 | 2,793 | 2,881 |
| (17) | Other (Specify) | | | | | | | | | | | | | |
| (18) | PC | 1000 Ton | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Notes:**
Values shown may be affected due to rounding.
Actual values exclude ignition.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.

## Schedule 6.1

### History and Forecast of Net Energy for Load by Fuel Source
### Base Case Forecast Basis

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Energy Sources | Unit | Actual 2022 | Actual 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
| (1) | Annual Firm Interchange | GWh | 23 | 21 | 58 | 208 | 150 | 150 | 151 | 150 | 150 | 150 | 151 | 150 |
| (2) | Nuclear | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (3) | Coal | GWh | 1,337 | 769 | 349 | 197 | 217 | 200 | 200 | 212 | 209 | 169 | 144 | 139 |
| (4) | Residual | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (5) | ST | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (6) | CC | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (7) | GT | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (8) | D | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (9) | Distillate | GWh | 6 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (10) | ST | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (11) | CC | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (12) | GT | GWh | 6 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (13) | D | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (14) | Natural Gas | GWh | 17,066 | 17,814 | 18,406 | 18,293 | 17,873 | 17,620 | 17,472 | 17,212 | 17,034 | 16,924 | 16,819 | 16,721 |
| (15) | ST | GWh | 831 | 473 | 276 | 141 | 225 | 188 | 358 | 160 | 233 | 507 | 532 | 533 |
| (16) | CC | GWh | 14,907 | 17,323 | 18,081 | 18,036 | 17,479 | 17,279 | 16,935 | 16,889 | 16,480 | 16,111 | 16,021 | 15,913 |
| (17) | GT | GWh | 1,327 | 18 | 49 | 116 | 169 | 153 | 179 | 163 | 321 | 306 | 266 | 275 |
| (18) | Renewable | GWh | 1,492 | 1,748 | 2,471 | 2,768 | 3,423 | 3,891 | 4,251 | 4,710 | 5,113 | 5,490 | 5,853 | 6,191 |
| (19) | Solar | GWh | 1,492 | 1,748 | 2,471 | 2,768 | 3,423 | 3,891 | 4,251 | 4,710 | 5,113 | 5,490 | 5,853 | 6,191 |
| (20) | Other (Specify) | | | | | | | | | | | | | |
| (21) | PC | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (22) | Net Interchange | GWh | 1,600 | 1,315 | (14) | (33) | (35) | (39) | (40) | (38) | (39) | (40) | (40) | (40) |
| (23) | Purchased Energy from Non-Utility Generators | GWh | 49 | 97 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| (24) | Other | GWh | 0 | 0 | 0 | (5) | (7) | (7) | (19) | (18) | (20) | (21) | (22) | (22) |
| (25) | Net Energy for Load | GWh | 21,572 | 21,767 | 21,355 | 21,513 | 21,706 | 21,900 | 22,100 | 22,313 | 22,532 | 22,757 | 22,990 | 23,224 |

**Notes:**

Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.
Generation quantities do not reflect periodic testing of distillate fuel oil capability.
Batteries are represented in row (24).

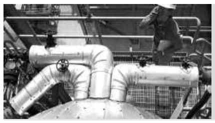
## Schedule 6.2

### History and Forecast of Net Energy for Load by Fuel Source
### Base Case Forecast Basis

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Energy Sources | Unit | Actual 2022 | Actual 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
| (1) | Annual Firm Interchange | % | 0.1 | 0.1 | 0.3 | 1.0 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.6 |
| (2) | Nuclear | % | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (3) | Coal | % | 6.2 | 3.5 | 1.6 | 0.9 | 1.0 | 0.9 | 0.9 | 1.0 | 0.9 | 0.7 | 0.6 | 0.6 |
| (4) | Residual | % | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (5) | ST | % | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (6) | CC | % | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (7) | GT | % | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (8) | D | % | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (9) | Distillate | % | 0.0 | 0.01 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (10) | ST | % | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (11) | CC | % | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (12) | GT | % | 0.0 | 0.01 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (13) | D | % | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (14) | Natural Gas | % | 79.1 | 81.8 | 86.2 | 85.0 | 82.3 | 80.5 | 79.1 | 77.1 | 75.6 | 74.4 | 73.2 | 72.0 |
| (15) | ST | % | 3.9 | 2.2 | 1.3 | 0.7 | 1.0 | 0.9 | 1.6 | 0.7 | 1.0 | 2.2 | 2.3 | 2.3 |
| (16) | CC | % | 69.1 | 79.6 | 84.7 | 83.8 | 80.5 | 78.9 | 76.6 | 75.7 | 73.1 | 70.8 | 69.7 | 68.5 |
| (17) | GT | % | 6.2 | 0.1 | 0.2 | 0.5 | 0.8 | 0.7 | 0.8 | 0.7 | 1.4 | 1.3 | 1.2 | 1.2 |
| (18) | Renewable | % | 6.9 | 8.0 | 11.6 | 12.9 | 15.8 | 17.8 | 19.2 | 21.1 | 22.7 | 24.1 | 25.5 | 26.7 |
| (19) | Solar | % | 6.9 | 8.0 | 11.6 | 12.9 | 15.8 | 17.8 | 19.2 | 21.1 | 22.7 | 24.1 | 25.5 | 26.7 |
| (20) | Other (Specify) | | | | | | | | | | | | | |
| (21) | PC | % | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| (22) | Net Interchange | % | 7.4 | 6.0 | (0.1) | (0.2) | (0.2) | (0.2) | (0.3) | (0.3) | (0.3) | (0.2) | (0.2) | (0.2) |
| (23) | Purchased Energy from Non-Utility Generators | % | 0.2 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| (24) | Other | % | 0.0 | 0.0 | 0.0 | (0.0) | (0.0) | (0.0) | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) | (0.1) |
| (25) | Net Energy for Load | % | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

**Notes:**
Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.
Generation quantities do not reflect periodic testing of distillate fuel oil capability.
Batteries are represented in row (24).

# Chapter V



## FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility changes and additions shown in Schedule 8.1 integrate energy efficiency and conservation programs and generating resources to provide economical, reliable service to TEC's customers. Various energy resource plan alternatives, comprised of a mixture of generating technologies, purchased power, and cost-effective energy efficiency and conservation programs, are developed to determine this plan. These alternatives are combined with existing resources and analyzed to determine the resource options which best meets TEC's future system demand and energy requirements. A detailed discussion of TEC's integrated resource planning process is included in Chapter III.

The results of the IRP process provide TEC with a cost-effective plan that maintains system reliability and environmental requirements while considering technology, availability, dispatchability, resiliency, and lead times for construction. To cost-effectively meet the expected system demand and energy requirements over the next ten years, solar PV, base load, intermediate, and distributed energy resources are needed. TEC will add incremental utility-scale solar PV capacity and is researching the viability of additional renewable technologies. The completion of the Big Bend Power Station modernization through the repowering of Unit 1 to a 2x1 combined cycle unit, the retirement of Unit 2 and Unit 3, and the advanced hardware upgrades on the CTs at Bayside provide low-cost, reliable, and grid-friendly options for customers. Additionally, distributed energy resources such as batteries and reciprocating engines provide reliability and resiliency to our system. The operating and cost parameters are shown in Schedule 9 for proposed generating facilities.

TEC will continue to compare purchased power options as an alternative and/or enhancement to planned unit additions, conservation, and load management. At a minimum, the purchased power must have firm transmission service and firm fuel transportation to support firm reserve margin criteria for reliability. Assumptions and information that impact the plan are discussed in the following sections and in Chapter III.

### COGENERATION

In 2024, TEC plans for 196 MW of cogeneration capacity operating in its service area.

| **Table IV-I**<br>**2024 Cogeneration Capacity Forecast** | **Capacity**<br>**(MW)** |
|---|---|
| Self-service [1] | 137 |
| Firm to Tampa Electric | 0 |
| As-available to Tampa Electric | 6 |
| Export to other systems | 53 |
| Total | 196 |

[1] Capacity and energy that cogenerators produce to serve their own internal load requirements.

## FIRM INTERCHANGE SALES AND PURCHASES

TEC has one (1) long-term firm purchase power agreement. That agreement is with Pasco County (Pasco) for TEC to purchase 18 MW from Pasco's waste-to-energy (WTE) facility begins in 2025. The term is 10 years, beginning January 2025 and continuing through December 2034. The company also has three (3) short-term agreements that provide firm capacity during the winter of 2024. The short-term purchases are (i) 75 MW from the Florida Municipal Power Agency (FMPA), (ii) 75 MW from Orlando Utilities Commission and (iii) 250 MW from Duke Energy Florida (DEF). These winter purchases provide firm capacity for the period January through February 2024.

## FUEL REQUIREMENTS

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2. TEC currently uses a generation portfolio consisting mainly of natural gas and solar for its energy requirements. TEC has long-term firm transportation contracts with the Florida Gas Transmission Company and Gulfstream Natural Gas System LLC for delivery of natural gas to Big Bend, Bayside, and Polk. As shown in Schedule 6.2, TEC forecasts serving net energy for load in 2024 with 86.2% natural gas, 11.6% solar, 1.6% coal, and less than one (1) percent of other resources, such as non-firm purchases from the market and non-utility generators. Some of the company's generating units have dual-fuel (i.e., natural gas or oil) capability, which enhances system reliability, increases resiliency, and provides fuel cost reduction opportunities.

## ENVIRONMENTAL CONSIDERATIONS

### Air Quality

TEC continually strives to reduce emissions from its generating facilities, and since 2000, has reduced sulfur dioxide, nitrogen oxide, particulate matter and mercury emissions by 96% or more. Carbon emissions have also been reduced by more than 50%, and TEC has committed to a 60% reduction of carbon emissions by 2025, 80% by 2040, and has a vision to achieve net zero carbon emissions by 2050.

The installation of 1,350 megawatts of solar power by the end of 2024 enabled the company to continue to reduce its dependence on carbon-based fuels. 13% of TEC's energy will be fueled by the sun, and TEC continues to be a leader in solar capacity in Florida.

TEC's emission reduction activities also include:

1. Completed the modernization of Big Bend Unit 1 combined cycle unit and retired Unit 2.
2. The retirement of Big Bend Unit 3 in April of 2023.
3. The Polk Power Station combined-cycle project improved system reliability and efficiency, and reduced emissions system-wide.
4. The upgrade of gas path components on Bayside Power Station's Unit 1 and Unit 2 combustion turbines will increase output, efficiency and reliability while reducing fuel consumption.
5. Energy storage capacity that will capture low cost generation and discharge when it's needed most.

**Water Conservation**

TEC's Big Bend and Polk Power Station use reclaimed water from local municipalities to minimize the use of potable water and groundwater for plant processes. Most of the properties purchased by TEC for solar generation are former agricultural lands with existing water use permits. When land is sold to new owners, Southwest Florida Water Management District (SWFWMD) rules require that these water permits are transferred as well. Since solar generation requires no water, TEC conserves this groundwater, which otherwise would have pumped and used for agricultural needs. To date, TEC's acquisition of land for the development of solar power has saved more than 6.1 billion gallons of water, which significantly helps an area of the state that has critical concerns over water use.

**Water Quality**

The final 316(b) rule became effective in October 2014 and seeks to reduce impingement and entrainment at cooling water intakes. This rule affects both Big Bend and Bayside Power Stations, since both withdraw cooling water from waters of the U.S. The full impact of the new regulations will be determined by the results of the study elements performed to comply with the rule as well as the actual requirements of the state regulatory agencies. Bayside Power Station replaced the circulator pumps on Unit 1 in 2023, which included fish friendly screens and a fish return system, with Unit 2 to be included in 2024. Tampa Electric is negotiating an alternative schedule for Big Bend (as allowed by the rule) but completed a portion of the compliance requirements with the Big Bend modernization project with the installation of fish-friendly modified traveling screens and a fish return on modernized Unit 1. The remainder of the compliance requirements for Big Bend Station are to be determined and completed at a later date.

FDEP's numeric nutrient regulations are effective and may potentially impact the discharge from the Polk Power Station cooling water reservoir in the future. The established nitrogen allocations by Tampa Bay Nitrogen Management Consortium for both Bayside and Big Bend Power Stations are expected to meet the numeric nutrient criteria in Tampa Bay.

The final Effluent Limitations Guidelines (ELG) were published on November 3, 2015. The ELGs establish limits for wastewater discharges from flue gas desulfurization (FGD) processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals, gasification processes, and flue gas mercury controls. Big Bend completed construction of a deep injection well system in December 2023 for disposal of FGD wastewater, bottom ash transport water, stormwater and other process wastewaters, which means ELG are no longer applicable

**Solid Waste**

The Coal Combustion Residuals Rule (CCR) became effective on October 19, 2015. The former Big Bend Unit #4 Economizer Ash & Pyrites Pond System (EAPPS), converted Units 1-3 West Slag Disposal Pond (WSDP) and North Gypsum Stackout Area (NGSA) were covered by this rule. Three ECRC projects were proposed and approved by the Commission for these operating units to comply with the CCR Rule requirements, as follows. The WSDP was remediated and lined in 2020 to allow for continued storm water storage and the EAPPS Closure Project was completed in 2021 by removing and disposing of the CCRs offsite and restoring the site. Phase III of the NGSA Drainage Enhancements Project were initiated in 2023 and will be completed in 2024. The South Gypsum Storage Area Closure Project was completed as a component of the Big Bend Modernization in January 2020. There are no other CCR units at the Big Bend, Polk or Bayside Power Stations currently regulated under the rule.

## Schedule 7.1

### Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Total Installed Firm Capacity MW | Firm Capacity Import MW | Firm Capacity Export MW | QF MW | Total Capacity Available MW | System Firm Summer Peak Demand MW | Reserve Margin Before Maintenance MW | Reserve Margin Before Maintenance % of Peak | Scheduled Maintenance MW | Reserve Margin After Maintenance MW | Reserve Margin After Maintenance % of Peak |
| **2024** | 5,314 | 0 | 0 | 0 | 5,314 | 4,143 | 1,171 | 28% | 0 | 1,171 | 28% |
| **2025** | 5,439 | 18 | 0 | 0 | 5,457 | 4,182 | 1,275 | 30% | 0 | 1,275 | 30% |
| **2026** | 5,486 | 18 | 0 | 0 | 5,504 | 4,222 | 1,282 | 30% | 0 | 1,282 | 30% |
| **2027** | 5,488 | 18 | 0 | 0 | 5,506 | 4,261 | 1,245 | 29% | 0 | 1,245 | 29% |
| **2028** | 5,559 | 18 | 0 | 0 | 5,577 | 4,302 | 1,274 | 30% | 0 | 1,274 | 30% |
| **2029** | 5,560 | 18 | 0 | 0 | 5,578 | 4,343 | 1,234 | 28% | 0 | 1,234 | 28% |
| **2030** | 5,781 | 18 | 0 | 0 | 5,799 | 4,385 | 1,414 | 32% | 0 | 1,414 | 32% |
| **2031** | 5,780 | 18 | 0 | 0 | 5,798 | 4,427 | 1,371 | 31% | 0 | 1,371 | 31% |
| **2032** | 5,780 | 18 | 0 | 0 | 5,798 | 4,469 | 1,329 | 30% | 0 | 1,329 | 30% |
| **2033** | 5,779 | 18 | 0 | 0 | 5,797 | 4,511 | 1,287 | 29% | 0 | 1,287 | 29% |

Values shown may be affected due to rounding.
92° F at time of Peak.

## Schedule 7.2

### Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Installed Firm Capacity | Firm Capacity Import | Firm Capacity Export | QF | Total Capacity Available | System Firm Winter Peak Demand | Reserve Margin Before Maintenance | | Scheduled Maintenance | Reserve Margin After Maintenance | |
| Year | MW | MW | MW | MW | MW | MW | MW | % of Peak | MW | MW | % of Peak |
| 2023-24 | 5,194 | 400 | 0 | 0 | 5,594 | 4,292 | 1,302 | 30% | 0 | 1,302 | 30% |
| 2024-25 | 5,323 | 18 | 0 | 0 | 5,341 | 4,345 | 995 | 23% | 0 | 995 | 23% |
| 2025-26 | 5,403 | 18 | 0 | 0 | 5,421 | 4,404 | 1,018 | 23% | 0 | 1,018 | 23% |
| 2026-27 | 5,441 | 18 | 0 | 0 | 5,459 | 4,461 | 998 | 22% | 0 | 998 | 22% |
| 2027-28 | 5,511 | 18 | 0 | 0 | 5,529 | 4,517 | 1,012 | 22% | 0 | 1,012 | 22% |
| 2028-29 | 5,511 | 18 | 0 | 0 | 5,529 | 4,572 | 957 | 21% | 0 | 957 | 21% |
| 2029-30 | 5,758 | 18 | 0 | 0 | 5,776 | 4,626 | 1,149 | 25% | 0 | 1,149 | 25% |
| 2030-31 | 5,758 | 18 | 0 | 0 | 5,776 | 4,679 | 1,097 | 23% | 0 | 1,097 | 23% |
| 2031-32 | 5,758 | 18 | 0 | 0 | 5,776 | 4,729 | 1,046 | 22% | 0 | 1,046 | 22% |
| 2032-33 | 5,758 | 18 | 0 | 0 | 5,776 | 4,780 | 996 | 21% | 0 | 996 | 21% |

Values shown may be affected due to rounding.
31° F at time of Peak.

## Schedule 7.2.1*

### Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Installed Firm Capacity | Firm Capacity Import | Firm Capacity Export | QF | Total Capacity Available | System Firm Winter Peak Demand | Reserve Margin Before Maintenance | | Scheduled Maintenance | Reserve Margin After Maintenance | |
| Year | MW | MW | MW | MW | MW | MW | MW | % of Peak | MW | MW | % of Peak |
| 2023-24 | 5,194 | 400 | 0 | 0 | 5,594 | 4,498 | 1,096 | 24% | 0 | 1,096 | 24% |
| 2024-25 | 5,323 | 18 | 0 | 0 | 5,341 | 4,554 | 786 | 17% | 0 | 786 | 17% |
| 2025-26 | 5,403 | 18 | 0 | 0 | 5,421 | 4,617 | 805 | 17% | 0 | 805 | 17% |
| 2026-27 | 5,441 | 18 | 0 | 0 | 5,459 | 4,677 | 782 | 17% | 0 | 782 | 17% |
| 2027-28 | 5,511 | 18 | 0 | 0 | 5,529 | 4,737 | 792 | 17% | 0 | 792 | 17% |
| 2028-29 | 5,511 | 18 | 0 | 0 | 5,529 | 4,795 | 734 | 15% | 0 | 734 | 15% |
| 2029-30 | 5,758 | 18 | 0 | 0 | 5,776 | 4,852 | 923 | 19% | 0 | 923 | 19% |
| 2030-31 | 5,758 | 18 | 0 | 0 | 5,776 | 4,908 | 868 | 18% | 0 | 868 | 18% |
| 2031-32 | 5,758 | 18 | 0 | 0 | 5,776 | 4,961 | 814 | 16% | 0 | 814 | 16% |
| 2032-33 | 5,758 | 18 | 0 | 0 | 5,776 | 5,015 | 761 | 15% | 0 | 761 | 15% |

Values shown may be affected due to rounding.
* For information purposes only
** 29° F at time of Peak.

## Schedule 8.1
## Planned and Prospective Generating Facility Additions and Changes

| (1) Plant Name | (2) Unit No. | (3) Location | (4) Unit Type | (5) Fuel Primary | (6) Fuel Alternate | (7) Fuel Trans. Primary | (8) Fuel Trans. Alternate | (9) Const. Start Mo/Yr | (10) Commercial In-Service Mo/Yr | (11) Expected Retirement Mo/Yr | (12) Gen. Max. Nameplate kW | (13) Firm Net Capability Summer MW | (14) Firm Net Capability Winter MW | (15) Status |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2024** | | | | | | | | | | | | | | |
| Bayside 2 Enhancement | 2 | Bayside | CC | NG | NA | PL | NA | - | 5/24 | * | 74,000 | 72.0 | 74.0 | U |
| Dover Energy Storage Capacity | 1 | Hillsborough | BA | N/A | N/A | N/A | N/A | - | 9/24 | * | 15,000 | 15.0 | 15.0 | U |
| English Creek Solar [1] | 1 | Hillsborough | PV | SOLAR | NA | NA | NA | - | 12/24 | * | 23,000 | 1.2 | - | U |
| Bullfrog Creek Solar [1] | 1 | Hillsborough | PV | SOLAR | NA | NA | NA | - | 12/24 | * | 74,500 | 3.7 | - | U |
| Solar Degradation [2] | N/A | | | | | | | | | | | (1.7) | - | |
| | | | | | | | | | | | **2024 Changes and Additions:** | 90.2 | 89.0 | |
| **2025** | | | | | | | | | | | | | | |
| Lake Mabel Energy Storage Capacity | 1 | Polk | BA | N/A | NA | N/A | N/A | - | 1/25 | * | 40,000 | 40.0 | 40.0 | U |
| Wimauma Energy Storage Capacity | 1 | Hillsborough | BA | N/A | N/A | N/A | N/A | - | 2/25 | * | 40,000 | 40.0 | 40.0 | U |
| South Tampa Energy Storage Capacity | 1 | Hillsborough | BA | N/A | N/A | N/A | N/A | - | 4/25 | * | 20,000 | 20.0 | 20.0 | U |
| Polk Unit 1 Simple Cycle Conversion | 1 | Polk | CT | NG | N/A | PL | N/A | - | 5/25 | 9/36 | 204,000 | (30.0) | (17.0) | P |
| South Tampa Resilience Project [4] | 1 | Hillsborough | IC | NG | NA | PL | N/A | - | 7/25 | * | 75,200 | 75.2 | 75.2 | U |
| Duette Solar [1] | 1 | Manatee | PV | SOLAR | NA | NA | NA | - | 12/25 | * | 74,500 | 3.7 | - | P |
| Cottonmouth Solar [1] | 1 | Hillsborough | PV | SOLAR | NA | NA | NA | - | 12/25 | * | 74,500 | 3.7 | - | P |
| Solar Degradation [2] | N/A | | | | | | | | | | | (2.0) | - | |
| | | | | | | | | | | | **2025 Changes and Additions:** | 150.7 | 158.2 | |
| **2026** | | | | | | | | | | | | | | |
| Big Four Solar [1] | 1 | Hillsborough | PV | SOLAR | NA | NA | NA | - | 5/26 | * | 74,500 | 3.7 | - | P |
| Farmland Solar [1] | 1 | Hillsborough | PV | SOLAR | NA | NA | NA | - | 12/26 | * | 54,400 | 2.7 | - | P |
| Brewster Solar [1] | 1 | Polk | PV | SOLAR | NA | NA | NA | - | 12/26 | * | 38,800 | 0.6 | - | P |
| Wimauma 3 Solar [1] | 1 | Hillsborough | PV | SOLAR | NA | NA | NA | - | 12/26 | * | 74,500 | 1.1 | - | P |
| Solar Degradation [2] | N/A | | | | | | | | | | | (2.0) | - | |
| | | | | | | | | | | | **2026 Changes and Additions:** | 6.2 | - | |

**Notes:**

* Undetermined
1 Solar MW values reflect capacity at time of peak. The firm capacity shows expected capacity values for the projected incremental solar additions.
2 Solar capacity degrades at approximately 0.4% every year.
Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.
3 Muliple Sites, each not to exceed 74.5MW
4 South Tampa Resiliency Project is transmission constrained to 37.6MW until Summer 2026.

## Schedule 8.1
## Planned and Prospective Generating Facility Additions and Changes

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Const. | Commercial | Expected | Gen. Max. | Firm Net Capability | | |
| Plant | Unit | | Unit | Fuel | | Fuel Trans. | | Start | In-Service | Retirement | Nameplate | Summer | Winter | |
| Name | No. | Location | Type | Primary | Alternate | Primary | Alternate | Mo/Yr | Mo/Yr | Mo/Yr | kW | MW | MW | Status |
| **2027** | | | | | | | | | | | | | | |
| Clear Springs I Solar [1] | 1 | Polk | PV | SOLAR | NA | NA | NA | - | 12/27 | * | 74,500 | 1.1 | - | P |
| Future Solar 1 [1] | 1 | Unknown | PV | SOLAR | NA | NA | NA | - | 12/27 | * | 74,500 | 1.1 | - | P |
| Solar Degradation [2] | N/A | | | | | | | | | | | (2.0) | - | |
| | | | | | | | | | | | **2027 Changes and Additions:** | 0.3 | - | |
| **2028** | | | | | | | | | | | | | | |
| Battery Storage 1 | 1 | Unknown | BA | N/A | N/A | N/A | N/A | - | 1/28 | * | 70,000 | 70.0 | 70.0 | P |
| Clear Springs II Solar [1] | 1 | Polk | PV | SOLAR | NA | NA | NA | - | 12/28 | * | 74,500 | 1.1 | - | P |
| Mattaniah Solar [1] | 1 | Hillsborough | PV | SOLAR | NA | NA | NA | - | 12/28 | * | 55,000 | 0.8 | - | P |
| Future Solar 2 [1] | 1 | Unknown | PV | SOLAR | NA | NA | NA | - | 12/28 | * | 74,500 | 1.1 | - | P |
| Solar Degradation [2] | N/A | | | | | | | | | | | (2.0) | - | |
| | | | | | | | | | | | **2028 Changes and Additions:** | 71.1 | 70.0 | |
| **2029** | | | | | | | | | | | | | | |
| Future Solar 3 [1,3] | 1 | Unknown | PV | SOLAR | NA | NA | NA | - | 12/29 | * | 149,000 | 2.2 | - | P |
| Solar Degradation [2] | N/A | | | | | | | | | | | (2.0) | - | |
| | | | | | | | | | | | **2029 Changes and Additions:** | 0.3 | - | |

**Notes:**

* Undetermined
[1] Solar MW values reflect capacity at time of peak. The firm capacity shows expected capacity values for the projected incremental solar additions.
[2] Solar capacity degrades at approximately 0.4% every year.
Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.
[3] Muliple Sites, each not to exceed 74.5MW
[4] South Tampa Resiliency Project is transmission constrained to 37.6MW until Summer 2026.

## Schedule 8.1
## Planned and Prospective Generating Facility Additions and Changes

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Fuel | | Fuel Trans. | | Const. | Commercial | Expected | Gen. Max. | Firm Net Capability | | |
| Plant Name | Unit No. | Location | Unit Type | Primary | Alternate | Primary | Alternate | Start Mo/Yr | In-Service Mo/Yr | Retirement Mo/Yr | Nameplate kW | Summer MW | Winter MW | Status |
| **2030** | | | | | | | | | | | | | | |
| Future CT 1 | 1 | Unknown | CT | NG | NA | PL | N/A | - | 1/30 | * | 255,000 | 222.0 | 247.0 | P |
| Future Solar 4 [1,3] | 1 | Unknown | PV | SOLAR | NA | NA | NA | - | 12/30 | * | 149,000 | 2.2 | - | P |
| Solar Degradation [2] | N/A | | | | | | | | | | | (2.0) | - | |
| | | | | | | | | | | | **2030 Changes and Additions:** | 222.3 | 247.0 | |
| **2031** | | | | | | | | | | | | | | |
| Future Solar 5 [1,3] | 1 | Unknown | PV | SOLAR | NA | NA | NA | - | 12/31 | * | 149,000 | 2.2 | - | P |
| Solar Degradation [2] | N/A | | | | | | | | | | | (2.0) | - | |
| | | | | | | | | | | | **2031 Changes and Additions:** | 0.3 | - | |
| **2032** | | | | | | | | | | | | | | |
| Future Solar 6 [1,3] | 1 | Unknown | PV | SOLAR | NA | NA | NA | - | 12/32 | * | 149,000 | 2.2 | - | P |
| Solar Degradation [2] | N/A | | | | | | | | | | | (2.0) | - | |
| | | | | | | | | | | | **2032 Changes and Additions:** | 0.3 | - | |
| **2033** | | | | | | | | | | | | | | |
| Future Solar 7 [1,3] | 1 | Unknown | PV | SOLAR | NA | NA | NA | - | 12/33 | * | 149,000 | 2.2 | - | P |
| Solar Degradation [2] | N/A | | | | | | | | | | | (2.0) | - | |
| | | | | | | | | | | | **2033 Changes and Additions:** | 0.3 | - | |

**Notes:**

* Undetermined
[1] Solar MW values reflect capacity at time of peak. The firm capacity shows expected capacity values for the projected incremental solar additions.
[2] Solar capacity degrades at approximately 0.4% every year.
Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.
[3] Muliple Sites, each not to exceed 74.5MW
[4] South Tampa Resiliency Project is transmission constrained to 37.6MW until Summer 2026.

**Schedule 9**
**(Page 1 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Bayside 2 Enhancement |
| (2) | Net Capability | |
| | A. Summer | 72 MW |
| | B. Winter | 74 MW |
| (3) | Technology Type | Combustion Turbine |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date | February 2024 |
| | B. Commercial In-Service Date | May 2024 |
| (5) | Fuel | |
| | A. Primary Fuel | Natural Gas |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | Dry-Low $NO_x$ |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | U |
| (10) | Certification Status | Undetermined |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | N/A |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 15 |
| | Total Installed Cost[1] (In-Service Year $/kW) | 407 |
| | Direct Construction Cost ($/kW) | 398 |
| | AFUDC[1] Amount ($/kW) | - |
| | Escalation ($/kW) | 8.77 |
| | Fixed O&M (In-Service Year $/kW – Yr) | - |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 1.21 |

[1] Total installed cost includes transmission interconnection

**Schedule 9**
**(Page 2 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Dover Energy Storage Capacity |
| (2) | Net Capability | |
| | A. Summer | 15.0 MW-ac |
| | B. Winter | 15.0 MW-ac |
| (3) | Technology Type | Battery |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | November 2023 |
| | B. Commercial In-Service Date | September 2024 |
| (5) | Fuel | |
| | A. Primary Fuel | N/A |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | 1 Acre |
| (9) | Construction Status | U |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | N/A |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 10 |
| | Total Installed Cost (In-Service Year $/kW) | 1,285 |
| | Direct Construction Cost[1] ($/kW) | 1,232 |
| | AFUDC Amount ($/kW) | 52.90 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 4.00 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.87 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 3 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | English Creek Solar |
| (2) | Net Capability | |
| | A. Summer | 23.0 MW-ac |
| | B. Winter | 23.0 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2024 |
| | B. Commercial In-Service Date | December 2024 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | +240 Acres |
| (9) | Construction Status | U |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 26% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,878 |
| | Direct Construction Cost[1] ($/kW) | 1,754 |
| | AFUDC Amount ($/kW) | 123.66 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 18.15 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.74 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 4 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Bullfrog Creek Solar |
| (2) | Net Capability | |
| | A. Summer | 74.5 MW-ac |
| | B. Winter | 74.5 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2024 |
| | B. Commercial In-Service Date | December 2024 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | +570 Acres |
| (9) | Construction Status | U |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 26% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,471 |
| | Direct Construction Cost[1,3] ($/kW) | 1,402 |
| | AFUDC Amount ($/kW) | 68.04 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 18.15 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.73 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land Lease costs not included

**Schedule 9**
**(Page 5 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Lake Mabel Energy Storage Capacity |
| (2) | Net Capability | |
| | A. Summer | 40 MW-ac |
| | B. Winter | 40 MW-ac |
| (3) | Technology Type | Battery |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2024 |
| | B. Commercial In-Service Date | January 2025 |
| (5) | Fuel | |
| | A. Primary Fuel | N/A |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | 2 Acres |
| (9) | Construction Status | U |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | N/A |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 10 |
| | Total Installed Cost (In-Service Year $/kW) | 1,281 |
| | Direct Construction Cost[1] ($/kW) | 1,215 |
| | AFUDC Amount ($/kW) | 65.57 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 4.19 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.94 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 6 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Wimauma Energy Storage Capacity |
| (2) | Net Capability | |
| | A. Summer | 40 MW-ac |
| | B. Winter | 40 MW-ac |
| (3) | Technology Type | Battery |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | February 2024 |
| | B. Commercial In-Service Date | February 2025 |
| (5) | Fuel | |
| | A. Primary Fuel | N/A |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | 2 Acres |
| (9) | Construction Status | U |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | N/A |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 10 |
| | Total Installed Cost (In-Service Year $/kW) | 1,108 |
| | Direct Construction Cost[1] ($/kW) | 1,067 |
| | AFUDC Amount ($/kW) | 40.64 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 4.19 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.94 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 7 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | South Tampa Energy Storage Capacity |
| (2) | Net Capability | |
| | A. Summer | 20 MW-ac |
| | B. Winter | 20 MW-ac |
| (3) | Technology Type | Battery |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | March 2024 |
| | B. Commercial In-Service Date | April 2025 |
| (5) | Fuel | |
| | A. Primary Fuel | N/A |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | 1 Acre |
| (9) | Construction Status | U |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | N/A |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 10 |
| | Total Installed Cost (In-Service Year $/kW) | 1,410 |
| | Direct Construction Cost[1] ($/kW) | 1,351 |
| | AFUDC Amount ($/kW) | 59.06 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 4.19 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.92 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 8 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Polk Unit 1 Simple Cycle Conversion |
| (2) | Net Capability | |
| | A. Summer | 190 MW |
| | B. Winter | 203 MW |
| (3) | Technology Type | Combustion Turbine |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | March 2025 |
| | B. Commercial In-Service Date | May 2025 |
| (5) | Fuel | |
| | A. Primary Fuel | Natural Gas |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | Dry-Low $NO_x$ |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Planned |
| (10) | Certification Status | Undetermined |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | 5% |
| | Forced Outage Factor (FOF) | 2% |
| | Equivalent Availability Factor (EAF) | 93% |
| | Resulting Capacity Factor | 5% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | 10,643 Btu/kWh |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 12 |
| | Total Installed Cost (In-Service Year $/kW) | 397 |
| | Direct Construction Cost[1] ($/kW) | 383 |
| | AFUDC Amount ($/kW) | 13.79 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | - |
| | Variable O&M (In-Service Year $/MWh) | 5.59 |
| | K-Factor | - |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 9 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | South Tampa Resilience Project |
| (2) | Net Capability | |
| | A. Summer | 75.2 MW (Consisting of 4 Units) |
| | B. Winter | 75.2 MW (Consisting of 4 Units) |
| (3) | Technology Type | Engine |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | December 2022 |
| | B. Commercial In-Service Date | July 2025 |
| (5) | Fuel | |
| | A. Primary Fuel | Natural Gas |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | Selective Catalytic Reduction (SCR) |
| (7) | Cooling Method | Closed Loop Cooling |
| (8) | Total Site Area | 2 Acres |
| (9) | Construction Status | U |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | 2% |
| | Forced Outage Factor (FOF) | 2% |
| | Equivalent Availability Factor (EAF) | 96% |
| | Resulting Capacity Factor | 8% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | 8,300 Btu/kWh |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 30 |
| | Total Installed Cost (In-Service Year $/kW) | 2,224 |
| | Direct Construction Cost[1] ($/kW) | 2,056 |
| | AFUDC Amount ($/kW) | 168.3 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 20.02 |
| | Variable O&M (In-Service Year $/MWh) | 2.41 |
| | K-Factor | 1.26 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 10 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Duette Solar |
| (2) | Net Capability | |
| | A. Summer | 74.5 MW-ac |
| | B. Winter | 74.5 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2025 |
| | B. Commercial In-Service Date | December 2025 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | +690 Acres |
| (9) | Construction Status | Planned |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 26% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,536 |
| | Direct Construction Cost[1,3] ($/kW) | 1,466 |
| | AFUDC Amount ($/kW) | 70.41 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 18.53 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.79 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

**Schedule 9**
**(Page 11 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Cottonmouth Solar |
| (2) | Net Capability | |
| | A. Summer | 74.5 MW-ac |
| | B. Winter | 74.5 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2025 |
| | B. Commercial In-Service Date | December 2025 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | +530 Acres |
| (9) | Construction Status | Planned |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 26% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,492 |
| | Direct Construction Cost[1,3] ($/kW) | 1,410 |
| | AFUDC Amount ($/kW) | 81.97 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 18.53 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.74 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land Lease costs not included

**Schedule 9**
**(Page 12 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Big Four Solar |
| (2) | Net Capability | |
| | A. Summer | 74.5 MW-ac |
| | B. Winter | 74.5 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | April 2025 |
| | B. Commercial In-Service Date | May 2026 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | +680 Acres |
| (9) | Construction Status | Planned |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 26% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,399 |
| | Direct Construction Cost[1,3] ($/kW) | 1,332 |
| | AFUDC Amount ($/kW) | 66.84 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 18.82 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.76 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land Lease costs not included

**Schedule 9**
**(Page 13 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Farmland Solar |
| (2) | Net Capability | |
| | A. Summer | 54.4 MW-ac |
| | B. Winter | 54.4 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2026 |
| | B. Commercial In-Service Date | December 2026 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | +330 Acres |
| (9) | Construction Status | Planned |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 26% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,755 |
| | Direct Construction Cost[1,3] ($/kW) | 1,641 |
| | AFUDC Amount ($/kW) | 113.07 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 18.92 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.82 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

**Schedule 9**
**(Page 14 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Brewster Solar |
| (2) | Net Capability | |
| | A. Summer | 38.8 MW-ac |
| | B. Winter | 38.8 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2026 |
| | B. Commercial In-Service Date | December 2026 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | +200 Acres |
| (9) | Construction Status | Planned |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 26% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,475 |
| | Direct Construction Cost[1,3] ($/kW) | 1,411 |
| | AFUDC Amount ($/kW) | 64.55 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 18.92 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.68 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

**Schedule 9**
**(Page 15 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Wimauma 3 Solar |
| (2) | Net Capability | |
| | A. Summer | 74.5 MW-ac |
| | B. Winter | 74.5 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2026 |
| | B. Commercial In-Service Date | December 2026 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | +680 Acres |
| (9) | Construction Status | Planned |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 28% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,695 |
| | Direct Construction Cost[1,3] ($/kW) | 1,637 |
| | AFUDC Amount ($/kW) | 57.42 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 18.92 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.75 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land Lease costs not included

**Schedule 9**
**(Page 16 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Clear Springs I Solar |
| (2) | Net Capability | |
| | A. Summer | 74.5 MW-ac |
| | B. Winter | 74.5 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2027 |
| | B. Commercial In-Service Date | December 2027 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | +450 Acres |
| (9) | Construction Status | Planned |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 28% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,677 |
| | Direct Construction Cost[1,3] ($/kW) | 1,592 |
| | AFUDC Amount ($/kW) | 84.32 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 19.32 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.74 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

**Schedule 9**
**(Page 17 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Future Solar I |
| (2) | Net Capability | |
| | A. Summer | 74.5 MW-ac |
| | B. Winter | 74.5 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2027 |
| | B. Commercial In-Service Date | December 2027 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Planned |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 28% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,854 |
| | Direct Construction Cost[1,3] ($/kW) | 1,754 |
| | AFUDC Amount ($/kW) | 100.15 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 19.32 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.79 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

**Schedule 9**
**(Page 18 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Battery Storage 1 |
| (2) | Net Capability | |
| | A. Summer | 70 MW |
| | B. Winter | 70 MW |
| (3) | Technology Type | Battery |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2027 |
| | B. Commercial In-Service Date | January 2028 |
| (5) | Fuel | |
| | A. Primary Fuel | N/A |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Proposed |
| (10) | Certification Status | Undetermined |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | N/A |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 10 |
| | Total Installed Cost (In-Service Year $/kW) | 2,284 |
| | Direct Construction Cost[1] ($/kW) | 2,025 |
| | AFUDC Amount ($/kW) | 158.95 |
| | Escalation ($/kW) | 99.99 |
| | Fixed O&M (In-Service Year $/kW – Yr) | 6.66 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.86 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 19 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Clear Springs II Solar |
| (2) | Net Capability | |
| | A. Summer | 74.5 MW-ac |
| | B. Winter | 74.5 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2028 |
| | B. Commercial In-Service Date | December 2028 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Planned |
| (10) | Certification Status | Undetermined |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 28% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,708 |
| | Direct Construction Cost[1,3] ($/kW) | 1,615 |
| | AFUDC Amount ($/kW) | 93.13 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 19.72 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.76 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

**Schedule 9**
**(Page 20 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Mattaniah Solar |
| (2) | Net Capability | |
| | A. Summer | 55.0 MW-ac |
| | B. Winter | 55.0 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2028 |
| | B. Commercial In-Service Date | December 2028 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Planned |
| (10) | Certification Status | Undetermined |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 26% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,614 |
| | Direct Construction Cost[1,3] ($/kW) | 1,514 |
| | AFUDC Amount ($/kW) | 100.01 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 19.72 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.88 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

**Schedule 9**
**(Page 21 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Future Solar 2 |
| (2) | Net Capability | |
| | A. Summer | 74.5 MW-ac |
| | B. Winter | 74.5 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2028 |
| | B. Commercial In-Service Date | December 2028 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Planned |
| (10) | Certification Status | Undetermined |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | 28% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | 1,690 |
| | Direct Construction Cost[1,3] ($/kW) | 1,633 |
| | AFUDC Amount ($/kW) | 57.42 |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | 19.72 |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | 0.78 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land price included

**Schedule 9**
**(Page 22 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Future Solar 3<br>(Multiple Sites, each not to exceed 74.5MW) |
| (2) | Net Capability | |
| | A. Summer | 149.0 MW-ac |
| | B. Winter | 149.0 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2029 |
| | B. Commercial In-Service Date | December 2029 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Proposed |
| (10) | Certification Status | Undetermined |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | TBD |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | TBD |
| | Direct Construction Cost[1] ($/kW) | TBD |
| | AFUDC Amount ($/kW) | TBD |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | TBD |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | TBD |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 23 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Future CT |
| (2) | Net Capability | |
| | A. Summer | 222 MW |
| | B. Winter | 247 MW |
| (3) | Technology Type | Combustion Turbine |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | TBD |
| | B. Commercial In-Service Date | January 2030 |
| (5) | Fuel | |
| | A. Primary Fuel | Natural Gas |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | Dry-Low $NO_x$ |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Proposed |
| (10) | Certification Status | N/A |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | 4% |
| | Forced Outage Factor (FOF) | 2% |
| | Equivalent Availability Factor (EAF) | 94% |
| | Resulting Capacity Factor | 8% |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | 10,867 Btu/kWh |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 30 |
| | Total Installed Cost (In-Service Year $/kW) | 954 |
| | Direct Construction Cost[1] ($/kW) | 823 |
| | AFUDC Amount ($/kW) | 65.72 |
| | Escalation ($/kW) | 64.70 |
| | Fixed O&M (In-Service Year $/kW – Yr) | 12.38 |
| | Variable O&M (In-Service Year $/MWh) | 1.33 |
| | K-Factor | 1.34 |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 24 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Future Solar 4<br>(Multiple Sites, each not to exceed 74.5MW) |
| (2) | Net Capability | |
| | A. Summer | 149.0 MW-ac |
| | B. Winter | 149.0 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2030 |
| | B. Commercial In-Service Date | December 2030 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Proposed |
| (10) | Certification Status | Undetermined |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | TBD |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | TBD |
| | Direct Construction Cost[1] ($/kW) | TBD |
| | AFUDC Amount ($/kW) | TBD |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | TBD |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | TBD |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 25 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Future Solar 5<br>(Multiple Sites, each not to exceed 74.5MW) |
| (2) | Net Capability | |
| | A. Summer | 149.0 MW-ac |
| | B. Winter | 149.0 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2031 |
| | B. Commercial In-Service Date | December 2031 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Proposed |
| (10) | Certification Status | Undetermined |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | TBD |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | TBD |
| | Direct Construction Cost[1] ($/kW) | TBD |
| | AFUDC Amount ($/kW) | TBD |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | TBD |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | TBD |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 26 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Future Solar 6<br>(Multiple Sites, each not to exceed 74.5MW) |
| (2) | Net Capability | |
| | A. Summer | 149.0 MW-ac |
| | B. Winter | 149.0 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2032 |
| | B. Commercial In-Service Date | December 2032 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Proposed |
| (10) | Certification Status | Undetermined |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | TBD |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | TBD |
| | Direct Construction Cost[1] ($/kW) | TBD |
| | AFUDC Amount ($/kW) | TBD |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | TBD |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | TBD |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

**Schedule 9**
**(Page 27 of 27)**
**Status Report and Specifications of Proposed Generating Facilities**

| | | |
|---|---|---|
| (1) | Plant Name and Unit Number | Future Solar 7<br>(Multiple Sites, each not to exceed 74.5MW) |
| (2) | Net Capability | |
| | A. Summer | 149.0 MW-ac |
| | B. Winter | 149.0 MW-ac |
| (3) | Technology Type | Single Axis Tracking PV Solar |
| (4) | Anticipated Construction Timing | |
| | A. Field Construction Start Date[2] | January 2033 |
| | B. Commercial In-Service Date | December 2033 |
| (5) | Fuel | |
| | A. Primary Fuel | Solar |
| | B. Alternate Fuel | N/A |
| (6) | Air Pollution Control Strategy | N/A |
| (7) | Cooling Method | N/A |
| (8) | Total Site Area | Undetermined |
| (9) | Construction Status | Proposed |
| (10) | Certification Status | Undetermined |
| (11) | Status with Federal Agencies | N/A |
| (12) | Projected Unit Performance Data | |
| | Planned Outage Factor (POF) | N/A |
| | Forced Outage Factor (FOF) | N/A |
| | Equivalent Availability Factor (EAF) | N/A |
| | Resulting Capacity Factor | TBD |
| | Average Net Operating Heat Rate (In-Service Year ANOHR) | N/A |
| (13) | Projected Unit Financial Data | |
| | Book Life (Years) | 35 |
| | Total Installed Cost (In-Service Year $/kW) | TBD |
| | Direct Construction Cost[1] ($/kW) | TBD |
| | AFUDC Amount ($/kW) | TBD |
| | Escalation ($/kW) | - |
| | Fixed O&M (In-Service Year $/kW – Yr) | TBD |
| | Variable O&M (In-Service Year $/MWh) | - |
| | K-Factor | TBD |

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

## Schedule 10

### Status Report and Specifications of Proposed Directly Associated Transmission Lines
### As of December 31, 2023

| Units | Point of Origin and Termination | Number of Circuits | Right-of-Way (ROW) | Circuit Length ** | Voltage | Anticipated In-Service Date | Anticipated Capital Investment *** | Substations | Participation with Other Utilities |
|---|---|---|---|---|---|---|---|---|---|
| **Bayside CC 2** | Bayside CC 2 does not require any new transmission lines **** | - | - | - | 230 kV | May 2024 | - | Gannon | None |
| **Polk CT 1*** *** | Polk CT 1 does not require any new transmission lines | - | - | - | 230 kV | May 2025 | - | Polk | None |
| **Farmland Solar*** *** | Farmland Solar - Farmland | 1 | Not Determined | 1 | 230 kV | December 2026 | Included in total installed cost on Schedule 9 | Farmland Solar Station; Farmland Substation | None |

**Note:**
*     Specific information related to "Unsited" units unknown at this time.
**    Approximate mileage listed is based on construction activity, not overall circuit length.
***   Cumulative capital investment at the in-service date. Cost included in total installed cost on Schedule 9.
****  Interconnection request studies pertaining to a Large Generating Facility have been completed and the unit does not require any new transmission lines.
***** Interconnection Requests pertaining to a Large Generating Facility have been submitted for these units. Pending completion of the Interconnection Request studies, the information provided on Schedule 10 may change.

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# Chapter VI

## ENVIRONMENTAL AND LAND USE INFORMATION

The H.L. Culbreath Bayside Power Station site is located in Hillsborough County on Port Sutton Road (See Figure VI-I), Polk Power Station site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-II) and Big Bend Power Station is located in Hillsborough County on Big Bend Road (See Figure VI-III). The solar sites identified in Schedule 1 are spread across Hillsborough, Polk, and Pasco counties (See Figure VI-IV). Additional land use requirements and/or alternative site locations are currently under consideration to accommodate the addition of future solar PV generation facilities and distributed energy resources.

**Figure VI-I: Site Location of H.L. Culbreath Bayside Power Station**

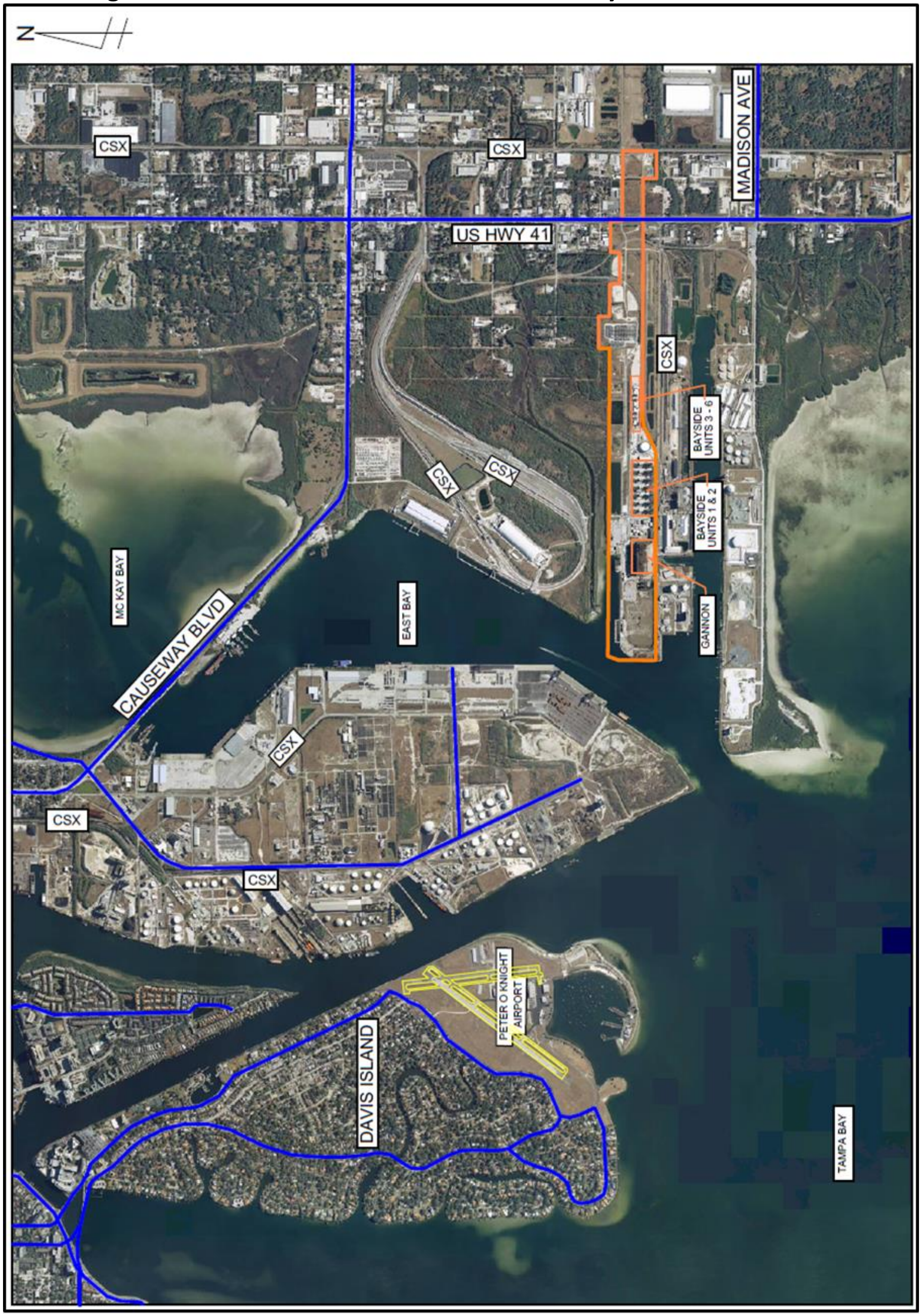


**Figure VI-II: Site Location of Polk Power Station**

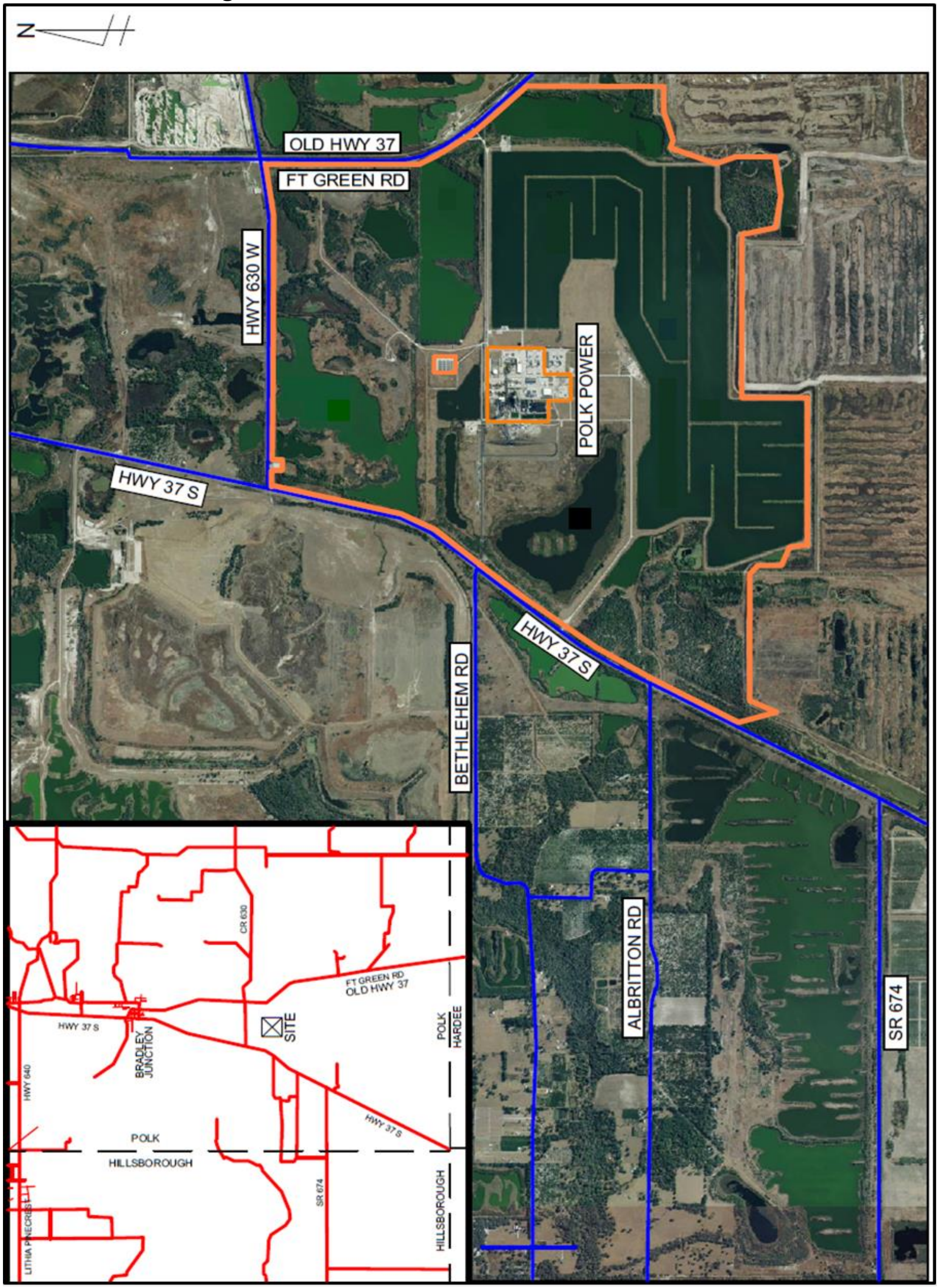
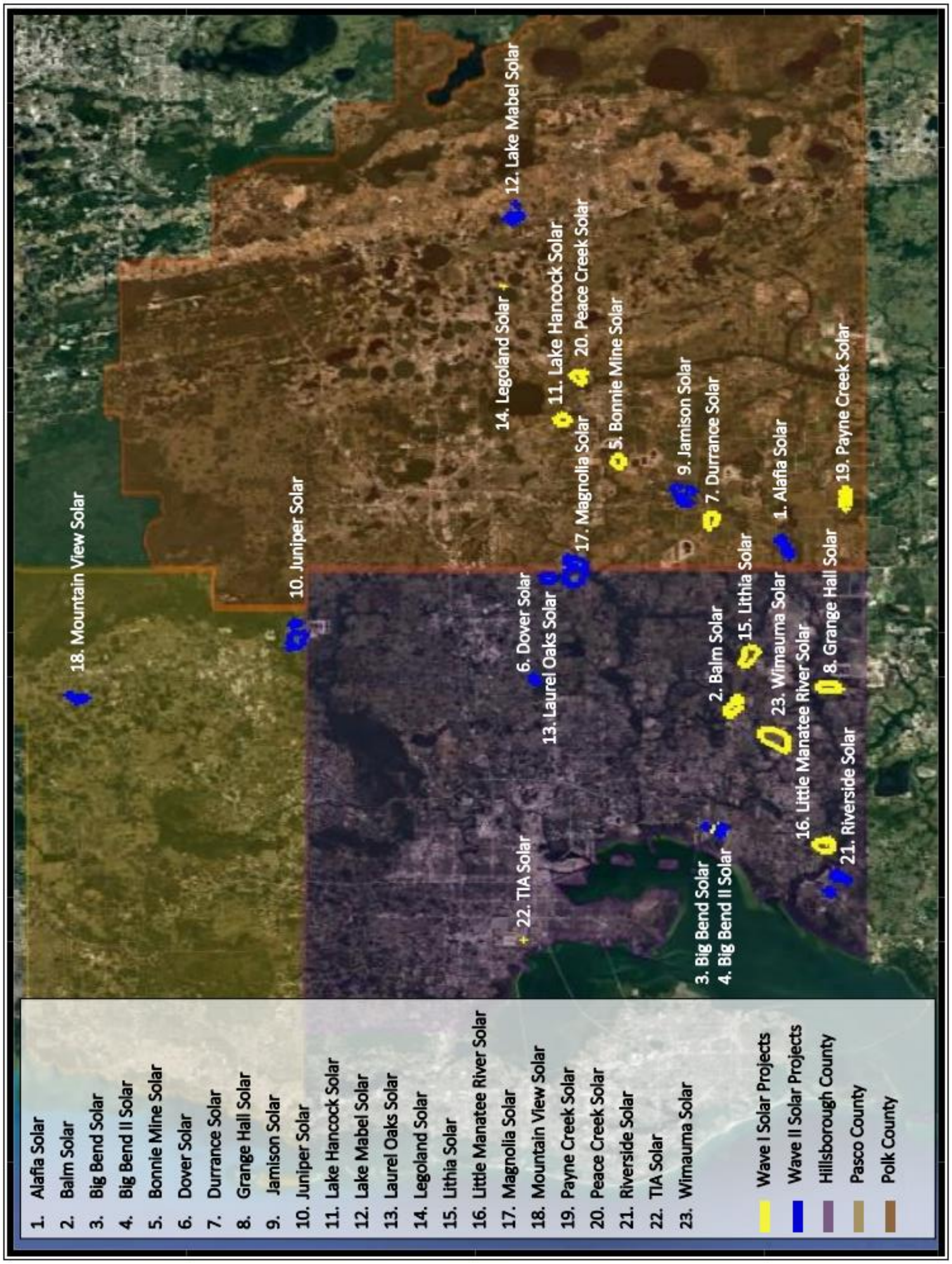


**Figure VI-III: Site Location of Big Bend Power Station**

TAMPA ELECTRIC COMPANY
UNDOCKETED: REVIEW OF TYSP'S
FIRST DATA REQUEST
REQUEST NO. 1
BATES PAGE(S): 1-108
FILED: APRIL 1, 2024

**Figure VI-IV: Site Location of Solar Power Stations**



# Exhibit DG-6:

# U.S. Department of Energy and Tampa Electric Company. 2000. The Tampa Electric Integrated Gasification Combined-Cycle Project: An Update. Topical Report Number 19

TOPICAL REPORT NUMBER 19 JULY 2000

CLEAN COAL TECHNOLOGY

# Tampa Electric Integrated Gasification Combined-Cycle Project

*An Update*

TOPICAL REPORT NUMBER 19 July 2000

# The Tampa Electric Integrated Gasification Combined-Cycle Project
## An Update

A report on a project conducted jointly under
a cooperative agreement between:

The U.S. Department of Energy and
Tampa Electric Company

Cover image: The Polk Power Plant site as seen from across the lake in early evening. Photography courtesy of Lee Schmoe, Bechtel Power Corporation.

CLEAN COAL TECHNOLOGY

# The Tampa Electric Integrated Gasification Combined-Cycle Project

# Executive Summary

The Clean Coal Technology (CCT) Demonstration Program is a government and industry co-funded effort to demonstrate a new generation of innovative coal utilization processes in a series of "showcase" facilities built across the country. These projects are carried out on a sufficiently large scale to prove technical feasibility and provide the information required for additional commercial applications.

The goal of the CCT Program is to furnish the marketplace with a number of advanced, more efficient coal-based technologies that meet strict environmental standards. These technologies will mitigate the economic and environmental barriers that limit the use of coal.

To achieve this goal, beginning in 1985, a multi-phased effort consisting of five separate solicitations has been administered by the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL), formerly the Federal Energy Technology Center. Projects selected through these solicitations have demonstrated technology options with the potential to meet the needs of energy markets while satisfying relevant environmental requirements.

This report discusses the Tampa Electric Integrated Gasification Combined-Cycle Project. In this project, the Texaco coal gasification process is used to fuel a gas combustion turbine generator, whose exhaust is integrated with a heat recovery steam generator and a steam turbine generator. Over 98% of sulfur contaminants are removed. Sulfur is recovered as sulfuric acid which is sold, as is the slag byproduct of gasification.

The project was conducted at Polk Power Station, a greenfield site located near Mulberry, Polk County, Florida.

The Tampa Electric CCT project has successfully demonstrated the commercial application of Texaco coal gasification in conjunction with electric power generation. Over 18,000 hours of operation have been accumulated. Net power production meets the target goal of 250 MWe at a high stream factor and plant availability. Carbon burnout exceeds 95%, and emissions of $SO_2$, NOx and particulates are well below the regulatory limits set for the Polk plant site. The Polk facility is one of the cleanest coal-based power plants in the world.

**IGCC Advantages**

- A Clean Environment
- High Efficiency
- Low-Cost Electricity
- Potential for Low Capital Costs
- Repowering of Existing Plants
- Modularity
- Fuel Flexibility
- Phased Construction
- Low Water Use
- Low $CO_2$ Emissions
- Public Acceptability

# The Tampa Electric Integrated Gasification Combined-Cycle Project

## Background

The Clean Coal Technology (CCT) Demonstration Program, sponsored by the U.S. Department of Energy (DOE) and administered by the National Energy Technology Laboratory (NETL), has been conducted since 1985 to develop innovative, environmentally friendly coal utilization processes for the world energy marketplace.

The CCT Program, which is co-funded by industry and government, involves a series of commercial-scale demonstration projects that provide data for design, construction, operation, and technical/economic evaluation of full-scale applications. The goal of the CCT Program is to enhance the utilization of coal as a major energy source.

The CCT Program has also opened a channel to policy-making bodies by providing data from cutting-edge technologies to aid in formulating regulatory decisions. DOE and the participants in several CCT projects have provided the Environmental Protection Agency (EPA) with data to help establish emissions targets for nitrogen oxide (NOx) emissions from coal-fired boilers subject to compliance under the 1990 Clean Air Act Amendments (CAAA).

**Aerial view of Polk Power Station**

## *Integrated Gasification Combined-Cycle*

Among the technologies being demonstrated in the CCT Program is Integrated Gasification Combined-Cycle (IGCC). IGCC is an innovative electric power generation process that combines modern coal gasification with gas turbine and steam power generation technologies. IGCC is one of the most efficient and cleanest of available technologies for coal-based electric power generation. This technology offers high system efficiencies, low costs, and very low pollution levels.

IGCC power plants offer excellent environmental performance. Gasification breaks down virtually any carbon-based feedstock into its basic constituents, enabling the separation of pollutants to produce clean gas for efficient electricity generation. As a result, atmospheric emissions of pollutants are very low. Water use is lower than conventional coal-based generation because gas turbine units require no cooling water, an especially important consideration in areas of limited water resources. Due to their high efficiency, less coal is used, causing IGCC power plants to emit less carbon dioxide ($CO_2$) to the atmosphere, thereby decreasing concerns about climate change. Less coal use also results in less ash requiring disposal.

Modularity and fuel flexibility are important attributes of IGCC power plants. The combined-cycle unit can be operated on other

**The sulfuric acid plant is located in the foreground and the gasifier and radiant syngas cooler are in the tall midground structure**

fuels, such as natural gas or fuel oil, before the gasifier is constructed, to provide early power. The size of gas turbine units can be chosen to meet specific power requirements. Ability to operate on multiple fuels permits continued operation of the gas turbine unit if the gasifier island is shut down for maintenance or repairs, or if warranted by fuel costs.

IGCC power plants use plentiful and relatively inexpensive coal as their fuel. In the United States there are several hundred years of coal reserves, and use of coal helps to reduce dependence on foreign oil.

Market forces, which are replacing regulatory structures, are resulting in expanded IGCC applications. As a result of both feedstock and product flexibility, traditional steam-powered electricity generation using single feedstocks is being supplanted by more versatile integrated technologies.

Four IGCC demonstration projects are included in the CCT Program: (1) the Piñon Pine IGCC Power Project, (2) the Wabash River Coal Gasification Repowering Project, (3) the Tampa Electric Integrated Gasification Combined-Cycle Project, and (4) the Kentucky Pioneer Energy Project. This Topical Report describes the Tampa Project.

# Project Description

The Tampa Electric Integrated Gasification Combined-Cycle Project was selected by DOE in December 1989 as a CCT Program Round III demonstration project. Construction was started in October 1994 and operation began in September 1996.

The project demonstrates use of the Texaco coal gasification process to fuel a gas combustion turbine generator, whose exhaust is integrated with a heat recovery steam generator (HRSG) and steam turbine generator. Over 98% of sulfur contaminants are removed. Sulfur is recovered as sulfuric acid which is sold, as is the slag byproduct of gasification. The greenfield site is located near Lakeland, Polk County, Florida.

The combustion turbine is an advanced General Electric gas turbine unit that produces 192 MWe (gross). The steam turbine produces an additional 121 MWe (gross). With parasitic power consuming 63 MWe, total net power output is 250 MWe.

The demonstration also includes integration of nitrogen from the air separation plant with the gas turbine. Steam produced at various gas cooling stages is integrated with the HRSG and other process needs.

## *Project Participant*

The Participant is Tampa Electric Company (TEC), headquartered in Tampa, Florida. Its service territory includes the city of Tampa and a 2000-square mile area in west-central Florida, primarily in and around Tampa. TEC, an investor-owned electric utility serving over 500,000 customers, has about 3650 MWe of generating capacity, of which about 97% is coal-fired. TEC is the principal wholly-owned subsidiary of TECO Energy, Inc., an energy related holding company heavily involved in coal mining, transportation, and power generation.

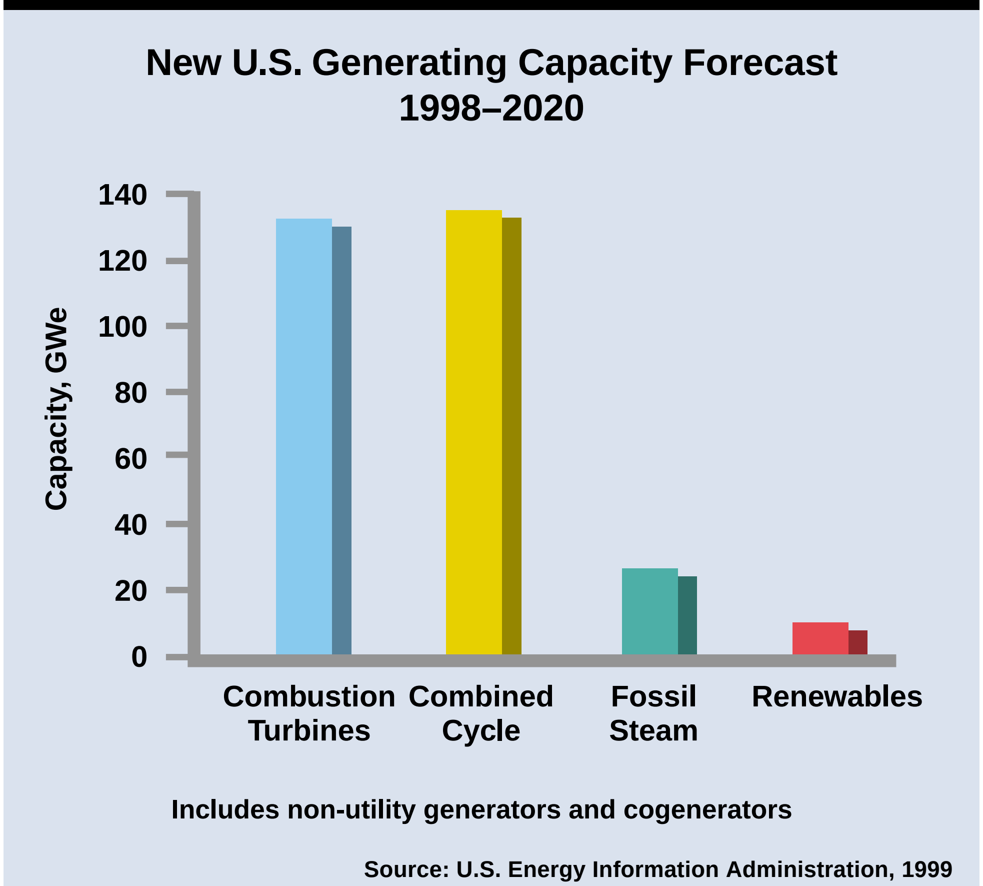
TECO Power Services Corporation (TPS), another subsidiary of TECO Energy, operates two power plants firing natural gas: a 295-MWe combined-cycle plant in Hardee County, Florida and a 78-MWe plant in Guatemala. In addition, TPS has several other projects at various stages of development.

## Major Participants

| | |
|---|---|
| Tampa Electric Company | Owner/operator |
| TECO Power Services Corporation | Project management and commercialization |
| Texaco Development Corporation | Licensor of gasification technology |
| General Electric Corporation | Supplier of gas turbine/combined-cycle equipment |
| Bechtel Power Corporation | Detailed engineering/construction management services, procurement, and startup |
| MAN Gutehoffnüngshutte AG | Supplier of radiant syngas cooling system |
| L. & C. Steinmüller Gmbh | Supplier of convective syngas cooling system |
| Air Products & Chemicals, Inc. | Turnkey supplier for air separation unit |
| Monsanto Enviro-Chem Systems, Inc. | Turnkey supplier for sulfuric acid plant |
| H.B. Zachry Company | Power block construction |
| The Industrial Company | Gasification area construction |
| Johnson Brothers Corporation | Site development and civil contractor |
| Aqua-Chem, Inc. | Supplier of brine concentration plant |
| Davenport Mammoet Heavy Transport | Transportation/erection of radiant syngas cooler |

## *Project Subcontractors*

Other participants in the CCT project are major technology suppliers, including Texaco Development Company, the licensor of the coal gasification process; General Electric Corporation, the supplier of the combined-cycle technology; Air Products and Chemicals, Inc., supplier of the air separation unit; Monsanto Enviro-Chem Systems, Inc., supplier of the sulfuric acid plant; TPS, project manager and marketer; and Bechtel Power Corporation, who provided detailed engineering and construction management services.




## *Site Description*

The demonstration unit is Unit 1 of the Polk Power Plant, a new facility built in 1996 and located near Mulberry in south central Polk County, Florida. The 4300-acre site is about 45 miles southeast of Tampa and 17 miles south of Lakeland, in the heart of central Florida's phosphate mining region.

The Polk site is on a tract of land that had been previously mined for phosphate rock, and has been redeveloped and revegetated by TEC for this project.

The area is predominantly rural. Polk County is an important citrus-raising and phosphate mining center, each being important Florida industries.

About one-third of the site is used for power generation facilities. Another third, about 1500 acres, is used to enhance the environment by creation of public fishing lakes for the Florida Fish and Game Commission. This area was converted from phosphate mining spoils to wetlands and uplands, thereby providing habitat for native plants and animals, and was transferred to the Commission in 1997. The final third of the site is used primarily for access and to provide a visual buffer.

The site contains an 850-acre cooling reservoir. State Highway 37 crosses the site about one mile from the IGCC power plant.

Makeup water for the power plant is provided from on-site wells. All process water is recycled.

## *Coal Supply*

Coal is delivered to the site by truck from a transloading facility at TEC's Big Bend Station in Apollo Beach, Florida. Coals tested include Illinois No. 6, Pittsburgh No. 8, Kentucky No. 9, and Kentucky No. 11, all bituminous coals having a sulfur content ranging from 2.5-3.5%.

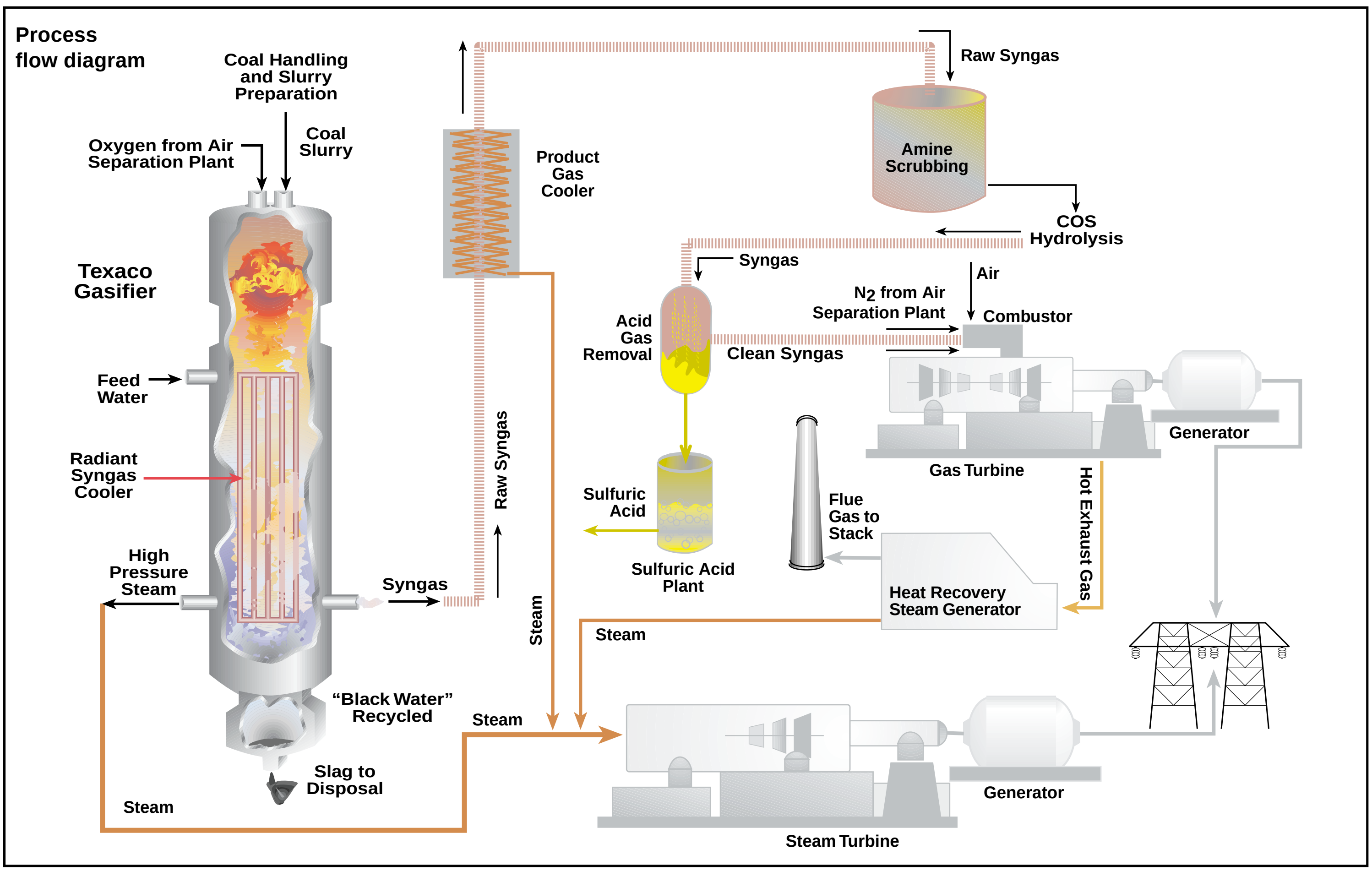
# Power Plant Description

The Tampa CCT project demonstrates advanced IGCC technology using Texaco's commercially available oxygen-blown, entrained-flow gasifier, integrated with a combined-cycle turbine system for power generation.

The facility processes approximately 2,200 tons/day of coal in a single Texaco gasifier. Once on site, the coal is ground and slurried using recycled process water and makeup water. The slurry contains 60-70% solids.

Coal is partially oxidized in the gasifier with 95% pure oxygen from the air separation unit to produce a high temperature, high pressure, medium-Btu synthesis gas (syngas) with a heat content of about 267 Btu per standard cubic foot. The gasifier achieves about 95% carbon conversion per pass. Molten ash flows from the bottom of the gasifier into a water-filled sump, where it solidifies into a marketable slag byproduct. The slag, which is nonleachable, is sold for use in blasting grit, roofing tiles, and construction products.

The syngas is cooled in a high-temperature radiant heat exchanger, generating high pressure steam. The cooled gas is washed with water for particulate removal, followed by a hydrolysis reactor where carbonyl sulfide (COS) is converted to hydrogen sulfide ($H_2S$). After additional cooling, the raw syngas is sent to a conventional acid gas removal unit, where $H_2S$ is absorbed by scrubbing with an amine solvent. $H_2S$ is removed from



## IGCC Inputs and Outputs

| *Inputs* | *Quantity, tons/day* |
|---|---|
| Coal | 2,200 |
| Oxygen | 2,171 |
| Slurry water (recycled) | 972 |
| Nitrogen to gas turbine | 5,600 |
| ***Solids Output*** | |
| Slag/fines from dewatering pit | 342 |
| Dry solids from brine concentrator | 3.1 |
| ***98% Sulfuric Acid*** | 240 |
| ***Net Electrical Output*** | 250 MWe |

## Selected Milestones

- Initial roll of the steam turbine: June 1996
- Sulfuric acid plant and gasifier completion: June 1996
- Start of operational test program: October 1996
- First continuous run > 50 days for combustion turbine: September 1998
- Produced > 1.2 million MWh in 1998
- 94% availability for the combined-cycle system achieved by end of 1999
- > 18,000 hrs. of operation by the end of 1999
- First petroleum coke burned: 1st quarter 2000

the amine by steam stripping and sent to the sulfuric acid plant.

As originally envisioned, the overall process scheme was to have incorporated hot gas cleanup on a portion of the raw syngas stream. After some initial test work, support for this option was discontinued.

The cleaned syngas is sent to the General Electric model MS 7001FA gas combustion turbine. Nitrogen from the air separation unit (at 98% purity) is mixed with the syngas at the combustor inlet. Nitrogen addition has important benefits to the power plant: (1) the increased mass flow through the gas turbine produces more power than without the nitrogen; (2) the overall efficiency of the system is enhanced; (3) NOx emissions are reduced; and (4) nitrogen injection is a viable alternative to steam. The use of nitrogen that would otherwise be vented represents a novel approach in oxygen-blown gasification technology.

Hot exhaust from the gas turbine passes through the HRSG, where three pressure levels of steam are produced. The majority of the steam is at high pressure and, with high pressure steam produced in the gasification stage, drives the reheat steam turbine generator.

A 220-kV, five-mile transmission line connects the Polk Power Station to the TEC grid.

The sulfuric acid plant uses oxygen and a catalytic reactor to convert the $H_2S$ from the gas cleanup system to sulfuric acid ($H_2SO_4$), which is sold to the local phosphate mining industry. $H_2SO_4$ production is about 240 tons/day.

A brine concentration unit processes "grey" water discharged from the gas cleanup systems, recovering a reusable water stream for slurry preparation and a land-fillable solid waste stream. There is no liquid effluent.

Gaseous emissions are controlled to very low levels. $SO_2$ emissions are below 0.15 lb/million Btu and NOx emissions are below 0.27 lb/million Btu. The target emissions for the Tampa Electric project are 0.21 lb/million Btu for $SO_2$ and 0.27 lb/million Btu for NOx. Emissions of particulates are consistently below 17 lb/hr, the permit limit. Thus, the plant performance exceeds project goals.

# Environmental Considerations

As indicated above, the Tampa IGCC Project has very low pollution impacts. Environmental considerations have been a major driving force from the inception of the project. The site was selected by an independent Community Siting Task Force, commissioned by TEC. Members included environmentalists, educators, economists, and community leaders. Economic factors were also considered. The Task Force evaluated 35 sites in six counties and recommended three in south-western Polk County that had previously been mined for phosphate.

EPA, the lead federal agency, issued the final Environmental Impact Statement for this project in June 1994. Favorable records of decision were issued by EPA, the U.S. Army Corps of Engineers, and DOE. Some of the inputs for this comprehensive document were provided by TEC and its environmental consultants.

All federal, state, and local environmental permits were obtained. An Environmental Monitoring Plan was developed by TEC that gives details of the performance monitoring of environmental control equipment, stack emissions, and the surrounding area.

**Polk Site before (above) and after (below) construction**

## Process Description

### Coal Gasification

Texaco coal gasification technology uses a single-stage, downward-firing, entrained-flow coal reactor fed with a coal/water slurry (60-70% water) and 95% pure oxygen. The coal reacts with steam and oxygen at a temperature of 2400-2600 °F to produce raw fuel gas and molten ash. The hot gas flows downward into a radiant gas cooler, where high pressure steam is produced. The syngas passes over the surface of a pool of water at the bottom of the syngas cooler and exits the vessel. The slag drops into the water pool and is fed to the lockhopper from the syngas cooler sump.

The radiant gas cooler is about 16 feet in diameter and 100 feet long, and weighs about 900 tons. The "black" water flowing out with the slag is separated and recycled after processing in the dewatering system.

The raw syngas exiting the radiant syngas cooler is sent to parallel convective coolers, where it is cooled to below 800°F and additional high pressure steam is produced.

### Gas Cleanup

Particulate matter and hydrogen chloride (HCl) are removed from the syngas by scrubbing with water. The scrubber bottoms are routed to the "black" water handling system where the solids are separated. The effluent is concentrated and crystallized as a solid that is shipped off-site either for reuse or for disposal in a permitted landfill. The separated water is recycled for slurrying coal feed.

### COS Hydrolysis

One compound produced in the gasification reactor is carbonyl sulfide (COS), which cannot be removed in the downstream amine scrubbing unit. If not removed from the syngas stream, COS is converted to $SO_2$, which must be minimized in the plant stack gas. The COS problem is accentuated when higher sulfur coals are fed to the gasifier.

To avoid this problem, Polk plant staff designed and installed a hydrolysis unit, a cylindrical vessel in which COS is reacted with water in the presence of a catalyst to form $CO_2$ and $H_2S$. Polk personnel selected the catalyst based on testing performed on the plant syngas. Six catalysts were tested, of which two proved satisfactory and one was chosen for this service. Preliminary operating results indicate negligible catalyst degradation. Long-term operation will be required to fully evaluate the COS hydrolysis step.

### Acid Gas Removal

The COS-free syngas flows to the amine absorber, where the $H_2S$ and some of the $CO_2$ is absorbed. The rich amine is stripped of acid gas in the stripper. The amine is recycled and the separated acid gas is routed to the sulfuric acid plant.

### Sulfuric Acid Plant

In the sulfuric acid plant, the sulfur-containing gases from the gas cleanup system are converted to 98% $H_2SO_4$ for sale to the local Florida fertilizer industry. The $H_2S$ is converted to $SO_2$ by combustion with air. Medium pressure steam is generated from the combustion products. The $SO_2$ is oxidized over a vanadium pentoxide catalyst, forming $SO_3$. The $SO_3$ is scrubbed with weak sulfuric acid to make 98% $H_2SO_4$. The concentration of $SO_2$ and $SO_3$ remaining in the gas stream is low enough to permit direct discharge to the atmosphere through a 200-ft stack.

### Simplified Gasification Chemistry

| | | | | | | |
|---|---|---|---|---|---|---|
| *C (coal)* | *+* | *$O_2$* | *--->* | *$CO_2$* | *+* | *Heat* |
| *C (coal)* | *+* | *$H_2O$ (steam)* | *--->* | *CO* | *+* | *$H_2$* |

### Power Block

The gas turbine is a General Electric model MS 7001FA, designed for low NOx emissions when fired with syngas and with low-sulfur fuel oil that is used for startup and backup. Rated output from the hydrogen-cooled generator when syngas is fired is 192 MWe. The gas turbine uses an advanced design that has been proven in a utility environment.

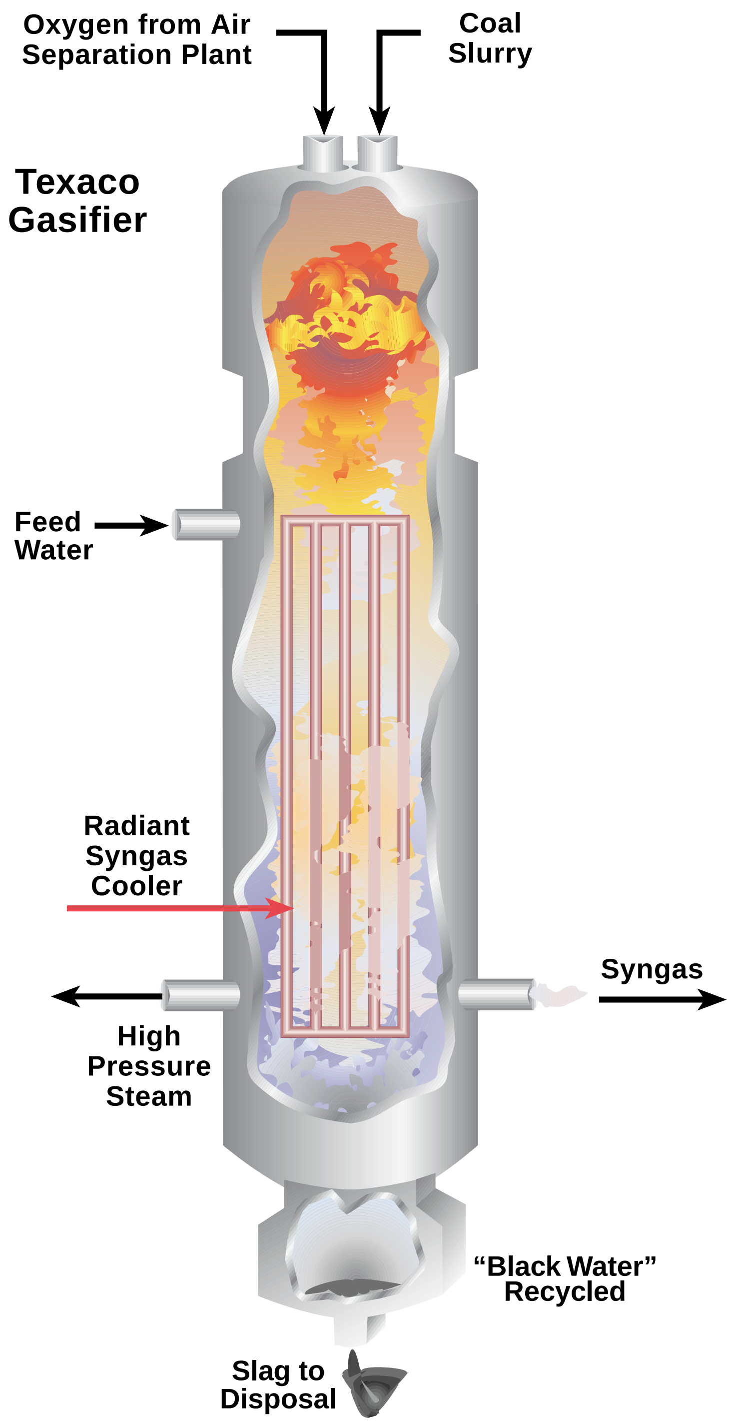
Nitrogen is used as a syngas diluent to reduce NOx formation and to increase mass flow, resulting in higher power output from the gas turbine.

The heat recovery steam generator (HRSG) is a three-pressure design with natural circulation and reheat. The exhaust gas leaving the HRSG is vented to the atmosphere via a 150-ft stack. The steam from the HRSG flows to a steam turbine, which is a double flow reheat unit with low-pressure extraction. Nominal steam inlet conditions are 1450 psig and 1000°F with 1000°F reheat temperature. Generator output during normal operation is 121 MWe.

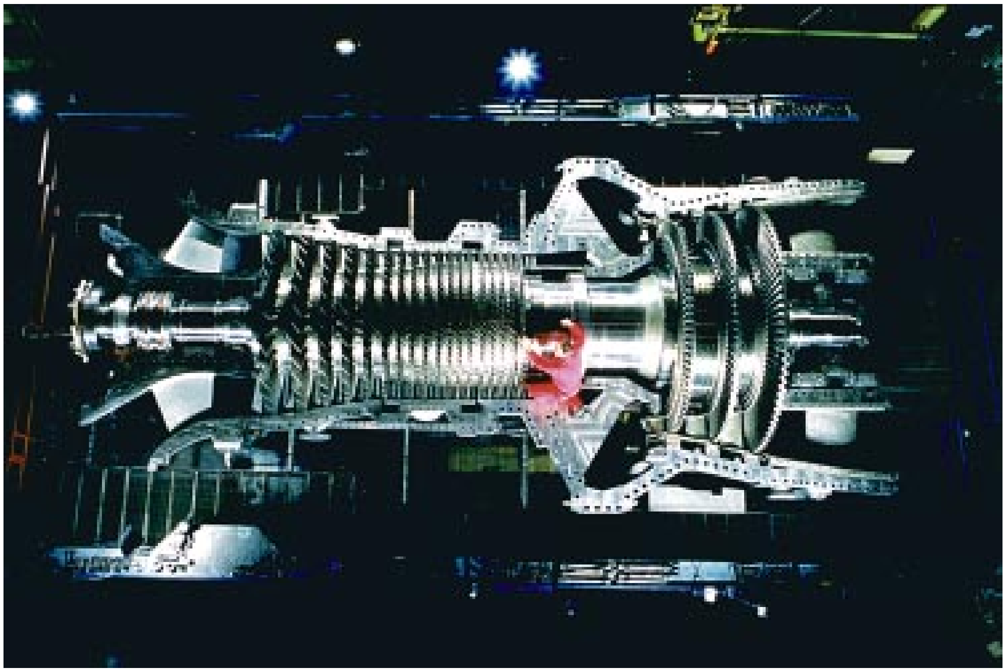
Total power production is 192 MWe from the gas turbine and 121 MWe from the steam turbine, giving a total of 313 MWe. With parasitic power of 63 MWe, total net power output is 250 MWe.

### Air Separation Unit

The conventional air separation unit provides 95% pure oxygen for the gasifier operation, and warmed compressed nitrogen for the gas turbine. Low-pressure 95% oxygen is also supplied to the sulfuric acid plant.




**A single Texaco gasifier processes 2,200 tons per day of coal to produce a raw syngas and molten slag. The gas flows downward into the radiant syngas cooler where it is partly cooled and high-pressure steam for power generation is produced. Slag is collected in a water pool at the bottom of the radiant syngas cooler and removed.**



**Gas turbine, model MS 7001F, during manufacture**

## Project Objective

The project objective is to demonstrate IGCC technology in a greenfield commercial electric utility application at the 250-MWe scale using a Texaco gasifier with full heat recovery, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection for power augmentation and NOx control.

## Allowed Stack Emissions

| Pollutant | Allowed Emissions, lb/hr |
|---|---|
| $SO_2$ | 357 |
| $NO_x$ | 223 |
| CO | 98 |
| VOC | 3 |
| PM/PM-10 | 17 |

## Cost/Schedule

The total cost of the Tampa Electric IGCC Project is $303 million, of which the Participant has provided $152 million (51%) and DOE has provided $151 million (49%). The cooperative agreement between TEC and DOE was signed in March 1991. Construction started in August 1994, and operation began in September 1996. A four-year demonstration program is in progress, with completion expected by October 2000.

The total project cost includes the cost of operating the unit throughout the demonstration peroid as well as experimental work on hot gas cleanup. The investment for a commercial unit would be significantly lower than that of the Tampa project.

## Plant Modifications/ Improvements

Several modifications to the original design and procedures were required to achieve the high availability that has been demonstrated. Soon after initial startup, ash plugging caused failure of some exchangers in the high-temperature heat recovery system. This led to serious damage to the combustion turbine. The exchangers were removed in 1997, and compensating adjustments were made in the rest of the heat recovery system. Additional particulate removal was provided to protect the turbine.

Pluggage in another bank of exchangers in the high-temperature heat recovery system was arrested by a design modification in 1999.

In late 1997, hot restart procedures were implemented. These eliminated the need to change burners and reheat the gasifier every time it shut down, reducing gasifier restart time by over 18 hours.

Initially, there were problems with the gasifier which is 50% larger than any previous Texaco gasifier. Carbon conversion in this larger gasifier was lower than expected, and refractory life has been identified as a significant issue. Liner replacement is expensive and requires considerable down time. To achieve the target life of two years, the gasifier is being operated at a lower temperature than design, which in turn results in a further decrease in carbon conversion efficiency. This caused load restrictions due to capacity limitations in the fines handling system. A slag crusher and a duplicate fines handling system installed in 1998 solved this problem.

Thermocouple replacement in the gasifier also presents a problem. Replacement is relatively expensive. Thermocouple failure by shearing is attributed to expansion of dissimilar materials.

In early 1998, revised operating procedures were developed to handle high shell temperatures in the dome of the radiant syngas cooler. This problem had caused two extended outages.

Numerous short forced outages occurred in 1997 and 1998 due to erosion and corrosion in the process water and coal/water slurry piping systems, pumps, and valves. Various changes have virtually eliminated these problems, and no such outages occurred in 1999. Some of the corrective actions taken to solve operating and maintenance problems in this project have resulted in patent applications.

**The Texaco gasifier is in the largest structure, which also contains the radiant syngas cooler. The hot gas cleanup system is installed in the smaller of the two large structures. In the foreground is the air separation unit.**

## Power Output

| | |
|---|---|
| Gas Turbine | 192 MWe |
| Steam Turbine | 121 MWe |
| ***Gross*** | ***313 MWe*** |
| Auxiliaries Power Use | 63 MWe |
| ***Net Power Output*** | ***250 MWe*** |

**The sulfuric acid plant is in the foreground and the combined-cycle unit is in the background. The large black object (left center) is the heat recovery steam generator**

## Gasifier Run Summary

| *Start Date* | *Major Accomplishments* |
|---|---|
| 7/96 | First production of syngas |
| 8/96 | Achieved steady state in process water system |
| 8/96 | First utilization of low-temperature gas cooling system |
| 9/96 | Achieved 100% gasifier load, first syngas to gas turbine, and first production of brine crystals |
| 9/96 | First integration of steam drums |
| 10/96 | First run >100 hours, full load gas turbine and combined-cycle operation on syngas, and first production of sulfuric acid |
| 1/97 | First continuous 30-day run |

# Results

Polk Power Station has operated over 18,000 hours, generating more than 4.8 million MWh of electricity through 1999. For the last six months of 1999, the gasifier had an 83.5% on-stream factor, and the combined-cycle availability was 94%. The gasifier and combustion turbine continuous operation records are 46 and 52 days, respectively.

Environmental performance has been excellent. The overall heat rate is 9350 Btu/kWh (36.5% efficiency, higher heating value basis). The efficiency is somewhat lower than design because of removal of the high temperature exchangers and lower than excepted carbon conversion discussed above, and a compressor failure in the brine concentration unit which necessitates its operation as a single effect evaporator. In the second half of 2000, a slag recovery system will be commissioned to recover and utilize the unconverted carbon, and the brine concentration unit will be restored to its original more efficient vapor compression cycle. Ways are being evaluated to utilize the heat available as a result of removing the high temperature exchangers. Together, these projects are expected to increase the efficiency to 38% (9000 Btu/kWh), consistent with the original design value.

Ten coals and blends were tested in the 3 years of operation to date to determine the impact of feedstock properties on system performance. These coals included Kentucky No. 9, Kentucky No. 11, two Illinois No. 6 coals, and three Pittsburgh No. 8 coals. The performance criteria were: (1) feasibility of processing into a high concentration slurry, (2) carbon conversion, (3) aggressiveness of the slag to the gasifier's refractory liner, and (4) tendency toward fouling of the syngas coolers. All of the coals were found to be suitable with some design modifications.

The unit is currently running Kentucky No. 9 coal. Testing of lower cost petroleum coke blends is in progress.

## Awards

The project was presented the 1997 Powerplant Award by *Power* magazine. In 1996, the project received the Association of Builders and Contractors Award for construction quality. Several awards were presented for using an innovative siting process, including the 1993 Ecological Society of America Corporate Award and the 1991 Florida Audubon Society Corporate Award.

## Commercial Applications

In addition to generating power, the IGCC process can also be modified to produce value-added chemicals or transportation fuels from coal by chemical processing of the gas produced, as opposed to using the gas to drive a combustion turbine. It may very well be that the near-term market niche for IGCC lies not only in the production of electricity, but also in the generation of multiple products, where electricity, steam, and chemicals are economically bundled as products from a fully integrated complex. Such plants are envisioned in forward-thinking concepts such as the DOE's "Vision 21" initiative.

As a result of the Tampa demonstration project, Texaco-based IGCC can be considered commercially and environmentally suitable for electric power generation utilizing a wide range of feedstocks. Sulfur capture for the project is

### Five Powerplant Awards Presented to CCT Projects by *Power* Magazine

- Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company) - 1997
- Wabash River Coal Gasification Repowering Project (Cinergy Corporation/PSI Energy Inc.) - 1996
- Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.) - 1994
- Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.) - 1993
- Tidd PFBC Demonstration Project (The Ohio Power Company) - 1991

**Dawn arrives over the reclaimed wetlands surrounding the Tampa Electric Integrated Gasification Combined-Cycle Project**

## Coal Gasification

Coal gasification has been used for many years. Primitive coal gasification provided town gas worldwide more than 100 years ago, and a gasification industry produced coal-based transportation fuels for Germany in World War II.

Today, coal gasification is seeing increasing use. In the U.S., a Texaco gasifier is utilized in commercial operation at the Tennessee Eastman chemical plant in Kingsport, Tennessee to produce synthesis gas for production of methanol. The Dakota Gasification plant in North Dakota produces substitute natural gas and chemicals based on an advanced World War II gasification technology.

Overseas, a major chemical and transportation fuel industry exists in The Republic of South Africa, mostly based upon advancements of World War II gasification technologies. An IGCC power plant is in operation in The Netherlands. There are several German gasifiers that are commercially available. Texaco gasifiers are in commercial operation, or planned operation, in the People's Republic of China and other nations.

Advanced gasification and IGCC technology development began in the U.S. in the 1960s, the stimuli being the desire for (1) development of coal-based replacements for natural gas and oil due to shortages and price increases; and (2) more efficient, clean coal-based power plants. Modern IGCC technology is a response of U.S. government and industry to these needs. Such systems use advanced pressurized coal gasifiers to produce a fuel for gas turbine-based electric power generation; the hot-gas turbine exhaust produces steam to generate additional electricity.

The first commercial scale use of a gasifier in a U.S. IGCC project was the Cool Water Project in California, which was based upon the Texaco coal gasification technology. The Cool Water Project, which received major support from the U.S. Synthetic Fuels Corporation, Southern California Edison Company, EPRI (formerly the Electric Power Research Institute), and others, was instrumental in proving the feasibility of IGCC, including their exceptional environmental performance.

Gas turbines for power generation have been one of the consequences of jet aircraft engine development. Initially utilized for peaking purposes by utilities, their reliability, efficiency and output have improved to the extent that they now also provide intermediate and baseload electric power. It is projected that gas turbines and IGCCs will contribute significantly to future increases in power generation.

Today's IGCC is efficient because of major improvements that have taken place in coal gasification and gas turbine technologies, and a high degree of system integration that efficiently recovers and uses waste heat.

Gas cleanup in an IGCC power plant is relatively inexpensive compared with flue gas cleanup in conventional coal-fired steam power plants. Smaller equipment is required because a much smaller volume of gas is cleaned. This results from the fact that contaminants are removed from the pressurized fuel gas before combustion. In contrast, the volume of flue gas from a coal-steam power plant is 40-60 times greater because the flue gas is cleaned at atmospheric pressure.

Atmospheric emissions are very low due to proven technologies for highly effective removal of sulfur and other contaminants from the syngas. Advancements being demonstrated in the CCT program are expected to result in still better efficiencies.

greater than 98%, while NOx emissions are reduced by over 90% compared with those of a conventional pulverized coal-fired power plant.

The integration and control approaches utilized at Polk and many of the other lessons learned can also be applied in IGCC Projects using different gasification technologies.

TECO Energy is actively working with Texaco to commercialize the technology in the U.S. and overseas as well.

**Polk Power Station control room**

## Future Developments

Work is in progress on two equipment modifications, both of which have efficiency improvement as a major objective. The first is to commission the slag handling system that separates the slag into its main constituents, a by-product for sale and a fuel for recycle. The second is to upgrade the brine concentration system by converting it to a more efficient vapor compression cycle.

The achievements and knowledge gained from the Tampa Electric IGCC project demonstration are expected to benefit future users of this technology. Evaluation of advanced features of the Project will determine their viability for future commercial applications. Future offerings of the technology are anticipated to have lower cost and exhibit improved performance.

DOE believes that future IGCC power plants, based on mature and improved technology, will cost in the range of \$900-1250/kW (1999 basis) depending on the degree to which existing equipment and infrastructure can be utilized. Heat rate ultimately is expected to be in the range of 7000-7500 Btu/kWh (46-49% efficiency, higher heating value basis).

### Typical Coal Analysis (Pittsburgh No. 8 Seam)

Ultimate Analysis, As-Received, wt%

| | |
|---|---|
| Moisture | 4.74 |
| Carbon | 73.76 |
| Hydrogen | 4.72 |
| Nitrogen | 1.39 |
| Chlorine | 0.10 |
| Sulfur | 2.45 |
| Ash | 7.88 |
| Oxygen | 4.96 |
| Total | 100.0 |

Higher Heating Value 13,290 Btu/lb

## Composition of Cleaned Syngas

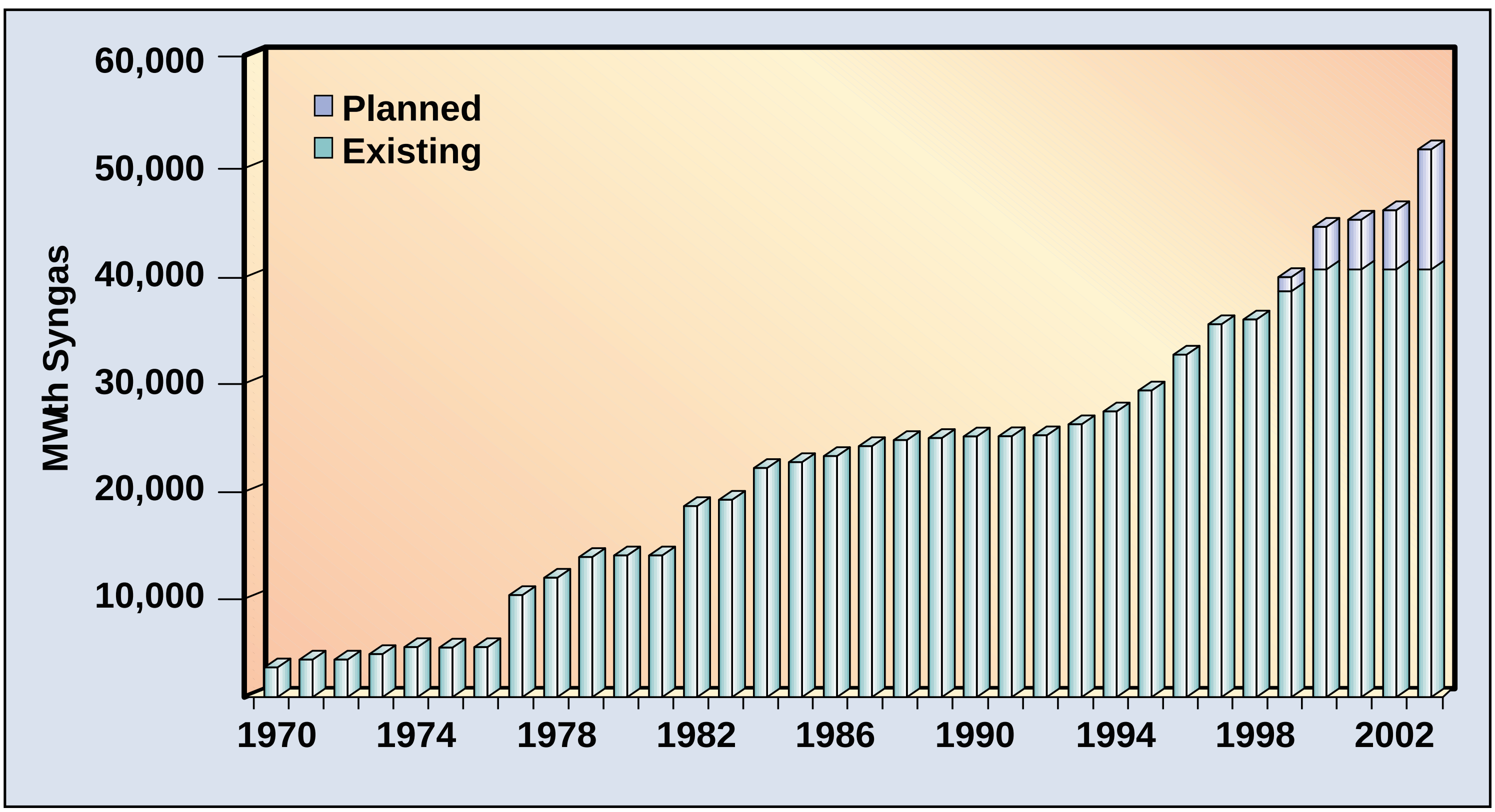
| Constituent | Volume % |
|---|---|
| Carbon monoxide | 42.7 |
| Hydrogen | 38.3 |
| Carbon dioxide | 14.4 |
| Methane | 0.1 |
| Water | 0.3 |
| Nitrogen | 3.3 |
| Argon | 0.9 |
| Hydrogen sulfide | 200 ppmv |
| Carbonyl sulfide | 10 ppmv |
| Ammonia | 0.0 ppmv |

# Market Potential

A number of factors are converging that contribute to the growth of gasification-based power generation worldwide. These factors include advances in gasification technology; improved efficiency and reduced cost of gas turbines; fuel flexibility, permitting use of lower quality, lower cost feedstocks; and deregulation of the power industry. This growth adds to an already important role gasification technologies have played in the production of chemicals and transportation fuels.

Currently there are over 160 existing or planned gasification projects worldwide, representing a total of more than 410 gasifiers with a combined syngas output of over 60,000 MWth. Conversion of all of this syngas to electricity by means of IGCC equates to over 33,000 MWe of power equivalent. Of the total worldwide capacity, gasification facilities currently operating or under construction account for about 130 plants with a total capacity of about 43,000 MWth. The current annual growth in gasification is about 3,000 MWth of syngas, or about 7% of the total operating worldwide capacity. Planned projects indicate that this growth will likely continue through the next five years, mostly in Western Europe, Asia, Australia, and North America.

At present, the use of syngas to produce chemicals is the dominant market for IGCC technology worldwide. Power generation is gaining quickly, and represents most of the recent and planned capacity additions. Much of this growth is in gasification-based power generation at oil refineries.




**Cumulative worldwide gasification capacity and growth**

Throughout the United States there are more than 95,000 MWe of existing coal-fired utility boilers over 30 years old. Many of these plants are without air pollution controls, and are candidates for repowering with IGCC technology. IGCC technology is projected to be a major candidate for both repowering and new power generating capacity. The Tampa Electric CCT Project is an example of a new power plant using IGCC technology.

IGCCs offer the advantages of modularity, rapid and staged on-line generation capability, high efficiency, flexibility, environmental controllability, and reduced land and natural resource needs. For these reasons, IGCCs are a strong contender for new electric power generation. Commercial offerings of IGCC technology will be based on a nominal 300-MWe train, which is ideally suited to utility-scale power production.

# Conclusions

The Tampa Electric IGCC project conducted at Polk Power Station has successfully demonstrated the commercial application of Texaco coal gasification in conjunction with electric power generation. Power production meets the target goal of 250 MWe at a high stream factor and plant availability. Carbon burnout exceeds 95%, and emissions of $SO_2$, NOx and particulates are well below the regulatory limits set for the Polk plant site.

Along with other IGCC demonstrations in the CCT Program, the Polk Plant is one of the cleanest coal-based power generation facilities in the world.

**GE frame 7FA combustion turbine (left background) and its generator (right center) and clean gas filter (lower left foreground). The clean syngas filter prevents pipe scale and any coal ash from damaging the combustion turbine. The filter was installed in response to two turbine failures from coal ash and pipe scale in 1997, and has proven its worth.**

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**Aerial view of Tampa skyline**

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**Installation of radiant syngas cooler**

## The Clean Coal Technology Program

The Clean Coal Technology (CCT) Program of the U.S. Department of Energy (DOE), a model of government and industry cooperation, supports DOE's mission to foster a secure and reliable energy supply system in the United States that is environmentally and economically sustainable. The CCT Program represents an investment of over $5 billion in advanced coal-based technology, with industry and state governments providing a significant share —66% —of the funding. With 26 of the 38 projects having completed operations, the CCT Program has resulted in clean coal technologies that are capable of meeting existing and emerging environmental regulations and competing in a deregulated electric power marketplace.

The CCT Program provides a portfolio of process options that will enable continued use of the United States' huge economically recoverable coal reserves (over 270 years at current consumption rates) to meet the nation's energy needs economically and in an environmentally sound manner.

As the new millennium begins, many of the clean coal technologies have reached commercial status. Industry stands ready to employ them both domestically and internationally to respond to the energy and environmental demands of the 21st century. For existing power plants, there are cost-effective environmental control devices to minimize emissions of sulfur dioxide ($SO_2$), nitrogen oxides (NOx), and particulate matter (PM). The CCT Program has taken a pollution prevention approach as well, providing technologies that remove pollutants or their precursors from coal before combustion.

Also ready is a new generation of technologies that can produce electricity and other commodities, such as steam and synthesis gas, at high efficiencies consistent with concerns about global climate change.

Additionally, new technologies have been introduced into major coal-using industries, such as steel production, to enhance environmental performance. Thanks in part to the CCT Program, coal—abundant, secure, and economical throughout much of the world—can continue in its role as a key component in supplying U.S. and world energy needs.

The CCT Program also has global importance in providing clean and efficient coal-based technologies to a burgeoning energy market in developing countries. World energy consumption is expected to increase 63% by 2020, and coal, the predominant indigenous fuel in much of the world, will be the fuel of choice for electricity production. CCT processes offer a cost-effective means to mitigate potential environmental problems associated with this unprecedented energy growth.

Most of the CCT demonstrations have been conducted at commercial scale, in actual user environments, and under circumstances typical of commercial operations. Each project addresses one of the following four market sectors:

- Advanced electric power generation
- Environmental control devices
- Coal processing for clean fuels
- Industrial applications

The project described in this Topical Report was developed under the category of Advanced Electric Power Generation.

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**This report is available on the Internet at U.S. DOE, Office of Fossil Energy's home page: www.fe.doe.gov and on the Clean Coal Technology Compendium home page: www.lanl.doe.gov/projects/cctc**

# List of Acronyms and Abbreviations

Btu. ............................................................ British thermal unit
CAAA ......................................................... Clean Air Act Amendments of 1990
CCT ........................................................... Clean Coal Technology
CO .............................................................. carbon monoxide
$CO_2$ ............................................................ carbon dioxide
COS ........................................................... carbonyl sulfide
DOE ........................................................... U.S. Department of Energy
EPA ........................................................... U.S. Environmental Protection Agency
HCl ............................................................ hydrogen chloride
HRSG ......................................................... heat recovery steam generator
$H_2S$ ............................................................ hydrogen sulfide
$H_2SO_4$ ......................................................... sulfuric acid
IGCC ......................................................... integrated gasification combined-cycle
kV .............................................................. kilovolt
kWh ........................................................... kilowatt hour
MWe .......................................................... megawatts of electric power
MWth ......................................................... megawatts of thermal power (1 MWth = $3.413 \times 10^6$ Btu/hr)
NETL ......................................................... National Energy Technology Laboratory
NOx ........................................................... nitrogen oxides
$O_2$ .............................................................. oxygen
PM ............................................................. particulate matter
ppmv .......................................................... parts per million by volume
psig ............................................................ pressure, pounds per square inch (gauge)
$SO_2$ ............................................................ sulfur dioxide
$SO_3$ ............................................................ sulfur trioxide
syngas ........................................................ synthesis gas
TEC ........................................................... Tampa Electric Company
TPS ............................................................ TECO Power Services Corporation
VOC ........................................................... volatile organic compounds
wt % ........................................................... percent by weight

# Exhibit DG-7:

# TECO response to SC IRR 1-8, Attachment (BS 28921) 2018 – 2023 GFP.xlsx

## 2018 GENERATION, FUEL, and PERFORMANCE REPORT

| PLANT/UNIT | SERVICE HOURS | GROSS CAPAB-ILITY (MW) | NET CAPAB-ILITY (MW) | GROSS GENERATION (MWh) | NET GENERATION (MWh) | NET CAPACITY FACTOR (%) | NET EQ. AVAILABILITY FACTOR (%) | NET OUTPUT FACTOR (%) | AVG GROSS HEAT RATE (BTU/KWh) | AVG NET HEAT RATE (BTU/KWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| BIG BEND #4 (Coal) | 5,747 | 472 | 439 | 2,289,486 | 2,078,323 | 54.1 | 60.2 | 82.5 | 9,805 | 10,801 |
| BIG BEND #4 (Gas) * | 593 | 223 | 203 | 23,229 | 20,782 | 1.2 | 73.0 | 18.4 | 9,294 | 10,389 |
| BIG BEND #4 | 6,306 | 472 | 439 | 2,312,715 | 2,099,105 | 54.6 | 60.2 | 76.0 | 9,800 | 10,797 |
| POLK 1 CT (Syngas) | 2,902 | 300 | 230 | 791,859 | 549,381 | 27.2 | 34.8 | 81.5 | 8,145 | 11,740 |
| POLK #1 (Gas) * | 4,655 | 203 | 198 | 387,772 | 377,000 | 21.7 | 64.1 | 40.9 | 8,147 | 8,379 |
| POLK #1 | 5,147 | 300 | 230 | 1,179,631 | 926,381 | 45.9 | 60.7 | 78.7 | 8,146 | 10,373 |

2019 GENERATION, FUEL, and PERFORMANCE REPORT

| PLANT/UNIT | SERVICE HOURS | GROSS CAPAB-ILITY (MW) | NET CAPAB-ILITY (MW) | GROSS GENERATION (MWh) | NET GENERATION (MWh) | NET CAPACITY FACTOR (%) | NET EQ. AVAILABILITY FACTOR (%) | NET OUTPUT FACTOR (%) | AVG GROSS HEAT RATE (BTU/KWh) | AVG NET HEAT RATE (BTU/KWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| BIG BEND 4 (Coal) | 3,973 | 471 | 438 | 1,345,231 | 1,214,307 | 31.6 | 52.6 | 69.7 | 9,755 | 10,807 |
| BIG BEND 4 (Gas) * | 681 | 203 | 188 | 94,852 | 83,516 | 5.1 | 52.6 | 65.4 | 10,436 | 11,853 |
| BIG BEND 4 | 4,416 | 471 | 438 | 1,440,083 | 1,297,823 | 33.8 | 52.6 | 67.1 | 9,800 | 10,875 |
| POLK 1 CT (Syngas) | - | 266 | 204 | 0 | (20,067) | - | - | - | - | - |
| POLK 1 CT (Gas) * | 4,120 | 184 | 157 | 471,224 | 452,156 | 32.9 | 76.4 | 70.0 | 11,836 | 12,335 |
| POLK 1 ST | 4,085 | 120 | 85 | 198,173 | 189,122 | 25.4 | 77.8 | 54.5 | | |
| POLK 1 Total | 4,125 | 308 | 238 | 669,397 | 621,212 | 29.9 | 76.9 | 63.4 | 8,332 | 8,978 |

**2020 GENERATION, FUEL, and PERFORMANCE REPORT**

| PLANT/UNIT | SERVICE HOURS | GROSS CAPAB-ILITY (MW) | NET CAPAB-ILITY (MW) | GROSS GENERATION (MWh) | NET GENERATION (MWh) | NET CAPACITY FACTOR (%) | NET EQ. AVAILABILITY FACTOR (%) | NET OUTPUT FACTOR (%) | AVG GROSS HEAT RATE (BTU/KWh) | AVG NET HEAT RATE (BTU/KWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| **BIG BEND 4 (Coal)** | **3,337** | **425** | **392** | **991,358** | **909,110** | **26.4** | **36.2** | **69.5** | **9,971** | **10,873** |
| **BIG BEND 4 (Gas) *** | **1,278** | **185** | **170** | **159,802** | **143,651** | **9.6** | **36.2** | **66.1** | **10,224** | **11,373** |
| **BIG BEND 4** | **4,418** | **425** | **392** | **1,151,160** | **1,052,761** | **30.6** | **36.2** | **60.8** | **10,006** | **10,942** |
| **POLK 1 CT (Syngas)** | **-** | **240** | **170** | **-** | **(13,003)** | **-** | **-** | **-** | **-** | **-** |
| **POLK 1 CT (Gas) *** | **3,956** | **164** | **159** | **454,388** | **433,218** | **31.0** | **72.0** | **68.9** | **11,450** | **12,010** |
| **POLK 1 ST** | **3,918** | **50** | **50** | **173,059** | **164,970** | **37.6** | **73.2** | **84.2** | | |
| **POLK 1 Total** | **3,956** | **214** | **209** | **627,447** | **585,184** | **31.9** | **72.3** | **70.8** | **8,292** | **8,891** |

2021 GENERATION, FUEL, and PERFORMANCE REPORT

| PLANT/UNIT | SERVICE HOURS | GROSS CAPAB-ILITY (MW) | NET CAPAB-ILITY (MW) | GROSS GENERATION (MWh) | NET GENERATION (MWh) | NET CAPACITY FACTOR (%) | NET EQ. AVAILABILITY FACTOR (%) | NET OUTPUT FACTOR (%) | AVG GROSS HEAT RATE (BTU/KWh) | AVG NET HEAT RATE (BTU/KWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| **BIG BEND 4 (Coal)** | **4,850** | **458** | **425** | **1,471,739** | **1,357,954** | **36.3** | **55.9** | **65.8** | **9,876** | **10,704** |
| **BIG BEND 4 (Gas) *** | **2,367** | **172** | **157** | **300,946** | **274,144** | **19.9** | **55.9** | **73.9** | **10,014** | **10,994** |
| **BIG BEND 4** | **6,174** | **458** | **425** | **1,772,685** | **1,632,098** | **43.7** | **55.9** | **62.2** | **9,900** | **10,752** |
| **POLK 1 CT (Syngas)** | **-** | **290** | **220** | **-** | **(17,939)** | **-** | **-** | **-** | **-** | **-** |
| **POLK 1 CT (Gas) *** | **1,971** | **166** | **161** | **216,387** | **203,830** | **14.4** | **45.5** | **64.1** | **11,592** | **12,307** |
| **POLK 1 ST** | **1,942** | **50** | **50** | **87,393** | **79,954** | **18.2** | **46.4** | **82.3** | | |
| **POLK 1 Total** | **1,971** | **216** | **211** | **303,780** | **265,845** | **14.3** | **45.7** | **63.8** | **8,258** | **9,436** |

**2022 GENERATION, FUEL, and PERFORMANCE REPORT**

| PLANT/UNIT | SERVICE HOURS | GROSS CAPAB-ILITY (MW) | NET CAPAB-ILITY (MW) | GROSS GENERATION (MWh) | NET GENERATION (MWh) | NET CAPACITY FACTOR (%) | NET EQ. AVAILABILITY FACTOR (%) | NET OUTPUT FACTOR (%) | AVG GROSS HEAT RATE (BTU/KWh) | AVG NET HEAT RATE (BTU/KWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| **BIG BEND 4 (Coal)**** | **5,575** | **458** | **425** | **1,467,328** | **1,336,581** | **35.9** | **60.3** | **56.4** | **10,126** | **11,116** |
| **BIG BEND 4 (Gas) *** | **1,355** | **428** | **418** | **91,558** | **83,267** | **2.3** | **60.3** | **14.7** | **10,050** | **11,050** |
| **BIG BEND 4** | **5,948** | **458** | **425** | **1,558,886** | **1,419,848** | **38.1** | **60.3** | **56.1** | **10,121** | **11,113** |
| **POLK 1 CT (Syngas)** | **-** | **290** | **220** | **-** | **(17,344)** | **-** | **-** | | **-** | **-** |
| **POLK 1 CT (Gas) *** | **4,582** | **170** | **161** | **495,684** | **474,121** | **33.7** | **75.0** | **64.4** | **11,618** | **12,146** |
| **POLK 1 ST** | **4,498** | **50** | **50** | **187,334** | **178,259** | **40.7** | **74.8** | **79.3** | | |
| **POLK 1 Total** | **4,582** | **220** | **211** | **683,018** | **635,036** | **34.4** | **75.0** | **65.8** | **8,431** | **9,068** |

**2023 GENERATION, FUEL, and PERFORMANCE REPORT**

| PLANT/UNIT | SERVICE HOURS | GROSS CAPAB-ILITY (MW) | NET CAPAB-ILITY (MW) | GROSS GENERATION (MWh) | NET GENERATION (MWh) | NET CAPACITY FACTOR (%) | NET EQ. AVAILABILITY FACTOR (%) | NET OUTPUT FACTOR (%) | AVG GROSS HEAT RATE (BTU/KWh) | AVG NET HEAT RATE (BTU/KWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| **BIG BEND 4 (Coal)**** | **3,404** | **458** | **425** | **810,492** | **769,413** | **20.7** | **54.4** | **53.1** | **10,143** | **10,684** |
| **BIG BEND 4 (Gas) *** | **3,331** | **428** | **413** | **276,938** | **263,553** | **7.3** | **54.4** | **19.1** | **10,786** | **11,334** |
| **BIG BEND 4** | **4,358** | **458** | **425** | **1,087,430** | **1,032,966** | **27.7** | **54.4** | **55.7** | **10,307** | **10,850** |
| **POLK 1 CT (Syngas)** | **-** | **300** | **230** | **-** | **(16,671)** | **-** | **-** | | **-** | **-** |
| **POLK 1 CT (Gas) *** | **1,149** | **183** | **168** | **115,492** | **105,510** | **7.2** | **96.8** | | **11,567** | **12,661** |
| **POLK 1 ST** | **1,116** | **50** | **50** | **44,176** | **38,213** | **8.7** | **96.7** | | | |
| **POLK 1 Total** | **1,149** | **233** | **218** | **159,668** | **127,053** | **6.7** | **96.7** | **50.9** | **8,367** | **10,514** |

# Exhibit DG-8:

# TECO response to SC IRR 31, Attachment (BS 28967) Sierra Club 1st Set 2024 - 2033 Firm Generators and RM IRR Q31

| Generator | Primary Fuel Type | 2024 | | 2025 | | 2026 | | 2027 | | 2028 | | 2029 | | 2030 | | 2031 | | 2032 | | 2033 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | W | S | W | S | W | S | W | S | W | S | W | S | W | S | W | S | W | S | W | S |
| BB 4 dual fuel | Natural Gas | 442 | 437 | 442 | 437 | 442 | 437 | 442 | 437 | 442 | 437 | 442 | 437 | 442 | 437 | 442 | 437 | 442 | 437 | 442 | 437 |
| BB CT 4 | Natural Gas | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 |
| BB1 Modernization | Natural Gas | 1,120 | 1,055 | 1,120 | 1,055 | 1,120 | 1,055 | 1,120 | 1,055 | 1,120 | 1,055 | 1,120 | 1,055 | 1,120 | 1,055 | 1,120 | 1,055 | 1,120 | 1,055 | 1,120 | 1,055 |
| Bayside 1 | Natural Gas | 847 | 749 | 847 | 749 | 847 | 749 | 847 | 749 | 847 | 749 | 847 | 749 | 847 | 749 | 847 | 749 | 847 | 749 | 847 | 749 |
| Bayside 2 | Natural Gas | 1,047 | 999 | 1,121 | 999 | 1,121 | 999 | 1,121 | 999 | 1,121 | 999 | 1,121 | 999 | 1,121 | 999 | 1,121 | 999 | 1,121 | 999 | 1,121 | 999 |
| Bayside 3 | Natural Gas | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 |
| Bayside 4 | Natural Gas | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 |
| Bayside 5 | Natural Gas | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 |
| Bayside 6 | Natural Gas | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 | 61 | 56 |
| Polk 1 | Natural Gas | 220 | 220 | 220 | 190 | 203 | 190 | 203 | 190 | 203 | 190 | 203 | 190 | 203 | 190 | 203 | 190 | 203 | 190 | 203 | 190 |
| Polk 2 CC | Natural Gas | 1,200 | 1,061 | 1,200 | 1,061 | 1,200 | 1,061 | 1,200 | 1,061 | 1,200 | 1,061 | 1,200 | 1,061 | 1,200 | 1,061 | 1,200 | 1,061 | 1,200 | 1,061 | 1,200 | 1,061 |
| TIA Solar | Solar | - | 0.7 | - | 0.7 | - | 0.7 | - | 0.7 | - | 0.6 | - | 0.6 | - | 0.6 | - | 0.6 | - | 0.6 | - | 0.6 |
| Big Bend Solar & Battery | Solar | 12.6 | 19.8 | 12.6 | 19.8 | 12.6 | 19.8 | 12.6 | 19.8 | 12.6 | 19.8 | 12.6 | 19.8 | 12.6 | 19.8 | 12.6 | 19.8 | 12.6 | 19.8 | 12.6 | 19.8 |
| LegoLand Solar | Solar | - | 0.5 | - | 0.5 | - | 0.5 | - | 0.4 | - | 0.4 | - | 0.4 | - | 0.4 | - | 0.4 | - | 0.4 | - | 0.4 |
| Balm Solar | Solar | - | 41.2 | - | 41.0 | - | 40.9 | - | 40.7 | - | 40.5 | - | 40.4 | - | 40.2 | - | 40.1 | - | 39.9 | - | 39.7 |
| Payne Creek Solar | Solar | - | 39.9 | - | 39.7 | - | 39.5 | - | 39.4 | - | 39.2 | - | 39.1 | - | 38.9 | - | 38.8 | - | 38.6 | - | 38.4 |
| Lithia Solar | Solar | - | 37.7 | - | 37.6 | - | 37.4 | - | 37.3 | - | 37.1 | - | 37.0 | - | 36.8 | - | 36.7 | - | 36.5 | - | 36.4 |
| Grange Hall Solar | Solar | - | 33.4 | - | 33.3 | - | 33.2 | - | 33.0 | - | 32.9 | - | 32.8 | - | 32.6 | - | 32.5 | - | 32.4 | - | 32.3 |
| Peace Creek Solar | Solar | - | 30.5 | - | 30.4 | - | 30.3 | - | 30.1 | - | 30.0 | - | 29.9 | - | 29.8 | - | 29.7 | - | 29.5 | - | 29.4 |
| Bonnie Mine Solar | Solar | - | 17.8 | - | 17.8 | - | 17.7 | - | 17.6 | - | 17.5 | - | 17.5 | - | 17.4 | - | 17.3 | - | 17.3 | - | 17.2 |
| Lake Hancock Solar | Solar | - | 26.1 | - | 26.0 | - | 25.9 | - | 25.8 | - | 25.7 | - | 25.6 | - | 25.5 | - | 25.4 | - | 25.3 | - | 25.2 |
| Wimauma Solar | Solar | - | 42.0 | - | 41.8 | - | 41.6 | - | 41.5 | - | 41.3 | - | 41.1 | - | 41.0 | - | 40.8 | - | 40.6 | - | 40.5 |
| Little Manatee River Solar | Solar | - | 37.9 | - | 37.7 | - | 37.6 | - | 37.4 | - | 37.3 | - | 37.1 | - | 37.0 | - | 36.8 | - | 36.7 | - | 36.5 |
| Durrance Solar | Solar | - | 34.4 | - | 34.3 | - | 34.1 | - | 34.0 | - | 33.9 | - | 33.7 | - | 33.6 | - | 33.5 | - | 33.3 | - | 33.2 |
| Magnolia Solar | Solar | - | 18.8 | - | 18.8 | - | 18.7 | - | 18.6 | - | 18.5 | - | 18.5 | - | 18.4 | - | 18.3 | - | 18.3 | - | 18.2 |
| Mountain View Solar | Solar | - | 13.8 | - | 13.8 | - | 13.7 | - | 13.6 | - | 13.6 | - | 13.5 | - | 13.5 | - | 13.4 | - | 13.4 | - | 13.3 |
| Jamison Solar | Solar | - | 18.8 | - | 18.8 | - | 18.7 | - | 18.6 | - | 18.5 | - | 18.5 | - | 18.4 | - | 18.3 | - | 18.3 | - | 18.2 |
| Big Bend II Solar | Solar | - | 11.6 | - | 11.5 | - | 11.5 | - | 11.4 | - | 11.4 | - | 11.4 | - | 11.3 | - | 11.3 | - | 11.2 | - | 11.2 |
| Riverside Solar | Solar | - | 13.9 | - | 13.9 | - | 13.8 | - | 13.7 | - | 13.7 | - | 13.6 | - | 13.6 | - | 13.5 | - | 13.5 | - | 13.4 |
| Laurel Oaks Solar | Solar | - | 15.5 | - | 15.4 | - | 15.4 | - | 15.3 | - | 15.2 | - | 15.2 | - | 15.1 | - | 15.1 | - | 15.0 | - | 14.9 |
| Juniper Solar | Solar | - | 17.8 | - | 17.7 | - | 17.6 | - | 17.6 | - | 17.5 | - | 17.4 | - | 17.4 | - | 17.3 | - | 17.2 | - | 17.2 |
| Dover Solar | Solar | - | 6.3 | - | 6.3 | - | 6.3 | - | 6.3 | - | 6.2 | - | 6.2 | - | 6.2 | - | 6.2 | - | 6.2 | - | 6.1 |
| Alafia Solar | Solar | - | 15.2 | - | 15.2 | - | 15.1 | - | 15.1 | - | 15.0 | - | 14.9 | - | 14.9 | - | 14.8 | - | 14.8 | - | 14.7 |
| Lake Mabel Solar | Solar | - | 18.9 | - | 18.8 | - | 18.8 | - | 18.7 | - | 18.6 | - | 18.5 | - | 18.5 | - | 18.4 | - | 18.3 | - | 18.3 |
| Bullfrog Creek Solar | Solar | - | - | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 |
| English Creek Solar | Solar | - | - | - | 1.2 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 |
| Cottonmouth Solar | Solar | - | - | - | - | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 |
| Duette Solar | Solar | - | - | - | - | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 |
| Big Four Solar | Solar | - | - | - | - | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 | - | 3.7 |
| Farmland Solar | Solar | - | - | - | - | - | - | - | 2.7 | - | 2.7 | - | 2.7 | - | 2.7 | - | 2.7 | - | 2.7 | - | 2.7 |
| Brewster Solar | Solar | - | - | - | - | - | - | - | 0.6 | - | 0.6 | - | 0.6 | - | 0.6 | - | 0.6 | - | 0.6 | - | 0.6 |
| Wimauma 3 Solar | Solar | - | - | - | - | - | - | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 |
| Clear Springs I Solar | Solar | - | - | - | - | - | - | - | - | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 |
| Future Solar I | Solar | - | - | - | - | - | - | - | - | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 |
| Clear Springs II Solar | Solar | - | - | - | - | - | - | - | - | - | - | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 |
| Mattaniah Solar | Solar | - | - | - | - | - | - | - | - | - | - | - | 0.8 | - | 0.8 | - | 0.8 | - | 0.8 | - | 0.8 |
| Future Solar 2 | Solar | - | - | - | - | - | - | - | - | - | - | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 | - | 1.1 |
| Future Solar 3 | Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | 1.5 | - | 1.5 | - | 1.5 | - | 1.5 |
| Future Solar 4 | Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1.5 | - | 1.5 | - | 1.5 |
| Future Solar 5 | Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1.5 | - | 1.5 |
| Future Solar 6 | Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1.5 |
| Future Solar 7 | Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| South Tampa Resilience Project | Natural Gas | - | - | - | 37.6 | 38 | 75.2 | 75 | 75.2 | 75 | 75.2 | 75 | 75.2 | 75 | 75.2 | 75 | 75.2 | 75 | 75.2 | 75 | 75.2 |
| Dover Energy Storage Capacity | N/A | - | - | 15 | 15.0 | 15 | 15.0 | 15 | 15.0 | 15 | 15.0 | 15 | 15.0 | 15 | 15.0 | 15 | 15.0 | 15 | 15.0 | 15 | 15.0 |
| Lake Mabel Energy Storage Capacity | N/A | - | - | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 |
| Wimauma Energy Storage Capacity | N/A | - | - | - | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 | 40 | 40.0 |
| South Tampa Energy Storage Capacity | N/A | - | - | - | 20.0 | 20 | 20.0 | 20 | 20.0 | 20 | 20.0 | 20 | 20.0 | 20 | 20.0 | 20 | 20.0 | 20 | 20.0 | 20 | 20.0 |
| Battery Storage 1 | N/A | - | - | - | - | - | - | - | - | 70 | 70.0 | 70 | 70.0 | 70 | 70.0 | 70 | 70.0 | 70 | 70.0 | 70 | 70.0 |
| Future CT | Natural Gas | - | - | - | - | - | - | - | - | - | - | - | - | 247 | 221.7 | 247 | 221.7 | 247 | 221.7 | 247 | 221.7 |
| **Total TEC Generation** | | 5,194 | 5,314 | 5,323 | 5,439 | 5,403 | 5,486 | 5,441 | 5,488 | 5,511 | 5,559 | 5,511 | 5,560 | 5,758 | 5,781 | 5,758 | 5,780 | 5,758 | 5,780 | 5,758 | 5,779 |
| **Firm Import** | | 400 | - | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| **Total TEC System Load** | | 4,292 | 4,143 | 4,345 | 4,182 | 4,404 | 4,222 | 4,461 | 4,261 | 4,517 | 4,302 | 4,572 | 4,343 | 4,626 | 4,385 | 4,679 | 4,427 | 4,729 | 4,469 | 4,780 | 4,511 |
| **Reserve Margin (%)** | | 30% | 28% | 23% | 30% | 23% | 30% | 22% | 29% | 22% | 30% | 21% | 28% | 25% | 32% | 23% | 31% | 22% | 30% | 21% | 29% |

# Exhibit DG-9:

# EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Unit-Level Costs and Loadings Estimates for the 2024 Final Rule (DCN SE11756A1), April 22, 2024

**Unit-Level Costs and Loadings Estimates for the 2024 Final Rule (DCN SE11756A1)**
4/22/2024

| Worksheet | Description |
|---|---|
| FGD Unit-Level Cost Estimates | Presents unit-level costs for flue gas desulfurization (FGD) wastewater treatment under all regulatory options. |
| BA Unit-Level Cost Estimates | Presents unit-level costs for bottom ash (BA) transport water handling under all regulatory options. |
| CRL Unit-Level Cost Estimates | Presents unit-level costs for combustion residual leachate (CRL) treatment under all regulatory options. |
| Legacy Unit-Level Costs | Presents unit-level costs for legacy wastewater treatment under all regulatory options. |
| FGD Unit-Level Loadings | Presents unit-level total pollutant loadings for FGD wastewater under baseline and all regulatory options. |
| BA Unit-Level Loadings | Presents unit-level total pollutant loadings for BA transport water under baseline and all regulatory options. |
| CRL Unit-Level Loadings | Presents unit-level total pollutant loadings for CRL under baseline and all regulatory options. |
| Legacy Unit-Level Loadings | Presents unit-level total pollutant loadings for legacy wastewater under baseline and all regulatory options. |

Available at: https://downloads.regulations.gov/EPA-HQ-OW-2009-0819-10336/attachment_1.xlsx

| EPA ICR ID | Plant Name | SE Unit ID | Capacity (MW) | Retire or Fuel Conversion Year | FGD Regulatory Option A | FGD Regulatory Option A Capital Cost (2023$) | FGD Regulatory Option A O&M Cost (2023$/yr) | FGD Regulatory Option A One-Time Cost (2023$) | FGD Regulatory Option B | Least Cost (Regulatory Options B and C) | FGD Regulatory Option B Capital Cost (2023$) | FGD Regulatory Option B O&M Cost (2023$/yr) | FGD Regulatory Option B One-Time Cost (2023$) | FGD Regulatory Option C | Least Cost (Regulatory Options B and C) | FGD Regulatory Option C Capital Cost (2023$) | FGD Regulatory Option C O&M Cost (2023$/yr) | FGD Regulatory Option C One-Time Cost (2023$) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 771 | OVEC - Kyger Creek Station | SE Unit-1 | 217 | 2040 | Zero Discharge | $7,530,127 | $1,042,267 | $38,094 | Zero Discharge | Membrane | $7,530,127 | $1,042,267 | $38,094 | Zero Discharge | Membrane | $7,530,127 | $1,042,267 | $38,094 |
| 771 | OVEC - Kyger Creek Station | SE Unit-2 | 217 | 2040 | Zero Discharge | $7,530,127 | $1,042,267 | $38,094 | Zero Discharge | Membrane | $7,530,127 | $1,042,267 | $38,094 | Zero Discharge | Membrane | $7,530,127 | $1,042,267 | $38,094 |
| 771 | OVEC - Kyger Creek Station | SE Unit-3 | 217 | 2040 | Zero Discharge | $5,020,085 | $694,845 | $25,396 | Zero Discharge | Membrane | $5,020,085 | $694,845 | $25,396 | Zero Discharge | Membrane | $5,020,085 | $694,845 | $25,396 |
| 771 | OVEC - Kyger Creek Station | SE Unit-4 | 217 | 2040 | Zero Discharge | $5,020,085 | $694,845 | $25,396 | Zero Discharge | Membrane | $5,020,085 | $694,845 | $25,396 | Zero Discharge | Membrane | $5,020,085 | $694,845 | $25,396 |
| 771 | OVEC - Kyger Creek Station | SE Unit-5 | 217 | 2040 | Zero Discharge | $5,020,085 | $694,845 | $25,396 | Zero Discharge | Membrane | $5,020,085 | $694,845 | $25,396 | Zero Discharge | Membrane | $5,020,085 | $694,845 | $25,396 |
| 864 | Williams Station | SE Unit-1 | 586 | 2032 | CP+LRTR | $0 | $0 | $0 | CP+LRTR | Membrane | $0 | $0 | $0 | Zero Discharge | Membrane | $9,354,963 | $1,623,054 | $152,374 |
| 904 | Muscatine Power and Water Generating Station | SE Unit-4 | 176 | 2052 | Zero Discharge | $2,927,023 | $279,118 | $152,374 | Zero Discharge | Membrane | $2,927,023 | $279,118 | $152,374 | Zero Discharge | Membrane | $2,927,023 | $279,118 | $152,374 |
| 1236 | Mitchell Plant | SE Unit-1 | 816 | 2040 | Zero Discharge | $26,105,492 | $3,032,065 | $0 | Zero Discharge | SDE | $26,105,492 | $3,032,065 | $0 | Zero Discharge | SDE | $26,105,492 | $3,032,065 | $0 |
| 1236 | Mitchell Plant | SE Unit-2 | 816 | 2040 | Zero Discharge | $26,105,492 | $3,032,065 | $0 | Zero Discharge | SDE | $26,105,492 | $3,032,065 | $0 | Zero Discharge | SDE | $26,105,492 | $3,032,065 | $0 |
| 1493 | Plant James H Miller Jr | SE Unit-1 | 706 | | Zero Discharge | $6,347,445 | $164,488 | $38,285 | Zero Discharge | Membrane | $6,347,445 | $164,488 | $38,285 | Zero Discharge | Membrane | $6,347,445 | $164,488 | $38,285 |
| 1493 | Plant James H Miller Jr | SE Unit-2 | 706 | | Zero Discharge | $6,305,039 | $163,389 | $38,030 | Zero Discharge | Membrane | $6,305,039 | $163,389 | $38,030 | Zero Discharge | Membrane | $6,305,039 | $163,389 | $38,030 |
| 1493 | Plant James H Miller Jr | SE Unit-3 | 706 | | Zero Discharge | $6,305,039 | $163,389 | $38,030 | Zero Discharge | Membrane | $6,305,039 | $163,389 | $38,030 | Zero Discharge | Membrane | $6,305,039 | $163,389 | $38,030 |
| 1493 | Plant James H Miller Jr | SE Unit-4 | 706 | | Zero Discharge | $6,305,039 | $163,389 | $38,030 | Zero Discharge | Membrane | $6,305,039 | $163,389 | $38,030 | Zero Discharge | Membrane | $6,305,039 | $163,389 | $38,030 |
| 1674 | Trimble County | SE Unit-1 | 566 | 2066 | Zero Discharge | $21,252,482 | $1,980,388 | $0 | Zero Discharge | SDE | $21,252,482 | $1,980,388 | $0 | Zero Discharge | SDE | $21,252,482 | $1,980,388 | $0 |
| 1674 | Trimble County | SE Unit-A | 738 | 2066 | Zero Discharge | $149,296,648 | $13,912,037 | $0 | Zero Discharge | SDE | $149,296,648 | $13,912,037 | $0 | Zero Discharge | SDE | $149,296,648 | $13,912,037 | $0 |
| 2244 | Georgia Power Company - Plant Bowen | SE Unit-1 | 806 | | Zero Discharge | $56,141,266 | $2,397,631 | $0 | Zero Discharge | SDE | $56,141,266 | $2,397,631 | $0 | Zero Discharge | SDE | $56,141,266 | $2,397,631 | $0 |
| 2244 | Georgia Power Company - Plant Bowen | SE Unit-2 | 789 | | Zero Discharge | $69,934,594 | $2,986,704 | $0 | Zero Discharge | SDE | $69,934,594 | $2,986,704 | $0 | Zero Discharge | SDE | $69,934,594 | $2,986,704 | $0 |
| 2244 | Georgia Power Company - Plant Bowen | SE Unit-3 | 952 | 2035 | Zero Discharge | $53,963,372 | $2,304,619 | $0 | Zero Discharge | SDE | $53,963,372 | $2,304,619 | $0 | Zero Discharge | SDE | $53,963,372 | $2,304,619 | $0 |
| 2244 | Georgia Power Company - Plant Bowen | SE Unit-4 | 952 | 2035 | Zero Discharge | $52,027,466 | $2,221,942 | $0 | Zero Discharge | SDE | $52,027,466 | $2,221,942 | $0 | Zero Discharge | SDE | $52,027,466 | $2,221,942 | $0 |
| 2601 | Ghent | SE Unit-1 | 557 | 2037 | Zero Discharge | $25,778,330 | $1,493,811 | $0 | Zero Discharge | SDE | $25,778,330 | $1,493,811 | $0 | Zero Discharge | SDE | $25,778,330 | $1,493,811 | $0 |
| 2601 | Ghent | SE Unit-3 | 557 | 2037 | Zero Discharge | $16,680,096 | $966,584 | $0 | Zero Discharge | SDE | $16,680,096 | $966,584 | $0 | Zero Discharge | SDE | $16,680,096 | $966,584 | $0 |
| 2601 | Ghent | SE Unit-4 | 556 | 2037 | Zero Discharge | $26,536,516 | $1,537,747 | $0 | Zero Discharge | SDE | $26,536,516 | $1,537,747 | $0 | Zero Discharge | SDE | $26,536,516 | $1,537,747 | $0 |
| 3235 | Cross Generating Station | SE Unit-1 | 591 | | Membrane filtration[a] | $0 | $0 | $0 | Membrane filtration[a] | | $0 | $0 | $0 | Zero Discharge[a] | | $0 | $0 | $0 |
| 3235 | Cross Generating Station | SE Unit-2 | 556 | | Membrane filtration[a] | $0 | $0 | $0 | Membrane filtration[a] | | $0 | $0 | $0 | Zero Discharge[a] | | $0 | $0 | $0 |
| 3235 | Cross Generating Station | SE Unit-3 | 652 | | Membrane filtration[a] | $0 | $0 | $0 | Membrane filtration[a] | | $0 | $0 | $0 | Zero Discharge[a] | | $0 | $0 | $0 |
| 3235 | Cross Generating Station | SE Unit-4 | 652 | | Membrane filtration[a] | $0 | $0 | $0 | Membrane filtration[a] | | $0 | $0 | $0 | Zero Discharge[a] | | $0 | $0 | $0 |
| 3265 | Cardinal | SE Unit-1 | 615 | 2052 | Zero Discharge | $29,190,003 | $1,435,600 | $0 | Zero Discharge | SDE | $29,190,003 | $1,435,600 | $0 | Zero Discharge | SDE | $29,190,003 | $1,435,600 | $0 |
| 3265 | Cardinal | SE Unit-2 | 615 | 2052 | Zero Discharge | $33,134,599 | $1,629,600 | $0 | Zero Discharge | SDE | $33,134,599 | $1,629,600 | $0 | Zero Discharge | SDE | $33,134,599 | $1,629,600 | $0 |
| 3464 | W. A. Parish E.G.S. | SE Unit-8 | 615 | 2045 | Zero Discharge | $9,217,699 | $1,178,981 | $152,374 | Zero Discharge | Membrane | $9,217,699 | $1,178,981 | $152,374 | Zero Discharge | Membrane | $9,217,699 | $1,178,981 | $152,374 |
| 3597 | Marshall Steam Station | SE Unit-3 | 710 | 2032 | CP+LRTR | $0 | $0 | $0 | CP+LRTR | Membrane | $0 | $0 | $0 | Zero Discharge | Membrane | $8,300,907 | $1,498,699 | $97,749 |
| 3597 | Marshall Steam Station | SE Unit-4 | 710 | 2032 | CP+LRTR | $0 | $0 | $0 | CP+LRTR | Membrane | $0 | $0 | $0 | Zero Discharge | Membrane | $4,638,742 | $837,508 | $54,625 |
| 3604 | Mill Creek | SE Unit-3 | 411 | 2052 | Zero Discharge | $5,867,772 | $776,910 | $68,181 | Zero Discharge | Membrane | $5,867,772 | $776,910 | $68,181 | Zero Discharge | Membrane | $5,867,772 | $776,910 | $68,181 |
| 3604 | Mill Creek | SE Unit-4 | 496 | 2052 | Zero Discharge | $7,245,778 | $959,362 | $84,193 | Zero Discharge | Membrane | $7,245,778 | $959,362 | $84,193 | Zero Discharge | Membrane | $7,245,778 | $959,362 | $84,193 |
| 4533 | Monroe Power Plant | SE Unit-1 | 817 | 2032 | Membrane filtration | $0 | $0 | $0 | Membrane filtration | | $0 | $0 | $0 | Zero Discharge | | $0 | $0 | $0 |
| 4533 | Monroe Power Plant | SE Unit-2 | 823 | 2032 | Membrane filtration | $0 | $0 | $0 | Membrane filtration | | $0 | $0 | $0 | Zero Discharge | | $0 | $0 | $0 |
| 4543 | Mountaineer Plant | SE Unit-1 | 1,300 | 2040 | Zero Discharge | $16,996,965 | $2,698,915 | $152,374 | Zero Discharge | Membrane | $16,996,965 | $2,698,915 | $152,374 | Zero Discharge | Membrane | $16,996,965 | $2,698,915 | $152,374 |
| 5318 | Clifty Creek Station | SE Unit-1 | 217 | 2040 | Zero Discharge | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 |
| 5318 | Clifty Creek Station | SE Unit-2 | 217 | 2040 | Zero Discharge | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 |
| 5318 | Clifty Creek Station | SE Unit-3 | 217 | 2040 | Zero Discharge | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 |
| 5318 | Clifty Creek Station | SE Unit-4 | 217 | 2040 | Zero Discharge | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 |
| 5318 | Clifty Creek Station | SE Unit-5 | 217 | 2040 | Zero Discharge | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 |
| 5318 | Clifty Creek Station | SE Unit-6 | 217 | 2040 | Zero Discharge | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 | Zero Discharge | SDE | $10,480,077 | $607,735 | $0 |
| 6334 | Leland Olds Station | SE Unit-1 | 216 | 2052 | Zero Discharge | $6,906,514 | $926,454 | $67,139 | Zero Discharge | Membrane | $6,906,514 | $926,454 | $67,139 | Zero Discharge | Membrane | $6,906,514 | $926,454 | $67,139 |
| 6334 | Leland Olds Station | SE Unit-2 | 440 | 2052 | Zero Discharge | $8,768,147 | $1,176,177 | $85,236 | Zero Discharge | Membrane | $8,768,147 | $1,176,177 | $85,236 | Zero Discharge | Membrane | $8,768,147 | $1,176,177 | $85,236 |
| 6377 | Tampa Electric - Big Bend Station | SE Unit-4 | 486 | 2052 | Zero Discharge | $129,250,339 | $9,090,395 | $0 | Zero Discharge | SDE | $129,250,339 | $9,090,395 | $0 | Zero Discharge | SDE | $129,250,339 | $9,090,395 | $0 |
| 7411 | Winyah Generating Station | SE Unit-1 | 315 | 2031 | CP+LRTR | $0 | $0 | $0 | CP+LRTR | SDE | $0 | $0 | $0 | Zero Discharge | SDE | $16,682,563 | $671,282 | $0 |
| 7411 | Winyah Generating Station | SE Unit-2 | 315 | 2031 | CP+LRTR | $0 | $0 | $0 | CP+LRTR | SDE | $0 | $0 | $0 | Zero Discharge | SDE | $18,858,549 | $758,840 | $0 |
| 7411 | Winyah Generating Station | SE Unit-3 | 315 | 2031 | CP+LRTR | $0 | $0 | $0 | CP+LRTR | SDE | $0 | $0 | $0 | Zero Discharge | SDE | $17,822,365 | $717,146 | $0 |
| 7411 | Winyah Generating Station | SE Unit-4 | 315 | 2031 | CP+LRTR | $0 | $0 | $0 | CP+LRTR | SDE | $0 | $0 | $0 | Zero Discharge | SDE | $18,858,549 | $758,840 | $0 |
| 7785 | Seminole Generating Station | SE Unit-2 | 715 | 2052 | Zero Discharge | $24,487,095 | $3,540,495 | $152,374 | Zero Discharge | Membrane | $24,487,095 | $3,540,495 | $152,374 | Zero Discharge | Membrane | $24,487,095 | $3,540,495 | $152,374 |
| 8179 | Plant Scherer | SE Unit-1 | 891 | | Membrane filtration | $0 | $0 | $0 | Membrane filtration | | $0 | $0 | $0 | Zero Discharge | | $0 | $0 | $0 |
| 8179 | Plant Scherer | SE Unit-2 | 891 | | Membrane filtration | $0 | $0 | $0 | Membrane filtration | | $0 | $0 | $0 | Zero Discharge | | $0 | $0 | $0 |
| 8353 | Jeffrey Energy Center | SE Unit-1 | 681 | 2039 | Zero Discharge | $24,665,899 | $1,179,913 | $0 | Zero Discharge | SDE | $24,665,899 | $1,179,913 | $0 | Zero Discharge | SDE | $24,665,899 | $1,179,913 | $0 |
| 8353 | Jeffrey Energy Center | SE Unit-2 | 681 | 2039 | Zero Discharge | $24,665,899 | $1,179,913 | $0 | Zero Discharge | SDE | $24,665,899 | $1,179,913 | $0 | Zero Discharge | SDE | $24,665,899 | $1,179,913 | $0 |
| 8353 | Jeffrey Energy Center | SE Unit-3 | 681 | 2030 | Retire by compliance date[a] | $0 | $0 | $0 | Retire by compliance date[a] | SDE | $0 | $0 | $0 | Retire by compliance date[a] | SDE | $0 | $0 | $0 |
| 8661 | Belews Creek Steam Station | SE Unit-1 | 1,245 | 2035 | Zero Discharge | $21,940,449 | $1,640,965 | $0 | Zero Discharge | SDE | $21,940,449 | $1,640,965 | $0 | Zero Discharge | SDE | $21,940,449 | $1,640,965 | $0 |
| 8661 | Belews Creek Steam Station | SE Unit-2 | 1,245 | 2035 | Zero Discharge | $25,074,798 | $1,875,389 | $0 | Zero Discharge | SDE | $25,074,798 | $1,875,389 | $0 | Zero Discharge | SDE | $25,074,798 | $1,875,389 | $0 |
| 9161 | John E. Amos Plant | SE Unit-1 | 816 | 2040 | Zero Discharge | $125,176,943 | $7,387,054 | $0 | Zero Discharge | SDE | $125,176,943 | $7,387,054 | $0 | Zero Discharge | SDE | $125,176,943 | $7,387,054 | $0 |
| 9161 | John E. Amos Plant | SE Unit-2 | 816 | 2040 | Zero Discharge | $40,609,689 | $2,396,495 | $0 | Zero Discharge | SDE | $40,609,689 | $2,396,495 | $0 | Zero Discharge | SDE | $40,609,689 | $2,396,495 | $0 |
| 9161 | John E. Amos Plant | SE Unit-3 | 1,300 | 2040 | Zero Discharge | $29,191,580 | $1,722,680 | $0 | Zero Discharge | SDE | $29,191,580 | $1,722,680 | $0 | Zero Discharge | SDE | $29,191,580 | $1,722,680 | $0 |
| 9225 | Fort Martin Power Station | SE Unit-1 | 552 | 2052 | Zero Discharge | $10,750,099 | $1,661,549 | $75,331 | Zero Discharge | Membrane | $10,750,099 | $1,661,549 | $75,331 | Zero Discharge | Membrane | $10,750,099 | $1,661,549 | $75,331 |
| 9225 | Fort Martin Power Station | SE Unit-2 | 555 | 2052 | Zero Discharge | $10,994,420 | $1,699,311 | $77,043 | Zero Discharge | Membrane | $10,994,420 | $1,699,311 | $77,043 | Zero Discharge | Membrane | $10,994,420 | $1,699,311 | $77,043 |
| 9391 | Roxboro Steam Plant | SE Unit-1 | 411 | 2029 | Retire by compliance date | $0 | $0 | $0 | Retire by compliance date | SDE | $0 | $0 | $0 | Retire by compliance date | SDE | $0 | $0 | $0 |
| 9391 | Roxboro Steam Plant | SE Unit-2 | 657 | 2029 | Retire by compliance date | $0 | $0 | $0 | Retire by compliance date | SDE | $0 | $0 | $0 | Retire by compliance date | SDE | $0 | $0 | $0 |
| 9391 | Roxboro Steam Plant | SE Unit-3 | 745 | 2034 | CP+LRTR | $0 | $0 | $0 | CP+LRTR | SDE | $0 | $0 | $0 | Zero Discharge | SDE | $47,656,977 | $3,110,401 | $0 |
| 9391 | Roxboro Steam Plant | SE Unit-4 | 745 | 2034 | CP+LRTR | $0 | $0 | $0 | CP+LRTR | SDE | $0 | $0 | $0 | Zero Discharge | SDE | $46,764,524 | $3,052,153 | $0 |
| 9971 | Dallman | SE Unit-4 | 230 | 2045 | Zero Discharge | $37,789,489 | $2,332,221 | $0 | Zero Discharge | SDE | $37,789,489 | $2,332,221 | $0 | Zero Discharge | SDE | $37,789,489 | $2,332,221 | $0 |
| 56068 | Elm Road Generating Station | SE Unit-A | 701 | 2035 | Zero Discharge | $20,786,218 | $1,549,694 | $0 | Zero Discharge | SDE | $20,786,218 | $1,549,694 | $0 | Zero Discharge | SDE | $20,786,218 | $1,549,694 | $0 |
| 56068 | Elm Road Generating Station | SE Unit-B | 701 | 2035 | Zero Discharge | $20,786,218 | $1,549,694 | $0 | Zero Discharge | SDE | $20,786,218 | $1,549,694 | $0 | Zero Discharge | SDE | $20,786,218 | $1,549,694 | $0 |
| | | | | | | **$1,308,508,921** | **$94,202,607** | **$1,371,367** | | | **$1,308,508,921** | **$94,202,607** | **$1,371,367** | | | **$1,497,447,060** | **$107,230,530** | **$1,676,115** |

Abbreviations: CP+LRTR (chemical precipitation plus low residence time reduction); SDE (spray dryer evaporator).

a - The EPA made adjustments to select electric generating units following final regulatory option cost estimation. Refer to the Updates to Estimated Compliance Costs and Pollutant Loadings memorandum for more information (DCN SE11780).

| EPA ICR ID | Plant Name | SE Unit ID | Retire or Fuel Conversion Year | CRL Regulatory Option A | CRL Regulatory Option A Capital Cost (2023$) | CRL Regulatory Option A O&M Cost (2023$/yr) | CRL Regulatory Option A One Time Cost (2023$) | CRL Regulatory Option A 6 Year Cost (2023$) | CRL Regulatory Option B | CRL Regulatory Option B Least Cost | CRL Regulatory Option B Capital Cost (2023$) | CRL Regulatory Option B O&M Cost (2023$/yr) | CRL Regulatory Option B One Time Cost (2023$) | CRL Regulatory Option B 6 Year Cost (2023$) | CRL Regulatory Option C | CRL Regulatory Option C Least Cost | CRL Regulatory Option C Capital Cost (2023$) | CRL Regulatory Option C O&M Cost (2023$/yr) | CRL Regulatory Option C One Time Cost (2023$) | CRL Regulatory Option C 6 Year Cost (2023$) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 34 | Edgewater Generating Station | SE Unit-5 | 2025 | CP - retired or NG | $11,371,632 | $396,453 | $0 | $147,211 | CP - retired or NG | CP - retired or NG | $11,371,632 | $396,453 | $0 | $147,211 | Zero Discharge | SDE (Zero Discharge) | $26,538,859 | $1,259,617 | $0 | $0 |
| 217 | Iatan Generating Station | SE Unit-1 | 2039 | CP | $4,967,893 | $194,662 | $0 | $65,168 | Zero Discharge | SDE (Zero Discharge) | $7,495,623 | $156,346 | $0 | $0 | Zero Discharge | SDE (Zero Discharge) | $7,495,623 | $156,346 | $0 | $0 |
| 217 | Iatan Generating Station | SE Unit-A | | CP | $6,254,344 | $245,070 | $0 | $82,043 | Zero Discharge | SDE (Zero Discharge) | $9,436,638 | $196,832 | $0 | $0 | Zero Discharge | SDE (Zero Discharge) | $9,436,638 | $196,832 | $0 | $0 |
| 265 | Kingston | SE Unit-1 | 2027 | CP - retired or NG | $1,146,662 | $36,955 | $0 | $15,154 | CP - retired or NG | CP - retired or NG | $1,146,662 | $36,955 | $0 | $15,154 | Zero Discharge | SDE (Zero Discharge) | $2,123,492 | $72,256 | $0 | $0 |
| 265 | Kingston | SE Unit-2 | 2027 | CP - retired or NG | $1,146,662 | $36,955 | $0 | $15,154 | CP - retired or NG | CP - retired or NG | $1,146,662 | $36,955 | $0 | $15,154 | Zero Discharge | SDE (Zero Discharge) | $2,123,492 | $72,256 | $0 | $0 |
| 265 | Kingston | SE Unit-3 | 2027 | CP - retired or NG | $1,146,662 | $36,955 | $0 | $15,154 | CP - retired or NG | CP - retired or NG | $1,146,662 | $36,955 | $0 | $15,154 | Zero Discharge | SDE (Zero Discharge) | $2,123,492 | $72,256 | $0 | $0 |
| 265 | Kingston | SE Unit-4 | 2027 | CP - retired or NG | $1,146,662 | $36,955 | $0 | $15,154 | CP - retired or NG | CP - retired or NG | $1,146,662 | $36,955 | $0 | $15,154 | Zero Discharge | SDE (Zero Discharge) | $2,123,492 | $72,256 | $0 | $0 |
| 265 | Kingston | SE Unit-5 | 2027 | CP - retired or NG | $1,310,471 | $42,234 | $0 | $17,319 | CP - retired or NG | CP - retired or NG | $1,310,471 | $42,234 | $0 | $17,319 | Zero Discharge | SDE (Zero Discharge) | $2,426,848 | $82,578 | $0 | $0 |
| 265 | Kingston | SE Unit-6 | 2027 | CP - retired or NG | $1,310,471 | $42,234 | $0 | $17,319 | CP - retired or NG | CP - retired or NG | $1,310,471 | $42,234 | $0 | $17,319 | Zero Discharge | SDE (Zero Discharge) | $2,426,848 | $82,578 | $0 | $0 |
| 265 | Kingston | SE Unit-7 | 2027 | CP - retired or NG | $1,310,471 | $42,234 | $0 | $17,319 | CP - retired or NG | CP - retired or NG | $1,310,471 | $42,234 | $0 | $17,319 | Zero Discharge | SDE (Zero Discharge) | $2,426,848 | $82,578 | $0 | $0 |
| 265 | Kingston | SE Unit-8 | 2027 | CP - retired or NG | $1,310,471 | $42,234 | $0 | $17,319 | CP - retired or NG | CP - retired or NG | $1,310,471 | $42,234 | $0 | $17,319 | Zero Discharge | SDE (Zero Discharge) | $2,426,848 | $82,578 | $0 | $0 |
| 265 | Kingston | SE Unit-9 | 2027 | CP - retired or NG | $1,310,471 | $42,234 | $0 | $17,319 | CP - retired or NG | CP - retired or NG | $1,310,471 | $42,234 | $0 | $17,319 | Zero Discharge | SDE (Zero Discharge) | $2,426,848 | $82,578 | $0 | $0 |
| 270 | Tampa Electric - Polk Power Station | SE Unit-1 | | CP | $10,437,244 | $348,870 | $0 | $147,211 | Zero Discharge | SDE (Zero Discharge) | $14,973,142 | $168,323 | $0 | $0 | Zero Discharge | SDE (Zero Discharge) | $14,973,142 | $168,323 | $0 | $0 |
| 493 | J. K. Spruce Power Plant | SE Unit-1 | 2028 | CP - retired or NG | $4,290,136 | $138,264 | $0 | $56,698 | CP - retired or NG | CP - retired or NG | $4,290,136 | $138,264 | $0 | $56,698 | Zero Discharge | SDE (Zero Discharge) | $7,944,862 | $270,338 | $0 | $0 |
| 493 | J. K. Spruce Power Plant | SE Unit-2 | 2027 | CP - retired or NG | $6,848,865 | $220,727 | $0 | $90,514 | CP - retired or NG | CP - retired or NG | $6,848,865 | $220,727 | $0 | $90,514 | Zero Discharge | SDE (Zero Discharge) | $12,683,348 | $431,574 | $0 | $0 |
| 494 | Twin Oaks Power | SE Unit-1 | | CP | $6,532,690 | $326,537 | $0 | $73,606 | Zero Discharge | SDE (Zero Discharge) | $10,766,111 | $393,606 | $0 | $0 | Zero Discharge | SDE (Zero Discharge) | $10,766,111 | $393,606 | $0 | $0 |
| 494 | Twin Oaks Power | SE Unit-2 | | CP | $6,532,690 | $326,537 | $0 | $73,606 | Zero Discharge | SDE (Zero Discharge) | $10,766,111 | $393,606 | $0 | $0 | Zero Discharge | SDE (Zero Discharge) | $10,766,111 | $393,606 | $0 | $0 |
| 654 | Jack Watson | SE Unit-5 | 2015 | CP - retired or NG | $11,060,593 | $346,364 | $0 | $147,211 | CP - retired or NG | CP - retired or NG | $11,060,593 | $346,364 | $0 | $147,211 | Zero Discharge | SDE (Zero Discharge) | $18,636,054 | $513,940 | $0 | $0 |

| EPA ICR ID | Plant Name | SE Unit ID | Retire or Fuel Conversion Year | CRL Regulatory Option A | CRL Regulatory Option A Capital Cost (2023$) | CRL Regulatory Option A O&M Cost (2023$/yr) | CRL Regulatory Option A One Time Cost (2023$) | CRL Regulatory Option A 6 Year Cost (2023$) | CRL Regulatory Option B | CRL Regulatory Option B Least Cost |
|---|---|---|---|---|---|---|---|---|---|---|
| 5318 | Clifty Creek Station | SE Unit-4 | 2040 | CP | $2,860,199 | $187,861 | $0 | $24,535 | Zero Discharge | SDE (Zero Discharge) |
| 5318 | Clifty Creek Station | SE Unit-5 | 2040 | CP | $2,860,199 | $187,861 | $0 | $24,535 | Zero Discharge | SDE (Zero Discharge) |
| 5318 | Clifty Creek Station | SE Unit-6 | 2040 | CP | $2,860,199 | $187,861 | $0 | $24,535 | Zero Discharge | SDE (Zero Discharge) |
| 5839 | JH Campbell Power Plant | SE Unit-1 | 2025 | CP - retired or NG | $2,126,318 | $102,483 | $0 | $24,617 | CP - retired or NG | CP - retired or NG |
| 5839 | JH Campbell Power Plant | SE Unit-2 | 2025 | CP - retired or NG | $3,238,385 | $156,082 | $0 | $37,492 | CP - retired or NG | CP - retired or NG |
| 5839 | JH Campbell Power Plant | SE Unit-3 | 2025 | CP - retired or NG | $7,350,710 | $354,286 | $0 | $85,102 | CP - retired or NG | CP - retired or NG |
| 6176 | Walter Scott Jr. Energy Center | SE Unit-3 | | CP | $5,593,611 | $269,108 | $0 | $64,822 | Zero Discharge | SDE (Zero Discharge) |
| 6176 | Walter Scott Jr. Energy Center | SE Unit-4 | | CP | $7,109,543 | $342,039 | $0 | $82,389 | Zero Discharge | SDE (Zero Discharge) |
| 6279 | Gallatin | SE Unit-1 | 2031 | CP - retired or NG | $2,662,285 | $85,801 | $0 | $35,184 | CP - retired or NG | CP - retired or NG |
| 6279 | Gallatin | SE Unit-2 | 2031 | CP - retired or NG | $2,662,285 | $85,801 | $0 | $35,184 | CP - retired or NG | CP - retired or NG |
| 6279 | Gallatin | SE Unit-3 | 2031 | CP - retired or NG | $2,907,215 | $93,695 | $0 | $38,421 | CP - retired or NG | CP - retired or NG |
| 6279 | Gallatin | SE Unit-4 | 2031 | CP - retired or NG | $2,907,215 | $93,695 | $0 | $38,421 | CP - retired or NG | CP - retired or NG |
| 6549 | Bay Front Steam Plant | SE Unit-2 | 2018 | CP - retired or NG | $4,215,389 | $126,987 | $0 | $56,620 | CP - retired or NG | CP - retired or NG |
| 6549 | Bay Front Steam Plant | SE Unit-3 | 2018 | CP - retired or NG | $6,744,622 | $203,180 | $0 | $90,592 | CP - retired or NG | CP - retired or NG |
| 6596 | Interstate Power and Light - Ottumwa Generating Station | SE Unit-1 | | CP | $12,703,154 | $611,148 | $0 | $147,211 | Zero Discharge | SDE (Zero Discharge) |
| 6602 | Shawnee | SE Unit-1 | 2033 | CP | $1,411,462 | $67,905 | $0 | $16,357 | Zero Discharge | Membrane (Zero Discharge) |
| 6602 | Shawnee | SE Unit-2 | 2033 | CP | $1,411,462 | $67,905 | $0 | $16,357 | Zero Discharge | Membrane (Zero Discharge) |
| 6602 | Shawnee | SE Unit-3 | | CP | $1,411,462 | $67,905 | $0 | $16,357 | Zero Discharge | Membrane (Zero Discharge) |
| 6602 | Shawnee | SE Unit-4 | 2033 | CP | $1,411,462 | $67,905 | $0 | $16,357 | Zero Discharge | Membrane (Zero Discharge) |
| 6602 | Shawnee | SE Unit-5 | 2033 | CP | $1,411,462 | $67,905 | $0 | $16,357 | Zero Discharge | Membrane (Zero Discharge) |
| 6602 | Shawnee | SE Unit-6 | 2033 | CP | $1,411,462 | $67,905 | $0 | $16,357 | Zero Discharge | Membrane (Zero Discharge) |
| 6602 | Shawnee | SE Unit-7 | 2033 | CP | $1,411,462 | $67,905 | $0 | $16,357 | Zero Discharge | Membrane (Zero Discharge) |
| 6602 | Shawnee | SE Unit-8 | 2033 | CP | $1,411,462 | $67,905 | $0 | $16,357 | Zero Discharge | Membrane (Zero Discharge) |
| 6602 | Shawnee | SE Unit-9 | 2033 | CP | $1,411,462 | $67,905 | $0 | $16,357 | Zero Discharge | Membrane (Zero Discharge) |
| 6606 | New Madrid Power Plant | SE Unit-1 | | CP | $9,433,880 | $662,349 | $0 | $73,606 | Zero Discharge | SDE (Zero Discharge) |
| 6606 | New Madrid Power Plant | SE Unit-2 | | CP | $9,433,880 | $662,349 | $0 | $73,606 | Zero Discharge | SDE (Zero Discharge) |
| 6622 | Naughton Power Plant | SE Unit-1 | 2026 | CP - retired or NG | $2,597,241 | $87,144 | $0 | $33,972 | CP - retired or NG | CP - retired or NG |
| 6622 | Naughton Power Plant | SE Unit-2 | 2026 | CP - retired or NG | $3,462,988 | $116,192 | $0 | $45,296 | CP - retired or NG | CP - retired or NG |
| 6622 | Naughton Power Plant | SE Unit-3 | 2019 | CP - retired or NG | $5,194,482 | $174,288 | $0 | $67,944 | CP - retired or NG | CP - retired or NG |
| 6672 | Choctaw Generation, LP | SE Unit-1 | | CP | $15,454,632 | $929,629 | $0 | $147,211 | Zero Discharge | SDE (Zero Discharge) |
| 6689 | Mayo Electric Generating Plant | SE Unit-1 | 2028 | CP - retired or NG | $11,139,000 | $358,991 | $0 | $147,211 | CP - retired or NG | CP - retired or NG |
| 6848 | George Neal North | SE Unit-3 | | CP | $11,092,585 | $424,725 | $0 | $147,211 | Zero Discharge | SDE (Zero Discharge) |
| 6933 | Northeastern Power Station | SE Unit-3 | 2026 | CP - retired or NG | $11,139,000 | $358,991 | $0 | $147,211 | CP - retired or NG | CP - retired or NG |
| 7135 | Harrison Power Station | SE Unit-1 | | CP | $4,904,245 | $281,252 | $0 | $49,070 | Zero Discharge | SDE (Zero Discharge) |
| 7135 | Harrison Power Station | SE Unit-2 | | CP | $4,904,245 | $281,252 | $0 | $49,070 | Zero Discharge | SDE (Zero Discharge) |
| 7135 | Harrison Power Station | SE Unit-3 | | CP | $4,904,245 | $281,252 | $0 | $49,070 | Zero Discharge | SDE (Zero Discharge) |
| 7162 | WPS Westwood Generation, LLC | SE Unit-1 | | CP [a] | $10,918,968 | $323,557 | $0 | $147,211 | Zero Discharge [a] | SDE (Zero Discharge) |
| 7411 | Winyah Generating Station | SE Unit-1 | 2031 | CP - retired or NG | $2,784,750 | $89,748 | $0 | $36,803 | CP - retired or NG | CP - retired or NG |
| 7411 | Winyah Generating Station | SE Unit-2 | 2031 | CP - retired or NG | $2,784,750 | $89,748 | $0 | $36,803 | CP - retired or NG | CP - retired or NG |
| 7411 | Winyah Generating Station | SE Unit-3 | 2031 | CP - retired or NG | $2,784,750 | $89,748 | $0 | $36,803 | CP - retired or NG | CP - retired or NG |
| 7411 | Winyah Generating Station | SE Unit-4 | 2031 | CP - retired or NG | $2,784,750 | $89,748 | $0 | $36,803 | CP - retired or NG | CP - retired or NG |
| 7434 | Louisa Generating Station | SE Unit-1 | | CP | $12,703,154 | $611,148 | $0 | $147,211 | Zero Discharge | SDE (Zero Discharge) |
| 7624 | Gerald Gentleman Station | SE Unit-1 | | CP | $6,351,577 | $305,574 | $0 | $73,606 | Zero Discharge | SDE (Zero Discharge) |
| 7624 | Gerald Gentleman Station | SE Unit-2 | | CP | $6,351,577 | $305,574 | $0 | $73,606 | Zero Discharge | SDE (Zero Discharge) |
| 7626 | Cooper | SE Unit-1 | | CP | $8,508,159 | $409,327 | $0 | $98,597 | Zero Discharge | SDE (Zero Discharge) |
| 7626 | Cooper | SE Unit-2 | | CP | $4,194,995 | $201,821 | $0 | $48,614 | Zero Discharge | SDE (Zero Discharge) |
| 7761 | EKPC Spurlock Station | SE Unit-1 | | CP | $2,848,992 | $137,065 | $0 | $33,016 | Zero Discharge | SDE (Zero Discharge) |
| 7761 | EKPC Spurlock Station | SE Unit-2 | | CP | $4,901,943 | $235,832 | $0 | $56,806 | Zero Discharge | SDE (Zero Discharge) |
| 7761 | EKPC Spurlock Station | SE Unit-3 | | CP | $2,455,161 | $118,118 | $0 | $28,452 | Zero Discharge | SDE (Zero Discharge) |
| 7761 | EKPC Spurlock Station | SE Unit-4 | | CP | $2,497,058 | $120,133 | $0 | $28,937 | Zero Discharge | SDE (Zero Discharge) |
| 7785 | Seminole Generating Station | SE Unit-2 | 2052 | CP | $13,816,305 | $739,994 | $0 | $147,211 | Zero Discharge | SDE (Zero Discharge) |
| 8179 | Plant Scherer | SE Unit-1 | | CP | $4,234,385 | $203,716 | $0 | $49,070 | Zero Discharge | SDE (Zero Discharge) |
| 8179 | Plant Scherer | SE Unit-2 | | CP | $4,234,385 | $203,716 | $0 | $49,070 | Zero Discharge | SDE (Zero Discharge) |

# Exhibit DG-10:

# EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule (DCN SE11756), April 22, 2024

**MEMORANDUM**

TO: Steam Electric Rulemaking Record - EPA-HQ-OW-2009-0819

FROM: U.S. EPA

DATE: April 22, 2024

SUBJECT: Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule – DCN SE11756

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For the 2024 final rule, the EPA evaluated data on wastewater flow rates, treatment technology costs, and pollutant concentration data from individual power plants, technology vendors, and previous rulemakings to estimate compliance costs and pollutant loadings associated with treating or managing flue gas desulfurization (FGD) wastewater, combustion residual leachate (CRL), legacy wastewater, and bottom ash (BA) transport water. The methodology for estimating these costs and loadings for each wastestream and regulatory option is presented in the *Technical Development Document for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (TDD) (EPA-821-R-24-004). This memorandum presents the treatment technology and estimated costs and pollutant loadings for each generating unit for the regulatory options considered by the EPA. The regulatory options for the 2024 final rule are shown in Table 1.

**Table 1. Steam Electric Regulatory Options**

| Wastestreams | 2020 Baseline | Technology Basis for the Regulatory Options A | B | C |
|---|---|---|---|---|
| FGD Wastewater[a] | CP+LRTR | Zero Discharge | Zero Discharge | Zero Discharge |
| FGD Wastewater for Plants Retiring or Meeting the Permanent Cessation of Coal (PCCC) Subcategory by 2034[a] | CP+LRTR | CP+LRTR | CP+LRTR | Zero Discharge |
| For High FGD Flow or Low Utilization Facilities[a] | CP | Zero Discharge | Zero Discharge | Zero Discharge |
| For FGD Wastewater Voluntary Incentives Program (Direct Dischargers Only)[a] | CP + Membrane Filtration | CP + Membrane Filtration | CP + Membrane Filtration | Zero Discharge |
| Bottom Ash Transport Water | Dry Handling or HRR System | Zero Discharge | Zero Discharge | Zero Discharge |
| Bottom Ash Transport Water For Units Retiring by 2034 | Dry Handling or HRR System | Dry Handling or HRR System | Dry Handling or HRR System | Zero Discharge |
| Bottom Ash Transport Water For Low Utilization Units | Best Management Practices (BMP) Plan | Zero Discharge | Zero Discharge | Zero Discharge |

Table 1. Steam Electric Regulatory Options

| Wastestreams | 2020 Baseline | Technology Basis for the Regulatory Options A | B | C |
|---|---|---|---|---|
| CRL[a] | BPT[b] | CP | Zero Discharge | Zero Discharge |
| CRL For Units Retiring by 2034 or Natural Gas-fired Units Only[a] | BPT[b] | CP | CP | Zero Discharge |
| Unmanaged CRL[c] | BPT[b] | CP | CP | CP |
| Legacy Wastewater | BPT[b] | BPT[b] | CP | CP |

CP = chemical precipitation.

CP+LRTR = chemical precipitation plus low residence time reduction.

Dry Handling = a BA handling system that does not generate BATW (i.e., a MDS, dry mechanical conveyor, dry vacuum or pressure system, or a vibratory belt system).

HRR System = A type of wet BA system that includes components that operate in conjunction with a traditional wet-sluicing system to recycle all BATW (i.e., remote MDS or complete recycle system).

a – The zero discharge technology basis for FGD wastewater and CRL represents the least cost option between CP plus membrane filtration and SDE. The EPA evaluated costs associated with thermal evaporation; however, the thermal cost estimates contain confidential business information and cannot be released. The EPA ran an alternative set of costs selecting the least-cost option between membrane filtration, SDEs, and thermal evaporation (see DCN SE11709).

b - Best Professional Judgement (BPJ) does not have a set technological process. For calculation purposes, the EPA is using Best Practical Technology (BPT).

c – The EPA notes that unlined landfills and surface impoundments potentially discharge unmanaged CRL that may be covered under the ELGs when they are determined on a case-by-case basis to be the functional equivalent of a direct discharge. See the EPA's memorandum *Evaluation of Unmanaged CRL* (DCN SE11501) for more information.

Costs and loadings estimates for the steam electric industry are presented in *Unit-Level Costs and Loadings Estimates for the Steam Electric Industry* (DCN SE11756A1):

- *FGD Unit-Level Cost Estimates* presents unit-level costs for FGD wastewater treatment under all regulatory options;
- *BA Unit-Level Cost Estimates* presents unit-level costs for BA transport water handling under all regulatory options;
- *CRL Unit-Level Cost Estimates* presents unit-level costs for CRL treatment under all regulatory options;
- *Legacy Unit-Level Costs* presents unit-level costs for legacy wastewater treatment under all regulatory options;
- *FGD Unit-Level Loadings* presents unit-level total pollutant loadings for FGD wastewater under baseline and all regulatory options;
- *BA Unit-Level Loadings* presents unit-level total pollutant loadings for BA transport water under baseline and all regulatory options;
- *CRL Unit-Level Loadings* presents unit-level total pollutant loadings for CRL under baseline and all regulatory options; and
- *Legacy Unit-Level Loadings* presents unit-level total pollutant loadings for legacy wastewater under baseline and all regulatory options.

The EPA estimated potential ranges of bromide and iodine loadings. Given that most coal-fired power plants use bromide additives, total loadings are calculated as the sum of bromide maximum loading and iodine minimum loading. See the *FGD Halogen Loadings from Steam Electric Power Plants – 2024 Final Rule* (DCN SE11703) for additional details on halogen loadings estimates.

**Exhibit DG-11:**

**NERC, 2023 State of Reliability Technical Assessment, June 2023**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# 2023 State of Reliability Technical Assessment

## June 2023

### Technical Assessment of 2022 Bulk Power System Performance

2023 SOR Overview | 2023 SOR Video | 2023 SOR Infographic

# Table of Contents

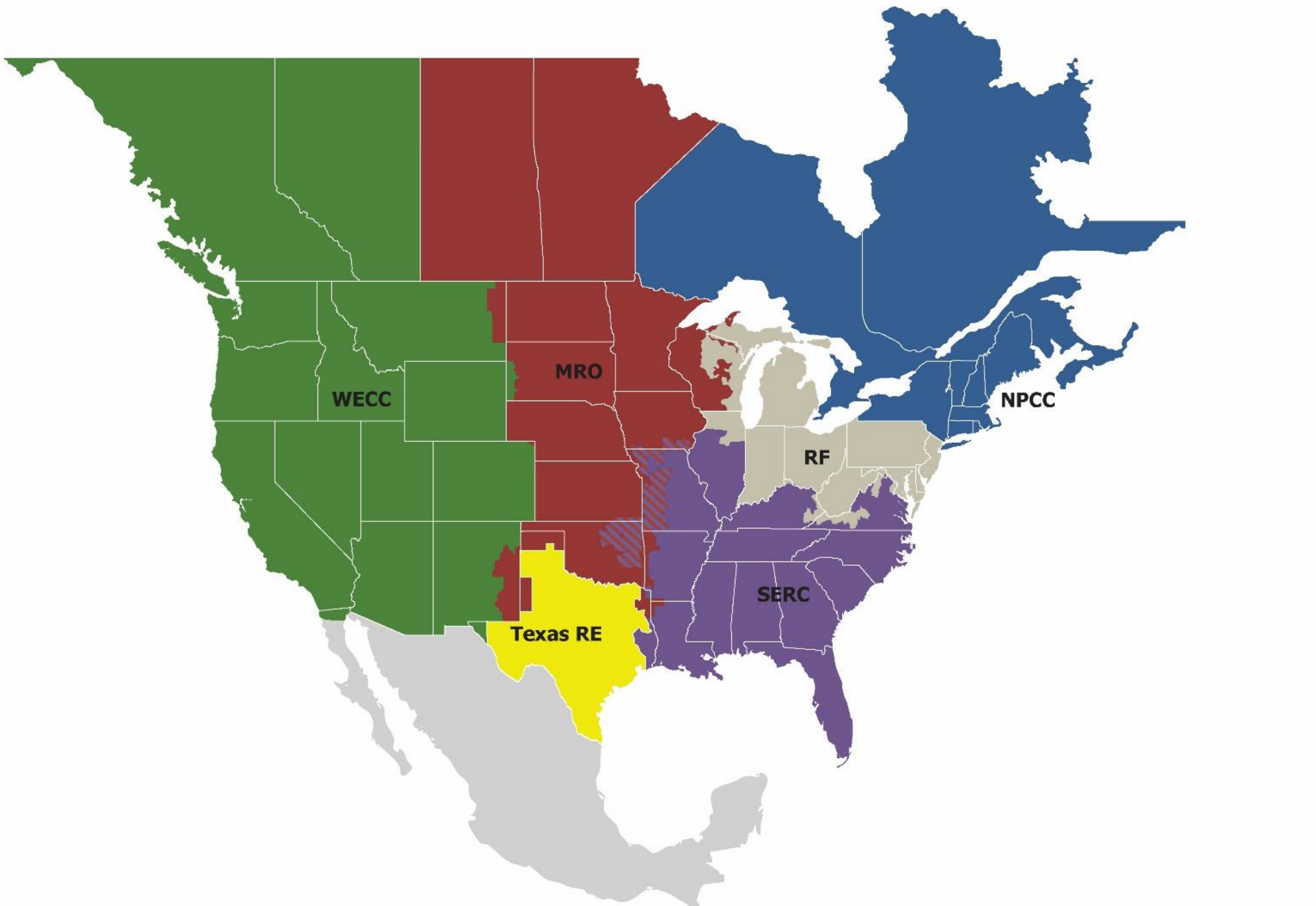
# Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

*Because nearly 400 million citizens in North America are counting on us*

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Transmission Operators participate in another.




| | |
|---|---|
| **MRO** | Midwest Reliability Organization |
| **NPCC** | Northeast Power Coordinating Council |
| **RF** | ReliabilityFirst |
| **SERC** | SERC Reliability Corporation |
| **Texas RE** | Texas Reliability Entity |
| **WECC** | WECC |

# About This Technical Assessment

## Introduction

This year's State of Reliability (SOR) is comprised of two publications: the *2023 State of Reliability Overview,*[1] which is a high-level summary of the important findings, and this *2023 State of Reliability Technical Assessment,* which provides NERC's detailed comprehensive and annual technical review of BPS reliability for the 2022 operating (calendar) year.

The *2023 State of Reliability Overview* replaces the executive summary normally found in NERC reports. This *2023 State of Reliability Technical Assessment* provides detailed descriptions of key findings and key occurrences for 2022 along with in-depth analysis of risks and resilience, grid transformation, grid performance, and the status of performance metrics.

## Purpose of the SOR

Both the overview and the technical assessment provide objective and concise information for policymakers, industry leaders, and regulators on issues that affect the reliability and resilience of the North American BPS. Specifically, the SOR does the following:

- Identifies system performance trends and emerging reliability risks
- Reports on the relative health of the interconnected system
- Measures the success of mitigation activities deployed

NERC, as the ERO, works to assure the effective and efficient reduction of reliability risks as well as the security risks of the North American BPS. Annual and seasonal risk assessments look to the future, and special reports on emergent risks serve to identify and mitigate potential risks. The annual SOR provides analyses of past BPS performance. This assessment documents BPS adequacy and identifies performance trends in addition to providing strong technical support for those interested in the underlying data and detailed analytics.

NERC defines the reliability[2] of the interconnected BPS in terms of the following three basic and functional aspects:

- Adequacy
- Operating Reliability
- Adequate Level of Reliability

The *2023 State of Reliability* focuses on BPS[3] performance during the prior calendar year as measured by an established set of reliability indicators and more detailed analysis performed by ERO staff and technical committee participants. Data used in the analysis comes from the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Misoperation Information Data Analysis System (MIDAS), the Long-Term Reliability Assessment (LTRA), voluntary reporting into The Event Analysis Management System (TEAMS), the Electricity Information Sharing and Analysis Center (E-ISAC), and the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group. ERO staff developed this independent assessment with support from the Performance Analysis Subcommittee.

[1] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Overview.pdf

[2] **Learn About NERC** provides background information about NERC, the definition of reliability, and the electric grid.

[3] The term BPS is defined in Section 215 of the Federal Power Act to encompass the facilities, control systems, and electric energy needed to operate an interconnected electric energy transmission network and maintain transmission system reliability, excluding facilities used to locally distribute electricity. BES is a FERC-approved term defined in NERC's *Glossary of Terms*. The BES is, in short, the portion of the BPS to which NERC's standards apply and from which data are collected for analysis.

## Considerations

- Data in the SOR represents the performance for the January–December 2022 operating year unless otherwise noted.
- Analysis is based on data from 2018–2022 that was available Spring 2023 and provides a basis to evaluate 2022 performance relative to performance over the last five years. All dates and times shown are in Coordinated Universal Time (UTC).
- The SOR is a review of industry-wide trends and not a review of the performance of individual entities.
- When analysis is presented by Interconnection, the Québec Interconnection is combined with the Eastern Interconnection unless specific analysis for the Québec Interconnection is shown.

# Key Findings and Resultant Actions

Based on data and information collected for this assessment of BES reliability performance in 2022, NERC identified four key findings and is taking actions to address them. Although extreme weather continues to present the biggest overlying reliability challenge to the BES, only topics related to the BES have been listed as key findings.

## Key Finding 1

### Conventional Generation Reliability

**The reliability of conventional generation is significantly challenged by more frequent extreme weather, high-demand conditions, and a changing resource mix, resulting in higher overall outage rates and surpassing transmission in their contribution to major load loss events.**

While the reliability of conventional generation has remained stable during normal operating conditions, the increased intensity and frequency of extreme weather events has contributed to a gradual rise in the conventional generation forced outage rate in recent years. In 2022, conventional generation experienced its highest level of unavailability (8.5%) overall since NERC began gathering GADS data in 2013 as measured by the weighted equivalent forced outage rate (WEFOR). WEFOR is the percentage of megawatt (MW) hours a generator is unavailable. Further analysis indicates that there is a statistical correlation between the number of startups and forced outages on coal units.

Each year, the SOR identifies top stressed days from across North America based on the severity risk index (SRI). The SRI is a calculation of daily performance based on transmission, generation, and load loss components. In past years, the highest stress SRI days have been reflected in the coincidence of significant transmission losses and load loss events related to specific storms, hurricanes, or other newsworthy events.

Recently, the highest SRI days have shifted to days when generation unavailability and load loss occur simultaneously, such as during the February 2021 and December 2022 time periods. This suggests that generation capability during periods of extreme weather is now the greatest indicator of risk for the BES. This is an emerging risk, particularly when considered with consistently increasing coal outage rates throughout the year, the higher penetration of variable energy resources (VER) (such as wind and solar photovoltaic (PV)), and poor natural gas performance during extreme weather and high demand conditions. Analysis of a wider range of planning scenarios to determine increasingly common weather conditions that may affect large numbers of generation over a wide geographic footprint may be needed.

***Resultant Actions***

- NERC issued a Level 3 essential action alert[4] in May 2023: *Essential Actions to Industry - Cold Weather Preparations for Extreme Weather Events*.[5]
- Three standards were revised as a result of the 2019 cold weather event that became effective April 1, 2022;[6] additional standards revisions resulting from the 2021 cold weather event are ongoing.[7]
- NERC published three lessons learned[8] documents.

[4] https://www.nerc.com/pa/rrm/bpsa/Pages/About-Alerts.aspx
[5] https://www.nerc.com/news/Pages/NERC-Releases-Essential-Action-Alert-Focused-on-Cold-Weather-Preparations.aspx
[6] https://www.nerc.com/pa/Stand/Pages/Project%202019-06%20Cold%20Weather.aspx
[7] https://www.nerc.com/pa/Stand/Pages/Project-2021-07-ExtremeColdWeather.aspx
[8] LL20220301 “Managing UFLS Obligations and Service to Critical Loads during an Energy Emergency
LL20221201 “Air Breaker Cold Weather Operations
LL20230401 “Combustion Turbine Anti-Icing Control Strategy

- *FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States.*[9]
- The Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity joint report on the 2022 Winter Storm Elliott is expected in late 2023.
- NERC hosted its annual Preparation for Severe Cold Weather webinar.
- Reliability assessment data requests were expanded to further measure preparedness during cold weather events.
- The WECC Reliability Risk Committee is identifying specific risk areas under "Extreme Natural Events" that pose unique risks to the Western Interconnection and how industry can best address them.
- NERC GADS Section 1600 data request revisions,[10] which include reporting of specific environmental contributing factors for outages and event performance for wind and solar PV plants, become effective January 1, 2024.

# Key Finding 2

## Solar PV Inverter Performance during Transmission Faults

**To continue benefiting from the rapid expansion of inverter-based resources, their dynamic performance during system events must improve.**

On June 4, 2022, more than 1,700 MW of solar PV resource power output was lost in the Texas Interconnection, titled the Odessa Disturbance event. This event is nearly identical to an event that occurred one year prior at the same location. When combined with the loss of synchronous generation, the event in 2022 nearly exceeded the Texas Interconnection's resource loss protection criteria (RLPC). Details on this event are provided in the Texas Loss of Solar PV section of **Chapter 1**.

Recent Western Interconnection events show that newly built solar PV and battery storage resources are still being commissioned with the same performance issues highlighted in multiple disturbance reports since 2016.

***Resultant Actions***

- FERC notice of Proposed Rulemaking issued November 17, 2022, was released to address concerns regarding reliability impacts on inverter-based resources (IBR).
- NERC issued a Level 2 alert[11] was issued March 14, 2023, on IBR issues.[12]
- Reliability Standard[13] modifications are in progress for PRC-024, MOD-025, MOD-026, MOD-027, FAC-001, FAC-002, PRC-002, PRC-019, and EOP-004.
- NERC published multiple guidelines and resources.[14]
- Immediate industry action is necessary to implement published guidelines and ensure reliable operation of the BPS with the increasing penetration of IBRs.
- IBR modeling requirements need significant improvement to ensure that high-quality, accurate models are used during reliability studies so performance issues can be identified before they occur during real-time operations.

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[9] FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States
[10] https://www.nerc.com/pa/RAPA/PA/Pages/Section1600DataRequests.aspx
[11] https://www.nerc.com/pa/rrm/bpsa/Pages/About-Alerts.aspx
[12] NERC Level 2 alert issued March 14, 2023 on IBR issues
[13] https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx
[14] Quick Reference Guide on IBR Activities

# Key Finding 3

## Security Threats

**Physical and cyber security attacks are increasing, reinforcing the need for further development and adaptation of standards and guidelines.**

Physical and cyber security are essential to BPS reliability, and security is becoming increasingly important in the ongoing grid transformation. The growing attack surfaces that result from the increasing penetration of distributed energy resources call for ongoing development and the adaptation of cyber and physical security standards and guidelines to keep up with the ever-changing threat landscape. Furthermore, cyber-informed planning should include designs and be considered when planning and integrating the technologies into the grid to strengthen the cyber robustness.[15]

Hostile nation-states persist in targeting North American critical infrastructure, constantly evolving their methods to compromise the grid's reliability, resilience, and security. Domestic extremists have demonstrated the intent to attack the electricity infrastructure and take violent action against grid assets. The Cyber and Physical Security section of **Chapter 4** provides more information on these topics.

***Resultant Actions***

- The E-ISAC continues to enhance and distribute industry threat intelligence and work with government and industry partners to mitigate risks and provide guidance as threats arise.
- Through coordination and collaboration with the ERO Enterprise and industry stakeholders, NERC will provide insightful white paper guidance, implement robust security strategies, and continue to refine and adapt critical standards about cyber-informed engineering design to ensure a reliable and secure BPS. These efforts will enable industry to be better positioned against physical and cyber threats now and in the future.

# Key Finding 4

## Transmission System Reliability

**The BES Transmission System continues to demonstrate significantly improved reliability for the fifth year in a row.**

The overall severity of outages to the transmission system continues to show improvement over the last five years. Unavailability of alternating current (ac) circuits in 2022 was the lowest it has been for the last four years, the number of outages due to failed ac substation equipment and protection system equipment both decreased, and the average daily performance was better than the prior four years for spring, summer, and fall.

Despite Hurricane Ian having a secondary landfall on the East Coast two days after impacting Florida, the effective restoration (95%) of the BES was completed within 3.8 days. This demonstrated the value of ongoing utility coordination and grid-hardening efforts.[16] Hard-to-predict high-wind and lightning systems, such as severe thunderstorms and tornadoes, continue to be the most regular notable challenge for the system. The single most impactful day to the transmission system in 2022 occurred during Winter Storm Elliott, which will be detailed in the upcoming NERC and FERC joint report that is expected in late 2023.

[15] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/ERO_Enterprise_Whitepaper_Cyber_Planning_2023.pdf
[16] A lessons learned on hardening will be posted to NERC's Lessons Learned page later this year: https://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx.

Figure KF.1 highlights a few key numbers and facts about the North American BPS.

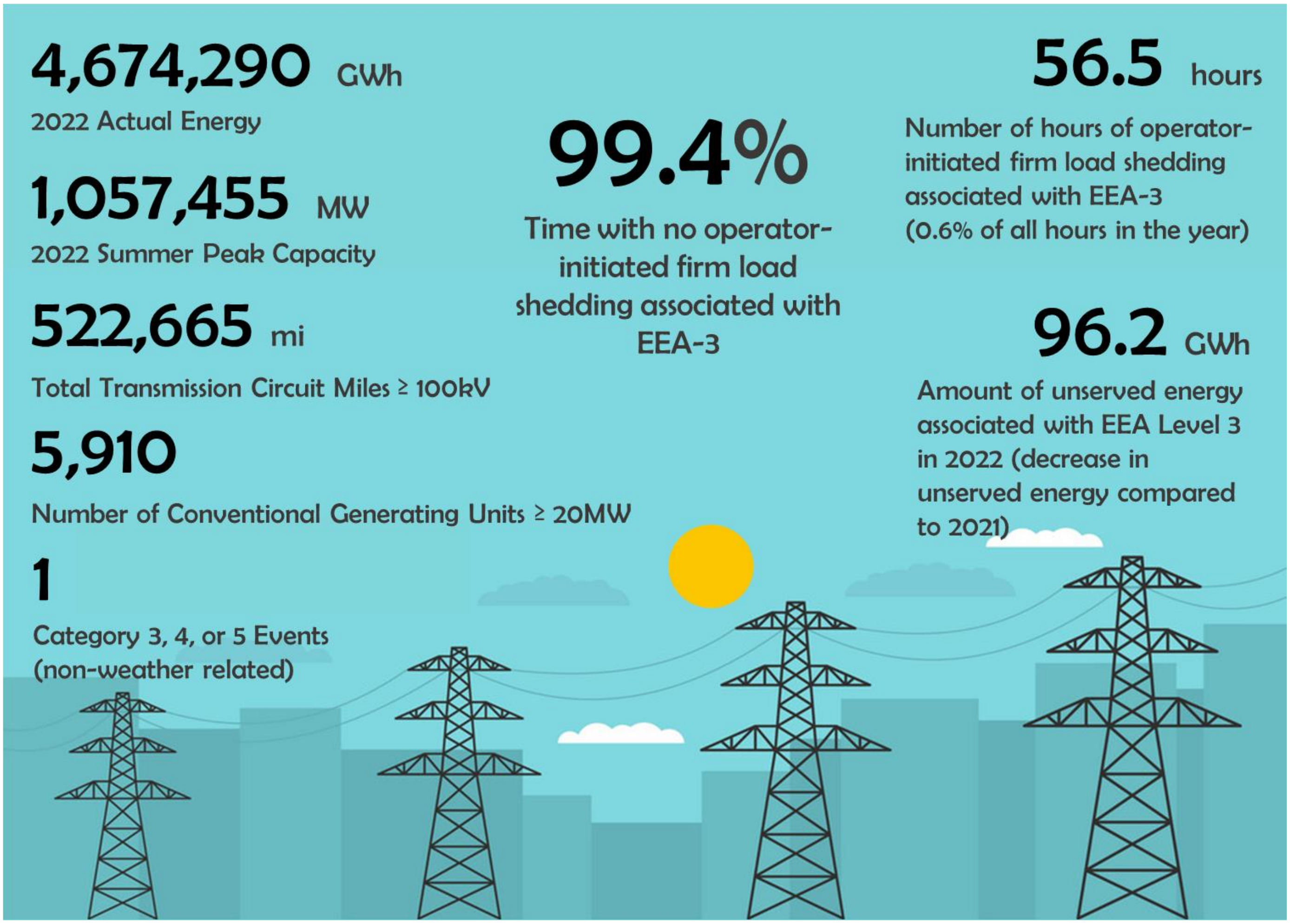



**Figure KF.1: 2022 BPS Inventory and Performance Statistics**

# Exhibit DG-12:

# TECO response to SC IRR 8, Attachment (BS 28923)
# 2019 - 2023 Factor and Rates

2019

| Station,Unit, and Fleet | Net Equivalent Forced Outage Rate (NEFOR) |
|---|---|
| Big Bend Power StationBig Bend 4 | 28.09% |
| Polk Power StationPolk 1 | 12.08% |
| Polk Power StationPolk 1 ST | 1.31% |
| | |
| Big Bend #4 | 28.09% |
| Polk #1 (IGCC) | 8.54% |

2020

| Station,Unit, and Fleet | Net Equivalent Forced Outage Rate (NEFOR) |
|---|---|
| Big Bend Power StationBig Bend 4 | 32.04% |
| Polk Power StationPolk 1 | 27.29% |
| Polk Power StationPolk 1 ST | 27.75% |
| | |
| Big Bend #4 | 32.04% |
| Polk #1 (IGCC) | 27.35% |

2021

| Station,Unit, and Fleet | Net Equivalent Forced Outage Rate (NEFOR) |
|---|---|
| Big Bend Power StationBig Bend 4 | 8.71% |
| Polk Power StationPolk 1 | 67.58% |
| Polk Power StationPolk 1 ST | 67.08% |
| | |
| Big Bend #4 | 8.71% |
| Polk #1 (IGCC) | 67.40% |

2022

| Station,Unit, and Fleet | Net Equivalent Forced Outage Rate (NEFOR) |
|---|---|
| Big Bend Power StationBig Bend 4 | 31.61% |
| Polk Power StationPolk 1 | 30.10% |
| Polk Power StationPolk 1 ST | 30.59% |
| | |
| Big Bend #4 | 31.61% |
| Polk #1 (IGCC) | 30.11% |

2023

| Station,Unit, and Fleet | Net Equivalent Forced Outage Rate (NEFOR) |
|---|---|
| Big Bend Power StationBig Bend 4 | 18.08% |
| Polk Power StationPolk 1 | 7.52% |
| Polk Power StationPolk 1 ST | 7.71% |
| | |
| Big Bend #4 | 18.08% |
| Polk #1 (IGCC) | 7.52% |

# Exhibit DG-13:

## Schlissel, D. 2017. Using Coal Gasification to Generate Electricity: A Multibillion-Dollar Failure. Institute for Energy Economics and Financial Analysis

# Using Coal Gasification to Generate Electricity: A Multibillion-Dollar Failure

## Kemper and Edwardsport: Painful Case Studies for Ratepayers and Investors Alike

Institute for Energy Economics and Financial Analysis
IEEFA.org

September 2017

By David Schlissel, Director of Resource Planning Analysis

# Table of Contents

# Executive Summary

Efforts to gasify coal for power generation have been major failures, technologically and financially.

Only two of the 25 coal-gasification electricity generating plants proposed in the U.S. since 2000 have ever come on line: Southern Company's Kemper plant in Mississippi and Duke Energy's Edwardsport plant in Indiana.

Both Kemper and Edwardsport have been economic disasters for consumers and investors alike.

Under pressure from the Mississippi Public Service Commission for having logged billions of dollars in cost overruns at Kemper, the Southern Company affiliate Mississippi Power announced in July 2017 that it will halt coal burning at Kemper. Henceforth the plant will run only on natural gas.

That leaves Edwardsport as the sole remaining plant built in the U.S. in the last decade burning gasified coal to produce power. It is the only modern plant built around "clean coal" gasification technology that continues to be promoted as a viable way to generate electricity but in fact is not.

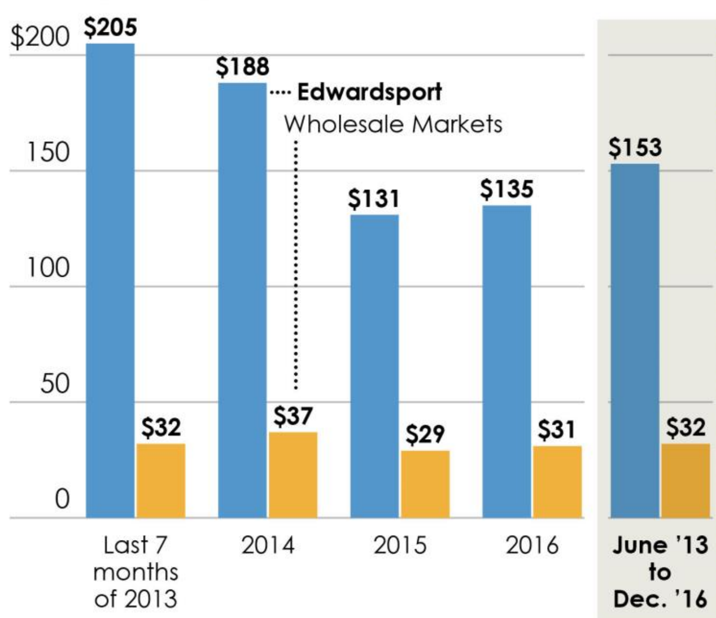
Edwardsport has been plagued by technological problems, and four years after opening is still not running properly. Because of its operational problems and its huge construction cost overruns, Edwardsport's electricity is wildly expensive. Power from the plant costs more than five times what electricity sells for in wholesale energy markets in Indiana.

Some in the electric utility and coal industries continue to push for new coal-gasification projects, even though natural gas plants are much less expensive to build and are more reliable, and wind- and solar-generated electricity is cheaper.

The technology used in coal gasification plants—known as Integrated Gasification Combined Cycle (IGCC)—poses major risks to ratepayers and investors alike as the technology remains both unreliable and expensive.

**Edwardsport "All-in" Cost vs. Cost of Buying From Competitive Wholesale Markets**

Dollars per megawatt hour




*Sources: Edwardsport costs from Duke Energy Indiana FERC Form 1 filings for the years 2013 through 2016. Market prices for MISO's Indiana Zone from SNL Financial.*

A number of important and painful lessons have emerged from Kemper and Edwardsport:

- Modern IGCC plants are far more expensive to build than proponents have been willing to publicly acknowledge.
- Such plants take much longer to construct than proponents typically assert.
- IGCC plants are very expensive to operate.
- IGCC plants have proven unreliable due to problems with modern coal-gasification technology.
- The high costs of building and operating IGCC plants, and their unreliable operations, mean that the technology is not an economically feasible option for capturing and sequestering carbon dioxide emissions from coal plants.
- IGCC plants cannot compete with wholesale market power prices or with falling prices for wind- and solar-generated electricity.

In sum, Kemper and Edwardsport prove the high cost and unreliability of IGCC technology and serve as a stark warning against investing in such projects.

# What Is Coal Gasification and Why Has It Been Promoted?

Traditional coal-fired power plants produce electricity by burning crushed coal in a boiler to produce steam. The steam then flows into a turbine-generator to generate electricity.

Coal gasification adds several steps to this straightforward, time-tested process. It still uses coal as its base fuel, but converts it—typically in one or two gasifiers—to create "syngas," a synthetic energy product that resembles natural gas. The syngas is then used to fuel a conventional combined cycle electricity generating power plant—a facility using gas-fired turbines to produce electricity *and* that captures the excess heat to power steam-driven turbines to produce additional electricity.
Such generating facilities are known as Integrated Gasification Combined Cycle (IGCC) plants.

IGCCs—which are often promoted as "clean coal" plants—are purportedly designed to reduce air pollution emissions while burning coal as the primary fuel. The origins of these plants stem from a time in which natural gas and renewables were not as abundant and cheap as they are today.
The concept of coal gasification is not new: Well over a century ago, coal was commonly converted into "town gas," a term for gaseous fuel produced from coal before the widespread use of natural gas. Town gas was sold to municipalities and

piped to customers for light, heating and cooking. Like coal-fired electricity generation, town gas production was a relatively simple process.

However, applying and implementing coal gasification in large electric power plants has proven to be technologically tricky and extremely expensive.
In the first decade of this century, more than 25 utility companies in the U.S., under pressure to reduce emissions and wanting at the time to continue to burn coal for fuel considered building new IGCC plants. (Natural gas and renewable energy prices were still comparatively high). In 2000, the U.S. had two small demonstration projects up and running, but there were no IGCC plants in operation anywhere in the world that were comparable in size to the proposed IGCC projects under consideration or that used the new technologies that were under consideration. All these projects carried a "first mover risk" as the first-of-their-kind commercial power plants.[1]

Many utilities and independent power plant developers around the U.S. (and two state regulatory commissions) rejected IGCC projects because the technology was untested and involved higher financial risk than conventional coal-fired power plants.

In June 2007, the Tondu Corp. in Houston announced that it was suspending plans to build a planned 600-megawatt (MW) IGCC facility in Texas, citing high costs and other issues related to technology and construction risks.[2] Similarly, Xcel Energy announced in October 2007 that it was deferring indefinitely its plans to build an IGCC plant in Colorado because the development costs were higher than the utility originally expected.[3]

At about the same time, the federal government pulled the plug on the marquee FutureGen project, an undertaking in which the U.S. Department of Energy had agreed to provide 74 percent of the funding, with private investors putting up the balance. This was to be a test project combining IGCC technology with carbon capture and sequestration (CCS). In early 2008, the Bush administration cancelled FutureGen, citing cost overruns. The proposal was revived under the Obama administration with the support of Congress. The U.S. Department of Energy cancelled it again in 2015 "in order to best protect taxpayer interests."[4]

Some state regulatory commissions also refused to make ratepayers bear the risks of new IGCC project. In August 2007, the Minnesota Public Utilities Commission rejected a contract under which Xcel Energy would have purchased power from a proposed

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1 Duke Energy Indiana claimed during construction that the Edwardsport IGCC project merely merged two mature technologies or represented the scaling-up of the technology used at the two existing demonstration projects in the U.S. This claim is analogous to saying that a new Boeing 747 did not represent a new airplane design in 1970 because the concepts of wind, lift and aircraft propulsion had been around since the Wright Brothers' first biplane flew at the turn of the 20th Century.

2 http://www.reuters.com/article/companyNewsAndPR/idUSN1526955320070615

3 "Xcel Delays IGCC Power Plant." Denver Business Journal, October 30, 2007, https://www.bizjournals.com/denver/stories/2007/10/29/daily26.html

4 http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead

IGCC facility in northern Minnesota. The commission cited uncertainties in construction and operating costs as well as operational and financial risks.[5]

In 2008, the Virginia State Corporation Commission refused to make the Virginia ratepayers of Appalachian Power Company (APCO) bear any of the costs of APCO's proposed IGCC plant, citing uncertainties on costs, technology and unknown federal mandates:

> "The record in this case indicates there is no proven track record for the development and implementation of large-scale IGCC generation plants like the one proposed by APCO. Evidence in this case also raises concerns whether large-scale IGCC generation plants are characterized by, among other things, (1) complexities attendant to a technology for which there is no proven track record for power plants of this size, (2) high initial capital costs compared to other coal-fired units, and (3) uncertainty surrounding performance and operating costs."[6]

The Virginia Commission found also that the project represented "an extraordinary risk that it could not allow the ratepayers of Virginia in APCO's service territory to assume." The commission said would not grant the "blank check" the company sought and concluded, "We cannot ask Virginia ratepayers to bear the enormous costs—and potentially huge costs" of the uncertainties associated with the IGCC project.[7] Such skepticism was common across the utility industry, and is even greater today. For example, an article in Power Magazine in late 2006 noted that IGCC technology was unproven and "still in its infancy."[8]

A July 1, 2007, editorial "IGCC Sticker Shock" by the editor in chief of Power Magazine framed commonly held industry doubts:

> "Former Illinois Senator Everett Dirksen once observed, 'A billion here and a billion there, and pretty soon you're talking real money.' The same can be said about skyrocketing estimated costs of integrated gasification combined cycle (IGCC) plants as their designs are fleshed out. The higher price tags shouldn't be a surprise—the more you learn about the complexity of a project, the higher your guess about its cost will go…
> "It seems to me that ratepayers should not assume any additional cost, performance, or scheduling risks over those presented by other, less-expensive and more-mature generation technologies. In balancing those risks, regulators should give IGCC-enamored utilities the opportunity to earn a higher than usual return on their investment – after the project has proven successful.

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5 Minnesota Public Utility Commission Final Order in Case E-6472/GS-06-668, available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={B05A0CFF-E2FA-4D4D-9EE8-FE89D2ADCA48}&documentTitle=5520555

6 Virginia State Corporation Commission Final Order in Case No. PUE-2007-00068, April 14, 2008. Available at http://www.scc.virginia.gov/docketsearch/DOCS/1_xm01!.PDF

7 Ibid.

8 http://www.powermag.com/speaking-of-coal-power-igcc-sticker-shock/

> "Fair allocation of the incremental costs and rewards of IGCC should be the goal of every state public service commission, as its ratepayers' eyes and ears. At the end of the day, the shareholders who elected the management team to make wise technology decisions should pay the freight if those decisions go south. "Corporate management teams come and go, but a bad project lives forever."[9]

Plans for all but two of the more than 25 proposed IGCC plants in the U.S. were cancelled because of customer and/or investor risks associated with high costs related to technology and construction.
As noted, those two IGCC plants were Southern Company's Kemper Plant in Mississippi and Duke Energy Indiana's Edwardsport Project.

# Southern Company / Mississippi Power's Kemper Plant: A $7.5 Billion Failure

When Southern Company subsidiary Mississippi Power first requested approval from the Mississippi Public Service Commission to build the Kemper plant, in late 2009, it put the project's cost at slightly below $2.9 billion, and said the 824MW-rated plant would be in full operation by May 2014. Kemper was supposed to burn lignite coal in its gasification process—one of the lowest-quality forms of coal—from the Red Hills Mine in Mississippi. The Sierra Club and the Public Service Commission's independent consultant warned that the cost of the project would be much higher than Southern Company estimating and that it would take much longer to build.[10] Nonetheless, the project was approved in early 2010.

Southern Company sought successfully to shift much of the project risk to ratepayers. While the company argued against having to bear such risks, it refused to agree to share any profits it stood to earn had the project succeeded and if it were able to sell the technology in other countries.[11]

The costs to build Kemper steadily increased as construction proceeded, as shown in Figure 1, below, and its scheduled commercial in-service date was repeatedly delayed. The "cost cap" in Figure 1 represents the cap adopted by the Mississippi Public Service Commission and was based on Southern Company's original cost estimate.

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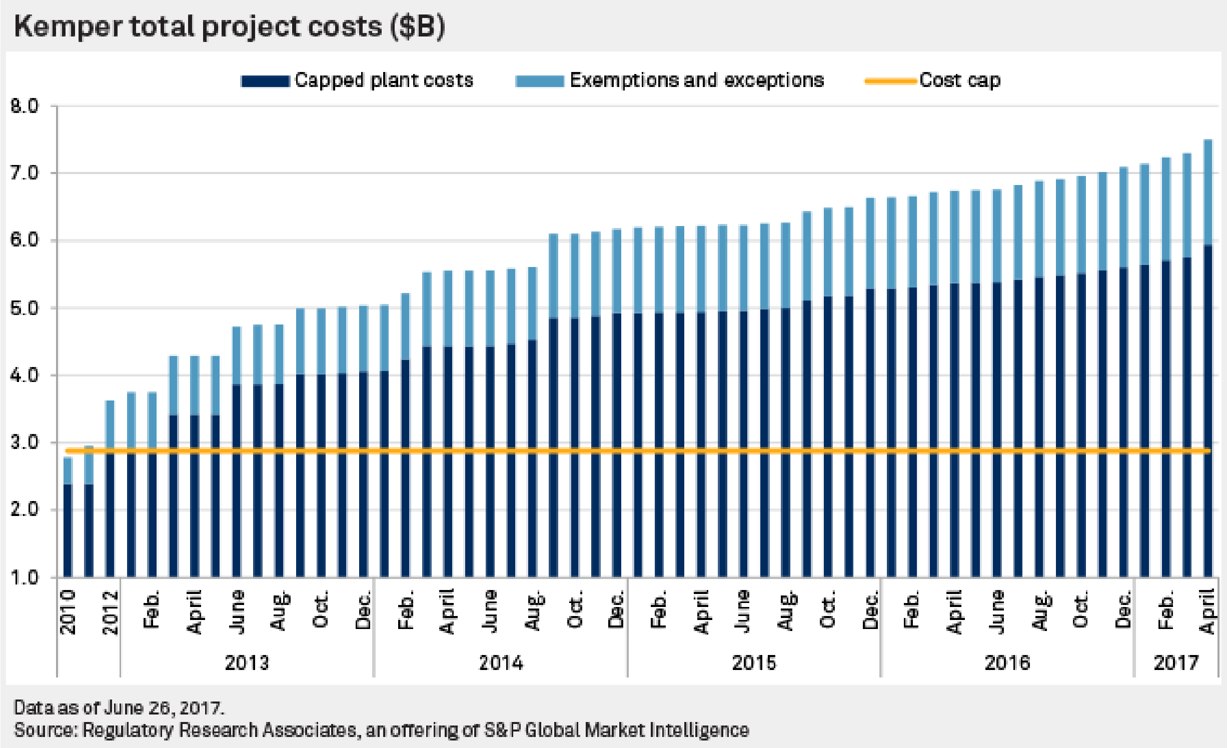
[9] Ibid.
[10] See the Direct Testimony of David A. Schlissel on Behalf of the Sierra Club in Mississippi Public Service Commission Docket No. 2009-UA-014, available at http://schlissel-technical.com/docs/testimony/testimony_21.pdf and *Kemper Update*, Mississippi Business Journal, February 2, 2010, http://msbusiness.com/2010/02/kemper-update-psc-resource-hearings-on-kemper-county-coal-plant/
[11] Ibid.

Figure 1: Kemper IGCC Project's Increasing Cost[12]

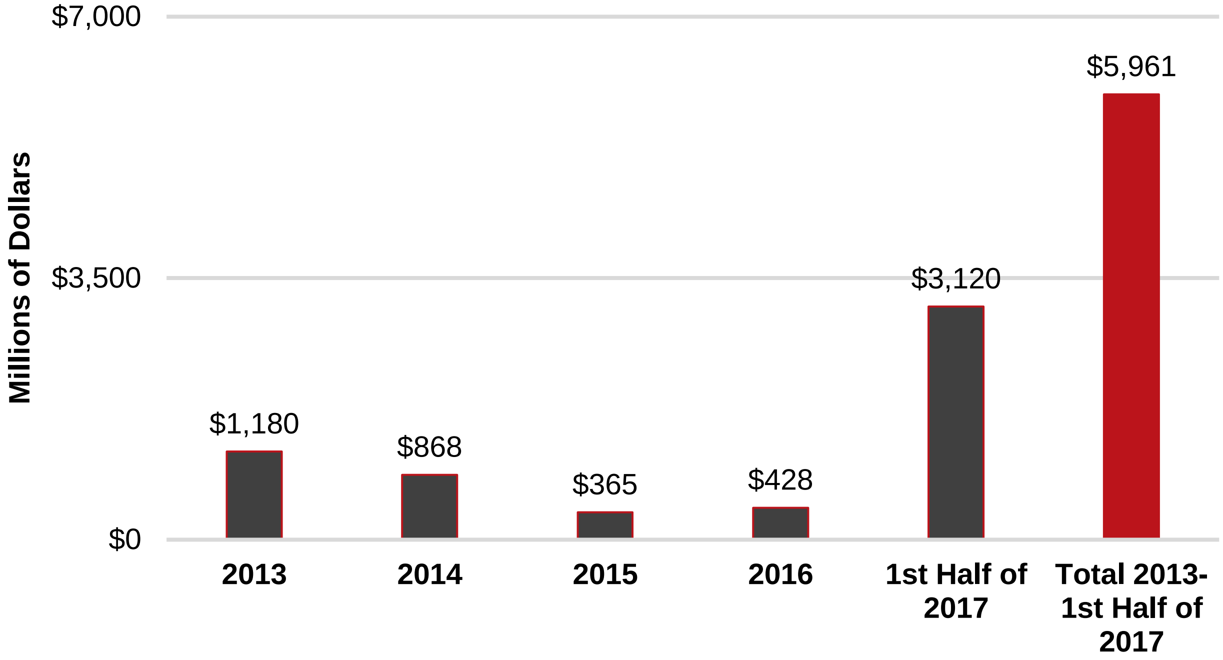



Although Kemper began producing electricity in mid-2014 *as a conventional combined cycle power plant burning natural gas*, problems with the operation of its unproven gasification systems—which were to have come online that same year—led to further cost increases and schedule delays. By June 2017, Kemper's estimated cost had jumped to $7.5 billion, and construction and startup testing of its gasifiers was still incomplete.

As the cost of building Kemper has skyrocketed, Southern Company has taken nearly $6 billion in pre-tax charges for its estimated losses on the project.

[12] Source: SNL Financial, a unit of S&P Global Market Intelligence.

Figure 2: Southern Company's Estimated Losses on Kemper From 2013 to June 2017.[13]




As its construction costs rose, Mississippi Power's estimates for how much it would cost to operate the project as an IGCC plant for its first five years also jumped from its $205 million estimate in 2010 to $730 million, an increase of more than 250 percent. The total capital expenditures that Mississippi Power said would be needed during the plant's first five years of operations skyrocketed from $52 million to more than $270 million.[14]

In a late concession to market realities, Mississippi Power released a study in February 2017 that suggested that low natural gas prices and the true costs of operating Kemper meant that the plant was far more viable running just on natural gas.[15] This was essentially the same point made in a Sierra Club affidavit to the Mississippi Public Service Commission filed in early 2012.[16] As that affidavit noted, the very decline in natural gas prices that has undermined the viability of the Kemper IGCC project was foreseeable.

As a result of the rising costs and continuing problems with the gasification system at Kemper, the Mississippi Public Service Commission expressed its intention on June 21, 2017, to order that Southern Company, in the interest of ratepayers, cease burning coal

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13 Southern Company's Quarterly Earnings Reports and SEC Form 10-K filings for calendar years 2013, 2014, 2015, and 2016 and its SEC Form Q filing for the first half of 2017.

14 Direct Testimony of Bruce C. Harrington on behalf of Mississippi Power Company, Mississippi Public Service Commission Docket No. 2016-AD-0161, October 13, 2016.

15 http://mississippipowernews.com/2017/02/22/mississippi-power-issues-statement-regarding-kemper-county-energy-facility-progress-and-schedule-2/

16 Sierra Club "Motion for Status Conference Pending Remand," Mississippi Public Service Commission Docket No. 2009-UA-014, March 19, 2012.

at Kemper and use only natural gas to run the plant.[17] The commission also expressed its belief that Kemper's gasifier technology was not and will not become "used and useful" in serving Mississippi customers and that Kemper's gasification technology has not operated reliably and is not likely do so in the near future.

In response, Southern Company announced on June 28, 2017, that it would stop burning coal at the plant, and the commission finalized its directive in an order issued on July 6.[18] Consequently, Kemper is now operating what is undoubtedly the world's most expensive natural-gas fired power plant—and it will not burn syngas made from gasified coal. The only outstanding question is how much of the costs of the Kemper debacle will be borne by Mississippi Power customers.

# Duke Energy's Edwardsport Plant: Unreliable Power at Five Times Market Prices

When Duke Energy Indiana asked the Indiana Utility Regulatory Commission (IURC) in October 2006 for approval to build an IGCC plant in Edwardsport, it estimated the project's construction cost at just under $2 billion. By the time the 618 MW-rated plant officially went online in June 2013, construction costs had ballooned to $3.5 billion—a number that did not include some $600 million Duke's Indiana customers were charged before June 2013.[19]

Since being declared operational in June 2013, Edwardsport has not operated reliably and has now cost Duke Energy Indiana customers over than $1 billion more than what they would have paid to buy the same amount of power from the competitive wholesale market.

There are many ways to measure a power plant's operational effectiveness, and Edwardsport performs poorly by all of them.

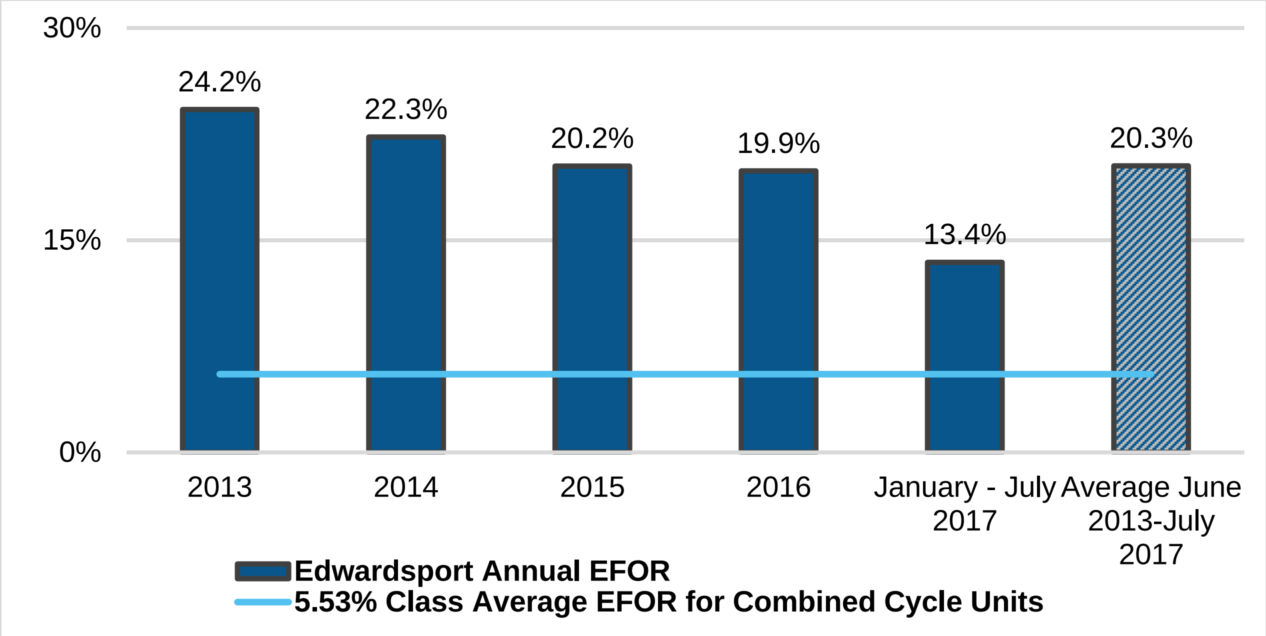
For example, a power plant's equivalent forced outage rate (EFOR) measures how much a plant is out of service as a result of unplanned outages or reductions in output ("derates"). The higher the EFOR, the worse a plant is performing. As shown below, Edwardsport's EFOR is more than 3.5 times higher than the typical combined cycle plant that burns natural gas—that is, a plant that does not include gasifiers/gasification technology.

[17] http://www.psc.state.ms.us/mpsc/press%20releases/2017/Joint%20Press%20Kemper%20Stipulation%20Docket%206.21.17.pdf

[18] http://www.southerncompany.com/newsroom/2017/june-2017/0628-kemper.html

[19] In addition, Duke Energy Indiana recorded pretax charges of approximately $897 million on its earnings through 2014 as a result of cost overruns at Edwardsport. See Duke Energy's SEC Form 10-K for the Year Ending December 31, 2014.

**Figure 3: Edwardsport's Equivalent Forced Outage Rate (EFOR) vs. Industry Average**[20]



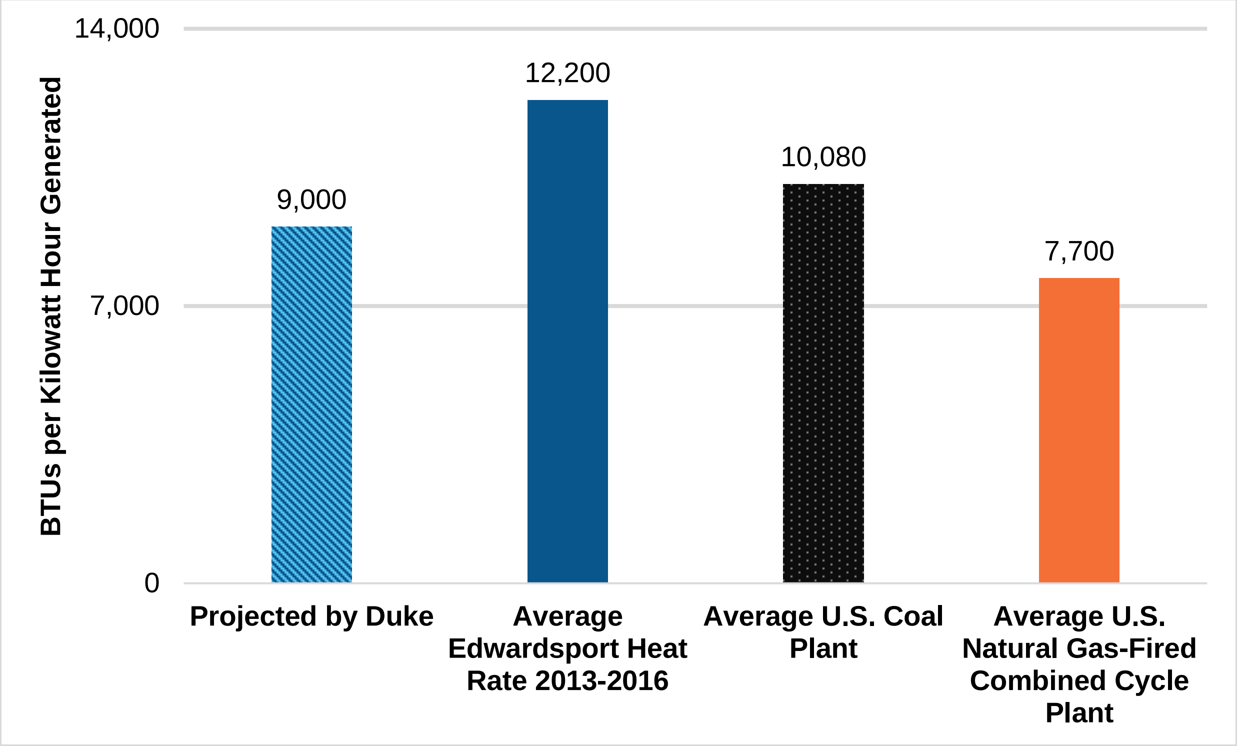

Thus, Edwardsport was out of service for unplanned outages, on average, more than 3.5 times as often as a typical natural gas-fired combined cycle unit.
In addition to unplanned outages, Edwardsport has been shut down every year for extended planned maintenance and was off line for planned spring and fall maintenance in 2014, 2015, 2016 and 2017. Each of those outages led to at least one of Edwardsport's two gasifiers being out of service for days or weeks.

Another measure of a plant's operating performance is its heat rate which measures how efficiently the plant burns fuel. The higher the heat rate, the less efficiently the plant burns fuel. The lower the heat rate, the more efficient the plant is. In other words, the higher the plant's heat rate, the more fuel it must burn to generate the same amount of power. This makes the plant less economic for consumers and less competitive with other plants in the wholesale market.

While Edwardsport was being built, Duke and General Electric, the plant's designer, claimed that it would achieve an average annual heat rate of less than 9,000 BTUs per KWh of generation.[21] Edwardsport's actual annual heat rates have ranged between a high of 13,882 BTU/KWh in 2013 and a low of 11,102 BTU/KWh in 2015. As shown in Figure 4, this means that Edwardsport's actual heat rate has been significantly higher than promised and far above the heat rates of other coal and gas-fired combined cycle units.

[20] Edwardsport data provided by Duke Energy Indiana in Indiana Utility Regulatory Commission Cause 43114, Sub-Dockets IGCC-12/13, IGCC-15 and IGCC-16. Industry data from the Generating Availability Data System of the North American Electric Reliability Corp., or NERC.
[21] See http://www.purdue.edu/discoverypark/energy/assets/pdfs/cctr/presentations/EdwardsportIGCC-041609.pdf

**Figure 4: Edwardsport's Actual vs. Projected Heat Rate and the Average Heat Rates of Other Coal and Gas-Fired Plants**[22]




Duke marketed Edwardsport to the public and the Indiana Utility Regulatory Commission as a plant that would generate power from syngas that had been produced in its gasifiers from coal mined in Indiana. [23] Indiana. However, Figure 5, below, shows that Edwardsport's gasifiers have been available only about 55 percent of the time since the plant was declared operational in June 2013, well below the levels Duke Energy Indiana said to expect.

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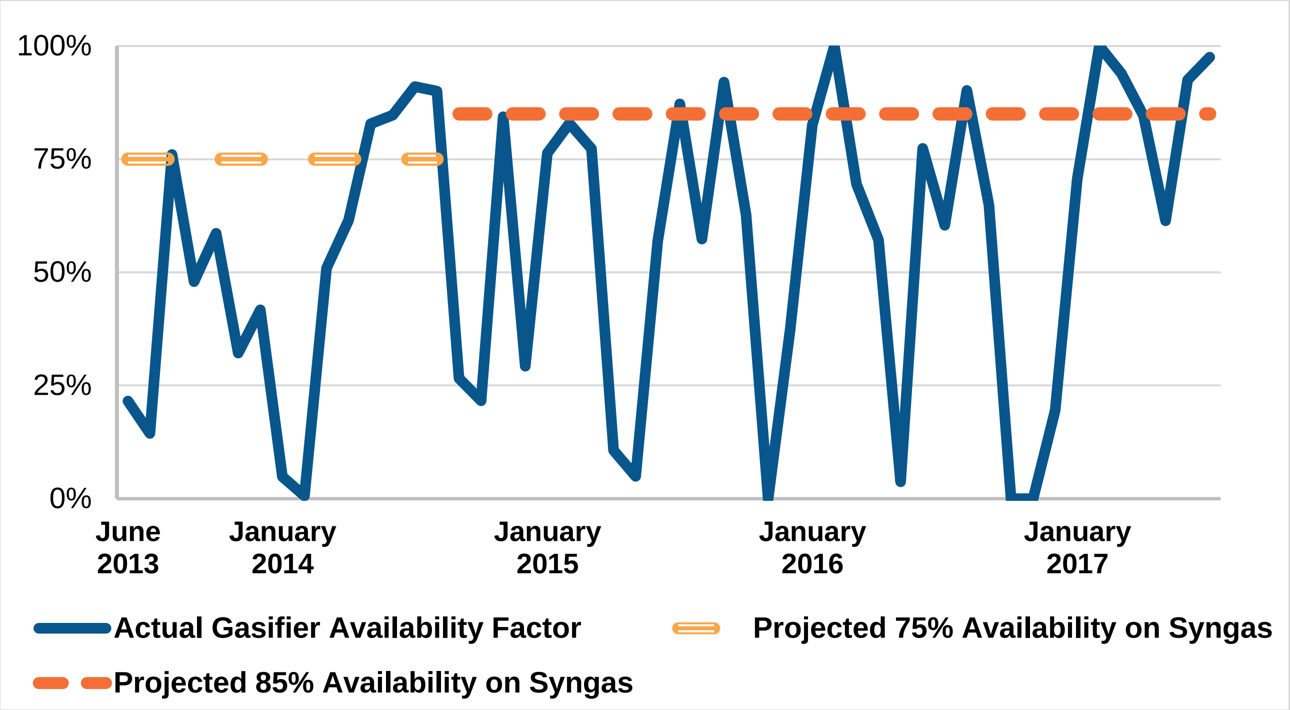
[22] Edwardsport heat rates from data in EIA Form 923, downloaded from SNL Financial on August 29, 2017.

[23] Starting as early as its original filing in IURC Cause 43114 in 2006, Duke Energy Indiana claimed that Edwardsport would operate at an 85 percent availability factor and, in its resource modeling analyses assumed (1) that the plant would operate this well starting immediately after it began commercial operations and (2) that all of this generation would be on SNG. The company later presented a revised projection that the plant would operate at a 75 percent availability factor for its first 15 months and at an 85 percent availability factor after that. However, its modeling analyses, which the company presented to support its claim that finishing Edwardsport was the most economic option, continued to assume that the plant would operate on SNG.

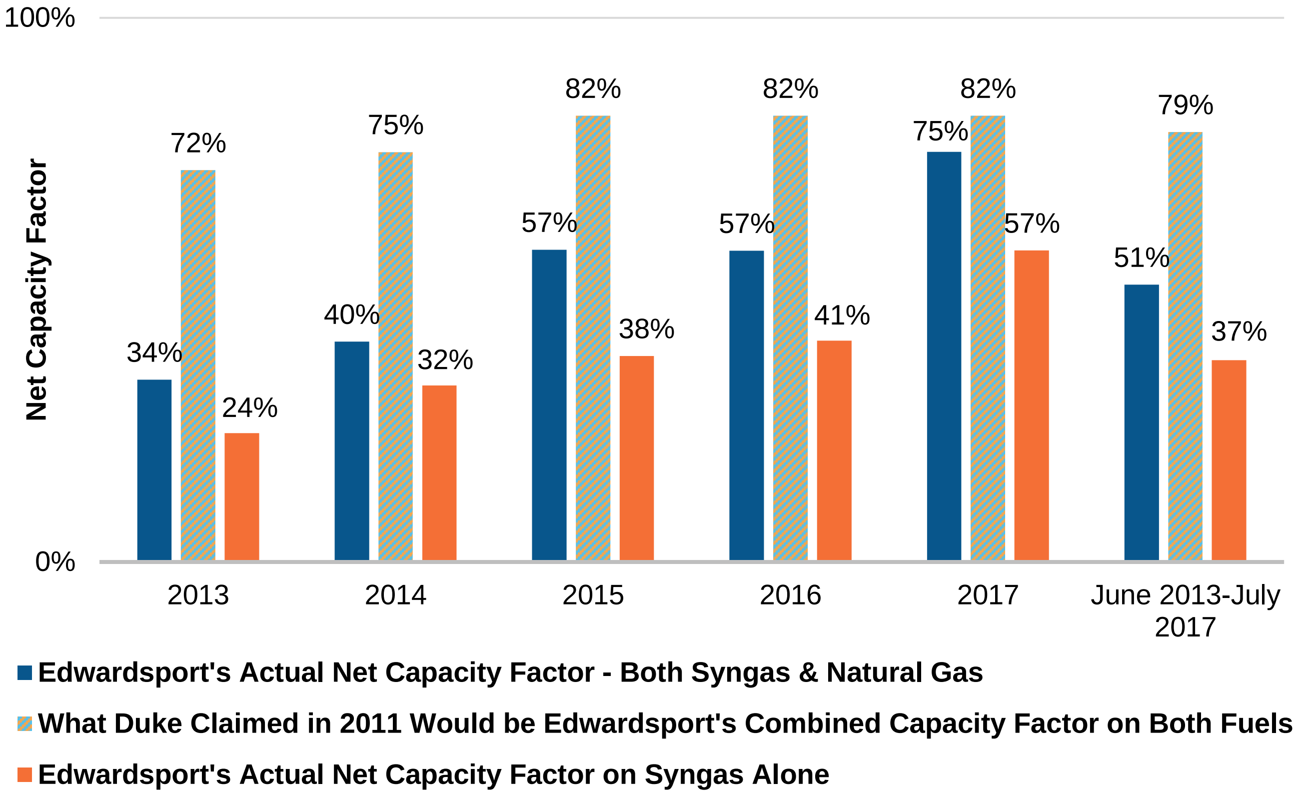
**Figure 5: Edwardsport's Actual vs. Projected Gasifier Availability**[24]




Because of its unreliable gasification systems, Edwardsport has generated far less power than Duke Energy Indiana said it would when Duke was arguing to the Indiana Utility Regulatory Commission that the plant should be built. We know this because the plant's actual capacity factors have been significantly below what Duke Energy said they would be. Capacity factor is a measure of how much power a plant actually produces in a month or a year compared to how much it would have produced had it operated at full power in that month or year.

[24] Ibid.

**Figure 6: Edwardsport's Actual vs. Projected Capacity Factors[25] [26]**




Edwardsport has averaged only a 51 percent capacity factor since it began commercial operations, far below the nearly 80 percent capacity factor Duke told the IURC it would. The plant's average capacity factor while running on syngas has been even lower, averaging only 37 percent through May 2017.

While Figures 3, 5 and 6 show that while Edwardsport's operating performance improved during the first seven months of 2017, it did not reach the levels the company promised when it was seeking to build the plant. Nor does this improved performance make the plant economic for consumers.

Another contributor to Edwardsport's poor operating performance is the fact that running the equipment for the gasification portion of the plant consumes a lot of power. A power plant's gross generation is the total amount of energy that it generates. Its net generation is the amount of power it sends out onto the electric grid. The difference between gross and net power is the "parasitic" load—the amount of power

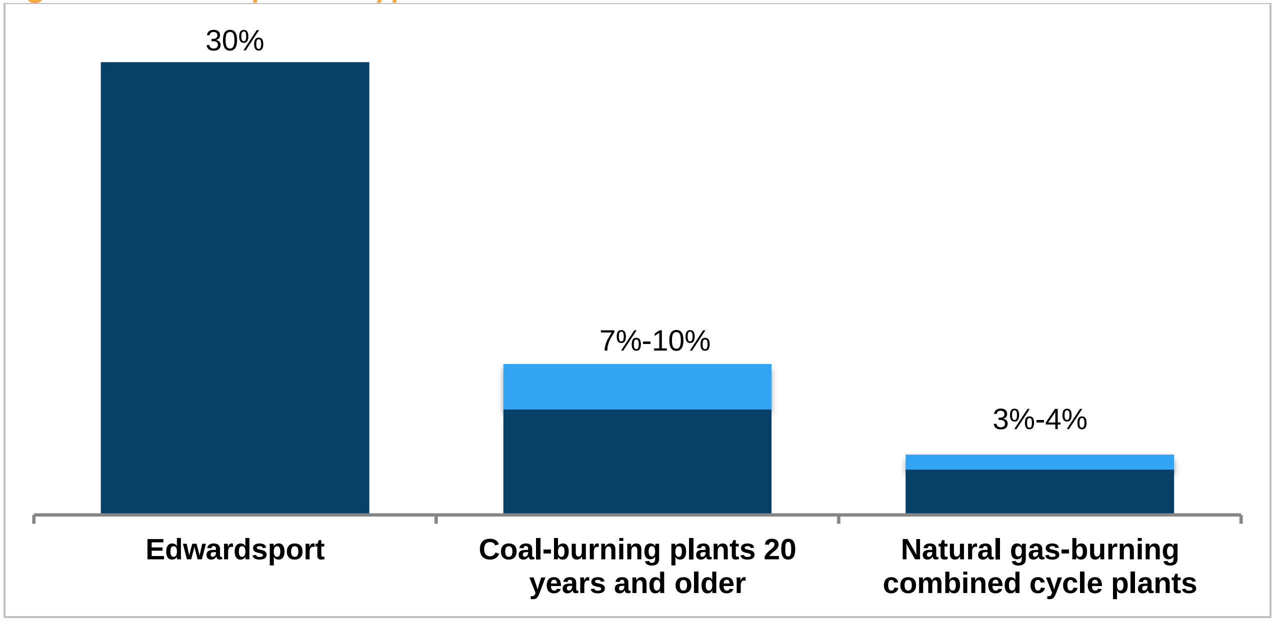
[25] Projected Edwardsport capacity factors from data provided by Duke Energy Indiana in IURC Cause 43114. Actual Edwardsport capacity factors on syngasl and natural gas from data submitted by the company in Form 923 of the Energy Information Administration (EIA).

[26] The Edwardsport actual capacity factor for 2017 in Figure 6 on both natural gas and syngas is for the months of January thru July. The capacity factor for the year on syngas alone is just for the months of January thru May 2017.

needed to operate onsite auxiliary equipment. When Edwardsport is operating on syngas, approximately 30 percent of its gross generation is lost to parasitic load.[27]

Thus, when it is operating on syngas, Edwardsport could be using as much as 190 MW of its 618 MW of capacity just to run internal equipment including gasifiers and other components of the gasification portion of the plant. As shown in Figure 7, below, this is much higher than the parasitic loads for natural gas-fired combined cycle plants; this on-site consumption of power adversely affects Edwardsport's economics.

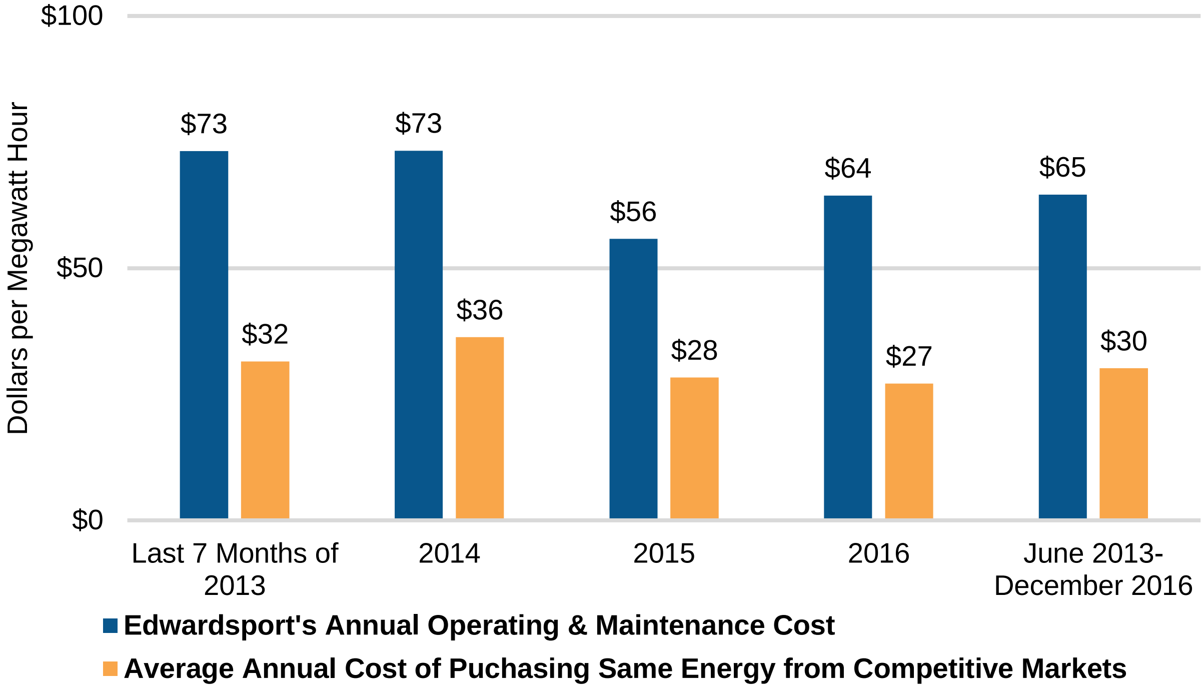
**Figure 7: Edwardsport vs. Typical Power Plant Annual Parasitic Loads**




Beyond having been very expensive to build and operating unreliably, Edwardsport is very costly to run. Figure 8, below, compares the annual cost of operating and maintaining Edwardsport with the average cost of buying power (both energy and capacity) from the competitive wholesale market in the Midwest.

[27] Based on a comparison of Edwardsport's gross generation on syngas provided in monthly compliance reports to the Lt. Governor of Indiana and the IURC and the plant's net generation reported in EIA Form 923.

**Figure 8: Edwardsport's Annual Operating & Maintenance Costs (O&M) per MWh**[28]

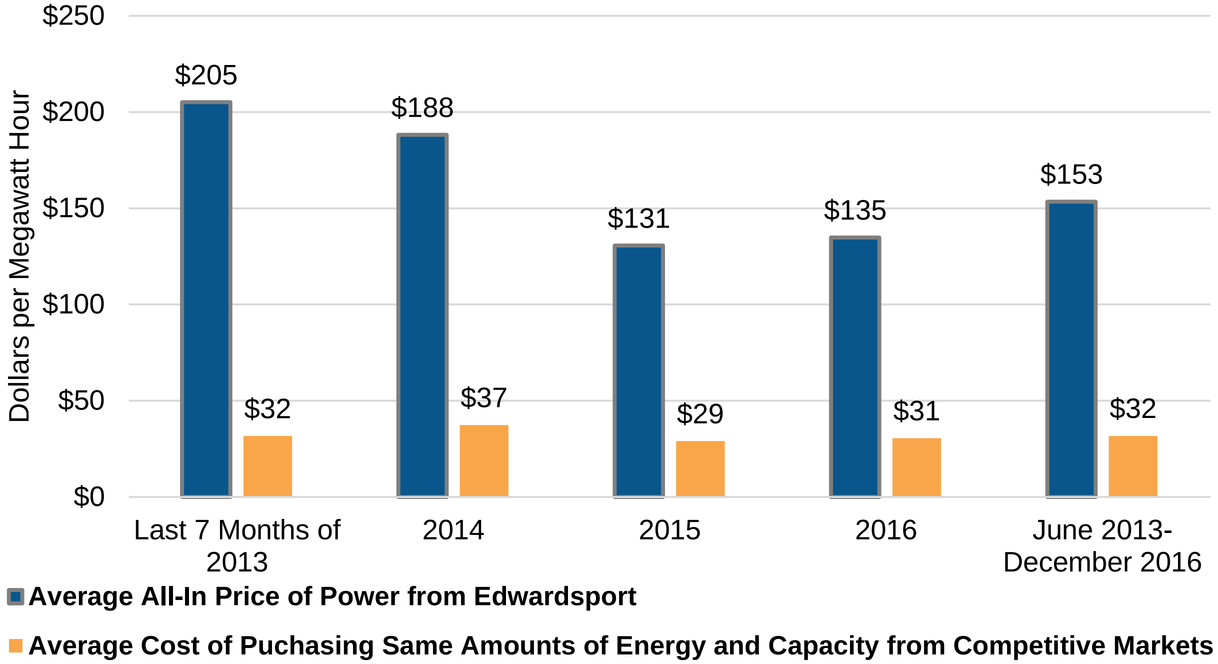



Customers don't pay just for the cost of operating and maintaining the Edwardsport IGCC plant. They also ultimately pay interest on the funds borrowed to build the plant, they pay for returns (profits) to Duke Energy Indiana, they pay the plant's property taxes and they absorb depreciation of plant costs. Customers pay as well for annual capital expenditures ("capex") to keep the plant operating and to keep it in compliance with environmental regulations.

All of these add up to the "All-In" cost of power from Edwardsport and represent all of the costs that customers must pay for the plant. Figure 9, below, shows that Edwardsport's "All-In" cost has been significantly more expensive than the cost of power in competitive wholesale markets.

[28] Edwardsport costs from Duke Energy Indiana FERC Form 1 filings for the years 2013 through 2016. Market prices for MISO's Indiana Zone downloaded from SNL Financial.

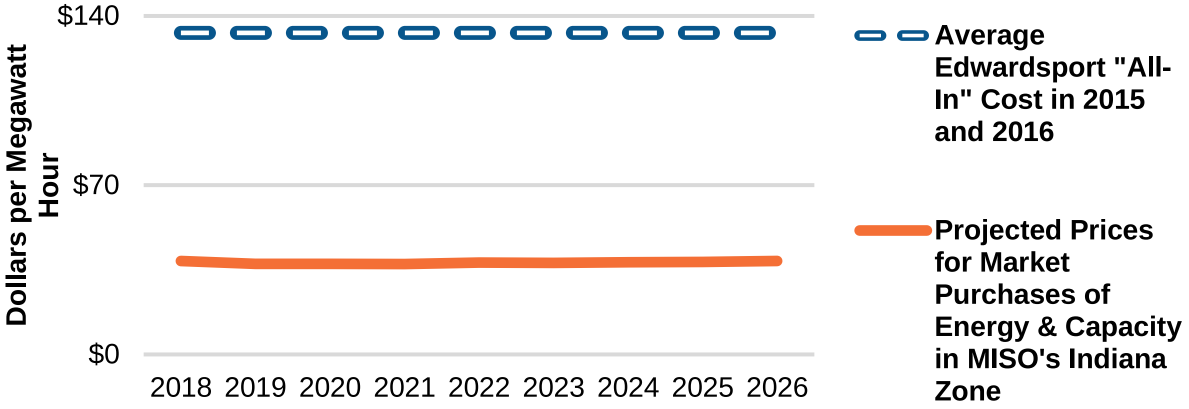
**Figure 9: Edwardsport "All-In" Cost vs. Cost of Buying Same Amounts of Energy and Capacity from Competitive Wholesale Markets.**




As a result, in the 43 months from June 2013 through December 2016, Duke Energy Indiana's customers paid almost five times as much, or around $1 billion more, for power from Edwardsport than they would have paid had Duke simply bought the same amounts of electricity and capacity from competitive wholesale markets.

Given Edwardsport's very high "All-In" costs, as shown in Figure 9, above—and given that the general expectation that future prices in the competitive wholesale markets will grow slowly for at least the next decade—it is extremely unlikely that the cost of buying capacity and energy from the competitive wholesale markets will ever equal, let alone exceed, the cost of the power produced by Edwardsport. This is true even if the company manages to maintain the improved plant performance reported during the first seven months of 2017.

**Figure 10: Edwardsport's All-In Cost vs. the Market's Expectation for Future Energy Market Prices in Indiana[29]**




Meanwhile—as Edwardsport has struggled to perform and as its costs have mounted—prices for wind- and solar-generated power have declined so far and so fast that wind and solar power now cost a fraction of the electricity produced at Edwardsport. And the prices for wind- and solar-generated power are expected to decline even further in coming years.

**Table 1: Edwardsport's Annual Operating & Maintenance and All-In Costs vs. the Costs of Wind and Solar Resources**

| | Cost per MWh |
|---|---|
| Edwardsport Average Operating & Maintenance Costs 2013-2016 | $65 |
| Edwardsport Average All-In Costs 2013-2016 | $153 |
| Average of Recent U.S. Wind Long-Term PPA Prices[30] | $22 |
| Average of Recent U.S. Solar Long-Term PPA Prices[31] | $40 |
| Market Expectations for Future Long-Term Wind PPA Prices in Early 2020s, Without Any Wind Production Tax Credit[32] | $20-$30 |
| Market Expectations for Future Long-Term Solar PPA Prices in Early 2020s, Without Any Solar Investment Tax Credit[33] | $20-40 |

[29] The projected market prices in Figure 10 reflect (i) forward energy market prices as of August 7, 2017 and (ii) the conservative assumption that capacity prices in MISO will jump back up to $72 per MW-day from their current level of $1.50 per MW-day and, on average, will remain at the level through 2026.

[30] Moody's Investors Service, *Rate-Basing Wind Generation Adds Momentum to Renewables*, March 15, 2017, and U.S. Department of Energy, *2016 Wind Technologies Market Report*, available at https://emp.lbl.gov/sites/default/files/2016_wind_technologies_market_report_final_optimized.pdf

[31] Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance and Pricing Trends in the United States, Lawrence Berkeley National Laboratory. Available at https://emp.lbl.gov/sites/all/files/lbnl-1006037_report.pdf

[32] UBS Global Research, *The Renewable Cost Deflation Trends Continue*, February 16, 2017, https://neo.ubs.com/shared/d1X1OBuc7TKNdeG/

[33] Ibid.

# Edwardsport Cancelled Plans for Carbon Capture Technology

When Duke Energy Indiana filed its petition in 2006 for a certificate to build Edwardsport, the company said that carbon capture technology would become a "strong potential benefit of IGCC plants"[34]:

> "Although capture and storage or sequestration techniques have not yet been commercially proven, IGCC technology offers the potential for relatively easier and less energy-intensive means of capturing $CO_2$ than [pulverized coal] plants."[35]

The company also cited a U.S. Department of Energy study that estimated that the costs of outfitting an IGCC plant with carbon capture equipment would increase the cost of producing electricity by about 30 percent, whereas the impact of adding carbon capture equipment to a supercritical pulverized coal plant would have an impact of around 68 percent on the plant's cost of producing electricity.[36]

Duke Energy Indiana decided not to pursue carbon capture after the Indiana Utility Regulatory Commission refused to approve the company's recovery of costs associated with the technology. As a result, Edwardsport now emits millions of tons of $CO_2$ into the atmosphere each year. In fact, Edwardsport today emits more $CO_2$, on a pounds per MMBTU basis, than any of Duke Energy Indiana's other coal-fired generators.[37]

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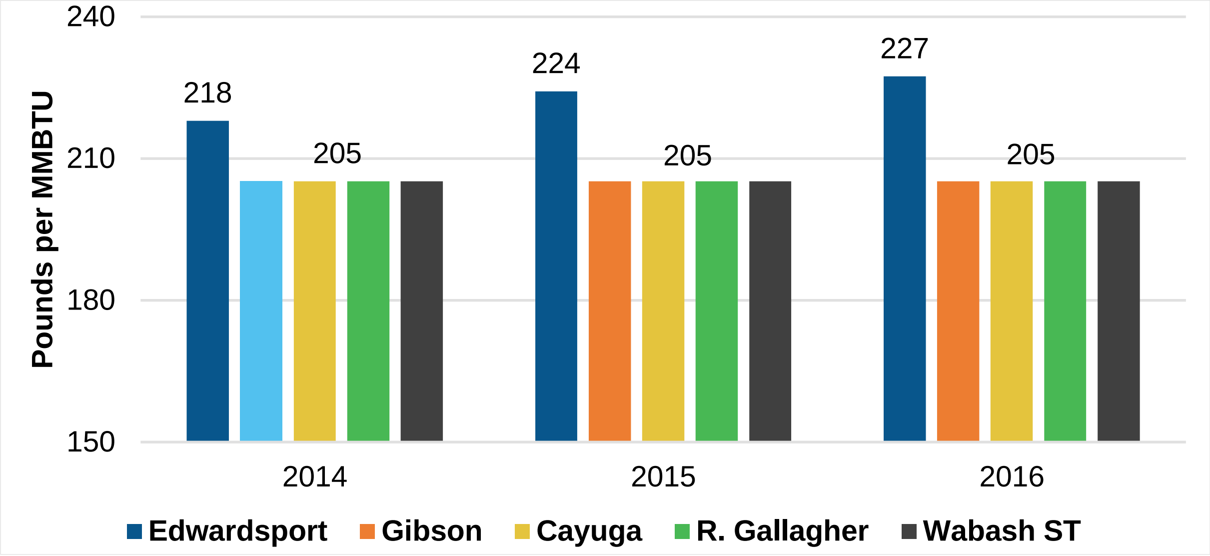
[34] Testimony of James E. Rogers, IURC Cause No. 43114, October 24, 2006, page 11, line 21, through page 12, line 3.
[35] Ibid.
[36] Ibid., page 12, line 22, through page 13, line 3.
[37] Mississippi Power planned to capture 65 percent of the CO2 from Kemper and sell it for enhanced oil recovery in a nearby oil field. However, this plan does not appear to be viable given the switch from coal gasification to burning natural gas.

Figure 11: Annual CO2 Emission Rates, Edwardsport and Duke Energy Indiana's Other Coal-Fired Generators[38]




# Demonstration IGCC Plants Built in the U.S. During the 1990s Have Shown Similar Results

Two demonstration projects using IGCC technology to generate electricity from coal were built during the 1990s: The Wabash Valley Power IGCC plant in Indiana and the Polk IGCC plant near Tampa, Fla.

Wabash Valley Power IGCC plant began operations in November 1995 but was retired after 20 years in operation, a relatively short life span for a power plant. With about 150 MW of net summer capacity, the plant was less than one-quarter the size of either Edwardsport or Kemper.

The plant did not operate reliably, achieving only an average 31 percent capacity factor over its operating life, which included a three-year period (2008-2010) when it did

[38] Emissions data downloaded from the EIA CEMS program through SNL Financial.

not generate any power at all. The cost of producing power at the plant was high, averaging from $40 per MWh to $60 per MWh in its last five years of operation.

The Polk IGCC plant is also substantially smaller than Edwardsport or Kemper, with only 294 MW of operating capacity versus Edwardsport's 618 MW and Kemper's 824 MW. Although it operated more often than Wabash Valley (achieving an average 58 percent capacity factor from 1996 to 2016), much of its generation was produced by burning natural gas, not syngas, especially in recent years.

Power from Polk IGCC has been expensive, reaching $60 per MWh in 2011 and 2012. The cost of producing power at the plant started to decline in 2013 when it began to burn more natural gas. The average price of power from the plant dropped to $36.21 per MWh in 2016, from $60.41 in 2012. The owner of Polk IGCC, Tampa Electric, received a permit from the Florida Department of Environmental Protection in October 2016 to burn natural gas only for 3,000 hours each year, up from a previous limit of 876 hours. Given the low price of natural gas, this will almost certainly lead to far more generation from natural gas and less from syngas.

# Conclusion

The Kemper and Edwardsport experiments, the only two coal gasification plants built in the U.S. in the past decade, show that Integrated Gasification Combined Cycle (IGCC) technology does not operate as advertised. Further, they demonstrate how high construction costs, unreliable performance, and high operating costs keep such plants from being financially viable or from effectively reducing carbon-dioxide emissions. Coal-gasification technology for the purposes of electricity generation is not feasible, especially given the declining costs of solar and wind resources and the expectation that natural gas prices will remain low for the foreseeable future.

# Institute for Energy Economics and Financial Analysis

The Institute for Energy Economics and Financial Analysis (IEEFA) conducts research and analyses on financial and economic issues related to energy and the environment. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy.More can be found at www.ieefa.org.

IEEFA would like to acknowledge the assistance of Alan Lindsay for his technical and financial modelling input.

# About the Authors

## David Schlissel

David Schlissel, director of resource planning analysis for IEEFA, has been a regulatory attorney and a consultant on electric utility rate and resource planning issues since 1974. He has testified as an expert witness before regulatory commissions in more than 35 states and before the U.S. Federal Energy Regulatory Commission and Nuclear Regulatory Commission. He also has testified as an expert witness in state and federal court proceedings concerning electric utilities. His clients have included state regulatory commissions in Arkansas, Kansas, Arizona, New Mexico and California. He has also consulted for publicly owned utilities, state governments and attorneys general, state consumer advocates, city governments, and national and local environmental organizations.

Schlissel testified as an expert witness in state regulatory commission cases in Mississippi and Indiana involving the Kemper and Edwardsport IGCC plants. In his testimony, he noted that because the projects involved first-of-their-kind technologies, the plants would cost far more and take much longer to build than the developers acknowledged. Schlissel testified also that future natural gas and energy market prices would be substantially lower than the developers projected.

Schlissel has undergraduate and graduate engineering degrees from the Massachusetts Institute of Technology and Stanford University. He has a Juris Doctor degree from Stanford University School of Law.

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# Exhibit DG-14:

# U.S. EPA. 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo), Attachment 1

**README**

This excel file is provided as an attachment to the 2024 Technical memo for the MATS Review of the RTR to document fPM rate and PM upgrade assumptions for the final PM analysis

*Note: "Not a Number" (NaN) are used as data flags or fillers for unavailable data*
*Note: Rounding in this spreadsheet may result in approximate values*

This document is organized as follows:

- **Unit-Level Information and Inputs sheet: Summarizes the relevant unit-level information for the analysis.**
  - Data sources: NEEDS (8-17-23 version): https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6
    - fPM compliance data for "N" in column L "Additional Data Review Since Proposal" was provided in the proposal docket
    - fPM compliance data for "Y" in column L "Additional Data Review Since Proposal" is provided in the docket for the final rule
  - Quarterly Lowest Achieved fPM Rates (99th percentile of each quarter, lb/MMBtu) prints the 99th percentile of each quarter of fPM data evaluated. The lowest value is the lowest achieved fPM rate used throughout the analysis
- **0.015, 0.010, and 0.006 Limit Assumption sheets: Summarizes the PM control upgrade assumption and cost for the EGUs identified as needing additional controls**
  - Capital Charge Rate (%) in column I is shown and applied for EGUs retiring in the near-term needing ESP upgrades. Other cost assumptions are already annual. Costs are in 2019$
  - Emission reductions (tons) for fPM2.5 and the individual metals uses emission factors provided in the "Metals Ratios" tab.
- **Metals Ratios: Emission factors for the 10 non-Hg HAP metals, total metals, and fPM2.5**
  - Unit-specific emission ratios were derived from the 2010 Information Collection Request (ICR) data, which is described in the 2018 memo "Emission Factor Development for RTR Risk Modeling Dataset for Coal- and Oil-fired EGUs" (Docket ID No. EPA-HQ-OAR-2018-0794-0010).
- **FF Upgrade Estimated Costs: Summarizes the Bag upgrade and Increased Std Bag Frequency costs used throughout the costs analysis. See 2024 Technical memo.**
- **FF Install Estimated Costs: Documents the Capital, VOM, and FOM costs used to estimate FF install costs**
  - The total costs were calculated by:
    - [(Capital Cost $/kW)*(Capacity, MW)*1000)*Capital Charge Rate (%)]+[(VOM $/MWh)*(Average Annual Gross Generation, MWh)*Capital Charge Rate ($)]+[FOM ($/kW yr)*Capacity (MW)*1000]
  - Average Annual Gross Generation was not available for Mayo (ORIS 6250). In this case, gross generation was estimated assuming a 50% capacity factor.

| | Plant Name | UniqueID_Final | Number of Units | Latitude | Longitude | State Name | Capacity (MW) | Modeled Fuels | PM Control | On Line Year | Retirement Year | Owner Name | Additional Data Review since Proposal | Number of Quarters Evaluated | Compliance Method | Heat Rate (Btu/kWh) | Average Annual Heat Input (mmBtu) | Quarterly Lowest Achieved fPM Rates (99th percentile of each quarter, lb/MMBtu) | Lowest Achieved fPM Rate (lowest 99th percentile, lb/MMBtu) | Average of All Data (lb/MMBtu) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | Barry | 3_B_5 | 1 | 31.0069 | -88.0103 | Alabama | 756 | Bituminou | ESPC + WS | 1971 | | Alabama F | N | 4 | Stack | 10141 | 3.3E+07 | 0.005, 0.0 | 0.00396 | 0.00775 |
| 1 | Platte | 59_B_1 | 1 | 40.8548 | -98.3482 | Nebraska | 100 | Subbitumi | ESPH + B | 1982 | | Grand Isla | N | 2 | PM CEMS | 11578 | 5565508 | 0.00407, ( | 0.00407 | 0.00212 |
| 2 | Whelan Energy Center | 60_B_1 | 1 | 40.5809 | -98.3124 | Nebraska | 77 | Subbitumi | ESPC | 1981 | | Hastings U | N | 1 | PM CEMS | 12708 | 4392679 | 0.00682 | 0.00682 | 0.00651 |
| 3 | Whelan Energy Center | 60_B_2 | 1 | 40.5809 | -98.3124 | Nebraska | 232 | Subbitumi | B | 2011 | | Heartland | N | 1 | PM CEMS | 12132 | 9879679 | 0.00105 | 0.00105 | 0.00102 |
| 4 | Holcomb | 108_B_SGU1 | 1 | 37.9308 | -100.973 | Kansas | 359 | Subbitumi | B | 1983 | | Sunflower | N | 2 | Stack | 10904 | 1.5E+07 | 0.00189, ( | 0.00189 | 0.00385 |
| 5 | Cross | 130_B_2 | 1 | 33.3715 | -80.1132 | South Carc | 570 | Bituminou | ESPC + WS | 1984 | | Santee Co | N | 3 | CPMS | 10475 | 2390664 | 0.00182, ( | 0.00182 | 0.00166 |
| 6 | Cross | 130_B_1 | 1 | 33.3715 | -80.1132 | South Carc | 580 | Bituminou | ESPC + WS | 1995 | | Santee Co | N | 1 | PM CEMS | 10570 | 2.2E+07 | 0.0025 | 0.0025 | 0.00233 |
| 7 | Cross | 130_B_3 | 1 | 33.3715 | -80.1132 | South Carc | 600 | Bituminou | ESPC + WS | 2007 | | Santee Co | N | 2 | Stack | 9772 | 3E+07 | 0.00508, ( | 0.0026 | 0.00342 |
| 8 | Cross | 130_B_4 | 1 | 33.3715 | -80.1132 | South Carc | 600 | Bituminou | ESPC + WS | 2008 | | Santee Co | N | 2 | Stack | 9801 | 3.4E+07 | 0.0052, 0. | 0.0029 | 0.00392 |
| 9 | Seminole | 136_B_2 | 1 | 29.7331 | -81.6328 | Florida | 657 | Bituminou | ESPC | 1984 | | Seminole I | N | 4 | Stack | 9871 | 3.8E+07 | 0.02592, ( | 0.00798 | 0.01417 |
| 10 | Apache Station | 160_B_3 | 1 | 32.0603 | -109.893 | Arizona | 175 | Bituminou | ESPH | 1979 | | Arizona El | N | 2 | Stack | 11040 | 1.1E+07 | 0.00418, ( | 0.00418 | 0.00413 |
| 11 | GREC | 165_B_2 | 1 | 36.1903 | -95.2894 | Oklahoma | 492 | Subbitumi | B | 1982 | | Grand Rive | N | 1 | Stack | 12314 | 6051936 | 0.001 | 0.001 | 0.001 |
| 12 | Limestone | 298_B_LIM1 | 1 | 31.4219 | -96.2525 | Texas | 831 | Lignite, Su | ESPC | 1985 | 2029 | NRG Texas | N | 2 | Stack | 10605 | 3.9E+07 | 0.0023, 0. | 0.0023 | 0.00457 |
| 13 | Limestone | 298_B_LIM2 | 1 | 31.4219 | -96.2525 | Texas | 858 | Lignite, Su | ESPC | 1986 | 2029 | NRG Texas | N | 2 | Stack | 10567 | 4.5E+07 | 0.00287, ( | 0.00287 | 0.00333 |
| 14 | Comanche | 470_B_3 | 1 | 38.2081 | -104.575 | Colorado | 750 | Subbitumi | B | 2010 | 2031 | Public Serv | N | 1 | PM CEMS | 10459 | 3.7E+07 | 0.0068 | 0.0068 | 0.00621 |
| 15 | Hayden | 525_B_H1 | 1 | 40.4856 | -107.185 | Colorado | 179 | Bituminou | B | 1976 | 2029 | Public Serv | N | 2 | Stack | 10910 | 1.3E+07 | 0.00498, ( | 0.002 | 0.00283 |
| 16 | Crystal River | 628_B_4 | 1 | 28.9656 | -82.6977 | Florida | 712 | Bituminou | ESPC | 1982 | 2034 | Duke Ener | N | 2 | PM CEMS | 10431 | 3.2E+07 | 0.00814, ( | 0.00814 | 0.00775 |
| 17 | Crystal River | 628_B_5 | 1 | 28.9656 | -82.6977 | Florida | 710 | Bituminou | ESPC | 1984 | 2034 | Duke Ener | N | 2 | PM CEMS | 10391 | 3.2E+07 | 0.00814, ( | 0.00814 | 0.00775 |
| 18 | Big Bend | 645_B_BB04 | 1 | 27.7944 | -82.4036 | Florida | 437 | Bituminou | ESPC | 1985 | | Tampa Ele | N | 1 | PM CEMS | 10792 | 2E+07 | 0.00953 | 0.00953 | 0.00257 |
| 19 | Northside Generating Station | 667_B_1 | 1 | 30.4172 | -81.5525 | Florida | 293 | Bituminou | B | 2002 | | JEA | N | 2 | Stack | 10368 | 1.5E+07 | 0.00307, ( | 0.00123 | 0.00107 |
| 20 | Northside Generating Station | 667_B_2 | 1 | 30.4172 | -81.5525 | Florida | 293 | Bituminou | B | 2002 | | JEA | N | 2 | Stack | 10386 | 9628369 | 0.002, 0.0 | 0.002 | 0.00183 |
| 21 | Bowen | 703_B_1BLR | 1 | 34.1256 | -84.9222 | Georgia | 724 | Bituminou | ESPC + WS | 1971 | | Georgia Pc | N | 2 | Stack | 10032 | 2.8E+07 | 0.006, 0.0 | 0.004 | 0.00467 |
| 22 | Bowen | 703_B_2BLR | 1 | 34.1256 | -84.9222 | Georgia | 724 | Bituminou | ESPC + WS | 1972 | | Georgia Pc | N | 2 | Stack | 9954 | 2.2E+07 | 0.00398, ( | 0.00398 | 0.00433 |
| 23 | Bowen | 703_B_3BLR | 1 | 34.1256 | -84.9222 | Georgia | 892 | Bituminou | ESPC + B + WS | 1974 | 2035 | Georgia Pc | N | 2 | Stack | 9780 | 3.2E+07 | 0.00496, ( | 0.003 | 0.00317 |
| 24 | Bowen | 703_B_4BLR | 1 | 34.1256 | -84.9222 | Georgia | 892 | Bituminou | ESPC + B + WS | 1975 | 2035 | Georgia Pc | N | 2 | Stack | 9726 | 3.7E+07 | 0.00298, ( | 0.002 | 0.002 |
| 25 | Dallman | 963_B_41 | 1 | 39.7548 | -89.6024 | Illinois | 208 | Bituminou | B | 2009 | 2050 | Springfielc | N | 2 | Stack | 11450 | 1.1E+07 | 0.00353, ( | 0.00192 | 0.00222 |
| 26 | Marion | 976_B_123 | 1 | 37.6197 | -88.9531 | Illinois | 120 | Bituminou | B | 1978 | 2030 | Southern I | Y | 26 | PM CEMS | 11487 | 9343124 | 0.00671, ( | 0.005 | 0.01383 |
| 27 | Clifty Creek | 983_B_1, 983_B_2, 983_B_3 | 3 | 38.7378 | -85.4206 | Indiana | 588 | Bituminou | ESPC | 1955 | | Indiana Ke | N | 2 | PM CEMS | 10819 | 3.2E+07 | 0.00316, ( | 0.00316 | 0.00302 |
| 30 | Clifty Creek | 983_B_4, 983_B_5, 983_B_6 | 3 | 38.7378 | -85.4206 | Indiana | 588 | Bituminou | ESPC | 1955 | | Indiana Ke | N | 2 | PM CEMS | 10734 | 2.8E+07 | 0.00231, ( | 0.00209 | 0.00184 |
| 33 | Cayuga | 1001_B_1 | 1 | 39.9242 | -87.4244 | Indiana | 500 | Bituminou | ESPC | 1970 | 2029 | Duke Ener | N | 2 | PM CEMS | 10203 | 2.7E+07 | 0.00438, ( | 0.00429 | 0.00405 |
| 34 | Cayuga | 1001_B_2 | 1 | 39.9242 | -87.4244 | Indiana | 495 | Bituminou | ESPC | 1972 | 2029 | Duke Ener | N | 2 | PM CEMS | 10254 | 2.3E+07 | 0.00348, ( | 0.00348 | 0.00322 |
| 35 | Whitewater Valley | 1040_B_1, 1040_B_2 | 2 | 39.8028 | -84.8953 | Indiana | 100 | Bituminou | ESPC + B | 1955 | | Richmond | N | 2 | Stack | 13048 | 488813 | 0.00398, ( | 0.00398 | 0.00317 |
| 37 | Walter Scott Jr Energy Center | 1082_B_3 | 1 | 41.18 | -95.8408 | Iowa | 708 | Subbitumi | ESPC + B | 1978 | | MidAmeri | Y | 26 | Stack | 9926 | 4E+07 | 0.00169, ( | 0.00169 | 0.00925 |
| 38 | Walter Scott Jr Energy Center | 1082_B_4 | 1 | 41.18 | -95.8408 | Iowa | 814 | Subbitumi | B | 2007 | | MidAmeri | Y | 11 | Stack | 9977 | 3.8E+07 | 0.00998, ( | 0.0022 | 0.00576 |
| 39 | George Neal North | 1091_B_3 | 1 | 42.2998 | -96.3617 | Iowa | 515 | Subbitumi | ESPC + B | 1975 | | MidAmeri | Y | 12 | Stack | 10462 | 1.9E+07 | 0.0016, 0. | 0.0008 | 0.0034 |
| 40 | Muscatine Plant #1 | 1167_B_8 | 1 | 41.3917 | -91.0569 | Iowa | 44 | Subbitumi | ESPC | 1969 | 2029 | Muscatine | N | 2 | Stack | 8300 | 4236794 | 0.00408, ( | 0.00239 | 0.00257 |
| 41 | Muscatine Plant #1 | 1167_B_9 | 1 | 41.3917 | -91.0569 | Iowa | 163 | Subbitumi | ESPC | 1983 | | Muscatine | N | 2 | Stack | 8800 | 7849716 | 0.00549, ( | 0.0036 | 0.00423 |
| 42 | La Cygne | 1241_B_1 | 1 | 38.3481 | -94.6456 | Kansas | 736 | Bituminou | B | 1973 | 2032 | Evergy Kai | N | 1 | PM CEMS | 10600 | 2.8E+07 | 0.00524 | 0.00524 | 0.00498 |
| 43 | La Cygne | 1241_B_2 | 1 | 38.3481 | -94.6456 | Kansas | 662 | Bituminou | B | 1977 | 2039 | Evergy Kai | N | 1 | PM CEMS | 10424 | 3.2E+07 | 0.002 | 0.002 | 0.00194 |
| 44 | E W Brown | 1355_B_3 | 1 | 37.7883 | -84.7126 | Kentucky | 409 | Bituminou | ESPC + B | 1971 | 2029 | Kentucky U | N | 1 | PM CEMS | 11543 | 1.3E+07 | 0.01007 | 0.01007 | 0.00591 |
| 45 | Ghent | 1356_B_1 | 1 | 38.7497 | -85.035 | Kentucky | 474 | Bituminou | ESPC + B | 1973 | 2034 | Kentucky U | N | 1 | PM CEMS | 10759 | 3E+07 | 0.00504 | 0.00504 | 0.00485 |
| 46 | Ghent | 1356_B_2, 1356_B_3 | 2 | 38.7497 | -85.035 | Kentucky | 980 | Bituminou | ESPH + B | 1977 | 2034 | Kentucky U | N | 2 | PM CEMS | 10767 | 5.2E+07 | 0.00862, ( | 0.00807 | 0.0076 |
| 48 | Ghent | 1356_B_4 | 1 | 38.7497 | -85.035 | Kentucky | 465 | Bituminou | ESPH + B | 1984 | 2037 | Kentucky U | N | 3 | PM CEMS | 10946 | 2.8E+07 | 0.01743, ( | 0.00602 | 0.00787 |
| 49 | Mill Creek | 1364_B_3 | 1 | 38.0525 | -85.9103 | Kentucky | 391 | Bituminou | ESPC + B | 1978 | 2039 | Louisville ( | Y | 26 | PM CEMS | 10521 | 2.3E+07 | 0.00189, ( | 0.00177 | 0.00191 |
| 50 | Mill Creek | 1364_B_4 | 1 | 38.0525 | -85.9103 | Kentucky | 477 | Bituminou | ESPC + B | 1982 | 2039 | Louisville ( | Y | 26 | PM CEMS | 10452 | 2.9E+07 | 0.00769, ( | 0.00345 | 0.01143 |
| 51 | Shawnee | 1379_B_1, 1379_B_2, 1379_B_3, 1379_B_4, 1379_B_5 | 5 | 37.1517 | -88.775 | Kentucky | 670 | Bituminou | B + C | 1953 | 2034 | Tennessee | N | 2 | Stack | 11164 | 3.8E+07 | 0.00547, ( | 0.00547 | 0.0052 |
| 56 | Shawnee | 1379_B_6, 1379_B_7, 1379_B_8, 1379_B_9 | 4 | 37.1517 | -88.775 | Kentucky | 536 | Bituminou | B + C | 1954 | 2034 | Tennessee | N | 2 | Stack | 11190 | 3E+07 | 0.00559, ( | 0.00559 | 0.00635 |
| 60 | Cooper | 1384_B_1, 1384_B_2 | 2 | 36.9981 | -84.5919 | Kentucky | 341 | Bituminou | ESPC + B | 1969 | | East Kentu | N | 1 | PM CEMS | 10639 | 3985228 | 0.005 | 0.005 | 0.00483 |
| 62 | R S Nelson | 1393_B_6 | 1 | 30.2844 | -93.2911 | Louisiana | 550 | Subbitumi | ESPC | 1982 | | Entergy Lc | N | 3 | PM CEMS | 11854 | 2.3E+07 | 0.00785, ( | 0.00785 | 0.0084 |
| 63 | Monroe | 1733_B_1 | 1 | 41.8906 | -83.3464 | Michigan | 758 | Bituminou | ESPC | 1972 | 2029 | DTE Electr | N | 2 | PM CEMS | 10181 | 3.9E+07 | 0.00609, ( | 0.00609 | 0.00415 |
| 64 | Monroe | 1733_B_2 | 1 | 41.8906 | -83.3464 | Michigan | 773 | Bituminou | ESPC | 1973 | 2029 | DTE Electr | N | 2 | PM CEMS | 10223 | 3.8E+07 | 0.007, 0.0 | 0.007 | 0.00486 |
| 65 | Monroe | 1733_B_3 | 1 | 41.8906 | -83.3464 | Michigan | 773 | Bituminou | ESPC | 1973 | 2029 | DTE Electr | N | 2 | PM CEMS | 10180 | 4E+07 | 0.00409, ( | 0.004 | 0.00324 |
| 66 | Monroe | 1733_B_4 | 1 | 41.8906 | -83.3464 | Michigan | 762 | Bituminou | ESPC | 1974 | 2029 | DTE Electr | N | 2 | PM CEMS | 10154 | 3.8E+07 | 0.003, 0.0 | 0.003 | 0.00344 |
| 67 | Clay Boswell | 1893_B_3 | 1 | 47.2611 | -93.6528 | Minnesota | 364 | Subbitumi | B | 1973 | 2030 | ALLETE Inc | N | 1 | PM CEMS | 10599 | 2.2E+07 | 0.0028 | 0.0028 | 0.00212 |
| 68 | Clay Boswell | 1893_B_4 | 1 | 47.2611 | -93.6528 | Minnesota | 584 | Subbitumi | B | 1980 | 2035 | ALLETE Inc | N | 1 | PM CEMS | 10639 | 3.8E+07 | 0.0106 | 0.0106 | 0.00747 |
| 69 | Allen S King | 1915_B_1 | 1 | 45.03 | -92.7786 | Minnesota | 511 | Subbitumi | ESPC + B | 1968 | 2029 | Northern S | N | 2 | Stack | 9792 | 2E+07 | 0.00559, ( | 0.0032 | 0.00405 |
| 70 | Hawthorn | 2079_B_5A | 1 | 39.1306 | -94.4778 | Missouri | 564 | Subbitumi | B | 2000 | | Evergy Me | N | 2 | Stack | 10285 | 2.6E+07 | 0.00209, ( | 0.00209 | 0.00474 |
| 71 | Labadie | 2103_B_1 | 1 | 38.5622 | -90.8377 | Missouri | 593 | Subbitumi | ESPC | 1970 | 2042 | Ameren M | Y | 27 | PM CEMS | 10396 | 4E+07 | 0.01654, ( | 0.014 | 0.01752 |
| 72 | Labadie | 2103_B_2 | 1 | 38.5622 | -90.8377 | Missouri | 593 | Subbitumi | ESPC | 1971 | 2042 | Ameren M | Y | 27 | PM CEMS | 10397 | 4.1E+07 | 0.01654, ( | 0.014 | 0.01752 |
| 73 | Labadie | 2103_B_3 | 1 | 38.5622 | -90.8377 | Missouri | 593 | Subbitumi | ESPC | 1972 | 2036 | Ameren M | Y | 27 | PM CEMS | 10427 | 3.7E+07 | 0.01654, ( | 0.014 | 0.01752 |
| 74 | Labadie | 2103_B_4 | 1 | 38.5622 | -90.8377 | Missouri | 593 | Subbitumi | ESPC | 1973 | 2036 | Ameren M | Y | 27 | PM CEMS | 10397 | 4E+07 | 0.01654, ( | 0.014 | 0.01752 |
| 75 | Sioux | 2107_B_1 | 1 | 38.9155 | -90.2902 | Missouri | 487 | Bituminou | ESPC | 1967 | 2030 | Ameren M | N | 1 | PM CEMS | 11127 | 2.4E+07 | 0.003 | 0.003 | 0.00276 |
| 76 | Sioux | 2107_B_2 | 1 | 38.9155 | -90.2902 | Missouri | 487 | Bituminou | ESPC | 1968 | 2030 | Ameren M | N | 1 | PM CEMS | 11339 | 2.2E+07 | 0.005 | 0.005 | 0.00416 |
| 77 | New Madrid | 2167_B_1 | 1 | 36.5147 | -89.5617 | Missouri | 579 | Subbitumi | ESPC | 1972 | | Associatec | N | 2 | Stack | 9859 | 3E+07 | 0.01094, ( | 0.00498 | 0.00617 |
| 78 | New Madrid | 2167_B_2 | 1 | 36.5147 | -89.5617 | Missouri | 575 | Subbitumi | ESPC | 1977 | | Associatec | N | 4 | Stack | 9814 | 3.3E+07 | 0.01588, ( | 0.00498 | 0.00983 |
| 79 | Thomas Hill | 2168_B_MB1 | 1 | 39.5522 | -92.6381 | Missouri | 165 | Subbitumi | ESPC | 1966 | | Associatec | N | 2 | Stack | 9907 | 1.3E+07 | 0.002, 0.0 | 0.0018 | 0.0016 |
| 80 | Thomas Hill | 2168_B_MB2 | 1 | 39.5522 | -92.6381 | Missouri | 270 | Subbitumi | ESPC | 1969 | | Associatec | N | 2 | Stack | 9930 | 1.9E+07 | 0.005, 0.0 | 0.003 | 0.00367 |
| 81 | Thomas Hill | 2168_B_MB3 | 1 | 39.5522 | -92.6381 | Missouri | 699 | Subbitumi | ESPC | 1982 | | Associatec | N | 2 | Stack | 9903 | 4.9E+07 | 0.00598, ( | 0.003 | 0.004 |
| 82 | Lon Wright | 2240_B_8 | 1 | 41.4281 | -96.4623 | Nebraska | 82 | Subbitumi | ESPH + B | 1976 | | Fremont D | N | 2 | Stack | 12240 | 4018529 | 0.00248, ( | 0.00248 | 0.00183 |
| 83 | Sheldon | 2277_B_2 | 1 | 40.5589 | -96.7847 | Nebraska | 115 | Subbitumi | B | 1961 | | Nebraska | Y | 9 | Stack | 11706 | 4242653 | 0.0007, 0. | 0.0007 | 0.00286 |
| 84 | Sheldon | 2277_B_1 | 1 | 40.5589 | -96.7847 | Nebraska | 104 | Subbitumi | B | 1968 | | Nebraska | Y | 10 | Stack | 11681 | 4304764 | 0.00456, ( | 0.00256 | 0.00499 |
| 85 | Merrimack | 2364_B_1, 2364_B_2 | 2 | 43.1411 | -71.4692 | New Ham | 438 | Bituminou | ESPC | 1960 | | GSP Merri | N | 2 | Stack | 11390 | 3580623 | 0.00786 | 0.00786 | 0.00597 |
| 87 | Schiller | 2367_B_4 | 1 | 43.0978 | -70.7842 | New Ham | 48 | Bituminou | ESPC | 1952 | | GSP Schille | N | 2 | Stack | 14500 | 400721 | 0.00328, ( | 0.00199 | 0.00202 |
| 88 | Schiller | 2367_B_6 | 1 | 43.0978 | -70.7842 | New Ham | 48 | Bituminou | ESPC | 1957 | | GSP Schille | N | 2 | Stack | 14500 | 444906 | 0.00566, ( | 0.00566 | 0.00537 |
| 89 | Four Corners | 2442_B_5 | 1 | 36.69 | -108.481 | New Mexi | 770 | Subbitumi | B | 1963 | 2031 | Arizona Pu | N | 2 | Stack | 9766 | 4.1E+07 | 0.00588, ( | 0.0029 | 0.00397 |
| 90 | Four Corners | 2442_B_4 | 1 | 36.69 | -108.481 | New Mexi | 770 | Subbitumi | B | 1969 | 2031 | Arizona Pu | N | 2 | Stack | 9771 | 4E+07 | 0.01042, ( | 0.00398 | 0.0053 |
| 91 | Roxboro | 2712_B_1 | 1 | 36.4833 | -79.0731 | North Carc | 379 | Bituminou | ESPC | 1966 | 2029 | Duke Ener | N | 1 | PM CEMS | 10245 | 7317537 | 0.00438 | 0.00438 | 0.00431 |
| 92 | Roxboro | 2712_B_2 | 1 | 36.4833 | -79.0731 | North Carc | 668 | Bituminou | ESPC | 1968 | 2029 | Duke Ener | N | 1 | PM CEMS | 10393 | 1.5E+07 | 0.00381 | 0.00381 | 0.00247 |
| 93 | Roxboro | 2712_B_3A, 2712_B_3B | 2 | 36.4833 | -79.0731 | North Carc | 694 | Bituminou | ESPC | 1973 | 2034 | Duke Ener | N | 1 | PM CEMS | 10296 | 2.1E+07 | 0.00256 | 0.00256 | 0.00245 |
| 95 | Roxboro | 2712_B_4A, 2712_B_4B | 2 | 36.4833 | -79.0731 | North Carc | 698 | Bituminou | ESPH | 1980 | 2034 | Duke Ener | N | 3 | PM CEMS | 10364 | 1.9E+07 | 0.01528, ( | 0.01277 | 0.0123 |
| 97 | James E. Rogers Energy Complex | 2721_B_5 | 1 | 35.22 | -81.7594 | North Carc | 544 | Bituminou | ESPC | 1972 | | Duke Ener | N | 1 | PM CEMS | 9385 | 1.2E+07 | 0.00202 | 0.00202 | 0.00197 |
| 98 | James E. Rogers Energy Complex | 2721_B_6 | 1 | 35.22 | -81.7594 | North Carc | 844 | Bituminou | B | 2012 | 2048 | Duke Ener | N | 1 | PM CEMS | 9090 | 4E+07 | 0.00184 | 0.00184 | 0.00178 |
| 99 | Marshall | 2727_B_1, 2727_B_2 | 2 | 35.5975 | -80.9658 | North Carc | 740 | Bituminou | ESPC | 1965 | 2029 | Duke Ener | N | 1 | PM CEMS | 9477 | 1.9E+07 | 0.00353 | 0.00353 | 0.00295 |
| 100 | Marshall | 2727_B_4 | 1 | 35.5975 | -80.9658 | North Carc | 660 | Bituminou | ESPC | 1965 | 2033 | Duke Ener | N | 1 | PM CEMS | 9300 | 3.3E+07 | 0.00249 | 0.00249 | 0.00239 |
| 102 | Marshall | 2727_B_3 | 1 | 35.5975 | -80.9658 | North Carc | 658 | Bituminou | ESPC | 1969 | 2033 | Duke Ener | N | 1 | PM CEMS | 9344 | 2.5E+07 | 0.00112 | 0.00112 | 0.00104 |
| 103 | Leland Olds | 2817_B_1 | 1 | 47.2808 | -101.321 | North Dak | 222 | Lignite, Su | ESPC | 1966 | | Basin Elect | N | 2 | Stack | 11851 | 1.2E+07 | 0.01025, ( | 0.00699 | 0.00728 |
| 104 | Leland Olds | 2817_B_2 | 1 | 47.2808 | -101.321 | North Dak | 445 | Lignite, Su | ESPC | 1975 | | Basin Elect | N | 2 | Stack | 11751 | 2.5E+07 | 0.00739, ( | 0.00569 | 0.00607 |
| 105 | Milton R Young | 2823_B_B1 | 1 | 47.0659 | -101.213 | North Dak | 237 | Lignite | ESPC | 1970 | | Minnkota | Y | 31 | PM CEMS | 11631 | 1.9E+07 | 0.01, 0.01, | 0.003 | 0.00531 |
| 106 | Milton R Young | 2823_B_B2 | 1 | 47.0659 | -101.213 | North Dak | 447 | Lignite | ESPC | 1977 | | Square Bu | Y | 31 | PM CEMS | 11391 | 3.4E+07 | 0.01, 0.01, | 0.01 | 0.01084 |
| 107 | Cardinal | 2828_B_1 | 1 | 40.2522 | -80.6486 | Ohio | 585 | Bituminou | ESPC | 1966 | | AEP Gener | N | 2 | Stack | 9899 | 3.4E+07 | 0.00318, ( | 0.00296 | 0.00212 |
| 108 | Cardinal | 2828_B_2 | 1 | 40.2522 | -80.6486 | Ohio | 585 | Bituminou | ESPC | 1967 | | Buckeye P | N | 2 | Stack | 9906 | 3.4E+07 | 0.00308, ( | 0.00139 | 0.00162 |
| 109 | Cardinal | 2828_B_3 | 1 | 40.2522 | -80.6486 | Ohio | 620 | Bituminou | ESPH | 1977 | 2029 | Buckeye P | N | 2 | Stack | 10103 | 3.4E+07 | 0.0052, 0. | 0.0052 | 0.00478 |
| 110 | Kyger Creek | 2876_B_1, 2876_B_2 | 2 | 38.9144 | -82.1289 | Ohio | 386 | Bituminou | ESPC | 1955 | | Ohio Valle | N | 1 | PM CEMS | 10558 | 2.4E+07 | 0.00179 | 0.00179 | 0.00155 |
| 112 | Kyger Creek | 2876_B_3, 2876_B_4, 2876_B_5 | 3 | 38.9144 | -82.1289 | Ohio | 576 | Bituminou | ESPC | 1955 | | Ohio Valle | N | 1 | PM CEMS | 10579 | 3.5E+07 | 0.00484 | 0.00484 | 0.00456 |
| 115 | FirstEnergy Bay Shore | 2878_B_1 | 1 | 41.6917 | -83.4378 | Ohio | 136 | Subbitumi | B | 2000 | | Walleye Pc | N | 2 | Stack | 12574 | 1.4E+07 | 0.00199, ( | 0.00199 | 0.00213 |
| 116 | Muskogee | 2952_B_6 | 1 | 35.7614 | -95.2873 | Oklahoma | 503 | Subbitumi | ESPC | 1984 | 2049 | Oklahoma | N | 3 | CPMS | 11137 | 2.1E+07 | 0.00694, ( | 0.0051 | 0.00562 |
| 117 | Seward | 3130_B_1, 3130_B_2 | 2 | 40.4063 | -79.0337 | Pennsylva | 520 | Waste Coa | B | 2004 | | Seward Ge | N | 2 | Stack | 10969 | 2.6E+07 | 0.00379, ( | 0.00379 | 0.00348 |
| 119 | Wateree | 3297_B_WAT1, 3297_B_WAT2 | 2 | 33.8264 | -80.6228 | South Carc | 684 | Bituminou | ESPC + B | 1970 | 2029 | Dominion | N | 2 | Stack | 10329 | 2.6E+07 | 0.00296, ( | 0.002 | 0.00183 |
| 121 | Williams | 3298_B_WIL1 | 1 | 33.0158 | -79.9297 | South Carc | 605 | Bituminou | ESPC | 1973 | 2029 | South Carc | N | 2 | Stack | 9833 | 2.5E+07 | 0.001, 0.0 | 0.001 | 0.00183 |
| 122 | Cumberland | 3399_B_1 | 1 | 36.3903 | -87.6539 | Tennessee | 1239 | Bituminou | ESPC | 1973 | 2029 | Tennessee | N | 2 | Stack | 10158 | 5.2E+07 | 0.00608, ( | 0.0039 | 0.00457 |
| 123 | Gallatin | 3403_B_1 | 1 | 36.3156 | -86.4006 | Tennessee | 225 | Bituminou | ESPC + B | 1956 | 2032 | Tennessee | Y | 25 | Stack | 10662 | 1.2E+07 | 0.00098, ( | 0.00098 | 0.00512 |
| 124 | Gallatin | 3403_B_2 | 1 | 36.3156 | -86.4006 | Tennessee | 225 | Bituminou | ESPC + B | 1957 | 2032 | Tennessee | Y | 23 | Stack | 10633 | 1E+07 | 0.001, 0.0 | 0.00063 | 0.00527 |
| 125 | Gallatin | 3403_B_3 | 1 | 36.3156 | -86.4006 | Tennessee | 263 | Bituminou | ESPC + B | 1959 | 2032 | Tennessee | Y | 25 | Stack | 10669 | 1.2E+07 | 0.0, 0.005 | 0 | 0.0038 |
| 126 | Gallatin | 3403_B_4 | 1 | 36.3156 | -86.4006 | Tennessee | 263 | Bituminou | ESPC + B | 1959 | 2032 | Tennessee | Y | 22 | Stack | 10657 | 1.2E+07 | 0.001, 0.0 | 0.001 | 0.00542 |
| 127 | W A Parish | 3470_B_WAP5 | 1 | 29.4828 | -95.6311 | Texas | 659 | Subbitumi | B | 1977 | | NRG Texas | N | 2 | Stack | 10451 | 3.7E+07 | 0.00127, ( | 0.001 | 0.00079 |
| 128 | W A Parish | 3470_B_WAP6 | 1 | 29.4828 | -95.6311 | Texas | 653 | Subbitumi | B | 1978 | | NRG Texas | N | 2 | Stack | 10463 | 3.5E+07 | 0.00141, ( | 0.0002 | 0.00049 |
| 129 | W A Parish | 3470_B_WAP7 | 1 | 29.4828 | -95.6311 | Texas | 577 | Subbitumi | B | 1980 | | NRG Texas | N | 2 | Stack | 10444 | 3.1E+07 | 0.00019, ( | 0.00019 | 0.0011 |
| 130 | W A Parish | 3470_B_WAP8 | 1 | 29.4828 | -95.6311 | Texas | 610 | Subbitumi | B | 1982 | | NRG Texas | N | 2 | Stack | 10480 | 3.6E+07 | 0.00154, ( | 0.00154 | 0.00199 |
| 131 | John E Amos | 3935_B_1 | 1 | 38.4731 | -81.8233 | West Virgi | 800 | Bituminou | ESPC | 1971 | 2040 | Appalachia | N | 2 | Stack | 9891 | 3.1E+07 | 0.00347, ( | 0.00347 | 0.0027 |
| 132 | John E Amos | 3935_B_2 | 1 | 38.4731 | -81.8233 | West Virgi | 800 | Bituminou | ESPC | 1972 | 2040 | Appalachia | N | 2 | Stack | 9911 | 3.4E+07 | 0.001, 0.0 | 0.001 | 0.0026 |
| 133 | John E Amos | 3935_B_3 | 1 | 38.4731 | -81.8233 | West Virgi | 1300 | Bituminou | ESPC | 1973 | 2040 | AEP Gener | N | 2 | Stack | 10019 | 5.6E+07 | 0.00169, ( | 0.00169 | 0.00277 |
| 134 | FirstEnergy Fort Martin Power Station | 3943_B_1 | 1 | 39.7108 | -79.9275 | West Virgi | 552 | Bituminou | ESPC + WS | 1967 | 2036 | Monongah | N | 2 | Stack | 10223 | 2.8E+07 | 0.00691, ( | 0.00691 | 0.00897 |
| 135 | FirstEnergy Fort Martin Power Station | 3943_B_2 | 1 | 39.7108 | -79.9275 | West Virgi | 546 | Bituminou | ESPC + WS | 1968 | 2036 | Monongah | N | 2 | Stack | 10240 | 2.9E+07 | 0.00517, ( | 0.00517 | 0.00586 |
| 136 | FirstEnergy Harrison Power Station | 3944_B_1 | 1 | 39.3842 | -80.3325 | West Virgi | 652 | Bituminou | ESPC + WS | 1972 | 2040 | Monongah | N | 2 | Stack | 10184 | 3.9E+07 | 0.01512, ( | 0.01462 | 0.01278 |
| 137 | FirstEnergy Harrison Power Station | 3944_B_2 | 1 | 39.3842 | -80.3325 | West Virgi | 651 | Bituminou | ESPC + WS | 1973 | 2040 | Monongah | N | 2 | Stack | 10116 | 4.1E+07 | 0.01945, ( | 0.01461 | 0.01387 |
| 138 | FirstEnergy Harrison Power Station | 3944_B_3 | 1 | 39.3842 | -80.3325 | West Virgi | 651 | Bituminou | ESPC + WS | 1974 | 2040 | Monongah | N | 2 | Stack | 10120 | 4.3E+07 | 0.02011, ( | 0.01511 | 0.01545 |
| 139 | Mitchell | 3948_B_1 | 1 | 39.8297 | -80.8153 | West Virgi | 770 | Bituminou | ESPC | 1971 | 2040 | AEP Gener | N | 2 | Stack | 10248 | 2.5E+07 | 0.00689, ( | 0.0035 | 0.00337 |
| 140 | Mitchell | 3948_B_2 | 1 | 39.8297 | -80.8153 | West Virgi | 790 | Bituminou | ESPC | 1971 | 2040 | AEP Gener | N | 2 | Stack | 9996 | 3.1E+07 | 0.00269, ( | 0.00269 | 0.0054 |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 141 | Mt Storm | 3954_B_1, 3954_B_2 | 2 | 39.2008 | -79.2636 | West Virgi | 1109 | Bituminou | ESPC + WS | 1965 | | Virginia El | Y | 28 | PM CEMS | 10094 | 4.1E+07 | 0.008, 0.0 | 0.008 | 0.01169 |
| 143 | Mt Storm | 3954_B_3 | 1 | 39.2008 | -79.2636 | West Virgi | 520 | Bituminou | ESPC + WS | 1973 | | Virginia El | Y | 31 | PM CEMS | 10433 | 1.6E+07 | 0.013, 0.0 | 0.006 | 0.01089 |
| 144 | Weston | 4078_B_3 | 1 | 44.8606 | -89.6553 | Wisconsin | 327 | Subbitumi | B | 1981 | | Wisconsin | N | 2 | PM CEMS | 9994 | 1.1E+07 | 0.007, 0.0 | 0.007 | 0.00649 |
| 145 | Weston | 4078_B_4 | 1 | 44.8606 | -89.6553 | Wisconsin | 550 | Subbitumi | B | 2008 | | Wisconsin | N | 2 | PM CEMS | 9679 | 3E+07 | 0.001, 0.0 | 0.001 | 0.00069 |
| 146 | Manitowoc | 4125_B_9 | 1 | 44.082 | -87.6558 | Wisconsin | 58 | Bituminou | B + C | 2005 | | Manitowo | N | 2 | PM CEMS | 12066 | 2137714 | 0.001, 0.0 | 0.001 | 0.001 |
| 147 | Dave Johnston | 4158_B_BW41 | 1 | 42.8378 | -105.777 | Wyoming | 93 | Subbitumi | ESPC | 1959 | 2029 | PacifiCorp | N | 2 | Stack | 11001 | 6992670 | 0.00298, ( | 0.00066 | 0.00137 |
| 148 | Dave Johnston | 4158_B_BW44 | 1 | 42.8378 | -105.777 | Wyoming | 330 | Subbitumi | B | 1959 | 2039 | PacifiCorp | N | 2 | Stack | 11341 | 2.2E+07 | 0.003, 0.0 | 0.003 | 0.00533 |
| 149 | Dave Johnston | 4158_B_BW42 | 1 | 42.8378 | -105.777 | Wyoming | 105 | Subbitumi | ESPC | 1961 | 2029 | PacifiCorp | N | 2 | Stack | 10996 | 7847159 | 0.00298, ( | 0.00211 | 0.00202 |
| 150 | John P Madgett | 4271_B_B1 | 1 | 44.3036 | -91.9126 | Wisconsin | 390 | Subbitumi | ESPH + B | 1979 | | Dairyland | N | 2 | PM CEMS | 11241 | 1.9E+07 | 0.0, 0.0 | 0 | 0 |
| 151 | James H Miller Jr | 6002_B_1 | 1 | 33.6319 | -87.0597 | Alabama | 688 | Subbitumi | ESPC + WS | 1978 | | Alabama F | Y | 27 | Stack | 10102 | 4.9E+07 | 0.00898, ( | 0.00198 | 0.00524 |
| 152 | James H Miller Jr | 6002_B_2 | 1 | 33.6319 | -87.0597 | Alabama | 695 | Subbitumi | ESPC + WS | 1985 | | Alabama F | Y | 27 | Stack | 10098 | 5E+07 | 0.00498, ( | 0.00198 | 0.00586 |
| 153 | James H Miller Jr | 6002_B_3 | 1 | 33.6319 | -87.0597 | Alabama | 687 | Subbitumi | ESPC + WS | 1989 | | Alabama F | Y | 27 | Stack | 10001 | 5E+07 | 0.00698, ( | 0.001 | 0.00432 |
| 154 | James H Miller Jr | 6002_B_4 | 1 | 33.6319 | -87.0597 | Alabama | 699 | Subbitumi | ESPC + WS | 1991 | | Alabama F | Y | 26 | Stack | 10011 | 5.3E+07 | 0.01296, ( | 0.001 | 0.00442 |
| 155 | East Bend | 6018_B_2 | 1 | 38.9036 | -84.8514 | Kentucky | 600 | Bituminou | ESPH | 1981 | 2041 | Duke Ener | N | 3 | PM CEMS | 10919 | 3.4E+07 | 0.01805, ( | 0.0099 | 0.00953 |
| 156 | Craig | 6021_B_C2 | 1 | 40.4627 | -107.591 | Colorado | 410 | Subbitumi | B | 1979 | 2029 | Salt River | N | 2 | Stack | 10240 | 2.8E+07 | 0.00992, ( | 0.006 | 0.00617 |
| 157 | Craig | 6021_B_C3 | 1 | 40.4627 | -107.591 | Colorado | 448 | Subbitumi | B | 1984 | 2030 | Tri State G | N | 2 | Stack | 10014 | 2.6E+07 | 0.00598, ( | 0.004 | 0.00467 |
| 158 | Coal Creek | 6030_B_1 | 1 | 47.3777 | -101.157 | North Dak | 574 | Lignite | ESPC | 1979 | | Great Rive | N | 2 | Stack | 9950 | 4.5E+07 | 0.00498, ( | 0.00298 | 0.00317 |
| 159 | Coal Creek | 6030_B_2 | 1 | 47.3777 | -101.157 | North Dak | 573 | Lignite | ESPC | 1981 | | Great Rive | N | 2 | Stack | 9950 | 4.5E+07 | 0.00298, ( | 0.002 | 0.002 |
| 160 | H L Spurlock | 6041_B_1 | 1 | 38.7 | -83.8181 | Kentucky | 300 | Bituminou | ESPC + WESP | 1977 | | East Kentu | Y | 30 | PM CEMS | 10121 | 1.6E+07 | 0.002, 0.0 | 0.001 | 0.00167 |
| 161 | H L Spurlock | 6041_B_2 | 1 | 38.7 | -83.8181 | Kentucky | 510 | Bituminou | ESPH + WESP | 1981 | | East Kentu | Y | 30 | PM CEMS | 10048 | 2.7E+07 | 0.002, 0.0 | 0.001 | 0.00166 |
| 162 | H L Spurlock | 6041_B_3 | 1 | 38.7 | -83.8181 | Kentucky | 268 | Bituminou | B | 2005 | | East Kentu | Y | 31 | PM CEMS | 10121 | 1.6E+07 | 0.007, 0.0 | 0.004 | 0.00735 |
| 163 | H L Spurlock | 6041_B_4 | 1 | 38.7 | -83.8181 | Kentucky | 268 | Bituminou | B | 2009 | | East Kentu | Y | 31 | PM CEMS | 10121 | 1.4E+07 | 0.003, 0.0 | 0.001 | 0.00327 |
| 164 | Big Cajun 2 | 6055_B_2B3 | 1 | 30.7261 | -91.3692 | Louisiana | 580 | Subbitumi | ESPC | 1981 | 2032 | Louisiana ( | N | 1 | PM CEMS | 10438 | 2.2E+07 | 0.009 | 0.009 | 0.009 |
| 165 | Nearman Creek | 6064_B_N1 | 1 | 39.1681 | -94.6975 | Kansas | 240 | Subbitumi | ESPC + B | 1981 | | Kansas Cit | Y | 23 | PM CEMS | 11426 | 1.3E+07 | 0.003, 0.0 | 0.003 | 0.00313 |
| 166 | Iatan | 6065_B_1 | 1 | 39.4472 | -94.98 | Missouri | 700 | Subbitumi | B | 1980 | 2039 | Evergy Me | N | 1 | PM CEMS | 9632 | 3.1E+07 | 0.002 | 0.002 | 0.00196 |
| 167 | Iatan | 6065_B_2 | 1 | 39.4472 | -94.98 | Missouri | 882 | Subbitumi | B | 2010 | | Evergy Me | N | 1 | PM CEMS | 9502 | 4.8E+07 | 0.009 | 0.009 | 0.00554 |
| 168 | Jeffrey Energy Center | 6068_B_1 | 1 | 39.2865 | -96.1172 | Kansas | 728 | Subbitumi | ESPC | 1978 | 2039 | Evergy Kai | N | 2 | Stack | 10990 | 3.1E+07 | 0.00269, ( | 0.00269 | 0.00365 |
| 169 | Jeffrey Energy Center | 6068_B_2 | 1 | 39.2865 | -96.1172 | Kansas | 733 | Subbitumi | ESPC | 1980 | 2039 | Evergy Kai | N | 4 | Stack | 11132 | 3.2E+07 | 0.00549, ( | 0.00549 | 0.00693 |
| 170 | Jeffrey Energy Center | 6068_B_3 | 1 | 39.2865 | -96.1172 | Kansas | 728 | Subbitumi | ESPC | 1983 | 2030 | Evergy Kai | N | 2 | Stack | 11180 | 3.1E+07 | 0.01116, ( | 0.00897 | 0.00874 |
| 171 | Trimble County | 6071_B_1 | 1 | 38.5847 | -85.4117 | Kentucky | 511 | Bituminou | ESPC + B | 1990 | 2045 | Louisville ( | Y | 28 | PM CEMS | 10039 | 3.1E+07 | 0.00898, ( | 0.00416 | 0.00698 |
| 172 | Trimble County | 6071_B_2 | 1 | 38.5847 | -85.4117 | Kentucky | 732 | Bituminou | ESPC + B | 2011 | 2066 | Kentucky U | Y | 30 | PM CEMS | 9716 | 4.4E+07 | 0.0048, 0.( | 0.00278 | 0.00545 |
| 173 | Colstrip | 6076_B_3 | 1 | 45.8831 | -106.614 | Montana | 740 | Subbitumi | WS | 1984 | | Talen Mor | Y | 37 | Stack | 10791 | 5.1E+07 | 0.0348, 0.( | 0.01796 | 0.02129 |
| 174 | Colstrip | 6076_B_4 | 1 | 45.8831 | -106.614 | Montana | 740 | Subbitumi | WS | 1986 | | NorthWes | Y | 37 | Stack | 10803 | 5E+07 | 0.01798, ( | 0.017 | 0.02316 |
| 175 | Gerald Gentleman | 6077_B_1 | 1 | 41.0808 | -101.141 | Nebraska | 665 | Subbitumi | B | 1979 | | Nebraska | Y | 12 | Stack | 10041 | 4E+07 | 0.00714, ( | 0.00067 | 0.00273 |
| 176 | Gerald Gentleman | 6077_B_2 | 1 | 41.0808 | -101.141 | Nebraska | 700 | Subbitumi | B | 1982 | | Nebraska | Y | 12 | Stack | 10068 | 3.8E+07 | 0.00333, ( | 0.00107 | 0.00301 |
| 177 | Sherburne County | 6090_B_3 | 1 | 45.3808 | -93.8931 | Minnesota | 876 | Subbitumi | B | 1987 | 2030 | Northern S | N | 2 | Stack | 10018 | 4.3E+07 | 0.00229, ( | 0.00229 | 0.00498 |
| 178 | Sooner | 6095_B_1 | 1 | 36.4531 | -97.0528 | Oklahoma | 520 | Subbitumi | ESPC | 1979 | 2044 | Oklahoma | N | 1 | CPMS | 10621 | 1.9E+07 | 0.01035 | 0.01035 | 0.00833 |
| 179 | Sooner | 6095_B_2 | 1 | 36.4531 | -97.0528 | Oklahoma | 520 | Subbitumi | ESPC | 1980 | 2045 | Oklahoma | N | 3 | Stack | 10479 | 1.9E+07 | 0.00189, ( | 0.00189 | 0.0019 |
| 180 | Nebraska City | 6096_B_1 | 1 | 40.6214 | -95.7764 | Nebraska | 654 | Subbitumi | ESPC | 1979 | | Omaha Pu | Y | 15 | Stack | 9818 | 3.9E+07 | 0.01367, ( | 0.00284 | 0.00807 |
| 181 | Nebraska City | 6096_B_2 | 1 | 40.6214 | -95.7764 | Nebraska | 691 | Subbitumi | B | 2009 | | Omaha Pu | Y | 8 | Stack | 10016 | 4.3E+07 | 0.00825, ( | 0.00201 | 0.00537 |
| 182 | Big Stone | 6098_B_1 | 1 | 45.3037 | -96.5101 | South Dak | 474 | Subbitumi | B | 1975 | | Otter Tail | Y | 5 | Stack | 10230 | 2.4E+07 | 0.0005 | 0.0005 | 0.0003 |
| 183 | Wyodak | 6101_B_BW91 | 1 | 44.2901 | -105.381 | Wyoming | 332 | Subbitumi | B | 1978 | 2039 | PacifiCorp | N | 2 | Stack | 12221 | 2.6E+07 | 0.00498, ( | 0.002 | 0.00283 |
| 184 | Gibson | 6113_B_1 | 1 | 38.3722 | -87.7658 | Indiana | 630 | Bituminou | ESPC | 1975 | 2035 | Duke Ener | N | 2 | PM CEMS | 10394 | 2.9E+07 | 0.00617, ( | 0.00604 | 0.00563 |
| 185 | Gibson | 6113_B_2 | 1 | 38.3722 | -87.7658 | Indiana | 630 | Bituminou | ESPC | 1975 | 2035 | Duke Ener | N | 2 | PM CEMS | 10508 | 3E+07 | 0.00446, ( | 0.00446 | 0.00386 |
| 186 | Gibson | 6113_B_3 | 1 | 38.3722 | -87.7658 | Indiana | 630 | Bituminou | ESPC | 1978 | 2029 | Duke Ener | N | 2 | PM CEMS | 10586 | 2.7E+07 | 0.00981, ( | 0.00981 | 0.00852 |
| 187 | Gibson | 6113_B_4 | 1 | 38.3722 | -87.7658 | Indiana | 622 | Bituminou | ESPC | 1979 | 2029 | Duke Ener | N | 2 | PM CEMS | 10404 | 2.7E+07 | 0.00443, ( | 0.00443 | 0.00342 |
| 188 | Flint Creek | 6138_B_1 | 1 | 36.2561 | -94.5241 | Arkansas | 528 | Subbitumi | ESPH + B | 1978 | 2039 | Arkansas E | N | 2 | Stack | 10629 | 2.7E+07 | 0.00308, ( | 0.00059 | 0.00122 |
| 189 | Martin Lake | 6146_B_1 | 1 | 32.2606 | -94.5706 | Texas | 800 | Lignite, Su | ESPC | 1977 | | Luminant | Y | 27 | PM CEMS | 11495 | 4.8E+07 | 0.003, 0.0 | 0.003 | 0.0131 |
| 190 | Martin Lake | 6146_B_2 | 1 | 32.2606 | -94.5706 | Texas | 805 | Lignite, Su | ESPC | 1978 | | Luminant | Y | 27 | PM CEMS | 11314 | 4.3E+07 | 0.006, 0.0 | 0.005 | 0.00631 |
| 191 | Martin Lake | 6146_B_3 | 1 | 32.2606 | -94.5706 | Texas | 805 | Lignite, Su | ESPC | 1979 | | Luminant | Y | 26 | PM CEMS | 11423 | 4.7E+07 | 0.014, 0.0 | 0.005 | 0.00817 |
| 192 | Hunter | 6165_B_1 | 1 | 39.1747 | -111.029 | Utah | 471 | Bituminou | ESPC + B | 1978 | 2031 | PacifiCorp | N | 2 | Stack | 10279 | 2.8E+07 | 0.00496, ( | 0.00247 | 0.00253 |
| 193 | Hunter | 6165_B_3 | 1 | 39.1747 | -111.029 | Utah | 460 | Bituminou | B + WS | 1978 | 2032 | PacifiCorp | N | 2 | Stack | 10156 | 3.1E+07 | 0.003, 0.0 | 0.00136 | 0.00169 |
| 194 | Hunter | 6165_B_2 | 1 | 39.1747 | -111.029 | Utah | 430 | Bituminou | B | 1980 | 2032 | PacifiCorp | N | 2 | Stack | 10244 | 3.1E+07 | 0.00596, ( | 0.00298 | 0.0035 |
| 195 | Rockport | 6166_B_MB1, 6166_B_MB2 | 2 | 37.9256 | -87.0372 | Indiana | 2600 | Bituminou | ESPC | 1984 | 2029 | AEP Gener | N | 2 | Stack | 10007 | 8.1E+07 | 0.00508, ( | 0.00337 | 0.00298 |
| 197 | Coronado | 6177_B_U1B | 1 | 34.5789 | -109.271 | Arizona | 380 | Subbitumi | ESPH | 1979 | 2032 | Salt River | Y | 31 | PM CEMS | 10617 | 1.8E+07 | 0.01377, ( | 0.0061 | 0.00929 |
| 198 | Coronado | 6177_B_U2B | 1 | 34.5789 | -109.271 | Arizona | 382 | Subbitumi | ESPH | 1980 | 2032 | Salt River | Y | 31 | PM CEMS | 10691 | 2.1E+07 | 0.01377, ( | 0.0061 | 0.00929 |
| 199 | Fayette Power Project | 6179_B_1 | 1 | 29.9172 | -96.7506 | Texas | 590 | Subbitumi | ESPC | 1979 | | Austin Ene | N | 2 | PM CEMS | 10589 | 3.8E+07 | 0.00555, ( | 0.00535 | 0.0053 |
| 200 | Fayette Power Project | 6179_B_2 | 1 | 29.9172 | -96.7506 | Texas | 590 | Subbitumi | ESPC | 1980 | | Austin Ene | N | 2 | PM CEMS | 10606 | 4.1E+07 | 0.0062, 0.( | 0.00613 | 0.00429 |
| 201 | Fayette Power Project | 6179_B_3 | 1 | 29.9172 | -96.7506 | Texas | 435 | Subbitumi | ESPC | 1988 | | Lower Col | N | 2 | PM CEMS | 10608 | 3.2E+07 | 0.00447, ( | 0.00378 | 0.00348 |
| 202 | Oak Grove | 6180_B_1 | 1 | 31.1803 | -96.4866 | Texas | 855 | Lignite | B | 2010 | | Oak Grove | Y | 31 | PM CEMS | 10406 | 6.7E+07 | 0.003, 0.0 | 0.002 | 0.00518 |
| 203 | Oak Grove | 6180_B_2 | 1 | 31.1803 | -96.4866 | Texas | 855 | Lignite | B | 2011 | | Oak Grove | Y | 31 | PM CEMS | 10472 | 6.1E+07 | 0.005, 0.0 | 0.001 | 0.00404 |
| 204 | San Miguel | 6183_B_SM-1 | 1 | 28.7044 | -98.4775 | Texas | 391 | Lignite | ESPC | 1982 | | San Migue | Y | 7 | Stack | 12358 | 3E+07 | 0.01852, ( | 0.00816 | 0.01357 |
| 205 | Brame Energy Center | 6190_B_3-1 | 1 | 31.395 | -92.7167 | Louisiana | 313 | Bituminou | B + C | 2010 | | CLECO Pov | N | 2 | Stack | 10177 | 1.8E+07 | 0.00479, ( | 0.00289 | 0.00348 |
| 206 | Brame Energy Center | 6190_B_3-2 | 1 | 31.395 | -92.7167 | Louisiana | 313 | Bituminou | B + C | 2010 | | CLECO Pov | N | 2 | Stack | 10177 | 1.8E+07 | 0.00129, ( | 0.00129 | 0.00283 |
| 207 | Tolk | 6194_B_171B | 1 | 34.1865 | -102.57 | Texas | 532 | Subbitumi | B | 1982 | 2029 | Southwest | N | 2 | Stack | 10342 | 1.6E+07 | 0.00099, ( | 0.0007 | 0.00062 |
| 208 | Tolk | 6194_B_172B | 1 | 34.1865 | -102.57 | Texas | 535 | Subbitumi | B | 1985 | 2029 | Southwest | N | 2 | Stack | 10255 | 1.8E+07 | 0.0007, 0.( | 0.00058 | 0.00053 |
| 209 | John Twitty Energy Center | 6195_B_1 | 1 | 37.1517 | -93.388 | Missouri | 184 | Subbitumi | B | 1976 | | Springfielc | Y | 12 | Stack | 10328 | 7587867 | 0.0021, 0.( | 0.0009 | 0.00228 |
| 210 | John Twitty Energy Center | 6195_B_2 | 1 | 37.1517 | -93.388 | Missouri | 275 | Subbitumi | B | 1976 | | Springfielc | Y | 11 | Stack | 10188 | 1.4E+07 | 0.0012, 0.( | 0.00045 | 0.00158 |
| 211 | Laramie River Station | 6204_B_1 | 1 | 42.1089 | -104.883 | Wyoming | 570 | Subbitumi | ESPH | 1980 | | Western N | N | 4 | Stack | 10218 | 2.7E+07 | 0.01486, ( | 0.0018 | 0.00799 |
| 212 | Laramie River Station | 6204_B_2 | 1 | 42.1089 | -104.883 | Wyoming | 570 | Subbitumi | ESPH | 1981 | | Basin Elec | N | 2 | Stack | 10164 | 4E+07 | 0.008, 0.0 | 0.008 | 0.007 |
| 213 | Laramie River Station | 6204_B_3 | 1 | 42.1089 | -104.883 | Wyoming | 570 | Subbitumi | ESPH | 1982 | | Basin Elec | N | 4 | Stack | 10137 | 4.4E+07 | 0.00598, ( | 0.00598 | 0.01476 |
| 214 | Merom | 6213_B_2SG1 | 1 | 39.0694 | -87.5108 | Indiana | 492 | Bituminou | ESPC | 1982 | | Hoosier Er | N | 2 | Stack | 10408 | 2.4E+07 | 0.00498, ( | 0.00496 | 0.00383 |
| 215 | Merom | 6213_B_1SG1 | 1 | 39.0694 | -87.5108 | Indiana | 496 | Bituminou | ESPC | 1983 | | Hoosier Er | N | 2 | Stack | 10352 | 2.6E+07 | 0.00498, ( | 0.00398 | 0.00383 |
| 216 | Winyah | 6249_B_1 | 1 | 33.3318 | -79.3572 | South Carc | 275 | Bituminou | ESPC + WS | 1975 | 2031 | Santee Coo | N | 1 | CPMS | 10751 | 7699849 | 0.00307 | 0.00307 | 0.00303 |
| 217 | Winyah | 6249_B_2 | 1 | 33.3318 | -79.3572 | South Carc | 285 | Bituminou | ESPC + WS | 1977 | 2031 | Santee Coo | N | 3 | CPMS | 10687 | 6061530 | 0.00914, ( | 0.00914 | 0.00746 |
| 218 | Winyah | 6249_B_3 | 1 | 33.3318 | -79.3572 | South Carc | 285 | Bituminou | ESPC + WS | 1980 | 2031 | Santee Coo | N | 3 | CPMS | 10784 | 4608333 | 0.00682, ( | 0.00682 | 0.00713 |
| 219 | Winyah | 6249_B_4 | 1 | 33.3318 | -79.3572 | South Carc | 285 | Bituminou | ESPC + WS | 1981 | 2031 | Santee Coo | N | 1 | CPMS | 10803 | 2481276 | 0.00795, ( | 0.00507 | 0.00614 |
| 220 | Mayo | 6250_B_1A, 6250_B_1B | 2 | 36.5278 | -78.8917 | North Carc | 728 | Bituminou | ESPH | 1983 | 2031 | Duke Ener | N | 4 | PM CEMS | 11143 | 1.6E+07 | 0.01611, ( | 0.01499 | 0.01445 |
| 222 | Ottumwa | 6254_B_1 | 1 | 41.0961 | -92.5558 | Iowa | 725 | Subbitumi | ESPH + B | 1981 | | MidAmeri | N | 1 | PM CEMS | 10369 | 4.1E+07 | 0.005 | 0.005 | 0.005 |
| 223 | Scherer | 6257_B_1 | 1 | 33.0606 | -83.8075 | Georgia | 860 | Subbitumi | ESPH + B + WS | 1982 | | Oglethorp | N | 2 | Stack | 10832 | 2.9E+07 | 0.002, 0.0 | 0.001 | 0.00133 |
| 224 | Scherer | 6257_B_2 | 1 | 33.0606 | -83.8075 | Georgia | 860 | Subbitumi | ESPH + B + WS | 1984 | | Oglethorp | N | 2 | Stack | 10756 | 2.8E+07 | 0.002, 0.0 | 0.002 | 0.00167 |
| 225 | Scherer | 6257_B_3 | 1 | 33.0606 | -83.8075 | Georgia | 860 | Subbitumi | ESPC + B + WS | 1987 | 2029 | Georgia Pc | N | 2 | Stack | 10740 | 3E+07 | 0.002, 0.0 | 0.002 | 0.00237 |
| 226 | Mountaineer | 6264_B_1 | 1 | 38.9794 | -81.9344 | West Virgi | 1299 | Bituminou | ESPC | 1980 | 2040 | Appalachi | N | 2 | Stack | 9925 | 6.8E+07 | 0.00877, ( | 0.00399 | 0.00527 |
| 227 | Antelope Valley | 6469_B_B1 | 1 | 47.3705 | -101.836 | North Dak | 450 | Lignite | B | 1984 | | Basin Elec | N | 1 | Stack | 11322 | 3.1E+07 | 0.00697 | 0.00697 | 0.00537 |
| 228 | Antelope Valley | 6469_B_B2 | 1 | 47.3705 | -101.836 | North Dak | 450 | Lignite | B | 1986 | | Basin Elec | N | 1 | Stack | 11263 | 3.5E+07 | 0.0034 | 0.0034 | 0.00327 |
| 229 | Independence Steam Electric Station | 6641_B_1 | 1 | 35.6784 | -91.4088 | Arkansas | 809 | Subbitumi | ESPC | 1983 | 2031 | Arkansas E | N | 3 | PM CEMS | 10428 | 3.2E+07 | 0.00536, ( | 0.00536 | 0.00643 |
| 230 | Independence Steam Electric Station | 6641_B_2 | 1 | 35.6784 | -91.4088 | Arkansas | 842 | Subbitumi | ESPC | 1985 | 2031 | Arkansas E | N | 1 | PM CEMS | 10427 | 3.3E+07 | 0.00412 | 0.00412 | 0.00319 |
| 231 | Louisa | 6664_B_101 | 1 | 41.3181 | -91.0931 | Iowa | 746 | Subbitumi | ESPH + B | 1983 | | MidAmeri | Y | 11 | Stack | 10591 | 3.7E+07 | 0.00337, ( | 0.00337 | 0.00573 |
| 232 | Warrick | 6705_B_4 | 1 | 37.915 | -87.3328 | Indiana | 295 | Bituminou | ESPC | 1970 | | Alcoa Pow | N | 3 | PM CEMS | 11131 | 2E+07 | 0.02412, ( | 0.007 | 0.00683 |
| 233 | Rawhide | 6761_B_101 | 1 | 40.8609 | -105.021 | Colorado | 280 | Subbitumi | B | 1984 | 2030 | Platte Rive | N | 2 | Stack | 10091 | 1.9E+07 | 0.00489, ( | 0.00489 | 0.00468 |
| 234 | Sikeston Power Station | 6768_B_1 | 1 | 36.8791 | -89.6209 | Missouri | 240 | Subbitumi | ESPC | 1981 | | Sikeston U | N | 1 | PM CEMS | 10648 | 1.8E+07 | 0.0029 | 0.0029 | 0.00204 |
| 235 | Hugo | 6772_B_1 | 1 | 34.0158 | -95.3206 | Oklahoma | 440 | Subbitumi | ESPC | 1982 | | Western F | N | 2 | Stack | 11061 | 1.4E+07 | 0.00288, ( | 0.00288 | 0.00338 |
| 236 | D B Wilson | 6823_B_W1 | 1 | 37.4497 | -87.0806 | Kentucky | 417 | Bituminou | ESPC | 1984 | | Big Rivers | Y | 27 | PM CEMS | 10643 | 3E+07 | 0.019, 0.0 | 0.01 | 0.01482 |
| 237 | Major Oak Power | 7030_B_U1 | 1 | 31.0919 | -96.695 | Texas | 152 | Lignite, Su | B | 1990 | | Major Oak | N | 2 | Stack | 11608 | 1.5E+07 | 0.007, 0.0 | 0.00698 | 0.00617 |
| 238 | Major Oak Power | 7030_B_U2 | 1 | 31.0919 | -96.695 | Texas | 153 | Lignite, Su | B | 1991 | | Major Oak | N | 2 | Stack | 11407 | 1.4E+07 | 0.007, 0.0 | 0.007 | 0.00833 |
| 239 | J K Spruce | 7097_B_BLR1 | 1 | 29.3097 | -98.3203 | Texas | 560 | Subbitumi | B | 1992 | 2029 | CPS Energ | N | 1 | Stack | 9995 | 2.8E+07 | 0.0021 | 0.0021 | 0.0021 |
| 240 | Clover | 7213_B_1 | 1 | 36.869 | -78.704 | Virginia | 440 | Bituminou | B + WS | 1995 | 2045 | Old Domir | N | 3 | PM CEMS | 10106 | 1.2E+07 | 0.00339, ( | 0 | 0.00058 |
| 241 | Clover | 7213_B_2 | 1 | 36.869 | -78.704 | Virginia | 437 | Bituminou | B + WS | 1996 | | Old Domir | N | 1 | PM CEMS | 10086 | 9870146 | 0.006 | 0.006 | 0.00502 |
| 242 | George Neal South | 7343_B_4 | 1 | 42.3006 | -96.3617 | Iowa | 645 | Subbitumi | ESPC + B | 1979 | | MidAmeri | Y | 10 | Stack | 10033 | 1.9E+07 | 0.0014, 0.( | 0.001 | 0.00247 |
| 243 | Bonanza | 7790_B_1-1 | 1 | 40.0864 | -109.284 | Utah | 458 | Bituminou | B | 1986 | 2030 | Deseret Pc | N | 2 | Stack | 9983 | 3.7E+07 | 0.00696, ( | 0.00696 | 0.00667 |
| 244 | Belews Creek | 8042_B_1 | 1 | 36.2811 | -80.0603 | North Carc | 1110 | Bituminou | ESPC | 1974 | 2036 | Duke Ener | N | 3 | PM CEMS | 9185 | 3.6E+07 | 0.00733, ( | 0.00233 | 0.00268 |
| 245 | Belews Creek | 8042_B_2 | 1 | 36.2811 | -80.0603 | North Carc | 1110 | Bituminou | ESPC | 1975 | 2036 | Duke Ener | N | 1 | PM CEMS | 9203 | 3.8E+07 | 0.00694 | 0.00694 | 0.0042 |
| 246 | Jim Bridger | 8066_B_BW73 | 1 | 41.7378 | -108.788 | Wyoming | 523 | Subbitumi | ESPC | 1976 | 2037 | PacifiCorp | N | 4 | Stack | 10441 | 3E+07 | 0.00779, ( | 0.00779 | 0.01023 |
| 247 | Jim Bridger | 8066_B_BW74 | 1 | 41.7378 | -108.788 | Wyoming | 530 | Subbitumi | ESPC | 1979 | 2037 | PacifiCorp | N | 2 | Stack | 10465 | 3E+07 | 0.00779, ( | 0.00779 | 0.00818 |
| 248 | Huntington | 8069_B_1 | 1 | 39.3792 | -111.078 | Utah | 459 | Bituminou | ESPC + B | 1977 | 2032 | PacifiCorp | N | 2 | Stack | 10283 | 2.8E+07 | 0.004, 0.0 | 0.004 | 0.00383 |
| 249 | Huntington | 8069_B_2 | 1 | 39.3792 | -111.078 | Utah | 450 | Bituminou | B | 1977 | 2032 | PacifiCorp | N | 2 | Stack | 10325 | 2.7E+07 | 0.00898, ( | 0.00694 | 0.00633 |
| 250 | Gavin Power, LLC | 8102_B_1 | 1 | 38.9347 | -82.1158 | Ohio | 1348 | Bituminou | ESPC | 1974 | | Gavin Pow | N | 2 | Stack | 9926 | 7.6E+07 | 0.01038, ( | 0.01038 | 0.00932 |
| 251 | Gavin Power, LLC | 8102_B_2 | 1 | 38.9347 | -82.1158 | Ohio | 1361 | Bituminou | ESPC | 1975 | | Gavin Pow | N | 4 | Stack | 9861 | 7.1E+07 | 0.01499, ( | 0.00389 | 0.00666 |
| 252 | Ray D Nixon | 8219_B_1 | 1 | 38.6335 | -104.706 | Colorado | 208 | Bituminou | B | 1980 | 2029 | Colorado S | N | 4 | Stack | 10457 | 1.2E+07 | 0.00282, ( | 0.002 | 0.00498 |
| 253 | Coyote | 8222_B_B1 | 1 | 47.2214 | -101.816 | North Dak | 429 | Lignite | B | 1981 | | Otter Tail | Y | 13 | Stack | 11481 | 2.8E+07 | 0.00879, ( | 0.00073 | 0.00293 |
| 254 | Springerville | 8223_B_2 | 1 | 34.3186 | -109.164 | Arizona | 406 | Subbitumi | B | 1990 | 2032 | Tucson Ele | N | 2 | Stack | 10293 | 2.4E+07 | 0.00429, ( | 0.00429 | 0.00564 |
| 255 | Springerville | 8223_B_3 | 1 | 34.3186 | -109.164 | Arizona | 417 | Subbitumi | B | 2006 | | Tri State G | N | 2 | Stack | 10191 | 2.5E+07 | 0.00266, ( | 0.00266 | 0.00175 |
| 256 | Springerville | 8223_B_4 | 1 | 34.3186 | -109.164 | Arizona | 415 | Subbitumi | B | 2009 | | Salt River | N | 2 | Stack | 10260 | 2E+07 | 0.00189, ( | 0.00119 | 0.00119 |
| 257 | John B Rich Memorial Power Station | 10113_B_CFB1, 10113_B_CFB2 | 2 | 40.7903 | -76.1983 | Pennsylva | 80 | Waste Coa | B | 1988 | | Gilberton | Y | 25 | PM CEMS | 13587 | 8000970 | 0.014, 0.0 | 0.014 | 0.01931 |
| 259 | Colver Power Project | 10143_B_ABB01 | 1 | 40.55 | -78.8 | Pennsylva | 110 | Waste Coa | B | 1995 | | Inter Powe | Y | 9 | Stack | 11032 | 9074811 | 0.0133, 0.( | 0.00765 | 0.01028 |
| 260 | Grant Town Power Plant | 10151_B_BLR1A, 10151_B_BLR1B | 2 | 39.5618 | -80.1631 | West Virgi | 80 | Waste Coa | B | 1993 | | American | N | 4 | Stack | 13650 | 8778034 | 0.00927, ( | 0.00449 | 0.00887 |
| 262 | Foster Wheeler Mt Carmel Cogen | 10343_B_SG-101 | 1 | 40.8112 | -76.453 | Pennsylva | 43 | Waste Coa | B | 1990 | | Mt Carme | Y | 12 | Stack | 14500 | 2892788 | 0.00982, ( | 0.00982 | 0.02289 |
| 263 | Ebensburg Power | 10603_B_031 | 1 | 40.455 | -78.7472 | Pennsylva | 50 | Waste Coa | B | 1991 | | Ebensburg | N | 2 | Stack | 14500 | 4403948 | 0.00652, ( | 0.00388 | 0.00479 |
| 264 | River Valley | 10671_B_1A, 10671_B_1B, 10671_B_2A, 10671_B_2B | 4 | 35.1931 | -94.6458 | Oklahoma | 320 | Bituminou | B | 1991 | | Oklahoma | N | 4 | Stack | 11851 | 1.6E+07 | 0.01298, ( | 0.00369 | 0.00724 |
| 268 | AES Warrior Run Cogeneration Facility | 10678_B_BLR1 | 1 | 39.5952 | -78.7453 | Maryland | 180 | Bituminou | B | 2000 | | AES Warri | N | 2 | Stack | 8909 | 1.3E+07 | 0.003, 0.0 | 0.003 | 0.00267 |
| 269 | Colstrip Energy LP | 10784_B_BLR1 | 1 | 45.9752 | -106.655 | Montana | 38 | Waste Coa | B | 1990 | | Colstrip Er | N | 2 | Stack | 13936 | 2319508 | 0.00319, ( | 0.00319 | 0.0065 |
| 270 | Westwood Generation LLC | 50611_B_031 | 1 | 40.6191 | -76.45 | Pennsylva | 30 | Waste Coa | B | 1987 | | Rausch Cr | Y | 12 | Stack | 14500 | 2640627 | 0.01447, ( | 0.01079 | 0.02416 |
| 271 | Panther Creek Energy Facility | 50776_B_BLR1, 50776_B_BLR2 | 2 | 40.8556 | -75.8781 | Pennsylva | 84 | Waste Coa | B | 1992 | | Panther Cr | N | 2 | Stack | 14141 | 1310194 | 0.00285, ( | 0.00285 | 0.0031 |
| 273 | Northampton Generating Company LP | 50888_B_BLR1 | 1 | 40.6917 | -75.4792 | Pennsylva | 112 | Waste Coa | B | 1995 | | Northamp | N | 2 | Stack | 10316 | 1663689 | 0.0036, 0.( | 0.0036 | 0.00375 |
| 274 | Sunnyside Cogen Associates | 50951_B_1 | 1 | 39.5472 | -110.392 | Utah | 51 | Waste Coa | B | 1993 | | American | N | 2 | Stack | 12284 | 2744000 | 0.0079, 0.( | 0.00598 | 0.0062 |
| 275 | Scrubgrass Generating Plant | 50974_B_UNIT 1 | 1 | 41.2691 | -79.8134 | Pennsylva | 43 | Bituminou | B + C | 1993 | | Scrubgras | N | 2 | Stack | 13904 | 2310374 | 0.00698, ( | 0.00698 | 0.00817 |
| 276 | Scrubgrass Generating Plant | 50974_B_UNIT 2 | 1 | 41.2691 | -79.8134 | Pennsylva | 43 | Bituminou | B + C | 1993 | | Scrubgras | N | 2 | Stack | 13904 | 2192802 | 0.00698, ( | 0.00698 | 0.00817 |
| 277 | St Nicholas Cogen Project | 54634_B_1 | 1 | 40.8222 | -76.1736 | Pennsylva | 86 | Waste Coa | B | 1990 | | Schuylkill I | Y | 19 | Stack | 14500 | 1.1E+07 | 0.03056, ( | 0.00571 | 0.01468 |
| 278 | Red Hills Generating Facility | 55076_B_AA001, 55076_B_AA002 | 2 | 33.3761 | -89.2183 | Mississipp | 440 | Lignite | B | 2002 | | Choctaw C | Y | 28 | Stack | 11206 | 3.1E+07 | 0.02492, ( | 0.0037 | 0.01242 |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 280 | Wygen 1 | 55479_B_3 | 1 | 44.2858 | -105.383 | Wyoming | 85 | Subbitumi | B | 2003 | | Black Hills | N | 2 | Stack | 11824 | 8220289 | 0.00494, ( | 0.00198 | 0.00217 |
| 281 | Hardin Generator Project | 55749_B_PC1 | 1 | 45.7578 | -107.6 | Montana | 107 | Subbitumi | B | 2006 | | Rocky Mou | N | 2 | Stack | 12466 | 2801310 | 0.005, 0.0 | 0.00198 | 0.0029 |
| 282 | Prairie State Generating Station | 55856_G_PC1 | 1 | 38.2792 | -89.6669 | Illinois | 815 | Bituminou | ESPC + WESP | 2012 | 2045 | Prairie Sta | N | 1 | PM CEMS | 9391 | 6.4E+07 | 0.007 | 0.007 | 0.00471 |
| 283 | Prairie State Generating Station | 55856_G_PC2 | 1 | 38.2792 | -89.6669 | Illinois | 815 | Bituminou | ESPC + WESP | 2012 | 2045 | Prairie Sta | N | 1 | PM CEMS | 9346 | 6.4E+07 | 0.007 | 0.007 | 0.00482 |
| 284 | Elm Road Generating Station | 56068_B_18 | 1 | 42.8492 | -87.8336 | Wisconsin | 633 | Bituminou | WESP + B | 2010 | | Wisconsin | N | 2 | PM CEMS | 9552 | 3.9E+07 | 0.002, 0.0 | 0.002 | 0.002 |
| 285 | Elm Road Generating Station | 56068_B_19 | 1 | 42.8492 | -87.8336 | Wisconsin | 633 | Bituminou | WESP + B | 2011 | | Wisconsin | N | 2 | PM CEMS | 9475 | 3.9E+07 | 0.001, 0.0 | 0.001 | 0.00087 |
| 286 | Wygen 2 | 56319_B_1 | 1 | 44.2919 | -105.381 | Wyoming | 90 | Subbitumi | B | 2008 | 2048 | Cheyenne | N | 2 | Stack | 11967 | 8866771 | 0.00298, ( | 0.001 | 0.0018 |
| 287 | Plum Point Energy Station | 56456_B_BLR1 | 1 | 35.6644 | -89.9489 | Arkansas | 680 | Subbitumi | B | 2010 | | Plum Poin | N | 2 | Stack | 9682 | 4.3E+07 | 0.00577, ( | 0.00577 | 0.00658 |
| 288 | John W Turk Jr Power Plant | 56564_G_1 | 1 | 33.6497 | -93.8119 | Arkansas | 609 | Subbitumi | B | 2012 | | Southwest | N | 2 | Stack | 9102 | 3.7E+07 | 0.0004, 0. | 0.0004 | 0.00058 |
| 289 | Wygen III | 56596_B_1 | 1 | 44.2919 | -105.381 | Wyoming | 100 | Subbitumi | B | 2010 | | Black Hills | N | 2 | Stack | 11509 | 9396902 | 0.00298, ( | 0.00199 | 0.002 |
| 290 | Dry Fork Station | 56609_B_1 | 1 | 44.3889 | -105.461 | Wyoming | 380 | Subbitumi | B | 2011 | | Basin Elec | N | 2 | Stack | 10552 | 3.2E+07 | 0.0, 0.002 | 0 | 0.00083 |
| 291 | Sandy Creek Energy Station | 56611_B_S01 | 1 | 31.4744 | -96.9571 | Texas | 933 | Subbitumi | B | 2013 | | Sandy Cre | Y | 14 | Stack | 9330 | 5.7E+07 | 0.01298, ( | 0.00129 | 0.00723 |
| 292 | Longview Power Plant | 56671_B_UHA01 | 1 | 39.7079 | -79.959 | West Virgi | 700 | Bituminou | B | 2011 | | Longview | N | 2 | PM CEMS | 8904 | 4.8E+07 | 0.00561, ( | 0.0055 | 0.003 |
| 293 | Spiritwood Station | 56786_B_1 | 1 | 46.9264 | -98.4997 | North Dak | 92 | Lignite | B | 2014 | | Great Rive | N | 2 | Stack | 8300 | 4861965 | 0.0009, 0. | 0.0009 | 0.00274 |
| 294 | Virginia City Hybrid Energy Center | 56808_G_1 | 1 | 36.9164 | -82.3381 | Virginia | 305 | Bituminou | ESPH + B | 2012 | | Virginia El | N | 1 | PM CEMS | 9943 | 9394043 | 0.001 | 0.001 | 0.00038 |
| 295 | Virginia City Hybrid Energy Center | 56808_G_2 | 1 | 36.9164 | -82.3381 | Virginia | 305 | Bituminou | ESPH + B | 2012 | | Virginia El | N | 1 | PM CEMS | 9943 | 1.1E+07 | 0.001 | 0.001 | 0.001 |

# Exhibit DG-15:

# Duke Energy, “Appendix F: Coal Retirement Analysis,” 2023 Carolinas Resources Plan

F

# Coal Retirement Analysis

## Highlights

- Decreasing fuel supply as producers shift to other markets has increased the degree of volatility in the entire coal supply chain. This volatility is expected to grow as United States' power producers continue to transition away from coal-fired generation.

- Dynamic natural gas prices, combined with coal retirements, transportation constraints, pipeline constraints and the addition of significant natural gas fired generation have contributed to large swings in the actual and forecasted burn in coal and gas generation.

- The Companies performed an updated coal retirement analysis for each Energy Transition Pathway as well as an analysis without carbon constraints to identify the most economic timing of coal retirements based on the availability of replacement resources. The updated coal retirement analysis was developed based upon Carolinas Resource Plan assumptions including the substantial increase in the load forecast and updated planning reserve margin.

- The updated coal retirement analysis weighs the continued operational benefits to the system of each coal unit as well as the costs to operate and maintain the units over time based on, for example, unit-specific maintenance schedules. The analysis also optimizes unit retirement dates based on the availability of new capacity additions and other considerations to ensure an orderly transition that maintains or improves system reliability, prudently manages risks and uncertainties, and enables the Companies to meet the growing energy needs of customers. These planning considerations support minor adjustments to the model-selected retirement dates for certain units to allow for more orderly and executable retirement schedules.

# A Changing Energy Landscape – Impacts of Industry Exit from Coal

## Changing Economics of Coal

As discussed in Chapter 1 (Planning for a Changing Energy Landscape), economics and environmental regulations are driving a decline in the coal industry and its supporting infrastructure. The transition away from coal generation by electric utilities has impacted every aspect of domestic coal production and supply transportation. This changing environment, coupled with current inflationary pressures, results in risks and uncertainties, described in more detail below, for coal supply assurance and reliable operations of the Companies coal generation facilities. A primary risk of coal supply lies within a producer's ability to maintain financial stability through downward cycles of pricing pressure and decreased demand. Although the coal market experienced an unexpected boost in demand and prices during calendar years 2021 and 2022 due to an economic resurgence following the COVID-19 pandemic, rising natural gas prices and Russia's invasion of Ukraine, prices have since retreated to close to pre-pandemic levels. Accelerating coal facility retirements, as well as competition from natural gas, and increasing renewable capacity have also put renewed downward pressure on domestic coal demand. Inflationary cost increases to mining operations including, but not limited to, labor, equipment and fuel have further impacted the coal industry's ability to respond to changes in market demand and its ability to compete with natural gas and renewables. The downward pressure on domestic coal demand and pricing coupled with rising coal production costs poses increasing risks to coal producers' ability to maintain financial stability. Finally, increasing competition for labor resources in coal-producing regions, coupled with increased post-COVID-19 era personnel retirements and an overall shift away from mining to positions with greater longevity and more favorable work conditions, are also expected to maintain production pressure on producers and further limit their ability to respond to shifts in demand.

The financial challenges of coal companies have direct implications on the Companies' ability to obtain low-cost and reliable coal supply through planned coal facility retirements. The United States coal sector continues to face challenges with accessing capital due to concerns about the industry's environmental impacts and long-term viability. None of the publicly traded coal mining companies operating in the United States currently have an investment-grade credit rating, substantially increasing their borrowing costs in the current interest rate environment. As demand for coal and the ability to obtain capital continues to decrease, there is potential for further consolidation of producers, leading to increased risks of non-performance, higher prices and less flexibility. Future financial instability of producers could result in fuel cost volatility and increased unavailability risk, which can impact electricity costs and reliability. International demand will also factor into future production and pricing volatility.

Similarly, long-term declines in demand for coal in the utility sector are also driving rail transportation providers to be less dependent on coal-related transportation revenues. Although rail transportation providers are required to provide rail service, the Companies' rail transportation providers have limited ability to respond timely to significant changes in scheduling demand due to lead times needed for adding crews and locomotive equipment. Additionally, there is competition for the same resources between the domestic and international coal supply chain as historically international export coal trains receive priority service. These factors, combined with increasing scrutiny surrounding railcar maintenance and inspections following the highly publicized derailment in East Palestine, Ohio, are expected to put increased pressure on rail transportation providers' ability to respond to demand volatility and increase the risk of higher customer costs.

## Coal Supply and Transportation Constraints

### *Coal Supply*

The coal supply chain relies on relatively ratable coal deliveries to drive efficiencies, maintain labor resources and protect financial viability. Longer term commitments priced above the cost to produce help to retain and support the labor force, plan future mining needs and ensure future revenue. Most coal producers have limited, if any, ability to respond timely to rapid changes in coal demand driven by the real-time switching between fuels due to labor constraints and the inability to absorb delivery shortfalls. Unexpected coal delivery decreases and disruptions due to decreased demand reduce coal producers expected revenues. Many coal producers have limited opportunity to store coal and the stored commodity is not generating cash flow. The producer's inability to withstand lulls in coal demand has the potential to result in further consolidation or deterioration of the coal supply.

Of most immediate concern to Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies") is the reduction in Central Appalachian ("CAPP") thermal coal production. Much of the reduced thermal production is due to producers shifting to the domestic and export metallurgical coal markets as suppliers look to maximize limited capital and labor resources. According to IHS Markit, in 2021 approximately 66% of total CAPP production was metallurgical coal as it increasingly becomes the primary driver of coal production in Central Appalachia.[1] CAPP thermal coal has lower sulfur dioxide ("$SO_2$") than other domestic coals and is critical to the coal units meeting their environmental permitting and operating design specifications. Without adequate future CAPP supply, non-traditional sources of lower $SO_2$ CAPP-like coals could be required for reliability.

### *Coal Transportation*

The magnitude of the volatility of coal demand continues to be larger than the coal transportation supply chain can effectively support. This degree of volatility is expected to continue and perhaps worsen as more and more United States power producers begin transitioning away from coal-fired generation. This volatility makes it much more difficult for the Companies' transportation providers, particularly the Class I railroads, to plan for resources around crews (personnel) and equipment (locomotives). Like coal producers, coal transportation providers have a need for a reasonably steady level of monthly coal shipments to retain and support their labor force and plan for locomotive usage. Historically, the railroads have had a difficult time timely accommodating significant delivery demand shifts resulting from the Companies' burn volatility. The lead times for attaining the appropriate number of crews (railroad personnel) have not historically aligned with the utilities' demand needs. Railroad

[1] IHS Markit, US Coal Market Briefing, February 2022, IHS Subscription Portal.

response time for training conductors and engineers typically takes a minimum of four to six months. This length of time has proven to be too long to support periods of increased coal delivery needs. By the time the appropriate number of crews are trained, certified and positioned where needed, the increased need for coal deliveries has most likely already occurred.

In the foreseeable future, declining CAPP coal supply may require the Companies' operating stations to shift coal basins to meet supply needs; however, coal basin shifts can take up to 12 months to establish effectively given the need to establish or right-size railroad crew bases and position equipment.

All the DEC and DEP coal supply is delivered by rail to its facilities. As a result, any disruptions in rail service due to labor and resource constraints, weather, maintenance and rail system demand, or derailments can significantly impact station deliveries.

While the Companies lease their own rail cars for use in transporting coal, the Companies do not have the unilateral right to add additional rail sets into service. The serving railroad approves both whether and how many rail sets may be added based on network traffic at the time of the request. The Companies have been denied the request to add equipment from time to time based on already high network traffic.

Lastly, during 2021 and 2022, the availability of coal cars from third party suppliers shrunk to "zero" as the surge in coal demand, a nationwide liquidation of coal cars over the previous decade, and longer-term lease contracts by other utilities basically removed all available coal cars from the market. Given the declining demand for domestic coal, manufacturers are not planning on building additional railcars to replace the cars that have been scrapped over the last decade.

Based on the transportation constraints discussed above, the Companies expect continued issues with the ability of the railroads to respond timely to changing demand along with limited availability of coal car transportation equipment to continue, all of which increases the risk of reliable supply and higher customer costs.

## Evolving Coal Unit Generation and Dispatch Equation

Dynamic natural gas prices, combined with coal retirements, regional transportation constraints, pipeline constraints, and the addition of significant natural gas fired generation and growing energy contributions from fuel-free solar have contributed to large actual and forecasted burn swings in Duke Energy coal and gas generation. In many parts of the Eastern and Southern United States, natural gas generation competes with the delivered cost of coal. The range of competing dispatch prices between coal and natural gas generation is dynamic based on market prices and real-time switching of natural gas for coal in the generation dispatch stack is common.

In addition, the United States Energy Information Administration announced that electricity generated from renewables surpassed coal in the United States for the first time in 2022. However, until new dispatchable zero carbon fuel technologies become economically viable for utility-scale use to maintain reliability, traditional fossil fuels will be required to maintain least-cost and reliable operations.

With limited elasticity of supply, coal is a constrained resource, requiring new dispatch protocols that optimize long-term economic value to customers subject to limitations on supply and transportation. The Companies anticipate any remaining supply elasticity will reflect the high marginal costs of increasing or decreasing production and transportation, and that these higher marginal costs will contribute to longer-term higher customer costs. Therefore, it has become increasingly important to redefine the time horizon of least-cost economic dispatch to reflect the true cost of ensuring reliability of coal supply through to the final coal generation plant retirement. Developing advanced dispatch methodologies to manage a more defined and decreasing volume of coal across intra-year and inter-year burn volatilities in a manner that provides the highest value to customers, while maintaining reliability of coal supply for critical periods, has been a necessary evolution in least-cost economic dispatch to support coal supply assurance through to planned station retirements.

## Policies and Regulations Impacting Coal

Increasing environmental regulations regarding coal ash, wastewater and air-borne emissions have put significant pressure on the viability of aging coal units to remain both cost-effective and compliant over time. Indeed, as seen in the May 2023 Environmental Protection Agency's ("EPA") Clean Air Act ("CAA") Section 111 Proposed Rule discussed further below, regulations are likely to become even more stringent. While the electric industry largely exits coal generation, it is becoming even less economically viable and increasingly risky to attempt to invest in and maintain coal units into the late 2030s and into the 2040s. In parallel, the majority of states have energy goals in the form of renewable or clean energy portfolio standards or greenhouse gas emission reductions mandates,[2] and Congress has created incentives such as the Inflation Reduction Act of 2022 and the Infrastructure Investment and Jobs Act for other types of resources and technologies, further driving an exit from coal. During this critical period of the energy transition, the increasing pressure on the coal industry poses challenges for the important role these units play in system reliability and adequacy, particularly during extreme weather events unless replaced with equally reliable resources before they retire.

## Implications for the Companies' Coal Facilities

Continuing to maintain the Companies' coal fleet presents challenges due to availability of a qualified workforce and maintaining aging equipment. Maintaining a qualified workforce is more difficult today due to limited career opportunities in a declining industry that does not have long-term job security. As the current employees reach retirement, it is very challenging to attract new workers given the short remaining life of the U.S. coal fleet. This leads to higher costs to maintain an adequate workforce to operate and maintain coal plants. Also, the current coal generation workforce is looking at other areas/industries to work that will provide more future security. The higher costs can be attributed to the need to attract employees not looking at the coal industry or the increased need for contract labor to meet gaps. The Companies do have a program, Transitional Resource Support Group, in place to assist employees with increasing their skillsets to find employment opportunities within the

[2] NARUC, State Clean Energy Policy Tracker, accessed May 17, 2023, available at https://www.naruc.org/nrri/nrri-activities/clean-energy-tracker/.

Companies. This is helpful, but many employees would like to have security and prefer to exit the industry prior to retirement.

There are many challenges that affect a utility's ability to maintain an aging coal fleet. One challenge is being able to get materials in a timely manner and secure equipment that is becoming obsolete. Companies are no longer supporting the declining coal industry as they have in the past causing these supply chain issues. Materials that could previously be secured in days, now can take weeks or months. Another challenge is making funding decisions with uncertainty of retirement, which requires agility in the planning process to respond to changing conditions to balance the right amount of investments in plants with limited future life while striving to maintain reliability. Some of the Companies' coal plants have the capability to burn both coal and natural gas. This provides operational flexibility and reduces fuel costs for customers. Having certainty of retirement dates supports an orderly transition and provides employees with a level of certainty on the path forward.

As noted above, an additional challenge potentially impacting coal-fired electricity generation nationally is the EPA's efforts to regulate carbon emissions. On May 23, 2023, EPA published a suite of proposals under CAA section 111 ("EPA CAA Section 111 Proposed Rule") regulating carbon dioxide emissions from fossil fuel-fired power plants. The EPA CAA Section 111 Proposed Rule addresses existing coal and gas (under section 111(b)) and new gas (under section 111(d)). The potential impact on coal-fired generating units is modest — Duke Energy is planning to retire remaining coal units by the end of 2035, pending regulatory approval and adequate dispatchable replacement generation. As the rule is currently crafted, the impacts would be limited to coal-only units that operate beyond the end of 2031. To the extent resource planning concludes any of these units are needed beyond 2031 for reliability support, a 20% annual capacity factor limitation will be imposed.

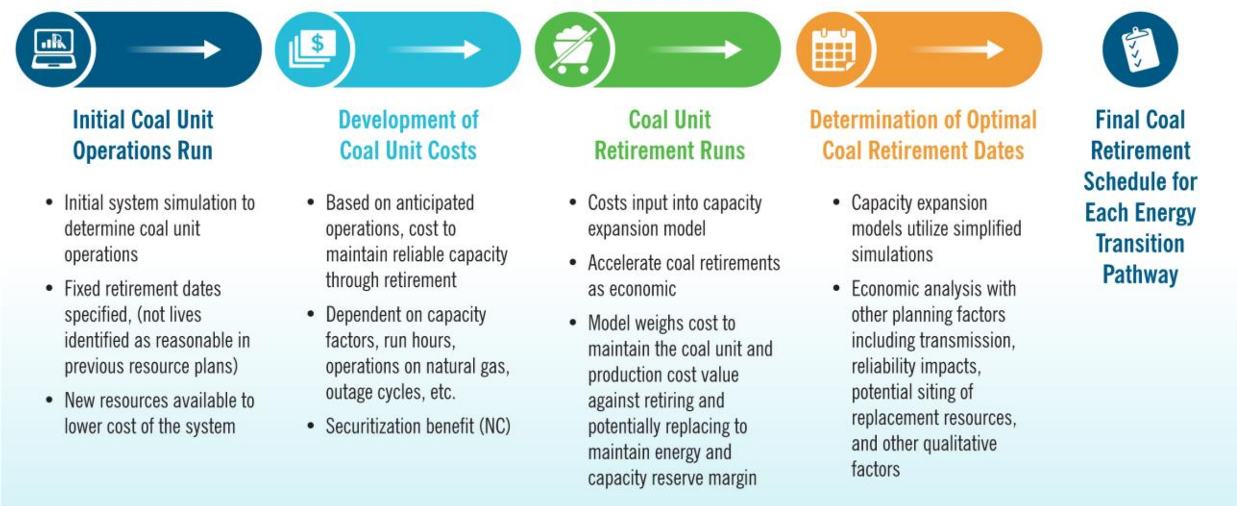
## Coal Retirement Analysis

Considering the substantial increase in the load forecast and update to the planning reserve margin from previous long range planning cycles, DEC and DEP conducted a new coal retirement analysis for the 2023 Carolinas Resource Plan (the "Plan" or "the Resource Plan"). Given the capacity expansion modeling capabilities and enhancements described in Appendix C (Quantitative Analysis), the Companies performed the coal retirement analysis endogenously within the capacity expansion model, optimizing the retirement dates with the expected availability of replacement resources. As described in Chapter 2 (Methodology and Key Assumptions), the Companies performed coal retirement analysis for each Energy Transition Pathway, and for informational purposes in a scenario without carbon constraints. The modeling and analysis to determine the final coal retirement schedule consisted of several steps, including development of the analytical assumptions, capacity expansion modeling, and final determination of optimal coal retirement dates considering results of the modeling and other relevant quantitative and qualitative planning factors.

The Plan utilized the capacity expansion model to identify economic timing of future coal retirements, endogenously optimizing retirements with available capacity and expected energy replacement resources. The capacity expansion model weighed the continued operational benefits to the system and costs to operate and maintain the coal units over time against the retirement and replacement of the coal units by selection of available supply-side resources, while also meeting the operational and planning constraints of the system, including achievement of emissions reductions targets.

Importantly, retirement dates selected by the endogenous analysis are limited to a single and static view of assumptions and costs and, therefore, should be treated as representative and directional in nature (rather than determinative) due to these limitations. To more accurately reflect the complex interdependencies of resource additions and retirements, the coal retirement analysis consists of multiple steps, in addition to the endogenous analysis, to determine costs to operate and maintain each unit, evaluate model-identified potential economic retirement dates, and then consider the modeling results in the context of real-world planning considerations to determine optimal retirement dates for each unit. Specifically, the Companies' Coal Retirement Analysis Process presented below in Figure F-1 and discussed in greater detail below accounts for the dynamic nature of costs associated with maintaining each coal unit, and used the endogenously identified retirement dates, along with considering other qualitative planning factors.

**Figure F-1: Coal Retirement Analysis Process**




## Analytical Assumptions for Maintaining Existing Coal Assets

To perform the capacity expansion modeling with endogenous selection of coal retirements, the model weighs the costs to continue to operate and maintain the coal units, and the production cost and emissions of the system against the cost and production cost benefits of resources that can be brought online while meeting the requirements of the system. These incremental resources selected provide energy and capacity to the system previously provided by the coal resources. To the extent that the aggregate resource additions can reliably replace the coal capacity and energy in a cost-effective manner, the model can economically select to retire these units.

For the capacity expansion model to complete this complex analytical balancing act, the Companies must specify to the model the parameters for retirements including costs to operate and maintain the coal units, the years the coal can be selected for retirement, and other quantitative factors to reflect real-world practicalities to retiring the units and maintaining the operational efficiency and reliability of the grid.

First, the Companies identified which units would be assessed in the coal retirement analysis. The Companies included all coal units for DEC and DEP, with the exception of Allen 1 and 5 and Cliffside 6. Allen 1 and 5 are planned for near-term retirement by the end of 2024. Because these units are already progressing towards near-term retirement, these retirements were not reoptimized as part of the retirement analysis. In the case of Cliffside 6, this unit is already capable of operating on 100% natural gas, as indicated in prior IRPs. The Companies assume Cliffside 6 ceases coal operations by the end of 2035 and operates exclusively on natural gas thereafter. Therefore, this unit was not included in the retirement analysis, as retiring this unit, and replacing it would be suboptimal given its current natural gas operating capabilities.

Initial modeling coal retirements dates were then specified to the model for each unit. This initial retirement date provided the model with the basis for economically accelerating retirements. As discussed earlier in this Appendix, the risks of continuing to operate coal capacity through the mid-2030s significantly increases as headwinds from supply availability, transportation constraints and environmental regulations combine with challenges to reliably maintain and operate these resources, ultimately increasing reliability and cost risks for customers. Therefore, all units were assumed to be retired by no later than the start of 2036 to mitigate exposing customers to the significant coal fuel supply risks discussed above. The Companies then relied on depreciable lives date as the latest date the unit could be retired, consistent with depreciation studies from the previous planning cycle. In limited cases for Marshall 1 and 2, which are among the oldest coal units still on the system, the latest date the unit could be retired was established with near-term projects to leverage generator replacement for the retirement of these units with new replacement resources. A summary of these initial coal retirement dates (retired by January 1 of the year listed), and other coal unit statistics, are shown in Table F-1 below.

**Table F-1: Coal Unit Statistics and Initial Modeling Coal Retirement Dates**

| Unit | Location[1] | Unit Capacity [Winter MW] | In-Service Date | Initial Modeling Coal Retirement Dates[2] |
|---|---|---|---|---|
| **Belews Creek 1** | NC | 1,110 | 1975 | 2036 |
| **Belews Creek 2** | NC | 1,110 | 1975 | 2036 |
| **Cliffside 5** | NC | 546 | 1972 | 2033 |
| **Marshall 1** | NC | 380 | 1965 | 2029 |
| **Marshall 2** | NC | 380 | 1966 | 2029 |
| **Marshall 3** | NC | 658 | 1969 | 2035 |
| **Marshall 4** | NC | 660 | 1970 | 2035 |
| **Mayo 1** | NC | 713 | 1983 | 2036 |
| **Roxboro 1** | NC | 380 | 1966 | 2029 |
| **Roxboro 2** | NC | 673 | 1968 | 2029 |
| **Roxboro 3** | NC | 698 | 1973 | 2034 |
| **Roxboro 4** | NC | 711 | 1980 | 2034 |
| **Total MW** | **-** | **8,019** | - | - |

Note 1: All the Companies' remaining coal units are located in North Carolina and serve customers in both South Carolina and North Carolina.
Note 2 : Initial Modeling Coal Retirement Dates assumed by beginning of the year (Jan. 1).

As a means of acknowledging the operational efficiencies of operating and retiring units together and to limit the complexities of simultaneously determining coal retirements with replacement resources within the capacity expansion model, the Companies leveraged coal unit groupings to retire pairs of units where reduced costs of common operations and equipment are realized with retiring both units simultaneously compared to isolated retirements. These groupings are listed below in Table F-2.

**Table F-2: Coal Retirement Analysis Unit Groupings**

| | Unit Group Capacity (Winter MW) |
|---|---|
| **Belews Creek 1 & 2** | 2,220 |
| **Cliffside 5** | 546 |
| **Marshall 1 & 2** | 760 |
| **Marshall 3 & 4** | 1,318 |
| **Mayo 1** | 713 |
| **Roxboro 1 & 2** | 1,053 |
| **Roxboro 3 & 4** | 1,409 |

Finally, to allow the endogenous analysis within the capacity expansion model to assess the economic coal retirements, the Companies had to develop the costs for maintaining the reliability of these units through their remaining lives. The Companies developed these costs utilizing projected operational factors including operations on natural gas, projected costs to reliability operate the units and comply with known and quantifiable environmental regulations and projected major maintenance cycles necessary to maintain the resources for their anticipated remaining lives. The analysis further included other potential benefits and costs of retirement including securitization benefits of a portion of the units' projected net book value for accelerated retirement for subcritical coal units (as permitted under North Carolina law), and transmission costs that may need to necessarily be incurred to upgrade the transmission system to maintain reliability if the coal units were retired. Table F-3 below summarizes some of the key coal unit characteristics impacting continued operations costs.

**Table F-3: Coal Unit Characteristics Impacting Continued Operations Costs**

| Coal Unit Grouping | Steam Generator Technology | Natural Gas Co-Firing Capability |
|---|---|---|
| **Belews Creek 1 & 2** | Supercritical | 50% |
| **Cliffside 5[1]** | Subcritical | 40% |
| **Marshall 1 & 2[1]** | Subcritical | 40% |
| **Marshall 3 & 4** | Supercritical | 50% |
| **Mayo 1** | Subcritical | 0% |
| **Roxboro 1 & 2** | Subcritical | 0% |
| **Roxboro 3 & 4** | Subcritical | 0% |

Note 1: Cliffside 5 and Marshall 1 and 2 are capable of co-firing on natural gas at 40% capacity. However, these units are only able to do so when the other units at these sites are not fully utilizing their natural gas capability. In the Carolinas Resource Plan modeling, Cliffside 5 assumes 10% natural gas co-firing capability and Marshall 1 and 2 remove natural gas co-firing as a simplifying model computational assumption for site natural gas availability.

## Endogenous Coal Retirement Modeling

### *Initial Coal Unit Operations Runs*

The costs to operate and maintain generation units over time as discussed in the previous section, are determined by how long the unit is expected to remain in the resource portfolio and how much the unit will run over that time. Investments are generally driven by operational characteristics dictated by how a unit is utilized and how much it is utilized. To accurately reflect the operations of these units, given the constraints of the system, an initial set of capacity expansion and production cost models ("Initial Coal Unit Operations Runs") were completed for each Energy Transition Pathway and in a supplemental scenario without carbon constraints or penalties. This initial modeling yielded unique projected coal unit operations for each Pathway and the no carbon constraints scenario and along with the associated additional resources needed to meet the requirements of the system. The simulation of the system provides the inputs needed to develop the costs of maintaining and investing in these coal units over the projected remaining lives of the assets, as discussed in the previous section. These Initial Coal Unit Operations Runs utilized fixed retirement dates consistent with the dates shown in Table F-1.

### *Development of Coal Unit Costs*

As discussed above, the costs for operating and investing in these units over time to maintain reliable operations over the projected lives of the resources were developed based on the unit-specific operational results of the Initial Coal Unit Operations Runs. Each run provided a representation of how the coal units might be utilized over the planning horizon, should they continue to operate through their initial modeling retirement date. The operations of the units may change from one Pathway to another based on the other resources added to the portfolio necessary to meet the energy and capacity needs of the system. Based on these operational projections, including capacity factors, operations hours and operation on natural gas at the Companies' natural gas co-fired coal units, the Companies developed cost projections for each coal retirement scenario that corresponds to an Energy Transition Pathway and the no carbon constraints portfolio. These sets of investments and ongoing maintenance and operation costs could then be put back into the capacity expansion model to determine economic retirement dates endogenously.

### *Coal Unit Retirement Runs*

Once the cost projections for each coal unit for Energy Transition Pathway and the no carbon constraints coal retirement scenario had been input into the capacity expansion model, the Companies conducted the "Coal Unit Retirement Runs." These model runs, performed within the capacity expansion screening model, assessed potential to economically accelerate the retirement of the coal units while simultaneously optimizing the selection of new resources and maintaining reliability meeting the energy and capacity needs of the system, and solving for the emissions reductions targets, as applicable for Pathways 1, 2 and 3.

The model's objective function is to minimize the cost of the system over time while adhering to constraints such as reliability, energy and capacity requirements of the system, and emissions targets as they apply to Pathways 1, 2 and 3. The model will weigh the cost of accelerating the retirement of the unit and avoiding the operations and maintenance cost of maintaining the coal unit with the costs and benefits of accelerating replacement resources. If the model deems it is lower cost to retire the coal capacity, avoiding the future investments in these units and to incur potential cost for adding incremental resources to maintain the planning reserve margins of the system, the model has the option to do so.

## Determination of Optimal Coal Retirement Dates

While the capacity expansion model was used to endogenously identify retirement dates economically on a level comparison with new resources to meet the requirements of the system, relying exclusively on results from the capacity expansion model is not appropriate for resource planning, neither for selecting resource additions nor retirements, especially with respect to executing the retirements and planning for an orderly transition. As discussed in Appendix C, the capacity expansion model is a screening model. The capacity expansion model's system simulation simplifications can provide high-level resource selection indications if a resource is generally beneficial to the portfolio. However, the capacity expansion model's inability to reflect dynamic costs associated with each unit's ongoing operations and maintenance schedule, and to assess such costs for units with different projected retirement dates, is an inherent limitation that cannot be captured with static cost inputs into the model. Furthermore, in line with the Plan's planning objectives, and as identified by the Companies in prior resource planning proceedings, the coal retirements are often contingent on a number of factors and must be executable to ensure the reliability of the system upon retirement. These contingencies include the timing of new resource additions, load growth and planning reserve margin requirements, transmission constraints and the ability to leverage sites for future development. To optimize unit retirement dates based on the availability of new capacity additions while considering an orderly transition that maintains or improves system reliability, prudently manages risks and uncertainties, and ensures the Companies can meet the growing energy needs of customers, the Companies made minor adjustments to the coal retirement dates for certain units to allow for more orderly and executable retirement schedules contributing to the continuing reliability of the system. Tables F-4 through F-7 below show the economic retirement dates identified by the capacity expansion screening model and the optimal retirement dates given the endogenous modeling results and planning considerations described above, all dates reflecting a beginning of year basis.

**Table F-4: Energy Transition Pathway 1**

| Coal Unit Grouping | Model Selected Retirement Date | Optimal Retirement Date |
|---|---|---|
| **Belews Creek 1 & 2** | 2030 | 2030 |
| **Cliffside 5** | 2029 | 2029 |
| **Marshall 1 & 2** | 2029 | 2029 |
| **Marshall 3 & 4** | 2034 | 2034 |
| **Mayo 1** | 2029 | 2029 |
| **Roxboro 1 & 2** | 2029 | 2029 |
| **Roxboro 3 & 4** | 2030 | 2030 |

The Companies did not adjust any of the coal unit retirement dates in Energy Transition Pathway 1. The challenges of achieving the interim emissions reduction targets in the Pathway may be further exacerbated by further adjusting the retirements economically selected by the capacity expansion model. To be clear, retiring approximately 6,700 megawatts ("MW") of firm winter capacity in a two-year span would require a significant and practically infeasible amount of replacement resources to maintain adequate planning reserve margins for the Companies in an extraordinarily compressed and accelerated timeline which could unduly jeopardize the reliability of the system. However, consistent with the Pathway, the level of replacement resources to enable retirement would be significant on an accelerated and compressed timeline needed to achieve the reduction targets and allow for the retirement of these resources.

**Table F-5: Energy Transition Pathway 2**

| Coal Unit Grouping | Model Selected Retirement Date | Optimal Retirement Date |
|---|---|---|
| **Belews Creek 1 & 2** | 2032 | 2036 |
| **Cliffside 5** | 2031 | 2031 |
| **Marshall 1 & 2** | 2029 | 2029 |
| **Marshall 3 & 4** | 2034 | 2032 |
| **Mayo 1** | 2032 | 2031 |
| **Roxboro 1 & 2** | 2029 | 2029 |
| **Roxboro 3 & 4** | 2033 | 2033 |

The model selected retirement dates for Energy Transition Pathway 2 were adjusted slightly when determining the optimal retirement dates to be used for the development of the Pathway's portfolios. Retirement dates for Cliffside 5, Marshall 1 and 2, Roxboro 1, 2, 3 and 4 were unadjusted from the model's identified dates. The capacity expansion model identified the retirement date for Mayo in 2032. However, given the retirement dates of Roxboro 1 and 2 selected in 2029, and Roxboro 3 and 4 selected in 2033, accelerating the economically identified Mayo 1 retirement from 2032 to 2031 provides for an orderly transition by scheduling two years between retirements of each of the DEP unit groups. The Mayo unit, at just over 700 MW, is more easily retired and replaced on a slightly accelerated timeline compared to the Roxboro 3 and 4 two unit grouping totaling 1,409 MW. In DEC, Belews Creek 1 and 2 were economically selected for retirement in 2032 and Marshall 3 and 4 were economically selected for retirement in 2034. Considering the large size of both unit groupings, the Companies identified that Marshall 3 and 4 may be more optimally suited for generator replacement at the site, and with an accelerated timeframe for retirement, economies of scope and scale may be able to be leveraged with retirement dates of these units closer to the retirement dates of Marshall 1 and 2 in 2029. For Belews Creek 1 and 2, in part because this site is well suited for and being pursued as the first early site permit for advanced nuclear, the Companies delayed the retirement of these units to 2036. This timeline is generally consistent with the timing planned for the first advanced nuclear small modular reactor unit coming online. Furthermore, the delay of Belews Creek with the acceleration of Marshall 3 and 4, provides slightly more capacity through the transition relative to the economically selected date, providing added reliability to the system.

**Table F-6: Energy Transition Pathway 3**

| Coal Unit Grouping | Model Selected Retirement Date | Optimal Retirement Date |
|---|---|---|
| **Belews Creek 1 & 2** | 2036 | 2036 |
| **Cliffside 5** | 2033 | 2031 |
| **Marshall 1 & 2** | 2029 | 2029 |
| **Marshall 3 & 4** | 2032 | 2032 |
| **Mayo 1** | 2036 | 2031 |
| **Roxboro 1 & 2** | 2029 | 2029 |
| **Roxboro 3 & 4** | 2034 | 2034 |

The model selected retirement dates for Pathway 3, some of which were adjusted slightly when determining the optimal retirement dates for this Pathway. Retirement dates for Marshall 1, 2, 3 and 4; Belews Creek 1 and 2; and Roxboro 1, 2, 3 and 4 were unadjusted from the model's identified dates. The model economically selected Cliffside 5 in 2033. When compared to the retirement dates of Marshall 3 and 4, it was determined that accelerating the retirement of Cliffside 5 to 2031 was optimal timing for this unit. Cliffside 5 is a subcritical coal unit with limited availability for operating on lower carbon emission natural gas with the dual fuel optionality. Given that Marshall 3 and 4 are supercritical units that are more efficient than Cliffside 5 and have more natural gas co-firing capability, the Companies decided to accelerate the retirement of Cliffside 5 ahead of Marshall 3 and 4, without adjusting the model selected retirement date for Marshall 3 and 4. In DEP, Mayo was selected for retirement by the capacity expansion model in 2036. Mayo is among the most expensive of the coal units to operate. Given the lack of operational efficiency for the single unit site and the low capacity factor and run hours projected by the model in the 2030s, the Companies determined the optimal retirement date for Mayo should be accelerated to 2031. This provides for consistent progress toward reducing coal generation risks to customers, while having little impact to the cost of operating the system.

Table F-7 below summarizes the final coal retirement schedule used for each of the Pathways for the development of Core Portfolios, Portfolio Variants and Sensitivity Portfolios under each Pathway.

**Table F-7: Coal Unit Retirements (effective by January 1 of year shown)**

| Unit | Utility | Winter Capacity (MW) | Effective Year by Pathway (Jan 1) | | |
|---|---|---|---|---|---|
| | | | Pathway 1 | Pathway 2 | Pathway 3 |
| Allen 1[1] | DEC | 167 | 2025 | 2025 | 2025 |
| Allen 5[1] | DEC | 259 | 2025 | 2025 | 2025 |
| Belews Creek 1 | DEC | 1,110 | 2030 | 2036 | 2036 |
| Belews Creek 2 | DEC | 1,110 | 2030 | 2036 | 2036 |
| Cliffside 5 | DEC | 546 | 2029 | 2031 | 2031 |
| Cliffside 6[2] | DEC | 849 | 2049 | 2049 | 2049 |
| Marshall 1 | DEC | 380 | 2029 | 2029 | 2029 |
| Marshall 2 | DEC | 380 | 2029 | 2029 | 2029 |
| Marshall 3 | DEC | 658 | 2034 | 2032 | 2032 |
| Marshall 4 | DEC | 660 | 2034 | 2032 | 2032 |
| Mayo 1 | DEP | 713 | 2029 | 2031 | 2031 |
| Roxboro 1 | DEP | 380 | 2029 | 2029 | 2029 |
| Roxboro 2 | DEP | 673 | 2029 | 2029 | 2029 |
| Roxboro 3 | DEP | 698 | 2030 | 2033 | 2034 |
| Roxboro 4 | DEP | 711 | 2030 | 2033 | 2034 |

Note 1: Allen 1 & 5 retirements are planned by December 31, 2024. Retirements were not included in the Coal Retirement Analysis due to near-term planned retirement dates.
Note 2: Cliffside 6 is assumed to continue operating on 100% on natural gas beyond 2035 and was not included in the coal retirement analysis for the Carolinas Resource Plan.

## Supplemental Scenario Analysis

As discussed above, the Companies developed coal retirement schedule that is optimized without CO2 constraints.  This portfolio is used in Supplemental Portfolios for informational purposes as discussed in Chapter 2, Chapter 3 (Portfolios), and Appendix C. The result of this analysis is presented below in table F-8.

**Table F-8: No Carbon Constraints Scenario**

| Coal Unit Grouping | Model Selected Retirement Date | Optimal Retirement Date |
|---|---|---|
| **Belews Creek 1 & 2** | 2036 | 2036 |
| **Cliffside 5** | 2033 | 2033 |
| **Marshall 1 & 2** | 2029 | 2029 |
| **Marshall 3 & 4** | 2035 | 2035 |
| **Mayo 1** | 2036 | 2036 |
| **Roxboro 1 & 2** | 2029 | 2029 |
| **Roxboro 3 & 4** | 2034 | 2034 |

The Companies did not adjust any of the coal retirement dates in the no carbon constraints scenario, as this analysis was performed as part of the supplemental scenario analysis. The resulting coal retirement dates leave this scenario exposed to economic and reliability risks and disruptions, as explained earlier in this Appendix, by waiting until the mid-2030s to retire the majority of the Companies' coal fleet. Similar to Pathway 1, retiring approximately 6,200 MW of firm winter capacity in a compressed, four-year span would require significant replacement resources in a short time frame to maintain adequate planning reserves. Furthermore, this supplemental and informational scenario relies heavily on coal generation to serve load through the remaining lives of these units, which leaves this scenario significantly exposed to risks of more stringent restrictions on fossil generation in the future. If a disruption in the coal industry were to materialize before this scenario begins transitioning out of coal, the scenario has few directions to turn to replace the energy and capacity needed by the system to maintain reliability. Finally, it is not practical to run these coal units indefinitely as the industry inclusive of labor markets, equipment suppliers, coal mining and coal transportation become increasingly obsolescent. As the components within these units age and the parts and workforce to reliably operate the coal fleet become increasingly harder to obtain, the Companies are further at risk of requiring significant investment to keep these units reliable for a potentially short remaining life.

## Moving from Planning to Execution

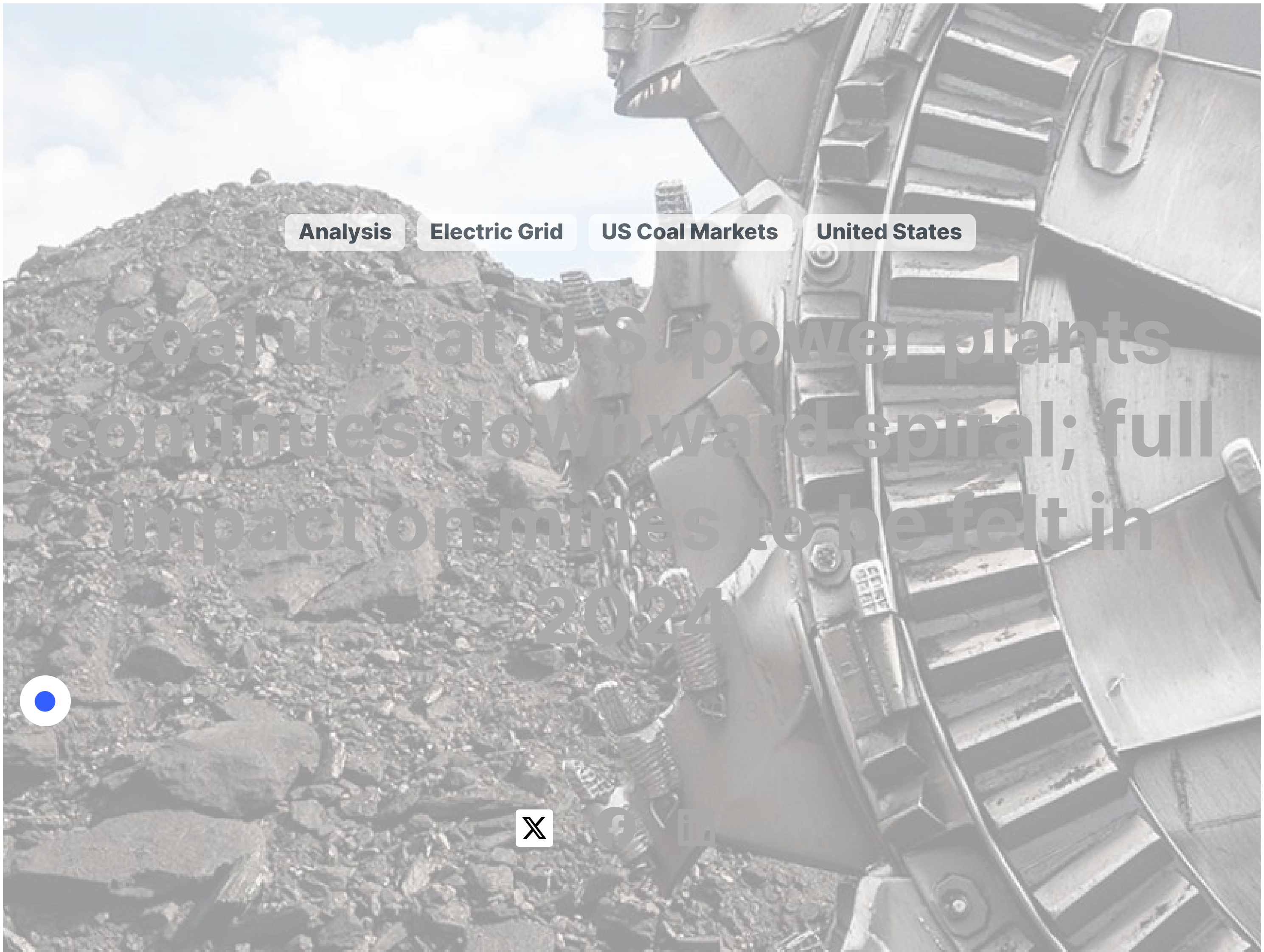
The coal retirement analysis is a critical component of the Carolinas Resource Plan. The assessment of economic and optimal coal retirement dates in the Plan allows the Companies to account for the changing energy landscape, including evolving economic factors, load growth in the region and continued headwinds facing the coal industry. The analysis affords the Companies the ability to check and adjust to ensure customers' expectations for reliable and affordable service are met throughout the energy transition.

As subcritical coal units are retired from the Companies' supply portfolio, the Companies will continue to assess the benefits of securitization of a portion of the units' projected net book value for accelerated retirement for subcritical coal units (as permitted under North Carolina law). As stated previously in this Appendix, the coal retirement analysis conducted for the Carolinas Resource Plan accounts for this benefit in the overall economics of retiring the subcritical coal units. The Companies also estimated the benefits of securitization for the customer and have included those benefits in the bill impact calculations.

The Companies will also continue to pursue the replacement resources necessary to fill the energy and capacity gap from remaining coal retirements that have reliably and affordably served customers over the last six decades. The approach of replacing before retiring ensures the Companies have adequate resources at the time of retirement to ensure the reliability of the system after these units is retired. Recognizing the changing energy landscape as the Companies progress closer to retirement, it will be essential that the dates reflected in this Carolinas Resource Plan are used as representative guides based on the best information available at the time of the development of the plan. As projected net load, the state of the coal industry and environmental regulations continue to evolve over time, the Companies will continue to check and adjust to maintain affordability and system reliability. The Companies are committed to mitigating risks associated with the continued operation of the coal fleet, while providing a reliable and increasingly clean resource mix, and an orderly transition away from coal is essential to those objectives.

**Exhibit DG-16:**

**Institute for Energy Economics and Financial Analysis, "Coal Use at U.S. Power Plants Continues Downward Spiral; Full Impact on Mines to be Felt in 2024," Nov. 2, 2023**




# Coal use at U.S. power plants continues downward spiral; full impact on mines to be felt in 2024

## Key Findings

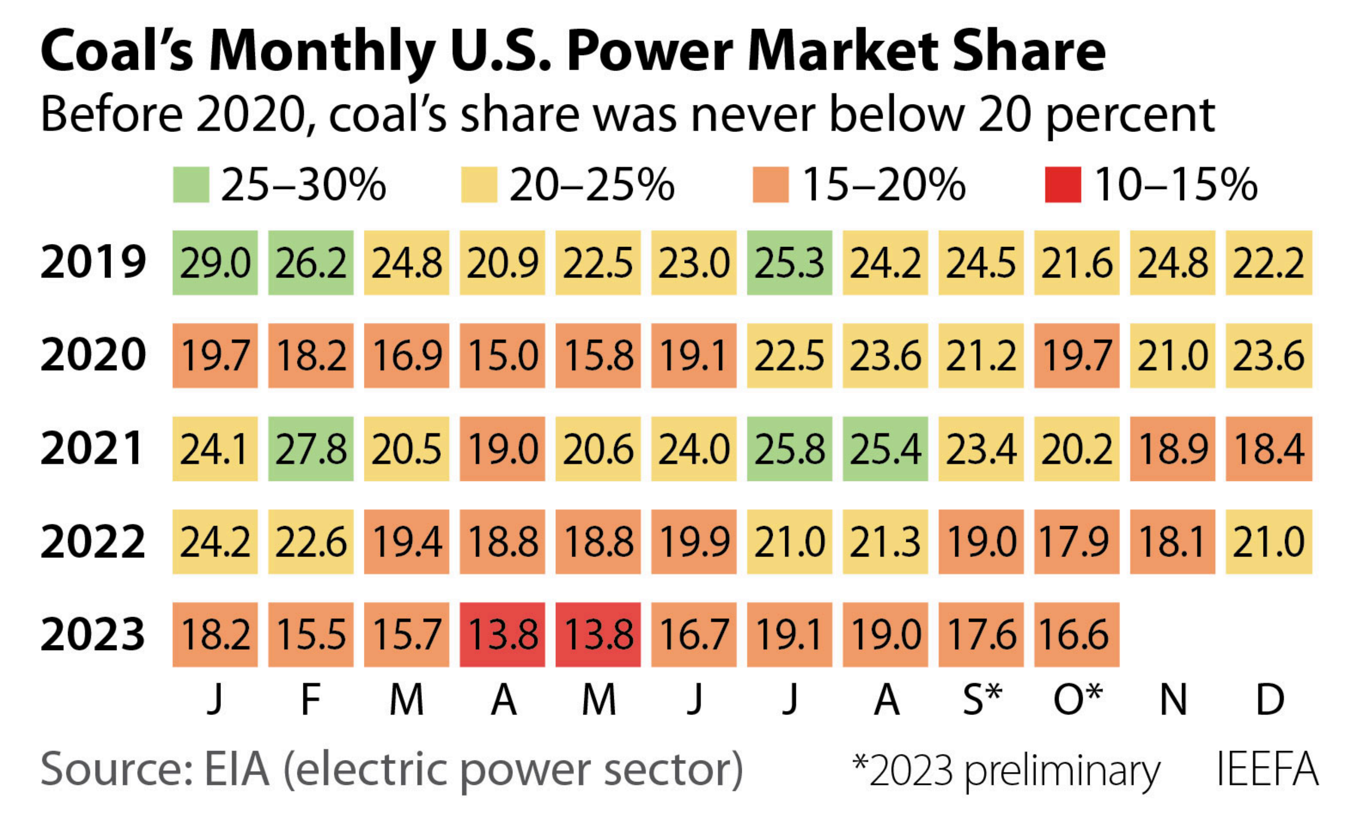
Coal use at U.S. power plants is slumping: The fuel has not achieved a

**amount of coal used over the previous year.**

**The amount of coal used each day in the U.S. has fallen from about 2.8 million tons a day in 2008 to about 1.1 million tons a day this year—a 62% drop.**

**A temporary reprieve in declining coal mine production has ended—coal companies are now staring at a substantial new downturn driven by an accelerating decline in domestic demand.**

This year, the use of coal by the U.S.'s power producers has been so anemic that the fuel has not achieved a 20% market share in any month so far, and the current outlook predicts low levels for the rest of the year. To put that into perspective, coal's power market share had never been *less than* 20% in any month before 2020, according to the U.S. Energy Information Administration (EIA).

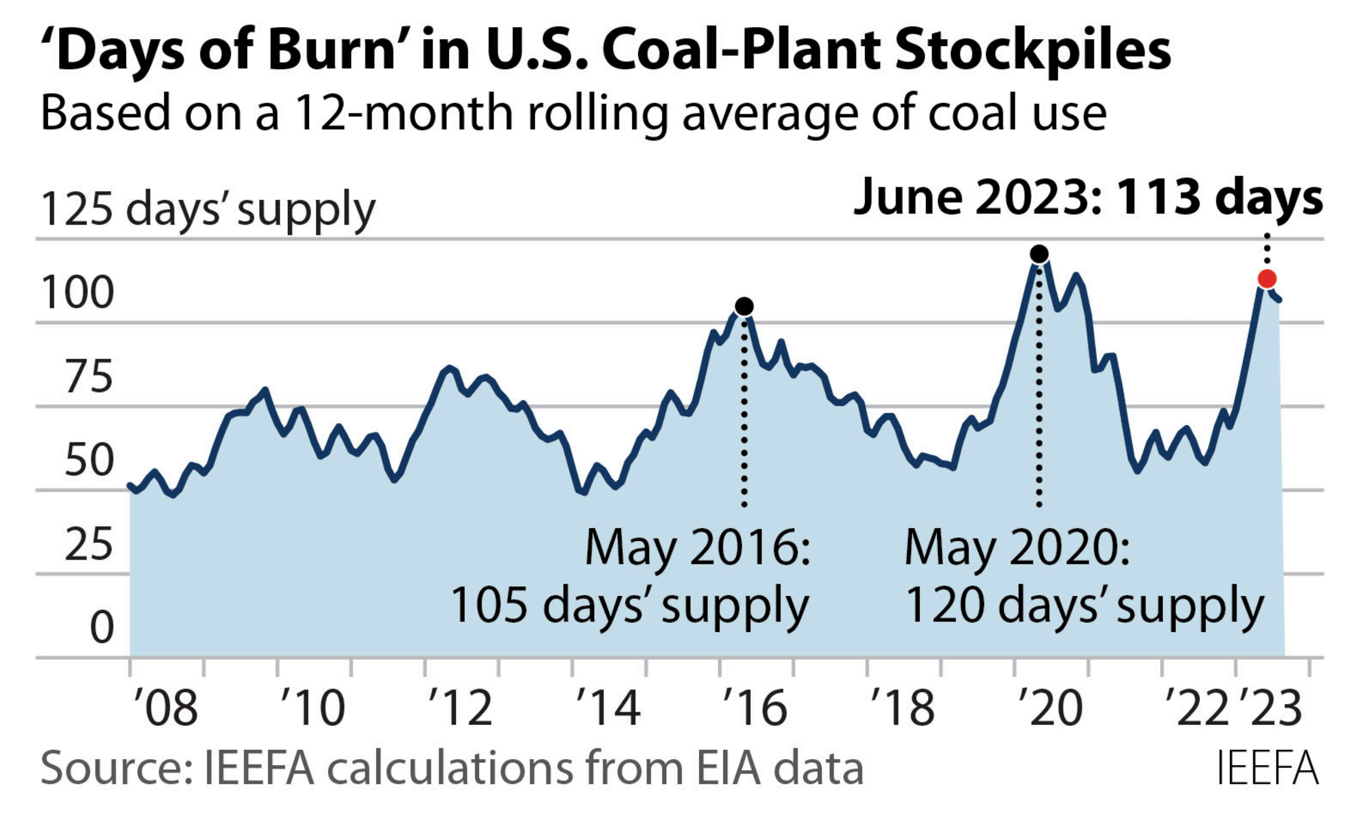



Despite hotter summer temperatures and increased power demand to run air conditioning in some parts of the country this summer, the use of coal has fallen. This is a result of lower prices for gas—coal's primary fossil-fuel competitor—and a surge in utility-scale solar generation, which was up 20% in July from July 2022, and up 23% in August from a year ago.

The EIA's current outlook suggests even more deterioration for coal power in the coming months. The energy agency not only sees coal's November market share returning to the record-low market share in the spring, but also dropping even more in 2024, to as low as 10 to 13% in both the spring and fall.

significantly this year.

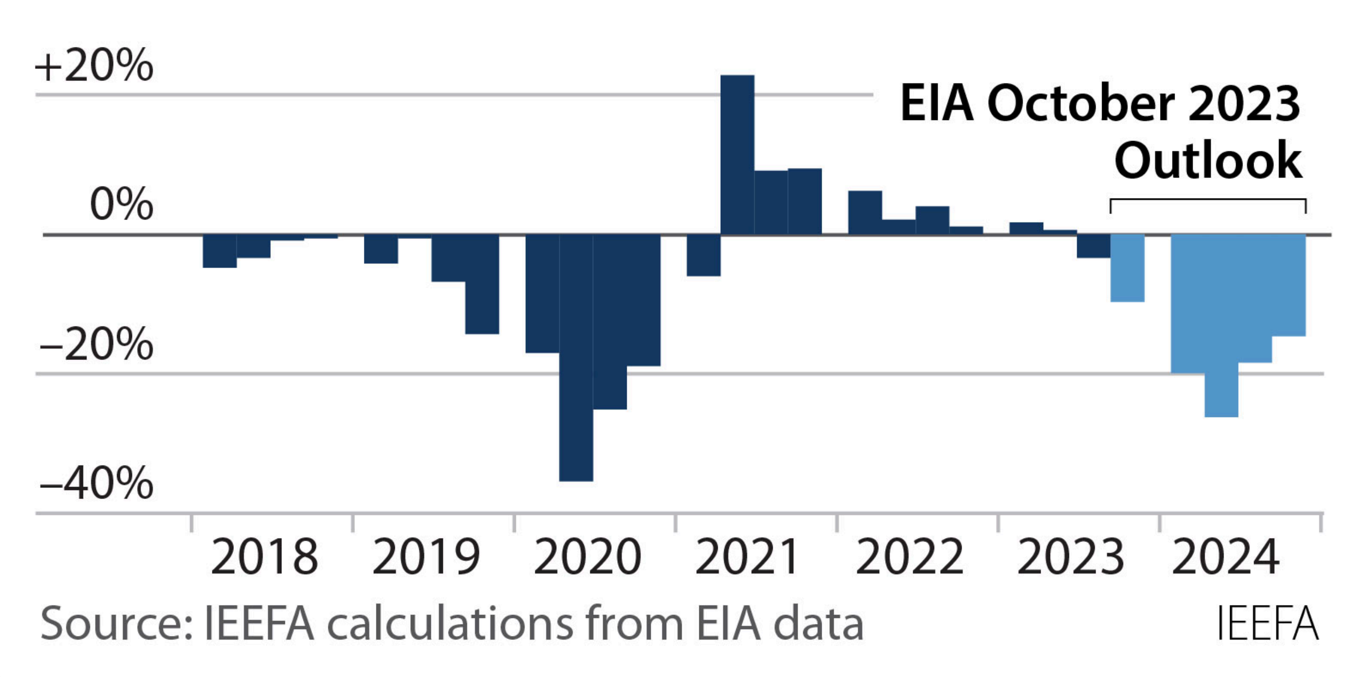
At the same time, coal stockpiles have surged, to almost 130 million tons in June, and remain high. That's enough to run coal plants for 113 days, or almost four months, based on the average amount of coal used over the previous year. This measure, called "days of burn," is more useful than simply looking at the size of the coal piles, since there are fewer coal plants than in the past, and the ones that are still operating are running less. In fact, the amount of coal used each day in the U.S. has fallen from about 2.8 million tons a day in 2008 to roughly 1.1 million tons a day this year—a 62% drop.



To cut stockpiles, coal-plant owners are likely to turn to a straightforward solution: Buy less coal.

That, of course, would directly affect coal mining in the U.S., and the EIA is already warning that a significant production downturn is coming for the remainder of 2023 and throughout 2024. Overall, coal output could fall to 466 million tons in 2024, a 25 percent decline of 115 million tons from 2023 levels, the EIA says. If that figure holds, it would be the smallest annual U.S. coal production since 1962—but most of the years between 1936 and 1957 also had higher output.

Western producers, which include the nation's largest mines in the Powder River Basin, could be hardest hit. The EIA is anticipating output in the region to slump 30% next year, or 73 million tons, to just 246 million tons. That would be the region's lowest production in at least 40 years. Appalachian production doesn't fare much better. There, the EIA expects production to fall almost 22%, or 29 million tons, to just 132 million tons. For comparison, when coal output in Appalachia peaked in 1990, almost four times as much of the fuel was mined.




After a sharp drop in coal demand in 2020 due to the pandemic, output from U.S. coal producers moderately rebounded and stabilized in 2021. Then, in 2022, coal prices soared after the Russian invasion of Ukraine, which broadly improved the financial health of U.S. coal companies—but provided only a modest improvement in the volume of coal produced, which declined again this year.

That temporary reprieve has ended. Coal companies are now staring at a substantial new downturn driven by an accelerating decline in domestic demand.

## Seth Feaster

Seth Feaster is an Energy Data Analyst whose work focuses on the coal industry and the U.S. power sector.

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### The case for reforming the economic regulation of distribution networks in Australia

June 04, 2024
Gabrielle Kuiper

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June 03, 2024
Kevin Leung

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May 31, 2024
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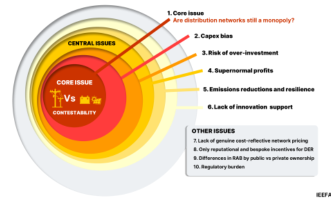

### Reforming the economic regulation of Australian electricity distribution networks

May 31, 2024
Gabrielle Kuiper

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# Exhibit DG-17:

# Earthjustice, “Toxic Coal Ash in Florida: Addressing Coal Plants’ Hazardous Legacy,” May 3, 2023

EARTHJUSTICE

# TOXIC COAL ASH IN FLORIDA

## Addressing Coal Plants' Hazardous Legacy

**Coal ash is leaching unsafe levels of toxic pollutants into groundwater at 91% of coal plants.**

For decades, utilities disposed of coal ash – the hazardous substance left after burning coal for energy – by dumping it in unlined ponds and landfills. **Florida has 28 coal ash dumpsites.** Coal ash contains hazardous pollutants including arsenic, boron, cobalt, chromium, lead, lithium, mercury, molybdenum, radium, selenium, and other heavy metals, which have been linked to cancer, heart and thyroid disease, reproductive failure, and neurological harm. Industry's own data indicate that across the country 91% of coal plants are currently polluting groundwater above federal health standards with toxic pollutants.[1]

Coal ash remains one of our nation's largest toxic industrial waste streams. U.S. coal plants continue to produce approximately 70 million tons every year.[2]

Despite EPA's 2015 Coal Ash Rule, which created the first-ever safeguards for coal ash disposal, many coal ash dumps remain unregulated due to sweeping exemptions for legacy coal ash ponds and inactive landfills. The exempted coal ash dumps are sited disproportionately in low-income communities and communities of color. The EPA will issue a proposed rule to address these exemptions in May 2023.

Florida utilities operate **15 federally regulated coal ash ponds and landfills** containing 16.7 million cubic yards of toxic waste at nine coal plants (Table 1). At all Florida plants, industry monitoring data indicate that groundwater is contaminated above federal safe standards.[3] Despite the serious water contamination, no Florida plant, to date, has selected a final plan to clean up groundwater, as required by state and federal law.

In addition, Florida hosts at least **13 *unregulated* inactive coal ash landfills and legacy ponds** that escape federal regulation (Table 2). The exact number remains unknown because utilities are not required to report these sites. These dumps are almost certainly contaminating water and threatening health and the environment; however, monitoring data are not currently available for most unregulated sites.

As we anticipate EPA's proposed rule on legacy ponds and unregulated landfills in May 2023, a concern remains that the agency will not address coal ash that was dumped off site or used as fill.

### Action Needed

The magnitude of harm from recklessly dumped toxic coal ash requires decisive action from federal and state regulators. Utilities must be required to comply with the law and immediately clean up their pollution.[4] EPA and states must make enforcement a priority and act quickly to ensure that utilities leave communities with sites that benefit rather than harm their health, environment, and economic status. EPA must swiftly strengthen the Coal Ash Rule to address the many legacy ponds and inactive landfills that are unregulated, and to prohibit coal ash used as fill unless protective measures are put in place, to ensure all Florida communities are protected from coal ash pollution.

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## Table 1: 15 Regulated Coal Ash Disposal Sites in Florida

| Coal Plant | City | Owner | Coal Ash Dumps | Groundwater Contamination from Coal Ash<br>Magnitude of exceedance above federal health-based guidelines[5] |
|---|---|---|---|---|
| **Big Bend*** | Apollo Beach | TECO Energy | 2 unlined ponds | Molybdenum (x2), Radium 226+228 (x7) |
| **CD McIntosh** | Chesterton | Lakeland Electric | 1 landfill | Antimony (x1), Arsenic (x10), Boron (x1), Lithium (x77), Radium 226+228 (x11), Sulfate (x3) |
| **Crystal River** | Crystal River | Duke Energy | 2 unlined ponds, 1 landfill | Arsenic (x144), Boron (x3), Lithium (x10), Molybdenum (x5), Radium 226+228 (x3), Sulfate (x2) |
| **Deerhaven** | Gainesville | Gainesville Reg Utilities | 1 unlined pond, 1 landfill | Boron (x2), Lithium (x4), Molybdenum (x3), Radium 226+228 (x1) |
| **OUC Stanton Energy Center** | Orlando | Orlando Utilities Commission | 1 landfill | Arsenic (x9), Cobalt (x3), Fluoride (x5), Lead (x1), Lithium (x4), Molybdenum (x1), Radium 226+228 (x3), Selenium (x2), Sulfate (x2) |
| **Plant Crist** | Pensacola | Gulf Power | 1 unlined pond, 2 landfills | Boron (x34), Cadmium (x1), Cobalt (x10), Mercury (x2), Molybdenum (x34), Radium 226+228 (x5), Sulfate (x1) |
| **Plant Smith** | Southport | Gulf Power | 1 unlined pond | Arsenic (x2), Boron (x9), Lithium (x5), Radium 226+228 (x9), Sulfate (x2) |
| **Seminole** | Palatka | Seminole Electric Coop | 1 landfill | Boron (x2), Molybdenum (x2), Radium 226+228 (x2), Sulfate (x2) |
| **St. Johns River** | Jacksonville | Jacksonville Electric Auth | 1 landfill | Boron (x17), Molybdenum (x2), Radium 226+228 (x2), Sulfate (x3) |

* This plant operates inactive coal ash ponds at the facility but has not reported the ponds on its CCR Rule Compliance Data and Information website nor has the owner complied with the CCR rule's requirements that apply to these ponds, including groundwater monitoring, closure, and corrective action.

For more information on regulated coal ash sites in Florida, see earthjustice.org/coalash/map.

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## Table 2: 13 Unregulated Coal Ash Legacy Ponds and Inactive Landfills in Florida (ash dumps exempted from the 2015 Coal Ash Rule)[6]

| Coal Plant or Landfill | City | Probable Owner / Source | # of Unregulated Ponds | # of Unregulated Landfills | Evidence of Site Contamination[7] |
|---|---|---|---|---|---|
| **Big Bend** | Apollo Beach | TECO Energy | 0 | 1 | Yes – EPA damage case |
| **CD McIntosh** | Chesterton | Lakeland Electric | 0 | 1 | Yes – EPA damage case |
| **Crystal River** | Crystal River | Duke Energy | 0 | 1 | Yes – Industry data[a] |
| **Plant Smith** | Southport | Gulf Power | 0 | 1 | Yes – EPA damage case |
| **Northside Generating Station** | Jacksonville | Jacksonville Electric Authority | 0 | 1 | Yes – Industry data[b] |
| **OUC Stanton Energy Center** | Orlando | Orlando Utilities Commission | 0 | 1 | Yes – EPA damage case |
| **Polk** | Mulberry | TECO Energy | 0 | 1 | Unknown |
| **Scholz** | Sneads | Southern Company | 3 | 0 | Unknown |
| **Seminole** | Palatka | Seminole Electric Coop | 0 | 1 | Yes – EPA damage case |
| **St. Johns River** | Jacksonville | Jacksonville Electric Authority | 0 | 2 | Yes – Industry data[a] |

[a] Industry monitoring data posted on the plant's CCR Compliance Data and Information website.

[b] Industry monitoring is the basis of a finding of contamination as described on Ashtracker.org.

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## Endnotes

1 Earthjustice and Environmental Integrity Project, "Poisonous Coverup, The Widespread Failure of the Power Industry to Clean Up Coal Ash Dumps," *available at* https://earthjustice.org/document/poisonous-coverup.

2 American Coal Ash Association, 2020 CCP Production and Use Survey Report, https://acaa-usa.org/wp-content/uploads/2021/12/News-Release-Coal-Ash-Production-and-Use-2020.pdf.

3 *See* endnote 1, "Poisonous Coverup," *supra*, at Table A4, Summary of Contamination by Site.

4 *See* endnote 1, *supra*, for more information re widespread utility non-compliance with the 2015 Coal Ash Rule.

5 All data derived from the utilities' publicly accessible CCR Compliance Data and Information websites, and exceedances were calculated by Environmental Integrity Project.

6 These data were developed by using EPA datasets relied upon in their 2007 and 2014 CCR risk assessments (Human and Ecological Risk Assessment of Coal Combustion Residuals) and comparing those datasets to the universe of regulated units.

7 "EPA damage case" denotes a site where US EPA has found documented groundwater contamination from coal ash. See: https://www.regulations.gov/document?EPA-HQ-RCRA-2009-0640-12123.

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# Exhibit DG-18:

# U.S. Department of Energy, Loan Programs Office, Program Guidance for Title 17 Clean Energy Financing Program, May 19, 2023

# Program Guidance for

# TITLE 17 CLEAN ENERGY FINANCING PROGRAM

OMB Control Number: 1910-5134
OMB Expiration Date: February 28, 2026
Original Issue Date: May 19, 2023

# Contents

In addition to this Title 17 Guidance, detailed Part I and Part II Application Instructions are provided under separate cover, available on the Title 17 Overview page on LPO's website.

# I. Purpose of Guidance

The Title 17 Clean Energy Financing Program is a critical tool for accelerating the deployment of clean energy and decarbonization technologies in the United States—creating good jobs, strengthening supply chains, and enabling an equitable energy transition. This guidance document provides a comprehensive overview of the Title 17 program for potential borrowers seeking flexible, custom debt financing solutions, with a focus on the what, why, and how. The guidance describes eligible project types, application requirements, loan terms and conditions, and evaluation criteria. In addition to the program overview contained here, detailed application instructions are available on LPO's Title 17 Overview page.

The materials consolidate and replace previous solicitations for existing Title 17 programs (including Innovative Clean Energy, Advanced Nuclear, and Fossil solicitations), and incorporate new authorities established by the Infrastructure Investment and Jobs Act (IIJA) in 2021 and the Inflation Reduction Act (IRA) in 2022, including the Energy Infrastructure Reinvestment (Section 1706) authority and a new category of financing under Section 1703 for projects supported by a State Energy Financing Institution (SEFI).[1] Projects currently under review in LPO's Title 17 application process do not need to resubmit in light of this guidance, and prior determinations made with respect to eligibility of those applications do not change.

If you have questions as you navigate, please reach out to LPO for support.

[1] See Attachment A (Loan Authority Limits by Appropriation) for a summary of the specific loan guarantee authority and appropriations reflected in this guidance.

# II. Title 17 Overview

Under Title 17, the U.S. Department of Energy (DOE) Loan Programs Office (LPO) may provide loan guarantees for projects that support clean energy deployment and energy infrastructure reinvestment in the United States. LPO administers the Title 17 program under the authority created in Title 17 of the Energy Policy Act of 2005.[2] Title 17 has been reauthorized, amended, and revised by legislation since that time, including by the IIJA in 2021 and IRA in 2022. DOE has promulgated regulations implementing the Title 17 program, which are set forth in Part 609 of Title 10 of the Code of Federal Regulations ("Title 17 Regulations").

The Title 17 Clean Energy Financing Program is central to LPO's mission to serve as a "Bridge to Bankability" for clean energy projects that are critical to achieving the decarbonization of the energy sector and enhancing the domestic clean energy supply chain. Repeat deployments that prove market adoption enable 'bankability,' unlocking commercial debt markets. The Title 17 program can support technologies at each deployment milestone—first-of-a-kind deployments that solve applied engineering challenges; follow-on deployments that establish engineering, procurement, and construction excellence and lower total project costs; substantial scaling of deployment and manufacturing capacity to drive advancement along the learning curve; and education of commercial debt markets to enable broadly available debt financing.


[2] The relevant statutory provisions relating to the Title 17 Clean Energy Financing Program are set forth in 42 U.S.C. §§16511-16517.

The new Energy Infrastructure Reinvestment (Section 1706) authority created under the IRA expands LPO's mission under Title 17 to include retooling, repowering, repurposing, or replacing American energy infrastructure that has ceased operations, and enabling operating energy infrastructure to avoid, reduce, utilize, or sequester air pollutants, including anthropogenic greenhouse gas emissions. This is a powerful tool to reinvest in the nation's energy infrastructure, revitalize the economy including in communities with aging infrastructure, and reduce overall emissions.

This section provides an overview of Title 17, including a perspective on why borrowers might seek to work with LPO; project categories covered under Title 17; who is eligible to seek funding under this authority; available terms; and the process for a Title 17 loan guarantee from pre-application through loan maturity.

## A. The LPO Value Proposition

LPO enables borrowers to access long-term, senior debt for the construction of clean energy projects that are challenged in obtaining adequate, flexible debt financing on competitive terms from private lenders. To do this, LPO leverages considerable in-house expertise to support large-scale project deployment and serves as a committed partner for the life of the loan. As of May 1, 2023, the Title 17 Clean Energy Financing Program is authorized to guarantee loans for eligible projects up to a total principal amount of more than $300 billion. (See Attachment A (Loan Authority Limits by Appropriation) for more detail.)

LPO operations are similar to those of commercial lenders or other private capital market lenders – underwriting eligible loans and offering terms with the expectation that those loans will be repaid with interest. LPO's process includes rigorous due diligence that is comparable to what is considered best practice in the private sector, with the additional benefit of an in-house engineering and environmental team that leverages the DOE enterprise to assess and manage technical risk. LPO has in place specific checks and balances for managing risk at all transaction phases, from the due diligence period all the way through conditional commitment, financial close, and loan payoff. Transactions undergo internal LPO validation by the Risk Management Division, interagency review by the Office of Management and Budget and the U.S. Department of Treasury, review by the DOE Credit Review Board, and Energy Secretary approval. Projects that receive a conditional commitment or loan guarantee from LPO will have demonstrated that they are bankable—which in turn creates a strong value signal to potential investors, offtakers, suppliers, and their own workforce.

LPO brings a deep bench of in-house technical, financial, market, environmental, and legal experts with specialized expertise in evaluating energy projects. As needed, LPO can also access the thousands of scientists, engineers, and specialists from across the DOE enterprise to address targeted issues and questions related to an applicant's technology and deployment plans. This is true throughout the life of the loan, not just during application review and due diligence—LPO's Portfolio Management Division will proactively monitor projects through construction, start-up, and operations and maintenance during the life of the loan.

# B. Project Categories Supported by Title 17 Authority

The Title 17 Clean Energy Financing Program offers loan guarantees to support clean energy deployment and energy infrastructure reinvestment. Flexible financing is available for projects qualifying under four categories:

**Innovative Energy (Section 1703)** projects deploy qualifying New or Significantly Improved Technology that is technically proven but not widely commercialized in the United States.

**Innovative Supply Chain (Section 1703)** projects employ a New or Significantly Improved Technology in the manufacturing process for a qualifying clean energy technology, or manufacture a qualifying New or Significantly Improved Technology.

**State Energy Financing Institution (SEFI; Section 1703)** projects support deployment of a qualifying clean energy technology and receive meaningful financial support or credit enhancements from an entity within a State agency or financing authority. SEFI projects are not required to employ innovative technology.

**Energy Infrastructure Reinvestment (EIR; Section 1706)** projects retool, repower, repurpose, or replace Energy Infrastructure (facilities used for electric generation or transmission, or facilities used for fossil fuel-related production, processing, and delivery) that has ceased operations; or enable operating Energy Infrastructure to avoid, reduce, utilize, or sequester air pollutants or emissions of greenhouse gases. EIR projects are not required to employ innovative technology.

# C. Types of Applicants for Title 17 Financing

Title 17 loan financing can be accessed by a wide range of entities in the Project Sponsor role. LPO has experience working with project developers, clean tech manufacturers and service providers, regulated utilities, public power entities, and independent power producers, among others.

# D. LPO Lending Terms

LPO can provide flexible, custom financing to meet the specific needs of Project Sponsors. Characteristics of Title 17 loan guarantees include:

- A Title 17 loan guarantee should reduce the all-in interest rates charged by third party lenders. Loans issued by the Federal Financing Bank typically bear a fixed interest rate pegged to U.S. Treasury rates (matched to loan tenor) plus "three-eighths" (0.375%), as well as a Risk-Based Charge.[3] The Risk-Based Charge is used to allow LPO to offer loans that more closely mirror private sector lenders, who commonly charge a higher interest rate on their loans as the creditworthiness of a potential deal decreases.
- Tenors are dependent on project needs and expected asset life, with a maximum of up to 30 years from guarantee issuance; however, tenors are usually less than the maximum.
- LPO-guaranteed loans may not be subordinate in payment or lien priority to other financing.
- LPO-guaranteed loans are secured financings. In DOE's discretion, LPO-guaranteed loans can share a first lien position with other debt on a pari passu basis. A pari passu intercreditor agreement allows multiple creditors to obtain a secured claim with equal ranking on an asset.

## Title 17 Loan Products

Title 17 can be used to facilitate federal debt and debt from third-party commercial lenders.

### Federal Loans

Applicants can work with LPO to receive a direct loan from U.S. Treasury's Federal Financing Bank (FFB) backed by a 100% "full faith and credit" DOE guarantee (through LPO). LPO handles all coordination with the Federal Financing Bank; no action is required of the applicant beyond the LPO application and approval process.

### Commercial Loans

Applicants that have identified a source of debt from eligible private sector lenders can apply for an LPO partial guarantee of that commercial debt. LPO can guarantee up to 90% of loans made by other financial institutions and allow the lenders to separately sell or participate the non-guaranteed portion in the secondary debt market.

[3] Title 17 regulations give the Department broad flexibility in setting Risk-Based Charges. 10 CFR § 609.13(c) says, in part: "In order to encourage and supplement private lending activity DOE may collect from Borrowers for deposit in the United States Treasury a non-refundable Risk-Based Charge which, together with the interest rate on the Guaranteed Obligation that LPO determines to be appropriate, will take into account the prevailing rate of interest in the private sector for similar loans and risks." 10 CFR § 609.2 defines a Risk Based Charge as "a charge that, together with the principal and interest on the Guaranteed Obligation, or at such other times as DOE may determine, is payable on specified dates during the term of a Guaranteed Obligation."

- LPO-guaranteed debt must consist of term loans and may not include a revolving credit facility.
- LPO transactions are typically structured as limited recourse project financings; however, LPO can accommodate other structures, including secured corporate lending, securitizations, and transactions involving tax equity.
- LPO does not set a minimum loan size; however, due to some of the fixed costs associated with receiving a loan guarantee from LPO, LPO loan guarantees are typically $100 million or more.
- LPO can guarantee up to 80% of eligible project costs, although project cashflows and credit risk considerations often lower leverage ratios with many projects ending up in the 50 to 70% range.[4]
- Title 17 borrowers must comply with certain federal and programmatic requirements under the financing, including prevailing-wage requirements and the Cargo-Preference Act.

## E. Process for Evaluating, Funding, and Monitoring Loans

LPO's financing process combines elements of traditional commercial underwriting with technical eligibility assessments unique to LPO's authorities and mandate. The timeline from first contact with LPO to conditional commitment can take anywhere from six months to more than a year and is largely dependent on the applicant's preparedness and ability to provide required documents. Interested applicants are invited to request a pre-application consultation and other pre-application support. Applicants who have been assigned an LPO point of contact should reach out to that person directly.

There are 6 steps to LPO's process:

[4] LPO loan guarantees of third-party debt are capped at 90% for loans from eligible private lenders, meaning that the maximum amount of eligible project costs LPO can guarantee for non-FFB loans is 72% (90% of the 80% of eligible project costs). LPO may elect to set the cap of a guarantee of third-party debt below 90%. LPO can guarantee 100% of FFB loans, meaning that the maximum amount of eligible project costs LPO can guarantee for FFB loans is 80%.

1 **Pre-Application:** LPO Outreach and Business Development (OBD) team meets with potential applicants to help them decide if LPO financing is a good fit for their project and, if so, provides step-by-step assistance to navigate the application process.

2 **Application and Review:** Title 17 employs a multi-step application process:

a. **In Part I**, LPO reviews the applicant's Part I Application to determine technical eligibility in accordance with the underlying statutes. This provides applicants an early indication of whether their project is eligible for LPO financing, and includes review of:
   i. Technical innovation (if required),
   ii. Other Title 17 eligibility criteria (see Section III),
   iii. The significance of reduction of air pollutants or greenhouse gas emissions, and
   iv. Confirmation that the proposed project is located in the United States or its territories.

b. **In Part II**, LPO determines project viability and readiness to proceed into due diligence based on programmatic, technical, environmental and financial evaluation.

3 **Due Diligence:** If the Part II Application is accepted, LPO and the borrower engage third-party advisors and negotiate transaction structure and term sheet details. This involves significant due diligence, similar to a private lender due diligence process, including detailed papers and presentations, risk and credit reviews, engineering, procurement, and construction schedule and cost, and environmental reviews in accordance with NEPA.

4 **Conditional Commitment:** Following due diligence, the finalization of a financing term sheet, receipt of required interagency and DOE approvals, and review of creditworthiness and validation that the proposed transaction possesses a Reasonable Prospect of Repayment, DOE will offer a conditional commitment and term sheet to the applicant and proceed to negotiate the terms of definitive financing documents with the applicant.

5 **Financial Close:** LPO and the applicant execute definitive financing documents, which may be subject to additional conditions precedent to loan advances.

6 **Monitoring:** LPO maintains active project monitoring and communication to collaborate, surveil, and act as needed in the best interest of the U.S. Government and taxpayers. There are mandatory reporting requirements that the borrower is required to fulfill on an ongoing basis.

This guidance document pertains mainly to Steps 1 and 2 of this process, focusing on project eligibility, loan terms, and application process. Detailed application instructions are available on LPO's Title 17 Overview page.

# III. Project Eligibility

Projects must satisfy certain eligibility criteria in order to receive a Title 17 loan guarantee. Unlike other DOE financial assistance programs, it is not a competition. This means that any potential borrower with a highly qualified and eligible project meeting the administration's national security and economic competitiveness objectives may receive a loan guarantee, subject to the underwriting and evaluation criteria described herein. This section identifies the eligibility criteria that apply to all projects seeking Title 17 financing, as well as eligibility criteria that are specific to each of the four Title 17 project categories (Innovative Energy, Innovative Supply Chain, SEFI, and EIR).

## A. Title 17 Eligibility Requirements

**To receive a Title 17 loan guarantee, all project applications (regardless of project category) must demonstrate satisfactory fulfillment of the following criteria:**

1. **Located in the United States.** The project must be located in the United States, defined as the several states, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and any other territory or possession of the United States of America.

2. **Be an energy-related project.** The project must concern the production, consumption, transportation, or storage of energy, or related manufacturing activities; or support industrial decarbonization, critical minerals, and other components or eligible energy-related project categories under section 1703(b) of Title 17 (see Box 1: 1703 Eligible Technologies, on page 15).

3. **Achieve significant and credible greenhouse gas (GHG) or air pollution avoidance, reduction, utilization, or sequestration.** All Section 1703 projects (Innovative Energy, Innovative Supply Chain, and SEFI) and Section 1706(a)(2)[5] projects are statutorily required to avoid, reduce, utilize, or sequester air pollutants or anthropogenic emissions of greenhouse gases, and any project under Section 1706(a)(1) involving electricity generation through the use of fossil fuels must have controls or technologies to avoid, reduce, utilize, or sequester air pollutants and

[5] 42 U.S.C. §16517(a)(2).

anthropogenic emissions of greenhouse gases. As a policy factor, LPO encourages all projects eligible under Section 1706(a)(1)[6] to demonstrate air pollutant or anthropogenic greenhouse gas emission avoidance, reduction, utilization, or sequestration, as discussed further in Section V.D (Application Process – Policy Factors) and Attachment I.A of the Part I Application.

4. **Have a Reasonable Prospect of Repayment.** There must be a reasonable prospect that the applicant will be able to repay the principal and interest on the guaranteed loan and any other project debt incurred.[7]

5. **Involve technically viable and commercially ready technology.** Commercially ready technology has been demonstrated at near commercial-scale under expected process conditions with results supporting the expected performance of the proposed deployment. Performance data from testing at pilot and demonstration scales (confirming at least a Technical Readiness Level 6) must have been performed and be available for review in order to confirm commercial readiness. Applications will be denied if the proposed project is for research, development, or demonstration.

6. **Include an analysis of how the proposed project will engage with and affect associated communities, as part of a Community Benefits Plan.** The application should identify community benefits, including economic, social, environmental, and equity considerations, as well as potential harms that would need to be mitigated over the life of the project. The project should have support from relevant stakeholders. Borrowers are expected to report on elements of this information as part of ongoing reporting requirements.

7. **Does not benefit from prohibited federal support.** DOE cannot issue loan guarantees to projects that are expected to benefit from certain other forms of federal support ("Federal Support Restriction"), including grants, cooperative agreements, or other loan guarantees from federal agencies or entities. Otherwise allowable federal tax benefits, including energy production and investment tax credits, are excluded from the Federal Support Restriction. See Section VI (Additional Provisions) for detail.

In addition to these baseline qualifying criteria, prospective applicants should review the full text of this guidance including the Additional Provisions section for certain disqualifying factors.

[6] 42 U.S.C. §16517(a)(1).
[7] 42 U.S.C. §16512(d)(1)(B).

# B. Eligible Project Categories

In addition to the common eligibility requirements above, Title 17 applicants must have a project that meets the eligibility criteria of one of four project categories as outlined in the table below. Three of these categories (Innovative Energy, Innovative Supply Chain, and SEFI) are authorized under section 1703 of Title 17,[8] while EIR projects fall under Section 1706.[9] Each project category has specific qualifications that must be met to be considered for a loan guarantee. In addition to the requirements outlined in the table below, applicants should review the category-specific application requirements laid out in the Part I and Part II Applications.[10] In some cases, a project might not fit neatly into a single category; it may, for example, include both manufacturing and deployment or Energy Infrastructure reinvestment and SEFI support. LPO staff will work with applicants to determine the best category and approach for each application.

| **Title 17 Project Categories and Notable Project Requirements (table continues on next page)** | **1703** | | | **1706** |
|---|---|---|---|---|
| | Innovative Energy | Innovative Supply Chain | SEFI | EIR |
| Is located in the United States | ✓ | ✓ | ✓ | ✓ |
| Is an energy-related project | ✓ | ✓ | ✓ | ✓ |
| Avoids, reduces, utilizes, or sequesters air pollutants or anthropogenic emissions of greenhouse gases[11] | ✓ | ✓ | ✓ | ✓ |
| Has a Reasonable Prospect of Repayment | ✓ | ✓ | ✓ | ✓ |
| Involves technically viable and commercially ready technology | ✓ | ✓ | ✓ | ✓ |
| Includes a Community Benefits Plan | ✓ | ✓ | ✓ | ✓ |
| Does not benefit from prohibited federal support | ✓ | ✓ | ✓ | ✓ |
| Involves one or more of the thirteen 1703 Eligible Technologies | ✓ | ✓ | ✓ | |

[8] 42 U.S.C. §16513.
[9] 42 U.S.C. §16517.
[10] Available on LPO's Title 17 Overview page.
[11] Certain EIR projects may be exempt from the GHG reduction requirement, as discussed further in Section V. D (Application Process – Policy Factors) and Attachment I.A of the Part I Application.

| **Title 17 Project Categories and Notable Project Requirements (continued from previous page)** | **1703** | | | **1706** |
|---|---|---|---|---|
| | Innovative Energy | Innovative Supply Chain | SEFI | EIR |
| Deploys a New or Significantly Improved Technology | ✓ | | | |
| Either (1) deploys a New or Significantly Improved Technology in the manufacturing process or (2) manufactures a product that represents a New or Significantly Improved Technology | | ✓ | | |
| Receives meaningful financial support or credit enhancements from a State Energy Financing Institution | | | ✓ | |
| Involves investment relating to existing Energy Infrastructure | | | | ✓ |
| Shares financial benefits with customers or associated communities (if electric utility application) | | | | ✓ |

The following sections detail the eligibility criteria that are specific to each of the four Title 17 project categories (Innovative Energy, Innovative Supply Chain, SEFI, and EIR), and provide examples of eligible projects.

## i. Innovative Energy Projects

An important element of LPO's mission is to support deployment of innovative and high-impact clean energy technologies to demonstrate to private debt and equity investors that these technologies are bankable and ready for large-scale deployment to support the transition to a clean energy future. LPO has demonstrated its ability to influence these markets through the deployment of the first utility-scale wind and solar projects in the United States and through its support for the next generation of advanced nuclear reactors and the nation's first clean hydrogen energy and storage project.

In addition to the common eligibility requirements that apply to all Title 17 projects, Innovative Energy projects must align with one or more of the "1703 Eligible Technologies" as specified in Section 1703 and identified below and must be deemed "innovative" based on the definition provided below.

1. **Eligible Technologies Requirement:** Section 1703(b) provides 13 statutorily defined technologies ("1703 Eligible Technologies") as eligible for LPO loan guarantees, as shown in Box 1.[12]

## Box 1: 1703 Eligible Technologies (Innovative Energy, Innovative Supply Chain, and SEFI)

1. Renewable energy systems
2. Advanced fossil energy technology
3. Hydrogen fuel cell technology
4. Advanced nuclear energy
5. Carbon capture and sequestration technologies
6. Efficient electrical generation, transmission, and distribution
7. Efficient end-use energy technologies
8. Production facilities for the manufacture of fuel-efficient vehicles or parts of those vehicles
9. Pollution control equipment
10. Oil refineries
11. Energy storage technologies
12. Industrial decarbonization technologies[13]
13. Supply of critical minerals[14]

2. **Innovation Requirement:** Innovative Energy projects must include a New or Significantly Improved Technology applied to one or more of the 1703 eligible technologies.

   "New or Significantly Improved Technology" means a technology, or a defined suite of technologies, concerned with the production, storage, consumption, or transportation of energy, including of associated critical minerals and other components or other eligible energy-related project categories under section 1703(b) of Title 17, and that is not a Commercial Technology, and that either:

   i. Has only recently been developed, discovered, or learned; or
   ii. Involves or constitutes one or more meaningful and important improvements in productivity or value, in comparison to Commercial Technologies in use in the United States.

[12] 42 U.S.C. §16513(b).
[13] Industrial decarbonization technologies are described as "Technologies or processes for reducing greenhouse gas emissions from industrial applications, including iron, steel, cement, and ammonia production, hydrogen production, and the generation of high-temperature heat" (42 U.S.C. §16513(b)(12)).
[14] Supply of critical minerals is described as "Projects that increase the domestically produced supply of critical minerals (as defined in section 1606(a) of title 30), including through the production, processing, manufacturing, recycling, or fabrication of mineral alternatives" (42 U.S.C. §16513(b)(13)). The current list of critical minerals as defined in 30 U.S.C. §1606(a) can be found at [U.S. Geological Survey Releases 2022 List of Critical Minerals | U.S. Geological Survey (usgs.gov)](https://www.usgs.gov).

When evaluating whether a technology is “New or Significantly Improved,” LPO will consider whether the technology could have a catalytic effect on the market and whether the technology has the potential to be employed in other commercial projects.

“Commercial Technology” means a technology in general use in the commercial marketplace. A technology is in general use if it is being used in three or more facilities that are in commercial operation in the United States for the same general purpose as the proposed project and has been used in each such facility for a period of at least five years.

The innovation requirement is specific to applications in commercial use in the United States. A project that intends to use a technology that may be considered “commercial” outside the United States (for example, offshore wind) can be considered innovative if it is one of the first three projects in operation in the United States in the last five years.

If regional variation significantly affects the deployment of a technology, it may still be considered innovative if no more than six projects employ the same or similar technology, and no more than two projects that use the same or a similar technology are located in the same region of the United States as the proposed project. Applicants who believe their project may satisfy Title 17’s innovation requirement on the basis of regional variation affecting the deployment of the project’s technology should explain this to LPO in the Part I Application. Examples of regional variation that DOE may consider impacting an innovation determination include, but are not limited to, evidence of how a technology is deployed in rural compared to urban areas, demonstration of geographic or climate related impacts on technology deployment, and ability of certain technologies to serve specific regional markets, including regional transmission organization or independent system operator territories.

In most cases, a single project should be sited at one location. A project may be located at two or more locations if the project is comprised of installations or facilities employing a single New or Significantly Improved Technology that is deployed pursuant to an integrated and comprehensive business plan. See Section V (Application Process) and the Part II Application for details regarding the integrated and comprehensive business plan. For example,

- Title 17 financing can support “hub and spoke” project configurations, where there may be multiple “spokes” (such as raw materials or intermediate processing facilities) that feed into a single “hub” which could supply the final assembly or processing facility.
- Title 17 financing can help project developers overcome market barriers to accelerate the deployment of innovative configurations or uses of distributed energy technologies such as virtual power plants (VPPs).

## Innovative Energy Project Examples

The following concepts describe hypothetical projects that could qualify for an Innovative Energy loan guarantee, for the purpose of illustrating the types of projects that LPO would consider.

**Grid-interactive distributed energy resources (Virtual Power Plant):** An applicant proposes to provide financing to individuals or businesses for the purchase and installation of distributed energy resources (DERs) such as onsite solar, batteries, EV chargers, smart electric panels, smart thermostats, and other grid-interactive-capable appliances and devices that are integrated with innovative software platforms that optimize these DERs to provide grid services in aggregate. A significant portion of project customers are expected to enroll and utilize the innovative software platform. Coordinated management of participating customer DERs enables the applicant to provide and monetize grid services that result in lower energy costs for customers, reduced $CO_2$ emissions, and enhanced grid reliability, among other benefits. The private lender seeks financing to support its customer offerings. Financing repayments from customers and revenue from the provision of grid services will be the source of repayment of the LPO-guaranteed loan.

**Direct Air Capture:** A direct air capture (DAC) developer is planning a new facility that will capture 100 thousand tons per annum (ktpa) of $CO_2$ from the atmosphere. The developer has secured site control for an area directly on top of a Class VI geologic storage facility, meaning there is no need for transportation of the captured $CO_2$. The project is eligible for the 45Q tax credit, as well as state and local incentives that the developer will arrange with local governments. The developer will also sell the right to claim the $CO_2$ removals to companies and other entities with net-zero goals. The developer is seeking a loan guarantee from LPO to support construction of the facility and will use 45Q revenue and revenue from sales of carbon removals to service the debt upon commercial operation.

**HVDC Transmission:** A developer is seeking LPO financing to support the construction of a new 350-mile high-voltage direct current (HVDC) transmission line. The developer has worked with DOE's Grid Deployment Office to facilitate coordination among the relevant permitting agencies and has secured the necessary rights-of-way and permits. The developer is utilizing innovative HVDC transmission technology which provides a higher power density compared to traditional alternating current technology. The chosen HVDC technology has been implemented in Europe and in one commercial project in the U.S., therefore meeting the criteria for New or Significantly Improved Technology. The new HVDC line will enable the interconnection of more renewable energy resources on the electrical grid, therefore reducing the carbon intensity of the regional energy mix. The developer is in discussion with LPO to determine whether a project is likely to have sufficient prospect of loan repayment given estimates of market demand and a limited set of signed firm transmission service agreements.

### Possible Innovative Energy Project Areas

The following is an expanded set of project types that would likely fit the Innovative Energy category. These examples are not exclusive or limiting. They are mentioned for the purpose of further illustrating types of projects that could be eligible, subject to technical review and determination of innovation criteria. Web links are provided in some cases where LPO has published materials relating to a technology or project type.

- Distributed solar and storage (virtual power plant)
- Distributed demand response (virtual power plant)
- Offshore wind
- Stationary and/or mobile energy storage
- HVDC transmission
- Small modular reactor (SMR) nuclear
- "Front-end" nuclear fuel cycle
- Advanced nuclear reactors
- Nuclear uprates or upgrades
- Advanced geothermal
- Carbon capture, utilization, and storage (CCUS)
- Hydrogen production and infrastructure
- Sustainable aviation fuels, biofuels
- Alternative vehicle fuel distribution facilities (e.g., hydrogen, LNG, CNG)

LPO is open to variations on these and invites discussion of additional project proposals.

**Prior Innovative Energy Projects**

Prior Innovative Energy (Section 1703) financed projects illustrate additional project types and loan structures that could qualify for an Innovative Energy loan guarantee. These past projects can be found on LPO's website, including at energy.gov/lpo/portfolio-projects.

## ii. Innovative Supply Chain Projects

The Innovative Supply Chain project category provides loan guarantees for production facilities that manufacture products with a 1703 Eligible Technology (see Box 1) end use, including products or components relating to industrial decarbonization technologies. Projects must either employ a New or Significantly Improved Technology in the manufacturing process or manufacture a component that represents a New or Significantly Improved Technology.

LPO debt financing can ramp up production of key input and component manufacturing for eligible energy technologies. To minimize supply chain bottlenecks, LPO can engage early with applicants and address "chicken or egg" situations through flexible financing that private lenders typically do not provide to developers that establish manufacturing capacity for innovative components of the low-carbon supply chain.

In addition to meeting the eligibility requirements that apply to all Title 17 projects, Innovative Supply Chain projects must meet the following requirements:

1. **1703 Eligible Technologies Requirement:** Innovative Supply Chain projects must involve one or more of the 13 statutorily defined 1703 Eligible Technologies (see Innovative Energy section). In the case of industrial decarbonization technologies, LPO encourages applications that align with the DOE Industrial Decarbonization Roadmap, including chemicals, iron and steel, aluminum, food and beverages, cement, and paper and forest products.[15] As a reminder, these projects will also need to meet project category requirements, such as Reasonable Prospect of Repayment and innovation requirements as applicable.

2. **Innovation Requirement:** Innovative Supply Chain projects must meet the same innovation requirements as Innovative Energy projects (see Innovative Energy section), either through (1) the manufacturing process of the relevant product or (2) innovation in the relevant product itself. Projects to finance a standard, non-innovative component, used within an innovative end-use product, may not satisfy the innovation requirement.

3. **Air Pollutant or GHG Avoidance, Reduction, Utilization, or Sequestration:** Innovative Supply Chain projects must avoid, reduce, utilize, or sequester air pollutants or anthropogenic emissions of greenhouse gases through (1) the manufacturing process of the relevant product or (2) the end use of the component on a full lifecycle basis.

[15] Industrial Decarbonization Roadmap (energy.gov).

## Innovative Supply Chain Project Examples

The following concepts describe hypothetical projects that could qualify for an Innovative Supply Chain loan guarantee, for the purpose of illustrating the types of projects that LPO would consider.

**Innovative solar manufacturing technique:** A solar manufacturing company has proposed the construction of a new U.S. facility for processing silicon wafers into solar cells. The company will use an innovative method of solar cell processing that is not being widely utilized in the U.S. They are currently making solar cells using the same process in their Southeast Asia manufacturing plant, and their cells are used in commercial solar modules. Signed offtake agreements with U.S.-based solar panel manufacturers provide assurances of future revenues that will be used to service the loan. Given that the process is new in the U.S. and will contribute to growth in renewable energy generation, the project is eligible for Title 17 LPO financing under the Innovative Supply Chain project category.

**Nuclear micro reactors and fuel manufacturing:** A developer has designed a micro reactor (~5 MW-electric) that can be factory assembled. The micro reactor has multiple use cases including industrial heat applications and deployment to remote communities for replacing diesel generation. The developer is seeking financing to build a manufacturing facility for scaled production of the micro reactors as well as a nuclear fuel manufacturing facility to produce the high assay low enriched uranium (HALEU) fuel. The developer has identified a mix of non-federal industrial and community customers for its first ten micro reactors; these initial sales will enable repayment of the LPO-guaranteed loan.

**Iron inputs for low-emissions steelmaking:** A steel producer has proposed the construction of a new U.S. facility to produce high-grade iron ore pellets that are suitable for use in direct reduced ironmaking (DRI) to reduce the emissions of the steel production process. The company plans to use the pellets to supply a clean hydrogen-fueled DRI facility to produce low-emissions steel, which is not otherwise available in the U.S. LPO's financing will enable the company to build a large-scale pellet production facility. Expected low-emissions steel sales provide reasonable assurances of repayment.

**Advanced grid components:** A manufacturing company has designed a new type of composite conductor that is lighter weight and higher strength than the conductors commonly used in high voltage alternating current transmission lines. The high strength-to-weight ratio of the new conductor will make it possible to increase the distance between towers, therefore reducing costs and complexity of new transmission lines. The new conductor will also be more efficient compared to existing conductors, which will lead to less transmission loss. The technology has been tested and certified as meeting industry specifications but has not been deployed in more than two commercial projects in the U.S. LPO's financing will enable the company to build a large-scale manufacturing facility; forecasted sales provide reasonable assurances of repayment.

## Possible Innovative Supply Chain Project Areas

The following is an expanded set of project types involving manufacturing, production, or processing that would likely fit the Innovative Supply Chain category. These examples are not exclusive or limiting. They are mentioned for the purpose of further illustrating types of projects that could be eligible, subject to technical review and determination of innovation criteria. Web links are provided in some cases where LPO has published materials relating to a technology or project type.

- Solar supply chain components
- Low-carbon cement, steel, or iron
- Onshore and/or offshore wind components
- Small modular reactors and micro reactors
- Advanced nuclear components
- Critical minerals (including processing, manufacturing, and recycling of mineral alternatives)
- Electric vehicle charging infrastructure
- Electric grid components
- Low-carbon pulp and paper
- Low-carbon chemicals
- Low-carbon aluminum
- Electrolyzer manufacturing

LPO is open to variations on these and invites discussion of additional project proposals.

## iii. State Energy Financing Institution (SEFI)-Supported Projects

Title 17's State Energy Financing Institution (SEFI) lending authority can be used to augment state-administered clean energy programs, providing additional financial support to projects that align federal energy priorities with those of U.S. states.

SEFI-supported projects are exempt from Title 17's innovation requirement, so long as the projects are from a 1703 eligible technology category (see Box 1) and receive meaningful financial support or credit enhancements from a SEFI. Exemption from the innovation requirement expands eligibility for LPO loan guarantees to projects that incorporate commercial technologies and aggregations of technology-diverse projects.

A SEFI is an entity established by a State, or an Indian Tribal entity or Alaska Native corporation, to provide financing support or credit enhancements for eligible projects and to take steps to reduce financial barriers to the deployment of existing and new eligible projects. For this purpose, "eligible projects" means projects that involve one or more of the statutorily defined 1703 Eligible Technologies and would otherwise meet the applicable prerequisites for LPO support under Title 17.

To qualify, a SEFI-supported project should receive meaningful financial support or credit enhancements from a SEFI. A demonstration of meaningful financial support or credit enhancements will be determined by LPO on a case-by-case basis taking into account the circumstances of the State and the position of SEFI support in the capital stack.

Examples of qualifying SEFI financial support may include, but are not limited to:

- Providing equity/subordinate portion of capital stack
- Providing loan loss reserve with respect to junior portion of capital stack
- Co-lending with LPO (pari passu or mezzanine)
- Providing financial backstop for specific key project elements that may be subject to regulatory or local market risk.

A SEFI-supported project may include a partnership between one or more SEFIs and private entities, Tribal entities, or Alaska Native corporations. Support that flows through a non-SEFI intermediary or contracted entity selected by the SEFI or its associated governmental jurisdiction may constitute SEFI support, as determined by DOE on a case-by-case basis.

City and county agencies will generally not qualify as SEFIs. Statewide policies, such as Renewable Portfolio Standards (RPS), that result in parties unrelated to the SEFI providing additional funding, such as renewable energy certificates (RECs) purchased by utilities to projects in a general category (such as renewable generation), typically will not constitute meaningful SEFI support for a particular project. LPO encourages local governments and other interested organizations to contact our office via the pre-application consultation page to discuss ideas for SEFI projects or other project opportunities.

The following are additional SEFI eligibility considerations, some of which represent additional considerations for Title 17 requirements that are described later in this guidance but that may have unique application to SEFI projects.

- **Build America, Buy America (BABA).** Public and nonprofit organizations that receive LPO-guaranteed loan proceeds for a project may be required to comply with BABA's domestic preference requirements. In the case of a publicly administered program the ultimate beneficiaries of which are private homeowners or for-profit organizations, the status of the ultimate beneficiaries of the loan proceeds may be taken into account. See Section V.E (Application process – Federal Requirements) for more details on BABA requirements.
- **Federal Support Restriction.** Like all Title 17 projects, a SEFI-supported project is subject to certain restrictions on receiving federal support. A SEFI project may not utilize federally appropriated funds for the repayment of a guaranteed loan. The fact that a SEFI receives federal support at an organizational level or for projects other than the project applying for LPO financing does not disqualify the proposed project, provided such federal support does not directly or indirectly support the project in question. See Section VI (Additional Provisions) for more details on Federal Support Restrictions.
- **Multistate Projects.** LPO loan guarantees can support multistate projects if the qualifying SEFI allows its support to benefit aspects of the project that are not within its State. In this case, the entire multistate project may be viewed as SEFI supported and eligible for an LPO loan guarantee, regardless of whether state support is provided by those other States.
- **Indirect SEFI support.** If a SEFI provides indirect project support, such as through the channeling of SEFI bond proceeds through a non-SEFI program or administering entity, this project may be eligible for consideration as a SEFI-supported project, provided that the intent to support the specific category of project is clear and the support is meaningful.

## SEFI Project Examples

The following concepts describe hypothetical projects that could qualify for a SEFI loan guarantee, for the purpose of illustrating the types of projects that LPO would consider.

**Energy improvements for residential housing:** A private lender provides debt financing and servicing to businesses that acquire, renovate, and rent or re-sell mid-market single-family and multi-family homes. The businesses use the proceeds to install on-site renewables, build EV infrastructure, and improve the overall energy efficiency of the homes. This home improvement will lower customer energy costs. One or more state agencies provide subordinated debt capital or loan loss reserves for the project. The lender seeks a loan guarantee from LPO for senior debt used to originate or purchase the portfolio of business loans. Loan repayment will be the source of repayment of the LPO-guaranteed loan.

**Community solar to expand access:** A community solar developer is constructing multiple solar facilities. The project portfolio has SEFI funding in the form of up-front state grants, which the developer receives for serving certain geographic areas of the state and for serving lower- and moderate-income and disadvantaged communities. The developer has requested that LPO guarantee a multi-draw construction loan or similar facility used to finance the portfolio of planned solar facilities. The developer plans to repay the construction loans through customer subscription payments and tax-credit support including the ITC low-income solar adder.

**Facilities related to decarbonized industrial products:** A state has invested in a project to transport natural gas for use in production of hydrogen that will be used as feedstock for low-carbon ammonia. Additionally, the SEFI has selected a developer to construct, own, and operate new electrolyzer facilities to produce hydrogen for the same ammonia plant. The clean ammonia will be sold for multiple uses, including fertilizer production and textile manufacturing. The ammonia may also be used in the future as a means of transporting hydrogen. The developer seeks an LPO guarantee of the loan used to construct the electrolyzer facilities, with loan repayment tied to future ammonia sales.

**High quality new housing construction:** A state housing finance agency (which has qualified as a SEFI) leverages state financing and credit enhancements to private developers who construct single- and multi-family residential housing projects to high energy efficiency, renewable energy, storage, resilience, and/or grid interactivity standards. The developers will need additional financing to build their projects. Acting on their behalf, the SEFI decides to bundle projects from multiple developers into a single application to LPO. This loan will be repaid by revenues from the rental or sale of the new housing.

**Energy efficient and/or grid-interactive devices:** A company finances the purchase of energy-efficient appliances through an online utility marketplace and provides point-of-sale rebates for customers around the U.S. Grid interactivity by the devices supports virtual power plant functions. The company's primary revenue stream is through customer loan repayment. In several states, the company developed loan-loss reserve (LLR) programs with state energy offices. The LLR programs cover a significant portion of qualifying losses resulting from consumer loan defaults, which are infrequent. The company seeks a loan guaranteed by LPO to scale up its offerings and make more loans available to consumers in states where it receives SEFI funding.

## iv. Energy Infrastructure Reinvestment (EIR) Projects

Energy Infrastructure Reinvestment (EIR) projects support reinvestment in communities throughout the United States where existing Energy Infrastructure has been challenged by market forces, resource depletion, age, technology advancements, or the broader energy transition. This infrastructure might include power plants, fossil fuel extraction sites, transmission systems, fossil fuel pipelines, refineries, or other energy facilities that have ceased to operate or that continue to operate but could benefit from GHG or pollution-reducing improvements.

These energy assets have often served as economic backbones for local communities for decades and can continue to do so, with targeted investment and economic development support. Redeveloping energy infrastructure typically comes with valuable benefits to new industry, including reuse of existing infrastructure assets, ready access to roads, rails and other means of transportation, existing grid connections, and water access, as well as additional use permits. In addition, these areas are often home to a workforce that is well-suited to building and operating complex energy infrastructure.

Applications for EIR financing must fall into one or more of the following types of projects:

i. Projects that retool, repower, repurpose, or replace **Energy Infrastructure that has ceased operations**; provided that if the project involves electricity generation through the use of fossil fuels, it is required to have controls or technologies to avoid, reduce, utilize, or sequester air pollutants **and** anthropogenic emissions of greenhouse gases; or
ii. Projects that enable **operating Energy Infrastructure** to avoid, reduce, utilize, or sequester air pollutants or anthropogenic emissions of greenhouse gases.

## Definition of Energy Infrastructure

For purposes of EIR eligibility, Energy Infrastructure means a facility, and associated equipment, used for (1) the generation or transmission of electric energy; or (2) the production, processing, and delivery of fossil fuels, fuels derived from petroleum, or petrochemical feedstocks.

This can encompass a wide variety of facilities and sites, including, but not limited to, decommissioned or operating power plants, related grid interconnection facilities, existing transmission lines and related facilities, oil and gas infrastructure including pipelines, refineries, gas stations, or refueling terminals, chemical production facilities, and distributed electric energy assets that are suitable for improvements.

EIR projects are not required to meet statutory requirements for use of innovative technology. The scope of a project receiving EIR project financing may include remediation of environmental damage associated with Energy Infrastructure. At DOE's discretion, the costs of refinancing outstanding indebtedness directly associated with eligible Energy Infrastructure may also be included as part of EIR financing.

The EIR category can support a wide range of investments to utilize existing facilities and support host communities, including:

- Repowering or retooling Energy Infrastructure, such as nuclear or wind facilities, to restart or operate more efficiently or at higher output;
- Replacing energy, capacity, or other grid services of retired Energy Infrastructure;
- Building new facilities for clean energy purposes, which utilize legacy Energy Infrastructure;
- Repurposing retired Energy Infrastructure for Title 17-qualified industrial purposes as presented above for 1703 Eligible Technologies; or
- Environmental remediation at sites of abandoned or uneconomic Energy Infrastructure and upgrades to the site.

## Energy Communities and EIR

EIR eligibility is not limited to particular geographic areas or communities. EIR financing can support projects in "energy communities" as defined in some federally administered programs, as well as other qualifying projects to reinvest in Energy Infrastructure throughout the United States. These include fossil and non-fossil electric infrastructure, as well as facilities used for the production, processing, and delivery of fossil fuels, petroleum, and petrochemical feedstocks. In some cases, EIR-financed projects are eligible for additional tax benefits available to IRS-defined energy communities, providing a boost to community reinvestment opportunities. LPO applicants should refer to IRS tax guidance and other (non-LPO) program documents for direction on eligibility for those benefits and consider Federal Support Restrictions applicable to non-tax benefits in some cases.

EIR projects qualifying under the "energy infrastructure that has ceased operations" clause must meet the following additional criteria:

- **Proximity Requirement.** The new or updated Title 17-financed infrastructure should be at or near the site of the legacy Energy Infrastructure, to credibly retool, repower, repurpose, or replace the Energy Infrastructure that has ceased operations. Applications that are replacing Energy Infrastructure must show a clear relationship between new services and benefits provided by the Title 17 financed infrastructure and services, and benefits lost from the legacy infrastructure that ceased operations, such as grid capacity, reliability, and workforce retention and opportunities, including if the replacement plan differs from the legacy infrastructure physically and/or geographically.

- **GHG and Pollution Controls Requirement.** Any project that will invest in Energy Infrastructure that has ceased operations and which will generate electricity through the use of fossil fuels is required to have controls or technologies to avoid, reduce, utilize, or sequester air pollutants and anthropogenic emissions of greenhouse gases.

As a policy matter, LPO encourages all EIR projects that will invest in Energy Infrastructure that has ceased operations to demonstrate air pollutant or anthropogenic greenhouse gas emission avoidance, reduction, utilization, or sequestration.

All EIR projects that involve an electric utility as the applicant must meet the following additional criterion:

- **Customer and/or Community Benefit Requirement.** Electric utilities that apply for an EIR loan guarantee must provide assurance to DOE that financial benefits received from the guarantee will be passed on to the customers of, or associated communities served by, that utility. This assurance can take a variety of forms, including approvals by State regulatory authorities or other utility governing bodies, and demonstrations of support by affected communities. For purposes of EIR projects, the term 'electric utility' means an entity that sells electric energy at retail and that includes its cost of capital in its cost of service recovered through retail electric rates and shall include a municipal or community utility or an electric cooperative.

## EIR Project Examples

The following concepts describe hypothetical projects that could qualify for an EIR loan guarantee, for the purpose of illustrating the types of projects that LPO would consider.

**Fossil replacement with solar and storage:** An independent power producer owns the site of a 300 MW coal-fired power plant that has ceased operations. The plant has been demolished, but the interconnection and road infrastructure remain. The company plans to reuse the site and repurpose the existing interconnection to build 30 MW of solar and 250 MW of 4-hour battery storage. The project is eligible for, and the company is exploring, relevant federal Investment Tax Credits.[16] The company has developed a plan to retrain and provide new employment opportunities for plant employees. The company is seeking a loan guaranteed by LPO to support construction of the solar and storage, which will be repaid through a combination of tax credits and revenue from the new solar-plus-storage facility. A portion of the loan will also be used to finance the remediation of several on-site coal ash ponds.

[16] Subject to compliance with the rules established by the U.S. Department of Treasury.

**Transition to nuclear:** A utility plans to install a small modular reactor (SMR) on the site of a retired coal-fired power plant. The SMR's 300 MW-electric generation capacity is similar to that of the retired coal plant, therefore making it well-suited for reusing the existing grid interconnection. Several balance of plant systems, such as the plant make-up water and water storage systems, cooling towers, and chemical stores from the coal plant can be repurposed for use with an SMR. The SMR has the potential to benefit from the existing pool of skilled workers able to transition from their prior employment at the coal plant. Further cost savings include avoiding land acquisition costs for the SMR, utilizing rail and road infrastructure, and having an existing water source. The SMR design has been certified by the U.S. Nuclear Regulatory Commission (NRC), and the utility's plans have received state regulatory approval. The utility is seeking a loan guaranteed by LPO to finance the construction of the SMR, with repayment assured through a long-term power purchase agreement (PPA) and the regulatory approval for cost recovery via customer rate base.

**Power plant replacement with an energy-related industrial facility:** A private developer has purchased the site of a retired gas-fired power plant and plans to repurpose the site through the construction of several large, clean energy manufacturing facilities. The developer has identified the existing electrical, pipeline, rail, and road infrastructure as attractive assets that will accelerate and simplify site conversion. The manufacturing facilities will create numerous construction and permanent jobs. The developer is working closely with the local community and labor organizations.

**Transmission reconductoring:** A utility plans to upgrade several high-voltage transmission lines through reconductoring. The utility estimates that replacing the conductive core of older transmission lines will double the electricity carrying capacity compared to the existing conductors, while reducing line losses by up to 50%. The reconductoring plan will retool the existing towers and utilize established rights-of-way. This investment will significantly increase the utility's ability to interconnect new clean energy generation without requiring the time and expense associated with the permitting and construction of new transmission lines. The reconductoring plan has received regulatory approval for cost recovery, which LPO considers sufficient to ensure Reasonable Prospect of Repayment on the loan.

## Possible EIR Project Areas

The following is an expanded set of project types that would likely fit the EIR category. These examples are not exclusive or limiting. They are mentioned for the purpose of further illustrating types of projects that could be eligible, subject to LPO review.

- Retired power plant or other qualifying Energy Infrastructure retooled, repowered, repurposed, or replaced with:
  - Renewable energy
  - Renewable energy and storage
  - Distributed energy (i.e., virtual power plant)
  - Transmission connection to off-site clean energy (e.g., onshore or offshore renewable energy)
  - Nuclear energy
- Fossil or biomass generation with carbon capture and sequestration
- New manufacturing facilities for clean energy products or services
- Repowering of nuclear power plant to resume operations
- Retrofitting of fossil-fuel power plant with carbon capture and sequestration
- Upgrades to wind farms to increase output
- Transmission reconductoring to expand transfer capacity
- Coal ash remediation with site redevelopment
- Oil & gas pipeline repurposing (e.g., hydrogen, $CO_2$ pipelines)
- Refinery retrofit or upgrades (e.g., biofuels, hydrogen)
- Energy Infrastructure repurposing for industrial decarbonization (e.g., low-carbon cement, etc.)
- Decarbonization of existing petrochemical facilities

LPO is open to variations on these and invites discussion of additional project proposals.

**Exhibit DG-19:**

**C. Fong, D. Posner, and U. Veradarajan, “The Energy Infrastructure Reinvestment Program: Federal financing for an equitable, clean economy,” RMI, February 16, 2024**

# The Energy Infrastructure Reinvestment Program: Federal financing for an equitable, clean economy



February 16, 2024

- Electricity
- The Energy Infrastructure Reinvestment Program: Federal financing for an equitable, clean economy

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The US Department of Agriculture's New ERA Program for rural electric cooperatives will channel tens of billions of dollars in grants and low-cost financing into this vital — and often undercapitalized — segment of the electric sector.

February 16, 2024

By Christian Fong, David Posner, Uday Varadarajan

It has been a year and a half since the United States passed the most significant climate legislation in the nation's history, the Inflation Reduction Act (IRA). Over the next few months, regulatory guidance for most of the programs created or expanded by the law will be finalized, and funding will begin to make its way from the federal government's coffers into the clean technologies that must scale — and do so rapidly — if we are to stave off climate disaster.

In keeping with this urgency, several IRA programs have already moved past the initial application phase, including the US Department of Agriculture's New ERA Program for rural electric cooperatives, which will channel tens of billions of dollars in grants and low-cost financing into this vital — and often undercapitalized — segment of the electric sector. An even larger IRA program — the US Department of Energy's Energy Infrastructure Reinvestment (EIR) program — is currently vetting a pipeline of potential projects requesting over a hundred billion dollars' worth of long-term loans priced just above the yield of US Treasury bonds — in other words, a borrowing cost lower than that commanded by even the most creditworthy of corporate issuers.

RMI has previously called the EIR the most important clean energy policy you've never heard about, because of its potential to revitalize local communities historically dependent on fossil fuel infrastructure while saving electricity ratepayers money and building new clean energy resources — a triple win for communities, customers, and the climate. EIR is administered by the Department of Energy's Loan Programs Office (LPO). While the LPO has traditionally lent to help commercialize advanced technologies — including providing financing for some of the country's earliest utility-scale wind and solar projects and kick-starting the electric vehicle industry — EIR's remit is to reutilize and repurpose existing energy infrastructure and build new clean energy assets that use already proven technologies like solar, wind, and battery storage.

With a $5 billion credit subsidy appropriation and authority to make up to $250 billion in loans, EIR has a huge bankroll to go along with its encompassing technological scope. In addition, the statute explicitly includes a provision allowing funds to be used for refinancing as well as for remediation or decommissioning costs, addressing two substantial risks that can add significant costs when retiring and replacing energy infrastructure. The program's concerning constraint, however, is its statutory requirement to approve loans by the end of September 2026. (However, while applications must be greenlit for funding by this date, loan disbursements and project construction are permissible through 2031.) With under three years left until the approval deadline, the sprint is on for utilities and other owners of retiring energy infrastructure to access this extremely affordable financing.

While EIR applications remain confidential at this point, utilities from all corners of the country have publicly announced their intention to apply to the program, including Portland General Electric in Oregon, Consumers Energy in Michigan, Duke Energy in the Carolinas, and Alliant Energy in Wisconsin and Iowa. Additionally, public utility commissions and staff in other states, such as Arkansas, Louisiana, and Colorado, have directed utilities under their purview to study how EIR could be utilized.

EIR can be particularly effective in managing competing community, customer, and shareholder interests in cases where power plants are already slated to cease operations. EIR loans can be used to refinance the obligation of customers to provide cost recovery to utilities for prudently incurred energy infrastructure costs (including remediation and decommissioning costs) and can be structured as off-balance sheet financing vehicles repaid through a dedicated bill surcharge. With tenors of up to 30 years, borrowing costs just slightly above the federal government's, and the flexibility to cover up to 80 percent of total project costs, EIR loans can make accelerated reinvestment in existing fossil sites much more attractive for both utility customers and shareholders. Since EIR loans require any refinancing of legacy investments be tied to reinvestment activities, their use also helps ensure that local communities can retain jobs and tax base while ratepayers benefit from additional cost reductions resulting from ongoing use of assets such as interconnection points and transmission capacity.

To highlight the potential of using EIR to refinance unrecovered legacy asset costs and reinvest in new clean energy, we look in detail below at two utilities, Interstate Power and Light (Alliant) in Iowa and Union Electric Company (Ameren) in Missouri, both of which are currently engaged in regulatory proceedings to manage the rate and financial implications from agreed-upon coal plant closures. LPO guidance requires EIR loans to total no more than 80 percent of project costs, which are defined as the new reinvestment in clean energy, transaction costs, and, where included, remediation and decommissioning costs with retiring fossil infrastructure and any refinanced plant balance. In our modeling, we assume that 20 percent of the new clean capital stack is financed with EIR, and 100 percent of the fossil plant balance is refinanced with EIR; transaction costs are capitalized and included in the project costs. (Note that for loan volume values and initial project cost comparisons, we use nominal dollars, but use net present value [NPV] dollars when comparing overall costs and savings).

The bottom-line is this: using EIR to refinance the entirety of remaining fossil plant balances as well as just a portion of the new clean energy assets that the utilities are planning to deploy through 2030 **could save Iowa ratepayers $124 million and Missouri ratepayers $413 million** in NPV terms.

### Alliant Iowa Analysis

In Iowa, Alliant is asking to recover the remaining $265 million balance of its Lansing coal plant using a regulatory asset amortized over the plant's previously expected remaining operating life of 13 years. According to Alliant's integrated resource plan (IRP), the utility is also planning to bring 400 MW of solar online in the coming year, along with 99 MW of repowered wind, 28 MW of storage, and 94 MW of solar plus storage by 2030.

For Alliant, total project costs for just EIR financing the clean energy portfolio would be $899 million: $173 million for the 20 percent of the clean energy portfolio capital stack financed by EIR, $710 million for the remaining 80 percent of the clean energy portfolio capital stack financed by the utility, and $15 million in transaction costs. Thus, total EIR loan volume for just EIR financing the clean energy portfolio inclusive of transaction costs would be $189 million, or 24 percent of total project costs net of transaction costs, well below the 80 percent threshold. For ratemaking, this $189 million would be financed at EIR loan rates and recovered via a dedicated rate surcharge, while the remaining clean energy costs would be recovered normally at the utility's rate of return.

When combining the Lansing refinancing of $265 million, total project costs would be $1.17 billion: the $173 million for the 20 percent of the clean energy portfolio capital stack financed by EIR, $710 million for the remaining 80 percent of the clean energy portfolio capital stack financed by the utility, $265 million for the Lansing refinancing, and $17 million in transaction costs. Total EIR loan volume would equal $455 million, or 43 percent of project costs. For ratemaking purposes, the $455 million again would be financed at EIR rates and recovered via the dedicated rate surcharge; however, the $265 million of remaining Lansing balance would be removed from rate base. With the plant balance out of rate base, the Lansing capital from the EIR loan is "recycled" back into the utility's balance sheet and can be used for the new clean energy assets. And the 80 percent of the clean capital stack, now with the $265 million directly from the EIR loan for Lansing, is recovered at the utility's rate of return.

As for the overall cost comparison, using traditional utility financing for full recovery of costs associated with Lansing and the new portfolio of renewables, we estimated total ratepayer costs at $1.08 billion (NPV 2024$), with $246 million coming from the Lansing recovery, and $835 million coming from new clean energy.

Next, we looked at how these costs would change if we instead used EIR to finance a portion of the new clean energy. We assume 20 percent of the capital stack is financed by 30-year EIR loans, with the remainder financed through traditional utility financing with roughly equal fractions of utility debt and equity. We estimate that EIR transaction costs would add approximately $4.6 million in NPV to overall financing costs but would reduce net costs for the new clean energy by $57 million.

If EIR were also used to refinance the remaining Lansing balance, an additional $63 million could be saved, **for a total of $123 million in ratepayer savings.** Given that Alliant has already stated its intention to apply for EIR funding for new clean energy projects, our analysis shows **only an additional $1.6 million in NPV transaction costs from including the remaining plant balance of Lansing in a broader EIR loan package,** which amounts to a 90:1 benefit-to-cost ratio.

### Ameren Missouri Analysis

In Missouri, Ameren is retiring its Rush Island coal plant and seeking to recover $512 million, inclusive of both the remaining plant balance as well as additional decommissioning costs and community transition funding. Ameren is also proposing to build 1,800 MW of solar, 1,000 MW of wind, and 400 MW of battery storage by 2030 according to its IRP.

For Ameren, total project costs for just EIR financing the clean energy portfolio would be $4.79 billion: $933 million for the 20 percent of the clean energy portfolio capital stack financed by EIR, $3.82 billion for the remaining 80 percent of the clean energy portfolio capital stack financed by the utility, and $39 million in transaction costs. Total EIR loan volume for just EIR financing the clean energy portfolio would be $971 million, or 26 percent of total project costs net of transaction costs, well below the 80 percent threshold. For ratemaking, this $971 million would be financed at EIR loan rates and recovered via a dedicated rate surcharge, while the remaining clean energy costs would be recovered normally at the utility's rate of return.

When combining the Rush Island refinancing of $513 million, total project costs would be $5.31 billion: $932 million for the 20 percent of the clean energy portfolio capital stack financed by EIR, $3.82 billion for the remaining 80 percent of the clean energy portfolio capital stack financed by the utility, $513 million for the Rush Island refinancing, and $42 million in transaction costs. Total EIR loan volume would equal $1.5 billion, or 35 percent of project costs. For ratemaking purposes, the $1.5 billion again would be financed at EIR rates and recovered via the dedicated rate surcharge; however, the $513 million of remaining Rush Island balance would be removed from rate base. With the plant balance out of rate base, the Rush Island capital from the EIR loan is "recycled" back into the utility's balance sheet and can be used for the new clean energy assets. And the 80 percent of the clean capital stack, now with the $265 million directly from the EIR loan for Rush Island, is recovered at the utility's rate of return.

As for the cost comparison analysis, Missouri has state legislation in place authorizing the use of securitization for financing coal plant cost recovery, which Ameren has proposed to utilize in this case. As such, we also model separate scenarios using either securitization or EIR to achieve Rush Island cost recovery.

Using traditional utility financing for both the recovery of Rush Island's remaining plant balance and the new clean energy portfolio, the costs would total $4.5 billion (NPV 2024$), with $482 million coming from the Rush Island recovery and $4 billion coming from new clean energy.

EIR financing for 20 percent of the clean energy portfolio while maintaining traditional utility financing for Rush Island would save ratepayers $278 million, net of $6.6 million in NPV of EIR transaction costs.

Under Ameren's proposal to securitize Rush Island cost recovery with a 15-year bond, Ameren ratepayers would save $72 million, net of $15.6 million in NPV of transaction costs. Combined, EIR financing for a portion of the new clean assets along with securitization of the fossil plant balance would result in $350 million in savings, with $22.2 million in NPV of transaction costs.

The use of EIR for Rush Island cost recovery delivers even greater savings than securitization. If Ameren is already applying for EIR financing for a portion of its clean energy portfolio, **the NPV of marginal transaction costs of bundling together the Rush Island recovery with this EIR package would be just over $1.3 million,** a substantial cost reduction compared with the NPV $15.6 million in securitization transaction costs. Lower transaction costs, a lower interest rate from EIR, and a longer loan tenor as allowed by EIR would lead to a further $131 million in savings from Rush Island, **for a total savings of $413 million** versus traditional utility financing for fossil plant cost recovery and new clean deployment.

### The Need to Move Quickly

Given the savings available to ratepayers, as well as the time-constrained authority of the EIR program, Alliant and Ameren should move quickly to take advantage of this program, and regulators should ensure utilities are looking into this program as an option that will help reduce costs. With an application approval deadline set for the end of September 2026 and a disbursement deadline at the close of 2031, utilities nationwide have a critical opportunity to refinance their retiring coal plants, build new clean energy, and increase their earnings, all while reducing costs to ratepayers.

### Modeling Appendix

- Clean Portfolios: We look at the latest IRPs for Alliant and Ameren. Specific deployment dates and costs are not publicly available for all resources, so we have made simplifying assumptions for modeling purposes. We assume clean technologies are deployed in the single earliest year, which is a very conservative assumption that would overestimate costs due to technological cost declines. Specifically, for Alliant, because exact deployment dates were not available for all resources, we assume 459 MW of solar and 99 MW of repowered wind come into service by the end of 2024, and that 63 MW of storage comes into service by the end of 2029. For Ameren, we conservatively assume that all clean technologies are built in the same year, with 1,800 MW of solar in 2025, 1,000 MW of wind in 2026, and 400 MW of storage in 2027. In reality, Ameren will spread this deployment over later dates, and these costs would be lower due to technological cost declines. We use NREL's 2023 annual technology baseline (ATB) for resource costs, utilizing moderate learning curves over a 30-year cost recovery period.
- Tax Credits: We assume that the production tax credit (PTC) is taken for solar and wind, and the investment tax credit (ITC) is taken for storage and that utilities opt out of the ITC normalization requirements. We assume a tax credit transferability discount of 5% (for example, the utility sells its tax credits in the transfer market made possible by the IRA for 95 cents on the dollar) and do not assume any bonus adders for domestic content adder or location in energy communities. This is also conservative, as these adders, especially the energy communities adder, will likely apply for some of the projects.

- Utility Financial Metrics: We looked at the latest rate cases, utility proposed capital metrics, and recent balance sheets to identify the utilities' returns on equity (ROE) and the equity ratios. For Alliant, the metrics are a 10% ROE, with a 10.75% ROE for clean projects as approved by the Iowa Utilities Board, and a 52% equity ratio. For Ameren, the metrics are a 10% ROE and 52.37% equity ratio. For corporate debt costs as well as securitization bond rates and EIR loan rates, we calculate forward-looking interest rates based on Treasury yield curves, with appropriate spreads added to the rates based on credit metrics. We calculate that Alliant's forward-looking WACC ranges between 7.5% and 7.9% and Ameren's WACC ranges between 7.6% and 7.7%, when accounting for future interest rates at these utilities' credit ratings. EIR loan rates are 37.5 basis points above Treasury rates, and securitization bonds assume a AAA-rating.
- Securitization Modeling Assumptions: For securitization, we analyze Ameren's proposal of a 15-year bond tenor. We rely on Ameren's given transaction costs of $6.6 million up-front and $792,000 annually. For interest rates, for simplicity, rather than calculating two separate tranches at different tenors as Ameren proposes, we assume a single tranche with a AAA-rated bond and an expected tenor of 15 years.
- EIR Modeling Assumptions: For EIR loans, we assume the maximum tenor allowed under the law, 30 years. We assume full plant balance refinancing for coal plants and analyze EIR as 20% of the capital stack for new clean energy, with the remainder financed through traditional utility financing. This is in fact, conservative, given that EIR can be used to finance up to 80% of project costs and greater leverage of EIR loans would result in even lower costs. Since EIR serves to reduce customer costs, both in the near-term and on an NPV basis, it frees up rate headroom and can make it possible for utilities to pull forward new clean asset deployments. As such, swapping out a portion of utility equity with EIR debt can still leave utility shareholders in an improved position by accelerating practicable opportunities to deploy capital, albeit with slightly more leverage, rather than delaying equity-richer investments into a less certain future. For EIR transaction costs, we look at LPO guidance, which states there is a facility fee of 0.6% of project costs up to $2 billion, and 0.1% after that initial $2 billion in costs. There are also third-party expenses, which range from $1–$3 million, and we use the lower bound of $1 million given these types of transactions, as the due diligence expected is simpler than most Title 17 projects that focus on innovative and emerging technologies. There is an annual maintenance fee of $150,000–$500,000, depending on the complexity (we assume annual maintenance fees of $300,000). Finally, we assume EIR loans are structured as off-balance sheet financings without recourse to the utility's balance sheet.

- Cost Differences: For simplicity, we assume securitization bonds and EIR loans are issued at the beginning of the year, rather than mid-year. Additionally, rather than using utilities' weighted average costs of capital (WACC) as the discount rate for NPV calculations, we use 7%. This is higher than Ameren's stated 6.82% WACC; however, WACCs approved a year ago now face a higher interest rate environment, which raises the cost of borrowing. Still, our analysis comparing securitizing Rush Island and traditional utility financing delivers results very close to what Ameren modeled — we estimate $72 million in savings, while Ameren estimates $75 million in savings. All NPV savings are in 2024 dollars.

*Correction as of February 16, 2024: A previous version of this article incorrectly stated the Clean Project Costs with Utility Financing for Alliant as $591 million, when it is $710 million; and for Ameren as $2.77 billion, when it is $3.82 billion. This has been corrected both in the text and in the EIR Project Cost Comparison graphics.*

## Donate

**Exhibit DG-20:**

**C. Fong, D. Posner, and U. Varadarajan, "Maximizing the value of the energy infrastructure reinvestment program for utility customers," RMI, May 24, 2024**

# MAXIMIZING THE VALUE OF THE ENERGY INFRASTRUCTURE REINVESTMENT PROGRAM FOR UTILITY CUSTOMERS

**"Capital recycling" can help deploy clean energy assets, cushion ratepayer impacts, and offer sustained earnings.**

May 24, 2024

By Christian Fong, David Posner, Uday Varadarajan

## Introduction

Clean energy costs are falling, driven by technological advancements, economies of scale, and federal tax credits that were significantly enhanced and extended by the Inflation Reduction Act (IRA). The most important improvements to the tax credits aim to unlock the benefits of clean energy for the customers of fossil-heavy electric utilities — making it more attractive for these utilities to reinvest in assets that can reduce energy bills and harmful emissions. RMI's recent work on clean repowering suggests that 250 GW of wind, solar, and battery storage assets — equivalent to nearly 20% of the total existing generating capacity of the US power sector — could be built rapidly by sharing existing or retiring fossil plant grid connections without impacting system reliability. This would reduce emissions by 25%, increase utility earnings, and save customers more than $12 billion annually through 2035.

That's good news, but it's only part of a more complicated and less rosy picture. As regulated utilities and their customers look to seize upon attractive clean energy opportunities, they must also manage the legacy of prior investments. Put simply, the transition to clean means passing through a zone of overlapping financial obligations, with the front-loaded capital expenditures of the clean system layered on top of ever-growing costs and risks associated with continued operation of the fossil-intensive system. At a time when Americans are feeling pinched by inflation at just about every turn, bearing the burden of overlapping energy systems is hardly an inviting prospect.

To address this looming burden, the framers of the IRA purposefully created the Energy Infrastructure Reinvestment (EIR) Program to make available up to $250 billion in extremely low-interest federal loans for a cleaner power sector. The question before us is how to maximize the benefits of this massive allocation of taxpayer resources. If utilities do nothing more than use EIR loans to displace corporate debt, overall ratepayer savings will be minimal, since most utilities can already borrow at reasonably attractive interest rates without the added complication and expense of participating in a government program.

However, if utilities and their regulators cooperate to combine more ambitious usage of federal debt with ratemaking strategies that concentrate equity in the financially attractive assets of the clean system, EIR has the potential to deliver substantial rate relief to customers as well as sustained earnings opportunities for shareholders. This win-win approach is called "capital recycling."

This insight brief, which builds on a February RMI article, describes how different EIR implementation choices will impact the financing costs that utility ratepayers will bear over the coming decades. The brief covers:

1. The legacy costs and risks of a fossil-intensive system and the challenges they pose for utility reinvestment in clean energy;
2. How the EIR program can be used to facilitate capital recycling;
3. Quantitative examples of capital recycling using EIR applied to our previously published Missouri and Iowa utility case studies;
4. The transaction costs of EIR lending and securitization; and
5. Compliance with the National Environmental Policy Act, the Davis-Bacon Act, and the Cargo Preference Act, all contingent requirements for federal financing such as EIR.

## 1. Legacy Costs are a Barrier to Utility Reinvestment in Clean Energy

Over the past decade, utilities have been faced with growing amounts of unanticipated costs linked to the operation of their fossil-intensive electricity system — fuel price spikes tied to geopolitical instabilities, environmental controls for legacy assets, conflicting policy mandates simultaneously requiring and preventing accelerated retirement of many of those same assets, and liability and recovery impacts from wildfires and storms supercharged by climate change. This surge in costs has required financing to spread customer impacts over time. Unfortunately, financing the burdens of the past has actually made investment in utility debt and equity riskier and less attractive, even if the capital is used for building clean energy assets whose future costs are extremely predictable and stable.

To understand why this is the case, it helps to start by reviewing how regulated utilities make money. Utilities earn profits by investing capital in electricity infrastructure to serve their customers, whose bills in turn cover the costs of repaying that investment over time ("depreciation and amortization costs") and providing a return to utility investors on any outstanding investment balance (known as the "rate base"). Utilities are also permitted by their regulators to recover unanticipated costs by including them in rate base (as "regulatory assets") rather than passing them through to customers at the same time they are incurred, which could cause rates to spike.

Regulatory assets are repaid in bills relatively quickly — in just 5 to 15 years — in part because utilities worry that regulators in the future may disallow costs that are not directly tied to current service delivery and could in hindsight be deemed imprudent or excessive. We refer to these types of assets as "low-quality" rate base components. This is because they are a lose-lose proposition with unattractive profiles for both utility shareholders (higher risk and rapidly declining earnings) and customers (high annual depreciation and amortization costs associated with shorter recovery periods).

Clean energy assets, on the other hand, are very capital intensive with long recovery periods (usually at least 30 years) and practically no risk of disallowance or early retirement. From the utility earnings perspective, this is rate base of the highest quality. Further, clean energy investments are eligible for tax credits that, as a result of IRA enhancements, can readily be used by utilities to directly offset rate impact.

But while new clean energy assets are ideally suited to enlarge high-quality rate base, they do nothing to remove the shareholder risks and ratepayer costs that derive from low-quality rate base components. These remain until recovery is complete, locking-up scarce ratepayer revenues and negatively impacting the balance sheet financing of new assets by raising a utility's forward-looking borrowing and equity-raising costs.

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## 2. EIR Capital Recycling Can Unlock Clean Utility Reinvestment

But what if utilities and ratepayers could instantly transform low-quality rate base into the high-quality version, improving earnings prospects for investors and extending depreciation and amortization pathways for energy consumers. Imagine, for instance, that long-term, low-interest loans were readily available to utilities and could help free up balance sheet capital to be recycled into wind turbines, solar arrays, and batteries. Ratepayers would see immediate rate relief from lengthier recovery periods and lower carrying charges on refinanced assets, while utilities would benefit from steadier forward-looking pathways for both earnings and rates. Avoiding near-term rate shocks would in turn make it easier for utilities to press the case for more rapid investment in additional clean energy projects to take advantage of IRA tax incentives to reduce energy burdens, meet growing loads, and improve shareholder value. This is the promise of "capital recycling," and the EIR program created by the IRA can help utilities make it a reality.

Overseen by DOE's Loan Programs Office (LPO), the EIR offers lower-cost debt (at an interest rate just 0.375% above US Treasuries of similar tenor). Loan terms as long as 30 years are permissible. At a minimum, this lending can displace slightly higher-cost utility debt. However, with $5 billion in credit subsidy appropriation and authority to make up to $250 billion in loans to cover up to 80% of project costs, it can also allow more leverage than would be achievable using normal financing channels without adversely impacting the borrower's credit rating, thereby displacing not only utility debt but also even more costly utility equity. While utilities and regulators may be wary of allowing leverage on the utility's balance sheet that is higher than the level in the utility's approved capital structure, LPO has the flexibility to lend to off-balance sheet special purpose vehicles (SPVs). Off-balance sheet accounting insulates the utility's capital structure, which means that the EIR debt can be taken on at a higher leverage ratio than the utility's approved capital structure with minimal risk to future private financing.

EIR loans can make accelerated reinvestment in existing utility systems more attractive for both utility customers and shareholders. And since the EIR requires reinvestment with a locational nexus to the assets being replaced or reduced, the loans can also help ensure that energy communities retain jobs and tax base. To the extent that components of energy infrastructure such as interconnection points and transmission capacity can be repurposed, ratepayers will likely benefit from further total cost reductions.

Specifically, a regulated utility can work with DOE and its regulator to use the EIR to implement capital recycling by taking the following five steps:

1. **Identify a reinvestment portfolio that qualifies for the EIR** such as new clean energy projects, grid improvements, or upgrades for existing clean energy infrastructure that meet the requirements to qualify for the EIR program and can complete construction by September 30, 2031.[1]
2. **Request a high-leverage EIR loan** to finance up to 80% of the total costs for the reinvestment portfolio and, if desired, structure part or all of the loan to use an off-balance sheet, bankruptcy-remote SPV to mitigate potential negative credit rating implications.
3. **Introduce a dedicated non-bypassable surcharge for EIR repayment,** which will be separated from base rates on customer bills and cover the cost of repaying the EIR loan to the SPV.
4. **Designate an amount equivalent to some or all of the EIR proceeds for regulatory purposes to recover low-quality rate base.**
    a. As utility financial resources are fungible at the corporate level, regulators may deem funds up to the amount being recovered through the surcharge as providing cost recovery of low-quality rate

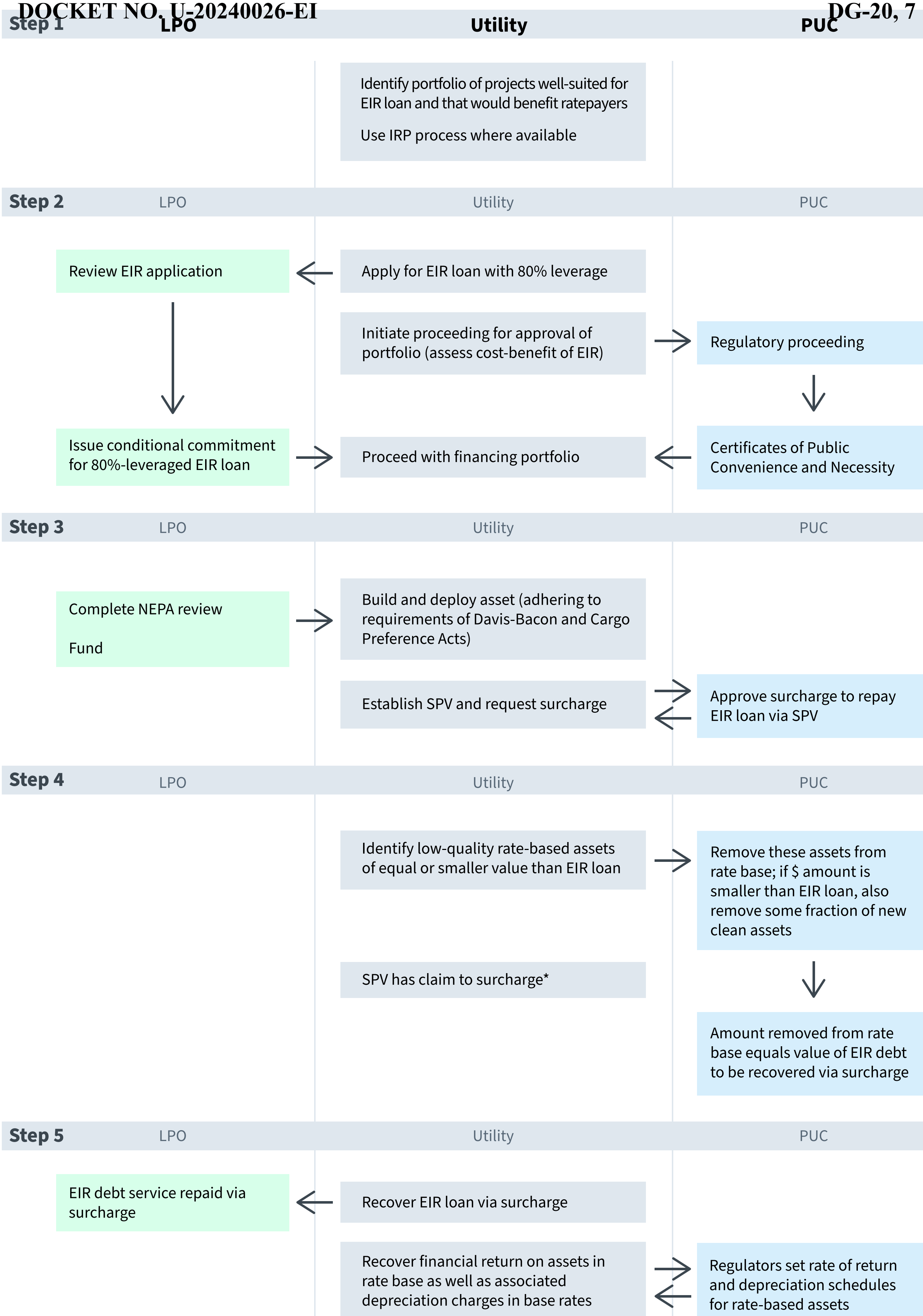
base. This amount no longer needs to be recovered through base tariffs in subsequent rate proceedings.

b. To balance this move, the regulator deems that less of the cost of the new assets is being recovered by the collections flowing to the SPV. An amount equivalent in size to the expunged low-quality rate base is now treated in base rates as if it were high-quality rate base (e.g., clean assets to be recovered over thirty years).

Purely as a matter of regulatory accounting, this intervention effectively allows refinancing of legacy system costs and frees up previously raised shareholder equity for clean portfolio reinvestment. The utility's equity reinvestment risk has been addressed. And the EIR loan repayment has not been compromised in any way.

5. **Assets remaining in rate base are billed to customers at the utility's regulator-approved cost of capital.** Any amount assigned to rate base, including any fraction of the reinvestment portfolio costs that will not be recovered through the surcharge, earns a financial return at the utility's rate of return (calculated including any EIR debt kept on balance sheet).

This approach is possible because steps three through five can be undertaken by a utility with approval from its regulator without impacting the terms and conditions of its loan agreement with DOE. These steps change how costs are recovered but do nothing to impact the ultimate source, amount, or timing of cash flows used by the utility to repay the federal government. Nevertheless, with this approach, the utility, its regulators, and its customers can remove the financial legacy of existing energy infrastructure from the ratemaking equation and focus all stakeholders on a clean energy future, *even though the EIR application is entirely tied to financing a clean reinvestment portfolio and **not** tied in any way to refinancing retired assets.*




***This is not part of rate base**

The driver of customer savings in a capital recycling is still the opportunity to refinance higher-cost utility capital — which generally includes roughly equal shares of debt and equity — with lower-cost EIR debt. These savings will be greatly diminished if utilities and regulators countervail the benefit of increased leverage in future rate proceedings. Effectively, regulators and utilities must chart a course between these two options:

1. **If EIR debt simply serves as a substitute for future corporate debt in the utility capital structure, the benefits of EIR for customers will be small**. This would be the result if regulators and utilities choose to reduce or eliminate future issuances of utility debt to restore the utility's overall debt-to-equity ratio to a level that existed without the EIR. Put simply, EIR debt would be a 1:1 substitute for future utility corporate debt. In practice, this could be achieved by adjusting downward the leverage on future projects, thereby offsetting the smaller deployment of shareholder equity in the EIR project and leaving the long-term capital structure unaffected. This approach effectively reduces ratepayer benefits from EIR debt to just the spread between the total EIR debt and utility corporate debt, net of any additional EIR transaction and compliance costs.
2. **If, however, the utility makes future capital structuring decisions using a leverage ratio that excludes the EIR debt, the benefits can be much greater**. In this case, the utility would accept the higher leverage on the EIR project without demanding any offsetting increase of equity deployed in other projects. This approach would lead to a greater reduction in the total utility cost of capital over the duration of the EIR loan through a lowering of the equity share of the capital stack. Nevertheless, the impacts could be credit neutral or even slightly credit positive as well as being beneficial on a risk-adjusted basis for shareholders, especially if there is
   a. the use of off-balance sheet financing through a bankruptcy-remote SPV and a dedicated surcharge to protect the utility's balance sheet;
   b. an overall increase in high-quality rate base and cash flows tied to utility investment in clean reinvestment projects;
   c. a reduction in overall utility investor risk tied to reduced rate pressure and disallowance risk as a result of shifting utility equity from riskier, low-quality rate base to high-quality clean reinvestment portfolios with attractive, transferable tax credits; and/or

d. greater certainty around, and potential acceleration of, earnings growth and expected cash flows due to more attractive rate impacts increasing the likelihood of regulatory approval for rapid deployment of the clean reinvestment portfolio.

**Utilities and regulators should work together to implement capital recycling and ensure that the full benefit of the higher leverage from EIR debt is not eroded through future ratemaking.** Such an approach would also aid compliance with the statutory requirement that electric utilities applying for an EIR loan provide assurance that financial benefits from the loan guarantee will be passed on to the customers of, or associated communities served by, that utility.

In the case studies that follow, we will show the results of RMI financial modeling that reflects the five steps outlined above. In our modeling scenarios, we implement capital recycling to varying degrees and assess the impacts of undoing the benefits of greater leverage in future rate proceedings. Note that in comparing the shareholder impacts of EIR scenarios with and without capital recycling, we account for the potential of capital recycling to convert low-quality rate base into higher quality rate base. By shifting deployed equity from short-term assets in jeopardy of disallowance to longer-term assets of unassailable prudency, risk-adjusted shareholder earnings will be higher even if the utility accepts the higher leverage EIR loan without an offsetting increase in equity deployment in other areas of rate base.

*[1] There is a statutory requirement to approve loans by the end of September 2026. While applications must be greenlit for funding by this date, loan disbursements and project construction are permissible through September 2031.*

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## 3. Case Studies: Iowa and Missouri

In February 2024, we presented two case studies from Iowa and Missouri to show how utilities could utilize the EIR to save ratepayers money while recovering the costs of retiring coal plants and building new clean energy assets such as wind turbines and solar PV. In those studies, we achieved ratepayer savings in part by increasing the volume of lending requested from the EIR program to cover refinancing of unrecovered coal plant balances (we call this the "refinancing method" to distinguish it from the "capital recycling method").

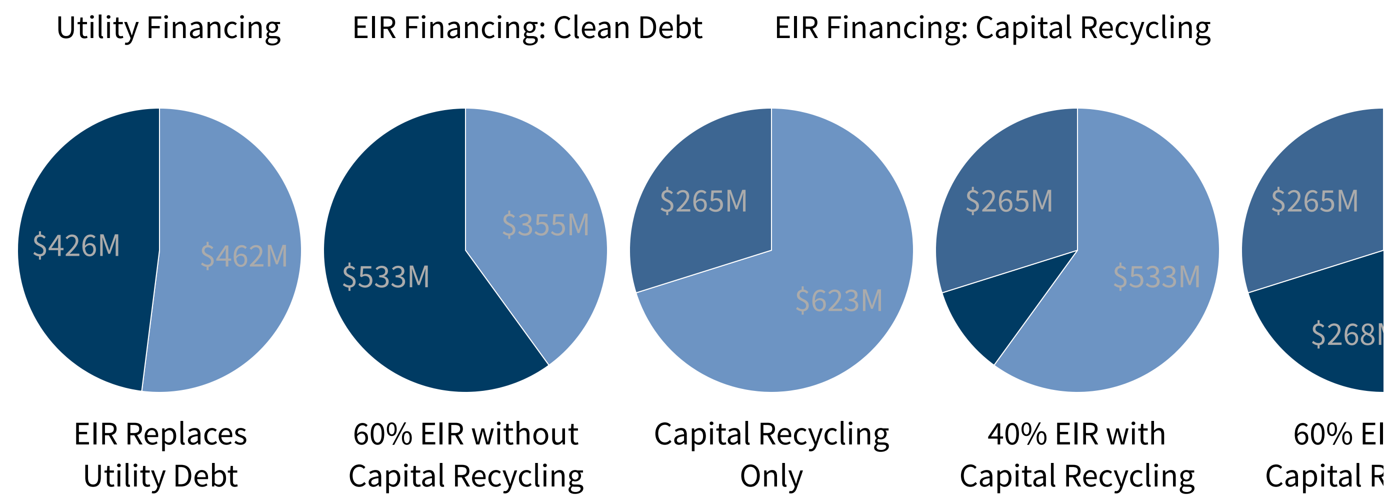
Here, we'll use those same case studies to illustrate the potential benefits of the "capital recycling method." We will also provide additional information concerning transaction costs and compliance requirements that are important to keep in mind when evaluating the feasibility and net benefits of using the EIR. Note that while the "refinancing method" is permissible under statute and can achieve similar outcomes, we believe that the "capital recycling method" outlined in this article is easier for DOE to execute, albeit at the expense of some increase in regulatory complexity at the utility commission level.

## Alliant Iowa

In Iowa, Alliant Energy Corporation is asking to recover the remaining $265 million balance of its Lansing coal plant using a regulatory asset amortized over the plant's previously expected remaining operating life of 13 years. According to Alliant's Clean Energy Blueprint, the utility is also planning to bring 400 MW of solar online in the coming year, along with 99 MW of repowered wind, 28 MW of storage, and 94 MW of solar plus storage by 2030. Alliant has already indicated that it is applying for EIR financing. However, given that the portfolio of projects in the application has not been disclosed, we rely on the company's Clean Energy Blueprint, along with the Lansing unrecovered plant balance. We estimate that the total nominal costs of this portfolio will be $888 million (see *Modeling Appendix* for assumptions).

**Exhibit 1: Alliant EIR Financing Structure Comparison**

Total project costs: $888 million.




*Utilities can apply for up to 80% of eligible project costs with the EIR. All costs here are in nominal dollars.*

**Source:** RMI Analysis • Get the data • Download image

Our financial analysis compares the NPV of costs, first-year costs, and forward earnings impacts of Alliant taking one or more of the steps we outlined in the previous section, including the possibility that EIR financing ultimately only substitutes for future utility debt issuances. Our reference scenario is a business-as-usual scenario.

- **Business as Usual (BAU) –** We estimate the cost of traditional utility financing for full recovery of Lansing and the new portfolio of renewables at $977 million (NPV 2024$), with $271 million coming from the Lansing recovery and $706 million coming from new clean energy. We estimate that the combination of the reinvestment portfolio and Lansing recovery results in three-year forward earnings of $35 million after the full portfolio is deployed in 2029.

We compare this reference point to five EIR scenarios:

- **48% EIR (replaces utility debt), No Capital Recycling –** This is a conservative EIR scenario, in which Alliant obtains just enough EIR financing to displace utility debt in the company's regulator-approved capital structure for its reinvestment portfolio. In this case, EIR debt would provide $426 million of the clean energy portfolio capital stack, while the remaining $462 million would be financed by utility equity. This scenario costs ratepayers $965 million (NPV 2024$), $12 million less than the traditional utility finance reference.

- **60% EIR, High EIR leverage, No Capital Recycling –** Here we assume both a larger EIR loan of $533 million and that any future rate base retains the same pre-approved equity ratio without regard for the increased leverage of the EIR projects. As a result, ratepayer savings would be significant, $217 million (NPV 2024$) less than the traditional utility financing reference point. Savings now also come from displacing some of Alliant's total equity — reducing three-year forward earnings by 63% or $22 million relative to BAU due to foregone equity investment in high-quality rate base. This is a very affordable approach for ratepayers, but it is the least attractive for shareholders both absolutely and on a risk-adjusted basis as it retains low-quality rate base while sacrificing high-quality rate base to leverage.
- **29% EIR, Capital Recycling only –** Alliant could also choose to use low EIR leverage, sufficient only for capital recycling of the Lansing plant — in other words, a loan of $265 million. Unlike in the previous scenarios, we assume that the EIR loan is recovered via a dedicated surcharge. As all utility financial resources are fungible at the corporate level, the regulator deems that, for ratemaking purposes, an amount equivalent to the EIR proceeds to be repaid through the surcharge has provided the utility cost recovery for Lansing. Therefore, in subsequent rate proceedings, Lansing costs would be deemed to be recovered through the dedicated surcharge and would no longer need to be recovered in base rates. Ratepayer savings are $94 million (NPV 2024$) relative to traditional utility financing. The low-quality rate base components are now financed with low-cost EIR debt over thirty years (as opposed to 13 years). As a result of these decisions, Year 1 costs are $63 million — $19 million lower than traditional utility finance and $18 million lower than the scenario with 48% EIR but no capital recycling.
- **40% EIR, Moderate leverage, Capital Recycling –** This capital recycling scenario assumes a larger $355 million EIR loan. The loan is recovered through a dedicated surcharge. For ratemaking purposes, an amount equivalent to the full EIR proceeds is assumed to cover Lansing cost recovery as well as $90 million in utility capital (both debt and equity at the

authorized rate of return) for the reinvestment portfolio. The utility sees net growth of $622 million in rate base. The utility also benefits from having $265 million in relatively short-duration Lansing rate base with uncertain prospects for cost recovery "recycled" into $265 million of longer-duration clean energy rate base. As is the case with securitization, for regulatory purposes, the company's approved capital structure and rate of return are calculated excluding the off-balance sheet EIR debt.

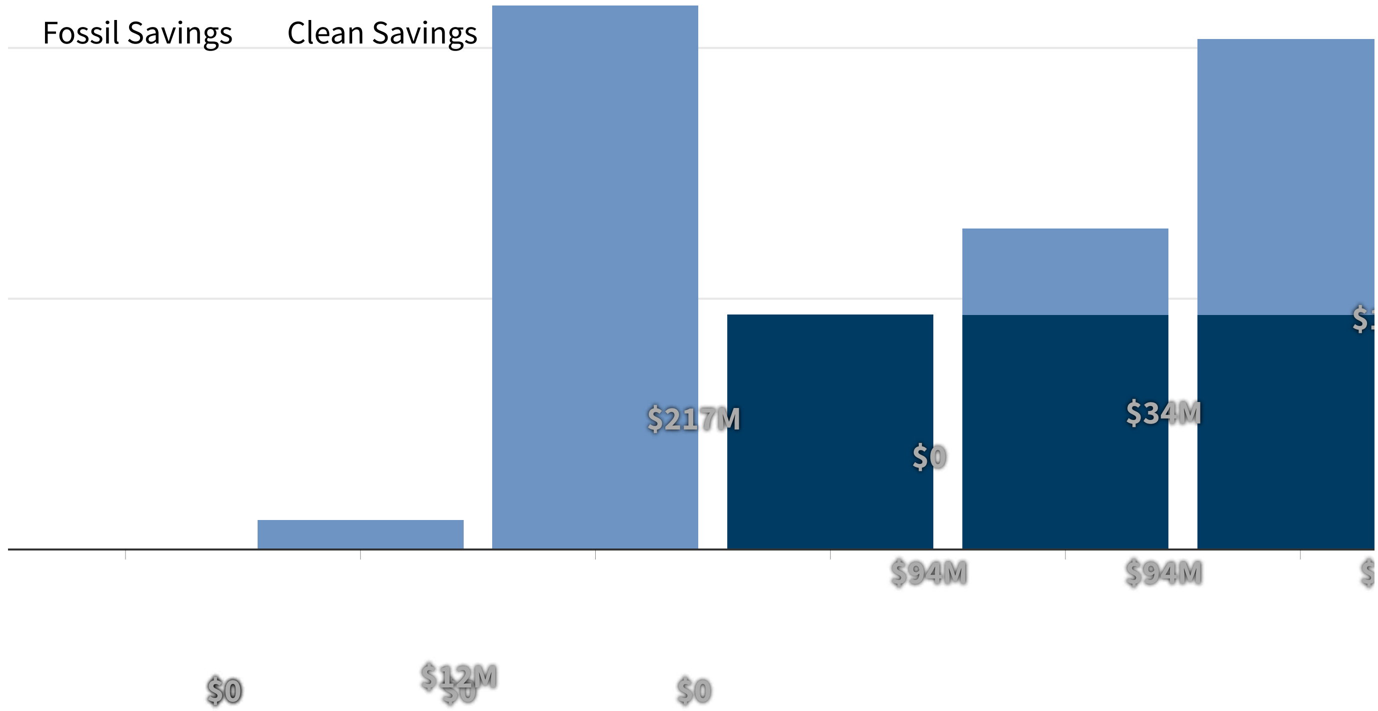
Ratepayer savings are $128 million (NPV 2024$) or 13% lower than BAU. Year 1 costs fall to $59 million, and three-year forward earnings are $25 million, or 72% of the earnings in the BAU scenario. This is an attractive outcome for ratepayers (who benefit from higher leverage across the rate base) and on a risk-adjusted basis for shareholders (who now earn on a rate base comprising only high-quality components).

- **60% EIR, High EIR leverage, Capital Recycling –** This scenario increases the EIR loan size to $533 million. Ratepayer saving grow to $204 million, only slightly below the savings in the 60% leverage scenario without capital recycling. This is the second-worst outcome for shareholders (the worst being the 60% leverage without capital recycling); three-year forward earnings are $18 million.

**Based on this analysis, we find that a scenario that uses capital recycling with moderate EIR leverage offers Alliant the best prospects for balancing the interests of shareholders and customers, providing 13% consumer savings relative to the BAU while delivering 72% of the BAU earnings with lower risk.**

**Exhibit 2: Alliant Savings Comparison**

Savings comparison in NPV 2024$ of traditional utility financing (BAU) vs. various EIR financing l scenarios.




*F... from the Lansing plant as well as savings incurred from the displacement of futu in scenarios where EIR does not impact the utility's equity ratio*

**Source:** RMI Analysis • Get the data • Download image

## Exhibit 3: Summary of Alliant Outcomes

Comparison of how NPV costs, first-year costs, three-year forward looking earnings, and new eq
change depending on how the EIR financing is structured.

| | NPV Costs | First-Year Costs | Three-Year Forward Looking Earnings | New Equity Ratio (Consol-idated) |
|---|---|---|---|---|
| BAU | $977M | $82M | $35M | 52% |
| EIR Replaces Utility Debt | $965M | $81M | $35M | 52% |
| 60% EIR without Capital Recycling | $760M | $58M | $13M | 49% |
| Capital Recycling Only | $883M | $63M | $29M | 50% |
| 40% EIR with Capital Recycling | $849M | $59M | $25M | 50% |
| 60% EIR with Capital Recycling | $773M | $50M | $18M | 49% |

*The colors represent the outcome for ratepayers (NPV Costs and First-Year Costs) and the utility (Three-Year Forward Lookin New Equity Ratio). Green represents the best outcome, followed by yellow, then orange, with red representing the worst ou respective point of view (ratepayers benefit from lower costs; utilities benefit from higher earnings and equity ratios).*

**Source:** RMI Analysis • Get the data • Download image

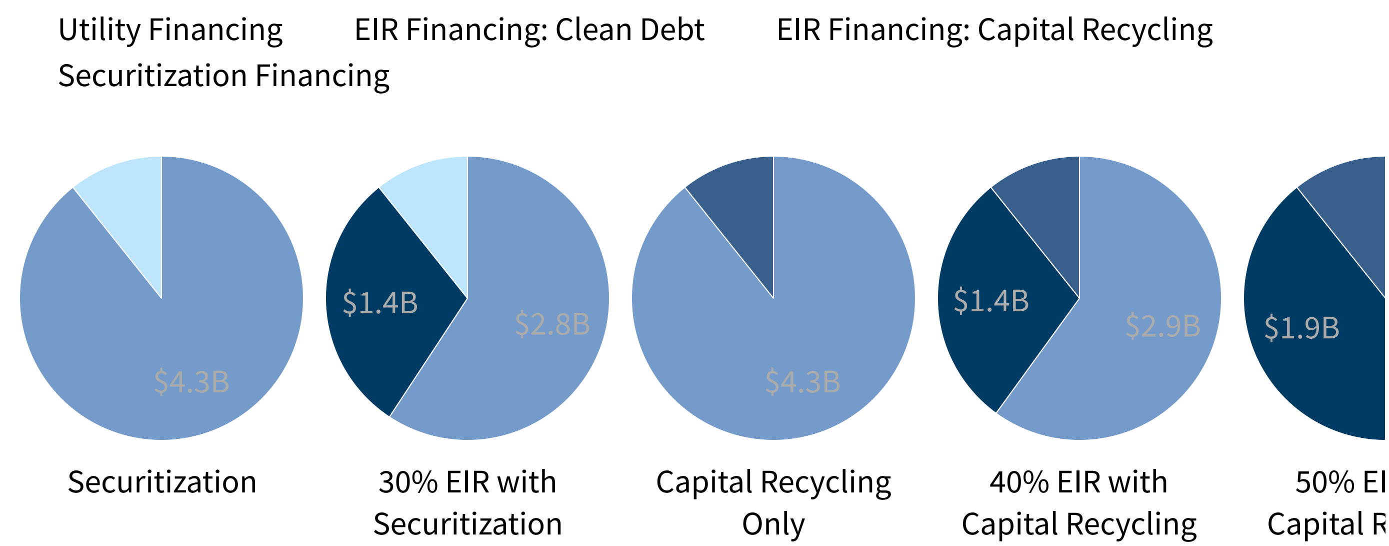
## Ameren Missouri

In Missouri, Ameren is retiring its Rush Island coal plant and seeking to recover $513 million, inclusive of both the remaining plant balance as well as additional decommissioning costs and community transition funding. Ameren has proposed using securitization to achieve recovery of this amount in order to reduce its impact on customers. Securitization is a utility financing mechanism employing highly rated bonds made possible by credit enhancements anchored in state legislation. Securitization is available in several US states, including Missouri; however, most states, Iowa among them, do not have such legislation in place. While securitization is less expensive than traditional utility financing (which includes shareholder equity as well as corporate debt), it is more costly than EIR debt for two reasons. First, securitization transaction expenses are typically larger than those charged by LPO. Second, securitization interest rates are higher than EIR rates, in part because of a 2022 decision by Bloomberg to reclassify these instruments as "asset-backed securities," a move that has reduced the pool of eligible investors and increased interest rates relative to other AAA-rated bonds.

Ameren is also proposing to build 1,800 MW of solar, 1,000 MW of wind, and 400 MW of battery storage by 2030 according to its integrated resource plan (IRP). We estimate that the total nominal costs of this portfolio will be $4.78 billion.

### Exhibit 4: Ameren EIR Financing Structure Comparison

Total project costs: $4.78 billion.




*Utilities can apply for up to 80% of eligible project costs with the EIR. All costs here are in nominal dollars.*

**Source:** RMI Analysis • Get the data • Download image

For Ameren, paralleling what we did for Alliant, we model a BAU, a capital recycling-only scenario, and moderate (40%) and high (50%) leverage EIR scenarios with capital recycling, but we also include securitization scenarios, as this mechanism for the cost recovery of retiring plants is available. We model securitization with a 15-year bond tenor to achieve Rush Island cost recovery, doing so in combination with either full traditional utility financing for new clean assets *or* a low/moderate (30%) leverage EIR loan for new clean assets.

- **Business as Usual –** For our initial reference point, we estimate the cost of traditional utility financing for full recovery of Rush Island and the new portfolio of renewables at $3.9 billion (NPV 2024$), with $529 million coming from Rush Island recovery and $3.4 billion coming from new clean energy.
- **Securitization of Rush Island –** Using state-enabled securitization for cost recovery of the retiring plant while relying on traditional utility finance for the new clean assets lowers the NPV of ratepayer costs to $3.8 billion, around $103 million cheaper than BAU. Year 1 ratepayer costs are $362 million, compared to $381 million in the BAU; the medium-length tenor of the envisioned securitization bonds limits the refinancing benefit. Three-year forward-looking earnings decline to $173 million from $190 million in the BAU, since the utility no longer earns any equity return on Rush Island's low-quality rate base, which has been securitized using AAA-rated bonds with an estimated yield of 5.2%.
- **30% EIR, Low/moderate leverage, Securitization of Rush Island. –** Combining low/moderate leverage EIR financing with securitization decreases the NPV of ratepayer costs to $3.3 billion, around $599 million cheaper than BAU. Year 1 ratepayer costs drop significantly to $294 million, but three-year forward-looking costs also drop to $111 million.
- **11% EIR, Capital Recycling only –** Ameren could also choose to use low EIR leverage, sufficient only for capital recycling of the Rush Island plant — in other words, a loan of $513 million. Unlike in the previous scenarios, we assume that the EIR loan is recovered via a dedicated surcharge. As all utility financial resources are fungible at the corporate level, the regulator deems that, for ratemaking purposes, an amount equivalent to the EIR proceeds to be repaid through the surcharge has provided the utility cost recovery for Rush Island. Therefore, in subsequent rate proceedings, Rush Island costs would be deemed to be recovered through the dedicated surcharge, and no longer need to be recovered in base rates.

  Ratepayer savings are $103 million (NPV 2024$) relative to traditional utility financing. The low-quality rate base components are now financed with low-cost EIR debt over thirty years (as opposed to 13 years). As a result of these decisions, Year 1 costs are $340 million — $41 million lower than the BAU exclusively relying on traditional utility finance and $21 million lower than the approach employing securitization for Rush Island and traditional utility finance for new clean assets.

- **40% EIR, Moderate leverage, Capital Recycling–** This capital recycling scenario assumes a $1.9 billion EIR loan. The loan is recovered through a dedicated surcharge. For ratemaking purposes, an amount equivalent to the full EIR proceeds is assumed to cover Rush Island cost recovery as well as $2.9 billion in utility capital (both debt and equity at the authorized rate of return) for the reinvestment portfolio.

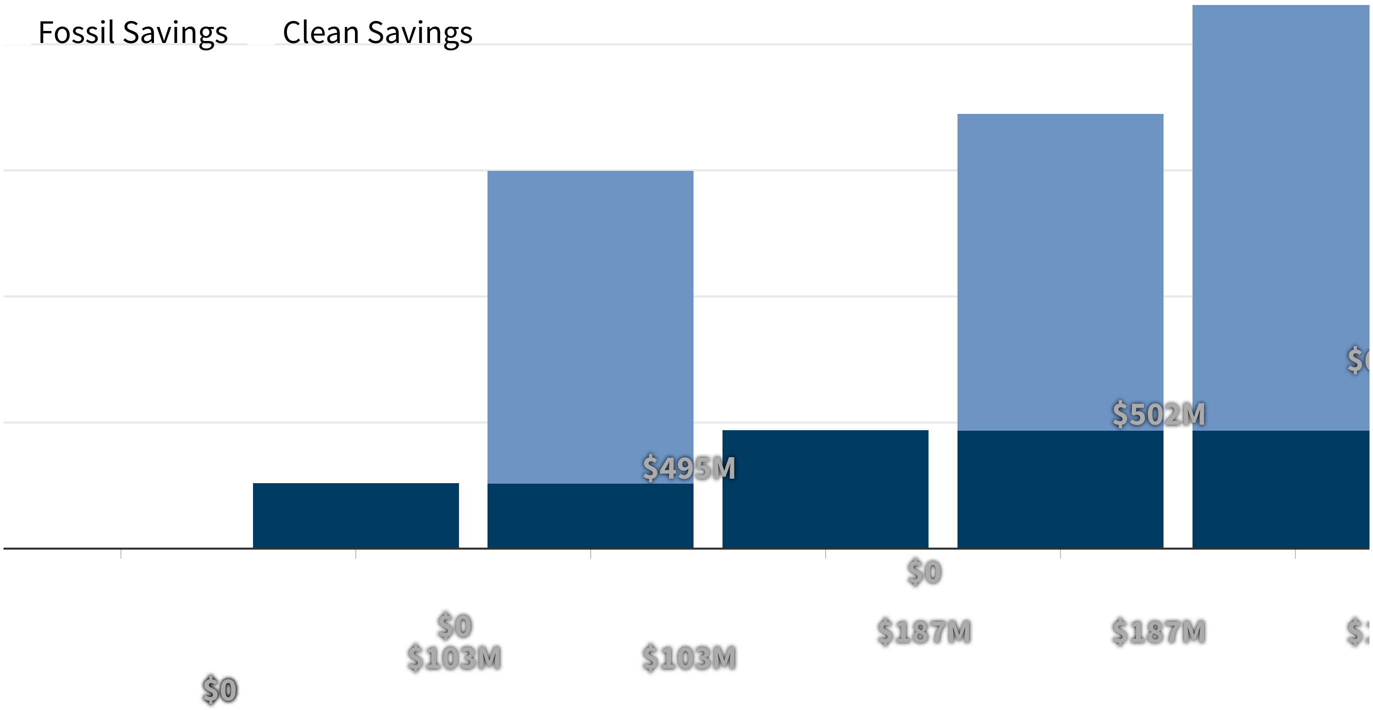
  The utility sees net growth of $2.9 billion in rate base. The utility also benefits from having $513 million in relatively short-duration Rush Island rate base with uncertain prospects for cost recovery "recycled" into $513 million of longer-duration clean energy rate base. As in the case with securitization, for regulatory purposes, the company's approved capital structure and rate of return are calculated excluding the off-balance sheet EIR debt. Ratepayer savings are $689 million (NPV 2024$) or 18% lower than BAU. Year 1 costs fall to $271 million, and three-year forward earnings are $110 million, or 58% of the earnings in the BAU scenario. <u>This is an attractive outcome for ratepayers (who benefit from higher leverage across the rate base) and on a risk-adjusted basis for shareholders (who now earn on a rate base comprising only high-quality components).</u>

- **50% EIR, High leverage, Capital Recycling–** This scenario increases the EIR loan size to $2.4 billion. Ratepayer saving grow to $862 million, the highest savings scenario we analyzed. This is the least attractive outcome for shareholders; three-year forward earnings are $88 million.

**As with Alliant, we find that Ameren can best balance the interests of its customers and shareholders with a scenario that makes use of capital recycling along with moderate EIR leverage, providing 18% consumer savings relative to the BAU while delivering 58% of the BAU earnings with lower risk.** Securitization is still an attractive alternative but has higher transaction costs and has become less attractive due to recent changes to bond indexing that have increased the interest rate on securitization bonds.

### Exhibit 5: Ameren Savings Comparison

Savings comparison in NPV 2024$ of traditional utility financing (BAU) vs. securitization and vari financing leverage scenarios.




s50%EIRwithCapitalRecycling • Download image

### Exhibit 6: Summary of Ameren Outcomes

Comparison of how NPV costs, first-year costs, three-year forward looking earnings, and new eq
change depending on how the EIR financing is structured.

| | NPV Costs | First-Year Costs | Three-Year Forward Looking Earnings | New Equity Ratio (Consol-idated) |
|---|---|---|---|---|
| BAU | $3.9B | $381M | $190M | 52% |
| Securitization | $3.8B | $362M | $173M | 51% |
| 30% EIR with Securitization | $3.3B | $294M | $111M | 46% |
| Capital Recycling Only | $3.7B | $340M | $173M | 51% |
| 40% EIR with Capital Recycling | $3.2B | $271M | $110M | 47% |
| 50% EIR with Capital Recycling | $3.1B | $247M | $88M | 45% |

*The colors represent the outcome for ratepayers (NPV Costs and First-Year Costs) and the utility (Three-Year Forward Lookin New Equity Ratio). Green represents the best outcome, followed by yellow, then orange, with red representing the worst ou respective point of view (ratepayers benefit from lower costs; utilities benefit from higher earnings and equity ratios).*

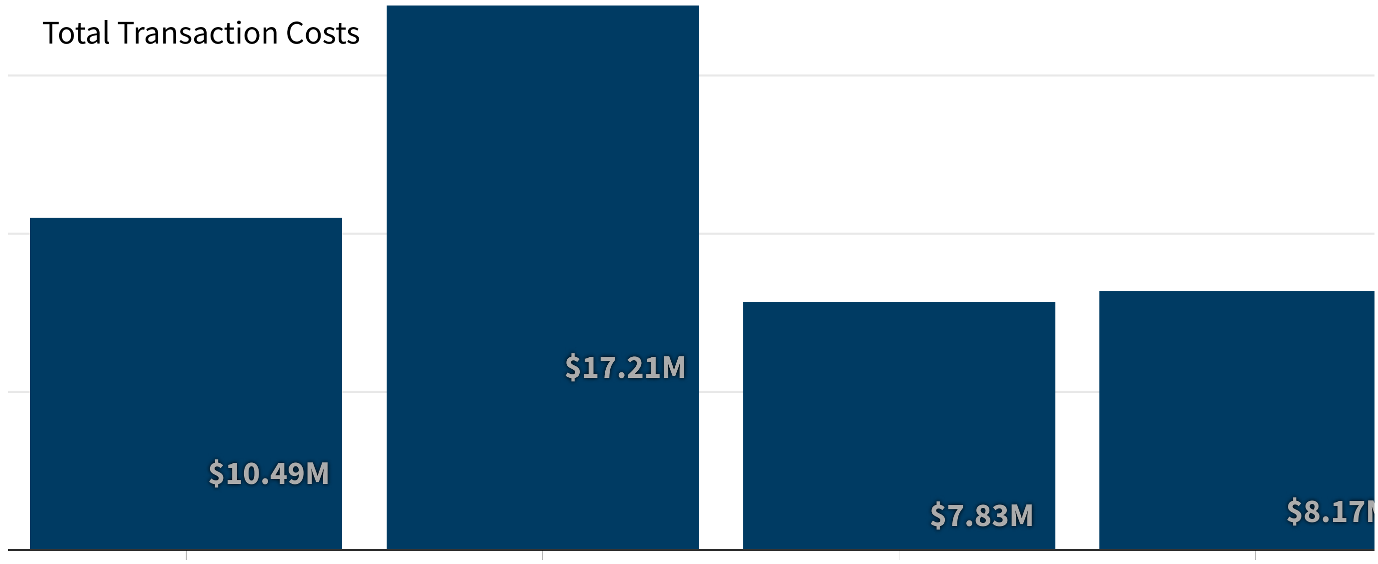
**Source:** RMI Analysis • Get the data • Download image

## 4. Accounting for Transaction Costs

For securitization transaction costs, we relied on Ameren's stated transaction costs of $6.6 million up-front and $792,000 annually. This roughly matches our own experience — our securitization modeling typically assumes $3 million plus 0.7% of the issuance size in up-front transaction costs ($6.6 million total on the $513 million needed for Rush Island), and $300,000 plus 0.05% of the issuance size in annual costs ($556,000).

### Exhibit 7: Ameren Transaction Costs Comparison

Transaction costs comparison in NPV 2024$ of traditional utility financing (BAU) vs. securitizatio various EIR financing leverage scenarios.




50% EIR with Capital Recycling

To estimate EIR transaction costs we referred to LPO guidance, which notes a facility fee of 0.6% of loan principal up to $2 billion and 0.1% thereafter. There are also third-party expenses ranging from $1 million to $4 million; we adopt the lower bound of $1 million, as the due diligence for EIR applications is expected to be simpler than previous Title 17 projects that required innovative and emerging technologies. LPO guides to an annual maintenance fee of between $150,000 and $500,000 depending on complexity; we put these annual fees at $300,000.

The NPV of the transaction costs for securitizing Rush Island is $10.5 million based on Ameren's given numbers. In the scenario where a 30% EIR leverage loan is used for new assets alongside securitization of Rush Island, the NPV of total transaction costs rises to $17.2 million. However, when a moderate leverage 40% EIR loan is used without any securitization, the NPV of total transaction costs is only $7.8 million — a decrease of 55% relative to the 30% EIR leverage plus securitization scenario, while the NPV of ratepayer savings increases by 15% and three-year forward earnings decline by only 1%.

For large EIR loans, the amount exceeding $2 billion is subject to a lower facility fee of 0.1%. If Ameren chooses to utilize 50% EIR leverage and forego securitization, transaction costs are only $8.2 million, a 4% increase over the transaction costs of the 40% EIR scenario, while the NPV of ratepayer savings increases by 25% and three-year forward earnings decline by 20%.

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## 5. Contingent Federal Compliance Requirements: National Environmental Policy Act (NEPA), Davis-Bacon Act, and Cargo Preference Act

We have seen that EIR with capital recycling can be an attractive way for utilities to balance the needs of shareholders and customers, allowing them to mitigate the risks and costs associated with the legacy of their existing system while investing in lower-risk, low-cost, long-term clean assets. However, the use of EIR financing also brings federal compliance requirements that may delay implementation — and must be considered when weighing the potential benefits of using the EIR for capital recycling relative to other options. Here, we provide a brief overview of these challenges and link to resources that can help utilities and regulators better understand how to address them.

### NEPA

EIR-financed projects must comply with the National Environmental Policy Act (NEPA), which can lead to time-consuming and costly reviews to determine if proposed projects will have significant environmental effects. Review under NEPA can occur in three forms:

i. Projects that will "significantly affect the quality of the human environment," require a full Environmental Impact Statement (EIS), which typically takes 1.5 to 2 years to complete.
ii. Projects determined to have no significant impact only require an Environmental Assessment (EA), which typically takes 6 to 9 months.
iii. Categories of projects that have been predetermined not to have a significant effect on the environment require Categorical Exclusions (CATEX) reviews, which typically take only 1 to 3 months.

DOE has issued a proposed rulemaking to make it far easier for many clean energy projects to qualify for CATEX. The proposal would:

i. Modify the categorical exclusion for upgrading and rebuilding existing powerlines (existing CATEX B4.13) to remove a previously imposed requirement that projects be no longer than 20 miles and also to allow "small" (but no longer necessarily "minor") segments to be relocated "within an existing right of way or with otherwise disturbed or developed lands;"
ii. Establish a new categorical exclusion (CATEX B4.14) for the construction, operation, upgrade, or decommissioning of battery or flywheel energy storage system "within a previously disturbed or developed area or within a small area contiguous to a previously disturbed or developed area;" and
iii. Modify the categorical exclusion for the installation, modification, operation, and removal of solar photovoltaic systems (existing CATEX B5.16) "on a building or other structure or, if located on land, within a previously disturbed or developed area" to remove the current area limitation of 10 acres and also to cover "decommissioning" activities.

For EIR loan disbursement to take place, projects with a value at or exceeding the amount of the disbursement must have demonstrated NEPA compliance. Ameren Missouri aims to retire Rush Island in late 2024; EIR clean energy projects that qualify for CATEXes or EAs could be ready for EIR funding at that same time. Environmental consultants experienced with NEPA reviews could help applicants navigate the NEPA process and properly determine which clean energy projects would be subject to which types of NEPA reviews — and ensure robust documentation of potential project impacts to reduce the risk of successful litigation of DOE's NEPA decision. EIR applicants can further mitigate potential risks of delay due to litigation (particularly, in rare cases, the issuance of an injunction halting project construction) by incorporating robust community engagement around potential project impacts in developing their community benefits plans, an important requirement for all loan applicants.

## The Davis-Bacon Act and the Cargo Preference Act

The Davis-Bacon Act imposes certain wage requirements on contractors or subcontractors working on projects financed by LPO. The IRA itself is not a Davis-Bacon-related act, but the IRA clean energy tax credits do require that workers be paid prevailing wages no less than wages determined by the Department of Labor for compliance with the Davis-Bacon Act or, failing the payment of such wages, to have the credit values divided by a factor of five. Full Davis-Bacon Act compliance, which is necessary for EIR lending, entails additional recordkeeping beyond what is needed to obtain IRA tax credits without the factor of five haircut, though these incremental administrative costs are likely to be small relative to the impact of the wage boost.

The Cargo Preference Act requires the use of US-flag vessels to ship cargo financed by the US government. For the purposes of LPO, this typically means that at least 50% of gross tonnage must be shipped on US-flag ships.

Entities applying for LPO financing are required to include cost assumptions of complying with the Davis-Bacon Act and Cargo Preference Act in their Part 2 applications.

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## Modeling Appendix

- Clean Portfolios: We look at the latest IRPs for Alliant and Ameren. Specific deployment dates and costs are not publicly available for all resources, so we have made simplifying assumptions for modeling purposes. We assume clean technologies are deployed in the single earliest year, which is a very conservative assumption that would overestimate costs due to technological cost declines. Specifically, for Alliant, because exact deployment dates were not available for all resources, we assume 459 MW of solar and 99 MW of repowered wind come into service by the end of 2024, and that 63 MW of storage comes into service by the end of 2029. For Ameren, we conservatively assume that all clean technologies are built in the same year, with 1,800 MW of solar in 2025, 1,000 MW of wind in 2026, and 400 MW of storage in 2027. In reality, Ameren will spread this deployment over later dates, and these costs would be lower due to technological cost declines. We use NREL's 2023 annual technology baseline for resource costs, utilizing moderate learning curves over a 30-year cost recovery period.

- Tax Credits: We assume that the production tax credit is taken for solar and wind, and the investment tax credit (ITC) is taken for storage and that utilities opt out of the ITC normalization requirements. We assume a tax credit transferability discount of 5% (for example, the utility sells its tax credits in the transfer market made possible by the IRA for 95 cents on the dollar) and do not assume any bonus adders for domestic content adder or location in energy communities. This no-adder assumption is also conservative, as it is likely that the energy communities adder will apply for some of the projects.

- Utility Financial Metrics: We relied on the latest Alliant and Ameren rate cases and the companies' recent balance sheets to identify the utilities' returns on equity (ROE) and the equity ratios. For Alliant, the metrics are a 10% ROE, with a 10.75% ROE for clean projects as approved by the Iowa Utilities Board, and a 52% equity ratio. For Ameren, the metrics are a 10% ROE and 52.37% equity ratio. For corporate debt costs as well as securitization bond rates and EIR loan rates, we calculate forward-looking interest rates based on Treasury yield curves, with appropriate spreads added to the rates based on credit metrics. We calculate that Alliant's forward-looking weighted average cost of capital (WACC) ranges between 7.5% and 7.9% and Ameren's WACC ranges between 7.6% and 7.7%, when accounting for future interest rates at these utilities' credit ratings. EIR loan rates are 37.5 basis points above Treasury rates, and securitization bonds assume a AAA-rating.

- Securitization Modeling Assumptions: For securitization, we analyze Ameren's proposal of a 15-year bond tenor. For interest rates, for simplicity, rather than calculating two separate tranches at different tenors as Ameren proposes, we assume a single tranche with a AAA-rated bond and an expected tenor of 15 years.

- EIR Modeling Assumptions: For EIR loans, we assume the maximum tenor allowed under the law, 30 years. We assume as a baseline EIR financing equivalent to the debt ratio of the utility for new clean energy. For capital recycling scenarios, additional EIR financing equivalent to the unrecovered plant balance of the identified retiring coal plants is assumed to finance the recovery of the coal plant balance, and the remainder of EIR financing goes toward the new clean assets. We also look at what happens when that additional debt displaces future corporate debt, as well as what happens when it does not, and thus alters the utility's approved equity ratio. For the scenarios that do not alter a utility's equity ratio, we estimate that the additional savings are achieved through displacing future corporate debt. The remainder of required capital is modeled as traditional utility financing. Since EIR serves to reduce customer costs, both in the near term and on an NPV basis, it frees up rate headroom and can make it possible for utilities to pull forward new clean asset deployments. As such, swapping out a portion of utility equity with EIR debt can still leave utility shareholders in an improved position by accelerating practicable opportunities to deploy capital, albeit with slightly more leverage, rather than delaying equity-richer investments into a less certain future. Finally, we assume EIR loans are structured as off-balance sheet financings for capital recycling scenarios without recourse to the utility's balance sheet.

- Cost Differences: For simplicity, we assume securitization bonds and EIR loans are issued at the beginning of the year, rather than mid-year. Additionally, rather than using utilities' WACC as the discount rate for NPV calculations, we use 7%. This is higher than Ameren's stated 6.82% WACC; however, WACCs approved a year ago now face a higher interest rate environment, which raises the cost of borrowing. Still, our analysis comparing securitizing Rush Island and traditional utility financing delivers results close to what Ameren modeled — we estimate $103 million in savings, while Ameren estimates $75 million in savings. All NPV savings are in 2024 dollars.

**CERTIFICATE OF SERVICE**

I hereby certify that a true and correct copy of the foregoing has been furnished by electronic mail on this 6th day of June, 2024, to the following:

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