DIRECT TESTIMONY OF

**AARON P. ABRAMOVITZ, SARAH P. ADAMS, ADAM D. HOUSTON,**

**AND MICHAEL B. ROBINSON**

**ON BEHALF OF**

**GEORGIA POWER COMPANY**

**DOCKET NO. 44280**

1. INTRODUCTION

**Q. Please state your names, titles, and business addresses.**

A. Aaron P. Abramovitz. I am the Executive Vice President, Chief Financial Officer, and Treasurer for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. Sarah P. Adams. I am the Vice President and Comptroller for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. Adam D. Houston. I am the Assistant Comptroller for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. Michael B. Robinson. I am the Vice President of Planning, Operations and Policy for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

**Q. Mr. Abramovitz, please summarize your education and professional experience.**

A. I graduated from the University of Georgia with a Bachelor of Business Administration in Finance and Management Information Systems. I joined Southern Company as a contractor in the Financial Strategy and Decision Support organization. This was followed by a series of Financial Analyst roles in various disciplines that included Financial Planning, Financial Analysis, and Regulatory Support. From there I transitioned to Georgia Power to serve as the Coordinator for Forestry and Right of Way services. In 2008, I was assigned to the Kemper Project in Mississippi, where I served in financial leadership roles of increasing responsibility, eventually serving as the Project’s Finance Director, where I was responsible for governance, reporting, regulatory support, and communications to Executives and the Board of Directors. In 2015, I returned to Atlanta to serve as the Director of Investor Relations for Southern Company, where I was responsible for Southern Company’s communications and relationships with the investment community. In 2018, I was named the Southern Nuclear Vogtle 3 and 4 Vice President of Business Operations. In this role, I had responsibility for Southern Nuclear’s Project Controls, Risk Management, Budgeting and Reporting, and Commercial Analysis & Controls. I moved to my current role as Executive Vice President, Chief Financial Officer, and Treasurer for Georgia Power in September 2021. I now oversee all accounting and finance functions for the Company including financial reporting, regulatory accounting, financial planning, analysis, and enterprise risk management.

**Q. Mr. Abramovitz, have you previously testified before the Georgia Public Service Commission (“Commission”)?**

A. Yes. I testified in the Vogtle Construction Monitoring proceeding, Docket No. 29849, regarding the Nineteenth, Twentieth/Twenty-first, Twenty-second, Twenty-third, and Twenty-fourth Semi-annual Reports and the Plant Vogtle Unit 3 and Common Rate Adjustment proceeding in Docket No. 43838 (“Plant Vogtle Unit 3 and Common Rate Adjustment”).

**Q. Ms. Adams, please summarize your education and professional experience.**

A. I graduated from the University of Georgia in 1993 with a Bachelor of Science in Middle School Education and in 1998 with a Master of Accountancy degree. I began my professional accounting career with Arthur Andersen, LLP in Atlanta as an auditor primarily serving Southern Company. From 2002 to 2003, I served as senior financial analyst at Mirant Corporation. In 2003, I joined Southern Company and held several leadership positions in the Southern Company Generation and Southern Power Company organizations. In 2011, I joined Georgia Power as the manager of fuel and bulk power accounting and led several departments, including internal controls and compliance, corporate secretary support, and accounting and finance operations before being elected to Assistant Comptroller in 2017. In 2020, I was promoted to Vice President and Comptroller where I am responsible for the financial and regulatory functions of Georgia Power and manage and oversee accounting research, preparation of financial statements, and regulatory accounting filings with the Securities and Exchange Commission (“SEC”), Federal Energy Regulatory Commission (“FERC”), and Commission. I am a Certified Public Accountant licensed in Georgia.

**Q. Ms. Adams, have you previously testified before the Commission?**

A. Yes, I testified before this Commission regarding Georgia Power’s 2019 base rate case in Docket No. 42516 (“2019 base rate case”). I also testified in the Company’s Fuel Cost Recovery proceeding in Docket No. 43011 and the Plant Vogtle Unit 3 and Common Rate Adjustment proceeding.

**Q. Mr. Houston, please summarize your education and professional experience.**

A. I graduated from Victoria University of Wellington, New Zealand in 1995 with a Bachelor of Commerce and Administration in Economics and Finance. I began my professional accounting career with Arthur Andersen, LLP in Wellington as an Associate performing audits for multinational and local clients. From 2002, I worked for PricewaterhouseCoopers, LLP in Los Angeles and Chicago specializing in Power and Utility audits across the United States, including Exelon utility subsidiaries, PHI Holdings and AGL Resources Inc. In 2017, I joined Southern Power Company (“Southern Power”) as the Assistant Comptroller responsible for accounting research, accounts payable, and internal controls and compliance. While at Southern Power, I was also given responsibility for financial accounting and reporting, and property accounting. In 2021, I joined Georgia Power as the Assistant Comptroller responsible for financial accounting and reporting, regulatory accounting (including fuel), and accounting research. I am a Chartered Accountant member of the Chartered Accountants Australia and New Zealand.

**Q.** **Mr. Houston, have you previously testified before the Commission?**

A. No, I have not previously testified before the Commission.

**Q.**  **Mr. Robinson, please summarize your education and professional experience.**

A. I graduated from Auburn University in 1993 with a Bachelor of Electrical Engineering. I began my career as a cooperative education student with Georgia Power working in distribution and marketing. After leaving the Company to serve in the United States Navy, I worked for an electric municipality in Texas, the Kerrville Public Utility Board, for five years where I was responsible for all distribution and substation facilities. In 1999, I returned to Southern Company as an engineer on the Enhanced Power Quality team with Alabama Power. Throughout my career at Southern Company, I have served in a variety of positions, including: principal engineer in Transmission Planning; supervisor of the transmission maintenance center in Albany, Georgia; supervisor of the transmission control center in Valdosta, Georgia; transmission planning manager; South Georgia area transmission manager; Metro South distribution manager; and general manager of Transmission Planning and Operations.

From 2017 through 2020, I served as the Power Delivery Operations General Manager for Georgia Power. I began my current role as Planning, Operations, and Policy Vice President in 2021. I lead a team of 425 employees that consists of Project Management, Planning and Policy, Systems and Standards, Storm Center operations, Transmission and Distribution Operations, and North American Electric Reliability Corporation (“NERC”) Compliance. This team is responsible for the planning and operation of 75,000 miles of distribution lines, 17,000 miles of transmission lines, and over 2,000 substations statewide.

**Q.** **Have you previously testified before the Commission?**

A. Yes, I testified before this Commission in Georgia Power’s 2019 base rate case in Docket No. 42516 and in Georgia Power’s 2022 Integrated Resource Plan (“IRP”) in Docket No. 44160.

**Q. What is the purpose of your testimony?**

A. The purpose of our testimony is to support the Company’s filing in this docket, including the calculation of the test period revenue requirement. The Company files this base rate case in accordance with the Commission’s Final Order in Docket No. 42516, which required that the Company file a base rate case by July 1, 2022, so that the Commission may consider whether to continue, modify, or discontinue the rate plan established in the 2019 base rate case. In our testimony, we demonstrate and explain how the Company’s revenues under current rates are insufficient to cover the Company’s increasing cost of service and we propose an Alternate Rate Plan (“ARP”) similar to the ARPs Georgia Power has had in place since 1995. Our testimony will also discuss the continuation of the Coal Combustion Residuals (“CCR”) Asset Retirement Obligation (“ARO”) recovery method and Grid Investment Plan that were both approved in the 2019 base rate case.

**Q. Please summarize the Company’s request in this case.**

A. The base rates established by the Commission’s final order in the Company’s 2019 base rate case and revised through the 2021 and 2022 compliance filings (collectively the “2019 base rate case Order”) are no longer sufficient for the Company to recover the costs necessary to provide our customers with the clean, safe and reliable electric service they expect.

The Company requests an increase to base rates, on a levelized basis, of $852 million in 2023, and additional step increases of $107 million in 2024, and $45 million in 2025. This requested rate adjustment will help ensure that Georgia Power remains positioned to continue meeting the energy needs of our customers and the communities we serve.

Since the approval of the 2019 base rate case and through the end of 2022, the Company expects to have invested approximately $8.6 billion on behalf of our customers, which includes investments that support enhanced reliability and resiliency in the electric grid, transitioning the Company’s generation fleet to more economical and cleaner resources, technology to enhance operations and our customers’ experience, and compliance with state and federal environmental regulations.

The Company’s ARP request in this case is a continuation of items approved in the 2019 base rate case and includes considerations for:

* The recovery of both the necessary capital investments in the electric grid the Company has made since 2019 and investments that are expected to be made over the next three years, as well as updates to the corresponding depreciation rates. These investments primarily relate to the Company’s transmission and distribution systems and the continuation of the previously approved Grid Investment Plan.
* The need to continue transitioning the Company’s generation fleet to more economical and cleaner resources, including renewables, with a proposed deferred recovery of a portion of depreciation expense associated with the generating units that the Company proposes retiring after 2025 as set-forth in the 2022 IRP.
* Timely recovery of the costs needed to comply with federal and state regulations for CCR ARO.
* Decreasing operations and maintenance (“O&M”) costs driven by a reduced storm damage accrual, lower costs for employee benefits, and continued focus on effective cost management throughout the business.
* Full recognition and return of certain benefits to customers from the Tax Cuts and Jobs Act of 2017 (“TCJA”).
* An 11% Return on Equity (“ROE”) and a retail capital structure of 56% equity and 44% debt that maintain the Company’s financial integrity and ensure its ability to raise capital at reasonable cost and upon reasonable terms for the benefit of customers.
* The recent significant levels of inflation impacting our cost of providing electric service.
* Establishing amortization periods for the following regulatory assets: (1) net book value for Wansley Units 1, 2, 5A, and Plant Boulevard Unit 1, (2) software and cloud computing costs, (3) incremental COVID-19 costs, and (4) customer hourly usage data costs.

**Q.** **How is your testimony organized?**

A.The remainder of our testimony is organized as follows:

* Section II (pages 9 to 14) provides an overview of the Company’s request.
* Section III (pages 14 to 21) provides a summary of the key cost drivers affecting the rate request.
* Section IV (pages 22 to 27) describes the ARP.
* Section V (pages 27 to 31) discusses various tariffs, including the Environmental Compliance Cost Recovery (“ECCR”), Demand Side Management (“DSM”) and Municipal Franchise Fee (“MFF”) Tariffs.
* Section VI (pages 31 to 35) discusses forecasted revenue requirements for both the statutory test period and the three-year proposed ARP.
* Section VII (pages 35 to 47) summarizes projections for the test period ending July 31, 2023.
* Section VIII (pages 47 to 49) discusses the 2022 IRP.
* Section IX (pages 49 to 53) discusses the Grid Investment Plan.
* Section X (pages 53 to 54) discusses taxes.
* Section XI (page 54) provides a discussion of wholesale sales.
* Section XII (pages 55 to 56) discusses working capital requirements.

1. OVERVIEW OF THE COMPANY’S REQUEST

**Q.** **Please explain the Company’s request in this case.**

A. The Company requests continuation of the three-year ARP with a levelized rate increase taking effect on January 1, 2023, combined with two annual step increases for specific cost components during the second and third years of the ARP. As shown in Table 1 below, the Company requests increases of $852 million, $107 million, and $45 million to become effective January 1, 2023, January 1, 2024, and January 1, 2025, respectively.

**Table 1: Proposed Rate Adjustments (in millions)**[[1]](#footnote-2)

*Amounts may not sum to total due to rounding*

|  |  |  |  |
| --- | --- | --- | --- |
| Effective Date | **January 1, 2023** | **January 1, 2024** | **January 1, 2025** |
| Traditional Base | $739 | $0 | $0 |
| ECCR |  |  |  |
| ECCR Traditional | (1) | 0 | 0 |
| ECCR CCR ARO\* | 64 | 78 | 47 |
| DSM\* | 30 | 27 | (2) |
| MFF | 20 | 2 | 1 |
| **Total** | **$852** | **$107** | **$45** |

\*As determined by the Commission through annual CCR ARO and DSM Compliance filings.

The proposed rate adjustment includes a levelized increase of $739 million for traditional base rates and a levelized decrease of $1 million for the traditional costs of the ECCR tariff effective January 1, 2023. As directed by the Commission, the Company’s base rates will be separately adjusted to account for the cost recovery of Plant Vogtle Units 3 and 4 per Docket No. 43838 and following the prudence review as provided in the Vogtle VCM 17 Order.

For each year 2023 through 2025, the Company requests recovery of CCR ARO compliance costs through annual increases in the ECCR tariff through required annual compliance filings, which is consistent with the methodology approved by the Commission in the 2019 base rate case. Therefore, the CCR ARO compliance costs are not included in the proposed levelized ECCR tariff amount over the three-year period, as the Company will continue to submit annual compliance filings to capture actual and revised projected CCR ARO compliance costs for recovery.

Similarly, the DSM tariffs will be adjusted annually to collect the Commission-approved DSM costs addressed in Georgia Power’s DSM certification proceeding in Docket No. 44161 (“2022 DSM Certification”). The Company will also continue the true-up of actual revenues collected and expenses incurred under the DSM tariffs through required annual compliance filings. Therefore, like the CCR ARO compliance costs, the proposed costs to be recovered through the DSM tariffs are not levelized over the three-year period.

The annual changes in the ECCR and DSM tariffs will have a corresponding effect on the MFF tariffs in 2024 and 2025. Accordingly, the MFF tariff will be adjusted to capture the increase in the tariffs discussed above and updated to incorporate any change in percentage of revenues collected from inside municipalities. Consistent with the current MFF tariff, the MFF tariff may be modified during the term of the proposed ARP to account for incorporation of any new municipalities.

As shown in Table 1, the Company’s 2023 requested rate increase totals $852million. This represents a change of 10.2% to the Company’s current retail rates and will result in an increase of approximately $14.32 to the monthly bill of a typical residential customer using an average of 1,000 kWh per month.

As further shown in Table 1, the requested rate increases for 2024 and 2025 are $107 million and $45 million, respectively. These represent the combination of expected increases from three tariffs: the (1) ECCR tariff (for projected incremental CCR ARO compliance costs); (2) DSM tariff; and (3) MFF tariff. These changes represent increases to retail rates of 1.2% in 2024 and 0.5% in 2025 and will result in increases of approximately $1.35 in 2024 and $0.62 in 2025 to the monthly bill of a typical residential customer using an average of 1,000 kWh per month.

In total, over the three-year period, the requested rate increase totals $1,004 million representing a change of 11.9% to the Company’s current retail rates and will result in an increase of approximately $16.29 to the monthly bill of a typical residential customer using an average of 1,000 kWh per month.

**Q.** **How does this rate request support the financial needs, credit quality, and overall financial integrity of Georgia Power?**

A. The current economic environment is challenging and volatile considering global economic challenges in recent years, the ongoing COVID-19 pandemic, the elevated inflationary environment, and uncertain market and worldwide geopolitical conditions. Given the challenges in the economic environment, the Company must maintain its financial integrity to effectively navigate and respond to both recent and future economic challenges to support both fair terms on and access to capital for the benefit of our customers.

Approval of the cost of equity and capital structure as supported by Mr. Coyne in his direct pre-filed testimony will provide an appropriate capital structure, a fair rate of return on the Company’s investments, and recovery of prudently incurred costs, which will help ensure that Georgia Power maintains the financial integrity needed to operate a reliable electric system and meet the energy needs of our customers.

Moreover, as discussed in Mr. Fetter's direct pre-filed testimony, the financial community views strong credit ratings as a measure of financial integrity. Accordingly, a utility’s credit ratings are central to its ability to raise capital at a reasonable cost and upon reasonable terms.

As Mr. Fetter further notes, regulation is a key qualitative component of a utility’s credit ratings, and Georgia’s demonstrated constructive regulatory environment is viewed by the financial community or market as among the most credit supportive states. This long-standing constructive and credit supportive environment is a very positive factor in the credit ratings assigned to this state’s regulated utilities.

**Q.** **Why is an appropriate capital structure critical to the financial health of the Company?**

A. Sufficient equity in the capital structure is a critical factor for maintaining Georgia Power’s financial integrity and investment grade credit rating and is an essential component of Georgia Power’s financial practices enabling access to capital on favorable terms in a variety of market circumstances. The Commission previously recognized Georgia Power’s need for, and the benefits of, a strong capital structure when it approved the current ratio of 56% equity and 44% debt. The Company requests that the Commission continue the currently approved capital structure, which supports the Company’s overall financial health and continued access to capital markets at reasonable rates and terms.

**Q.**  **HOW DOES the ROE band CONTRIBUTE to the financial health of the Company?**

A. Establishment of a reasonable ROE band allows the Company flexibility to conduct business and manage risk under a variety of economic and operational conditions during the three-year ARP period. The Company is proposing to continue the ROE band of 9.5%-12.0%, which was approved by the Commission in the 2019 base rate case. The earnings band defines a reasonable range of return within which the Company is allowed to earn. Earnings below this band could indicate a rate adjustment is necessary, whereas earnings above this band would trigger the sharing mechanism whereby 80% of the excess earnings above 12.0% is returned to benefit customers. The sharing mechanism provides direct financial benefits to Georgia Power customers. Since 2013, customers have received the benefit of approximately $297 million through the sharing mechanisms.

**Q.** **WHY IS IT VITAL FOR THE COMPANY TO HAVE THE ABILITY TO ACCESS capital markets UNDER A VARIETY OF MARKET CONDITIONS?**

A. Like most electric utilities, Georgia Power’s operations are extremely capital intensive and our credit rating is fundamental to how the Company accesses liquidity. In times of strained economic market conditions, our ability to access needed capital directly correlates to our credit ratings. For example, in the span of roughly one decade, there have been two acute economic disruptions that have highlighted the need for strong credit ratings. During the 2008-2009 financial crisis, and also during the onset of the COVID-19 pandemic, our economy experienced a severe tightening of credit. Lending institutions reduced the amount of credit supply and tightened lending standards. This meant that only the highest-rated companies enjoyed access to the constrained supply of debt capital. For certain companies with lower credit ratings, this simply meant a delay of non-critical business expansion and investment. For utilities, like ours, that provide customers with critical, continuous and essential services, the restricted credit markets were more threatening. In both of these historic, highly uncertain, and volatile financial instances, Georgia Power’s strong credit history and financial integrity allowed the Company to navigate through those threatening economic events. In order for the Company to safely and reliably provide electric service to our 2.7 million customers across the state, substantial utility infrastructure is necessary. Accordingly, we rely heavily on access to both debt and equity capital markets to conduct the construction activities that are essential to operating our business. Approval of the Company’s rate request will help ensure that we continue to have the ability to access capital markets to support these critical activities, and to continue providing reliable electric service to Georgia’s communities.

III. KEY DRIVERS OF THE COMPANY’S PROPOSED LEVELIZED REVENUE REQUIREMENT INCREASE

**Q.** **Please provide additional details regarding the key drivers of the Company’s LEVELIZED 2023-2025 INCREASE to its revenue requirement.**

A. The chart below illustrates the primary drivers of the Company’s proposed 2023-2025 levelized increase to its revenue requirement of $1,004 million, with each block identifying the amount by which the costs associated with a particular driver are projected to increase or decrease relative to costs included in 2022 rates.

**Chart 1: Drivers Impacting the 2023-2025 Levelized Revenue Requirement**



Additional details regarding each of these key cost drivers of the Company’s rate request are provided below:

* **Transmission and Distribution Reliability and Resiliency:** Over the last three years, the Company has made significant investments in its transmission and distribution infrastructure across the state. These investments were necessary to maintain safe and reliable electric service and expand our power delivery system to accommodate customer growth and development in the communities we serve. Over the next three years, to further enhance the reliability and resiliency of the system and accommodate projected customer growth, the Company must continue investing in the electric grid, including necessary transmission and distribution system investments and the continuation of the Grid Investment Plan approved in the 2019 base rate case. This and increased depreciation associated with our investments results in an increase of approximately $476 million in the Company’s revenue requirement.
* **Economic Fleet Transition with Clean Energy:** An increase of approximately $249 million in the Company’s revenue requirement associated with the fleet transition can be primarily attributed to the net increase in depreciation expense related to the change in depreciation rates, additional purchased power expense in 2024 and 2025 related to the purchased power contracts requested to be certified in the 2022 IRP, capital investments in solar, hydroelectric, and other renewable generation assets, and increase in DSM expenses associated with its programs and initiatives filed in the 2022 DSM Certification application. Also, as we transition the generation fleet to more economical and cleaner resources, we project to reduce or eliminate spending, where appropriate, for outages and maintenance work on existing and retired coal units, resulting in projected O&M reductions, which are included in the “Non-Fuel O&M” key cost driver.

In its 2022 IRP filing, the Company proposed to retire or make unavailable the following coal-fired generating units: Wansley 1-2, Bowen 1-2, and Scherer 1-3, and replace them with more economical generation resources. Consistent with this proposal, the depreciation rates established in the 2019 base rate case Order must be adjusted to reflect the updated useful lives of these assets in support of timely recovery of the Company’s related capital investments and removal costs. The shortened useful lives of these coal-fired units result in increased depreciation expense, a portion of which the Company is proposing to defer as a regulatory asset to partially mitigate impacts to customers as described in more detail in Section VII below. This regulatory asset treatment is similar to the treatment previously approved by the Commission for other unit retirements and allows for a longer recovery period than the depreciable lives contemplated in the Company's new depreciation study.

* **Environmental Compliance – CCR ARO:** The Company must continue to comply with, and recover costs associated with, state and federal environmental regulations pertaining to the ongoing closure of the Company’s twenty-nine coal ash ponds. Georgia Power will continue to meet its environmental compliance obligations in a cost-effective manner by implementing the Company’s environmental compliance strategy approved by the Commission in the 2019 IRP proceeding and updated in the 2022 IRP. Therefore, the Company’s revenue requirement for 2023 through 2025 will increase by approximately $189 million for incremental costs associated with CCR ARO compliance that are not currently reflected in rates.
* **Technology – Customer Experience & Operations:** The Company continues to recognize the importance of investing in applications and equipment that allow us to provide the level of customer service our customers expect and deserve. During the 3-year ARP we will be investing in a new Customer Information System (“CIS”) to replace our existing customer service and billing system that has been in place for over 25 years. This critical system currently uses technology that is increasingly challenging to support and it is cost prohibitive to update the existing system for the evolving needs of our growing customer base. In addition, using the accounting methodology for software and cloud computing costs approved in the 2019 base rate case, the Company proposes amortizing certain software and cloud computing costs deferred through December 2022 over the upcoming five-year period. Also, with the increasing levels of distributed energy resources being installed on our system, the Company will begin investing in a Distributed Energy Resource Management System (“DERMS”) that will enable enhanced monitoring and operational capabilities of a more complex power delivery system. In response to increasing customer interest and market demand, the Company is also continuing to invest in the infrastructure and technology needed to support the growth of electric transportation in Georgia. Cumulatively these items represent an approximate $98 million increase in the proposed levelized revenue requirement.
* **State & Local Taxes and Fees:** The Company projects its requested levelized revenue requirement to be increased by approximately $66 million for state and local taxes. This amount is made up of a $59 million increase for property taxes associated with increased capital investment and $23 million for increased MFF related to increased revenues partially offset by a reduction in other taxes.
* **Incremental Inflation:** In addition to the aforementioned drivers, to address the impact of current and near-term significant, incremental inflation levels on the cost of service, an adjustment beyond typical inflationary expectations was made to certain cost components used in preparing the Company’s annual budget. This incremental inflation results in an increase of approximately $94 million in the Company’s revenue requirement.
* **TCJA:** By the end of 2022, Georgia Power’s customers will have fully realized approximately $660 million in certain tax benefits resulting from the TCJA. These benefits were a portion of the total tax benefits, including the lower tax rate, provided by the Tax Reform Act. During the current ARP period (2020 – 2022), the Company was able to offset a portion of its revenue requirement by amortizing a regulatory liability of approximately $660 million over a three-year period, which reduced customers’ rates by $220 million annually. By the end of 2022, those tax benefits will have been fully passed on to customers, and the balance in the regulatory liability related to these tax benefits will be zero, which results in a $220 million net increase to the Company’s revenue requirement in this case.
* **Non-Fuel O&M:** A reduction of approximately $163 million to the Company's revenue requirement is attributed to projected decreases in costs for employee benefits and effective cost management. Customers will benefit from an approximately $81 million reduction in costs for employee benefits. Additionally, as we transition the generation fleet to more economical and cleaner resources, we project to reduce or eliminate O&M spending, where appropriate, for outages and maintenance work on existing and retired coal units, resulting in further projected O&M reductions of approximately $79 million.
* **Storm Cost Recovery:** The Company’s previously under-recovered storm restoration costs balance of $410 million is now fully recovered. In fact, at the time of this filing, the Company projects to have a positive storm reserve balance of approximately $100 million by the end of 2022. The Company is proposing to reduce the annual storm damage expense accrual from $213 million per year to $65 million per year, which reflects the average annual storm damage cost incurred over the past ten years and reduces the Company’s proposed revenue requirement by $149 million.
* **Sales Growth and Other:** On a weather-normalized basis, 2023 retail base revenues are projected to be higher than the 2022 retail base revenues approved in the 2019 base rate case, as adjusted by the 2021 and 2022 compliance filings. Although sales growth was slightly lower than expected in the Company’s pre-pandemic sales forecast, current forecasted sales growth, driven primarily by a growing residential customer base, has reduced the projected levelized revenue requirement increase by approximately $68 million. Additional items not included in other key cost drivers are reflected here as “other.” Together, the sales growth impact and “other” items result in a net revenue requirement decrease of $59 million.
* **Financial Integrity:** While there are multiple factors impacting the Company’s financial integrity, three key quantitative components impacting the Company’s revenue requirement in this request are the approved capital structure, projected cost of debt, and allowed cost of equity. Taken together, these components result in a net decrease of $18 million to our requested revenue requirement.

Maintaining the 56% equity and 44% debt capital structure approved in the 2019 base rate case reduces the company’s revenue requirement by approximately $1 million, while at the same time it provides an appropriate capital structure to support an optimal credit rating.

Over the past three years, with the continued credit supportive actions of the Commission, the Company has taken advantage of a historically low interest rate environment and relatively flat yield curve and is passing those savings to customers with the projected embedded cost of debt (or average interest rate) decreasing by 107 basis points, down to 3.53% for 2023 from 4.60% for 2022 in the 2019 base rate case. The projected lower cost of long-term debt financing from lower interest rates provides approximately $111 million in revenue requirement savings. Considering the current rising interest rate environment, it is possible that during the next base rate case, the long-term cost of debt could increase.

Finally, since the 2019 base rate case, when considering the current state of financial markets and when compared to peer companies, the required return on our equity investment has increased from a set point of 10.5% to the 11% recommended by Mr. Coyne, which corresponds to an increase in revenue requirement of $94 million.

The combination of the three quantitative components necessary to maintain the Company’s financial integrity – capital structure, cost of debt and cost of equity – results in a net reduction to the requested revenue requirement of approximately $18 million.

**Q.** **During the three-year ARP period, what would the annual rate increases be if the Company’s rate request was not levelized?**

A. If the Company proposed annual step increases as opposed to a levelized increase, the revenue deficiencies (and corresponding annual increases) would be as depicted in Table 2 below:

**Table 2: Projected Revenue Requirement Deficiency by Year (in millions)**[[2]](#footnote-3)

*Amounts may not sum to total due to rounding*

|  |  |  |  |
| --- | --- | --- | --- |
|  | **2023** | **2024** | **2025** |
| Traditional Base | $461 | $718 | $1,080 |
| ECCR |  |  |  |
| ECCR Traditional | 29 | (12) | (25) |
| ECCR CCR ARO\* | 64 | 143 | 189 |
| DSM\* | 30 | 56 | 54 |
| MFF | 14 | 22 | 31 |
| **Total** | **$599** | **$927** | **$1,330** |

\*As determined by the Commission through annual CCR ARO and DSM Compliance filings.

As Table 2 illustrates, under an annual step increase structure, the projected revenue requirement deficiency is substantially lower in 2023 and slightly lower in 2024 than the proposed levelized revenue requirement. However, the projected revenue requirement deficiency is significantly higher under a step increase structure for 2025. Notably, under an annual step increase structure, the ultimate amount of the rate change from year to year creates additional uncertainty for our customers as projected costs for traditional base and ECCR can change.

IV. THE PROPOSED ALTERNATE RATE PLAN

**Q.** **How does the Company propose to collect the revenue requirement under the three-year ARP?**

A. The Company proposes to continue the existing ARP structure, which includes the following:

* **Traditional Base Rate Tariffs:** Continue traditional base rate tariffs through December 31, 2025, with adjustments necessary to collect the levelized three-year revenue requirements effective January 1, 2023. The tariff adjustments will reflect currently projected revenues, expenses, rate base growth, and cost of capital that includes a fair and reasonable ROE, based on a test year ending July 31, 2023, modified for an appropriate levelization adjustment;
* **ECCR Tariff:** Continue the ECCR tariff through December 31, 2025, with revisions effective January 1, 2023 for currently projected revenues, expenses, rate base, and cost of capital that includes a fair and reasonable ROE based on a test year ending July 31, 2023, modified for an appropriate levelization adjustment for all items except the CCR ARO compliance costs. The ECCR tariff will be adjusted further on January 1, 2024 and January 1, 2025 to reflect the change in revenue requirement for CCR ARO compliance costs, as described later in our testimony;
* **DSM Tariff:** Adjust the DSM tariffs with revisions effective January 1, 2023 to account for prior period over-recovery, the cost of the Company’s programs, and additional sum as proposed in the 2022 DSM Certification, with annual filings to update the DSM tariffs to be effective January 1, 2024 and January 1, 2025;
* **MFF Tariff:** Adjust the MFF tariff with revisions effective January 1, 2023 to update the percentage of revenues inside municipalities with the option to file annual compliance filings to be effective January 1, 2024 and January 1, 2025 to account for the impacts on the MFF tariff from other rate changes, as well as account for any new incorporation of municipalities;
* **ROE Band:** Continue the currently approved ROE band of 9.50% to 12.00%;
* **Annual Surveillance Report (“ASR”):** Continue the ASR process whereby 80% of any earnings above the allowed ROE band are dedicated to the benefit of customers and 20% are retained by the Company; and
* **Interim Cost Recovery (“ICR”):** Continue the option to file an ICR tariff in the event that earnings are projected to fall below the bottom of the ROE band during any calendar year of the three-year term of the ARP.

The ARP proposed by the Company will retain the existing structural features, which were approved in the ARP under the 2019 base rate case Order. Importantly, this balanced approach provides stable and predictable rates for customers, annual adjustments over time for CCR ARO compliance, and provides Georgia Power with timely recovery of the costs to serve our customers and maintain strong credit metrics.

**Q. Please describe the accounting for levelization of the revenue requirement under the proposed three-year ARP.**

A. As presented in Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 2), the Company’s projected revenue requirements for traditional base rate tariffs in 2023 and 2024 is lower and the 2025 revenue requirement is higher than the levelized revenue requirement over the three-year period. To balance revenues associated with the revenue requirement for the corresponding years, the Company proposes to defer $277 million and $21 million of the levelized projected over-collections in 2023 and 2024, respectively, to a regulatory liability account that will reduce rate base in 2023 through 2025 and be fully amortized at the end of 2025.

For the ECCR tariff presented in Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 3 ECCR), the Company’s projected ECCR excluding the CCR ARO revenue requirement is higher in 2023, but lower in 2024 and 2025 than the levelized revenue requirement over the three-year period. To balance revenues associated with the revenue requirement for the corresponding years, the Company proposes to defer the projected under-collection of $30 million in 2023 to a regulatory asset account that will increase rate base in 2023 through 2025 and be fully amortized at the end of 2025.

**Q.** **Does the Company propose continuing an annual rate adjustment to recover CCR ARO compliance costs?**

A. Yes. The current ECCR tariff includes estimates for coal ash pond and certain landfill closure costs developed for the Company’s 2022 Compliance Filing made pursuant to the 2019 base rate case Order. Therefore, current recovery does not include projected CCR ARO compliance costs for 2023 and beyond for projected or adjustments for actual costs incurred in 2021 or 2022. The Company proposes to continue to recover CCR ARO compliance costs on an annual basis, adjusting rates January 1, 2023. The current CCR ARO compliance cost recovery is discussed further in Section V.

**Q. How will the Company’s proposed ARP benefit customers?**

A. The Company’s proposed ARP will provide several benefits for Georgia Power customers. First, the ARP provides rate stability and predictability over the three-year period during which it is in effect, thus allowing customers to better plan and manage their energy budgets. Second, both customers and the Company benefit from the fact that the ARP reduces regulatory lag, allowing the Company to recover prudently incurred costs on a more-timely basis. Timely recovery of costs is a cornerstone of a constructive regulatory policy and considered favorably by credit rating agencies. Favorable credit ratings, in turn, support the Company’s continued ability to access capital markets at competitive rates and on a timely basis, which ultimately translates into lower costs for Georgia Power customers. Sufficient access to capital markets is essential to the Company’s overall financial stability, which allows it to continue providing customers with safe and reliable electric service at affordable rates. Finally, the sharing mechanism provided for under the ARP provides direct financial benefits to Georgia Power customers. Through the sharing mechanism, if the Company performs better than expected, customers will receive 80% of any earnings above the approved ROE range through customer refunds and the reduction of the CCR ARO regulatory asset. Notably, since 2013, customers have received the benefit of approximately $297 million through the sharing mechanisms.

**Q. Please describe the exhibits supporting your testimony.**

A. The exhibits supporting our testimony are as follows:

* **Exhibit\_\_\_(APA/SPA/ADH/MBR-1)** consists of five schedules demonstrating and supporting the calculation of the requested revenue requirements based on a test period ending July 31, 2023, as well as calendar years 2023, 2024, and 2025.  
    
  Schedule 1 contains the calculations of the requested revenue requirements for the twelve months ending July 31, 2023 and calendar years 2023, 2024, and 2025 for the total Company (excluding MFF), including projected retail rate base by components and calculation of retail operating income.

Schedule 2 contains the calculations of the requested revenue requirements for the twelve months ending July 31, 2023 and calendar years 2023, 2024, and 2025 for the traditional base tariffs. This schedule also includes the calculation of the levelized revenue requirement necessary to provide stable rates over the three-year period.

Schedule 3 shows the components and calculation of the requested revenue requirements related to the ECCR tariff. This schedule covers the test period ending July 31, 2023 and calendar years 2023, 2024, and 2025. This schedule includes the calculation of the levelized revenue requirement excluding CCR ARO compliance costs as well as the projected annual step increases for those costs.

Schedule 4 shows the components and calculation of the proposed revenue requirements related to the DSM tariffs. This schedule covers the test period ending July 31, 2023 and calendar years 2023, 2024, and 2025.

Schedule 5 provides the calculation and the revenue requirement impact of the MFF tariff associated with each of the base tariffs for the test period ending July 31, 2023 as well as the calendar years 2023, 2024, and 2025.

* **Exhibit\_\_\_(APA/SPA/ADH/MBR-2)** is the Summary of Projections. This exhibit demonstrates the changes in revenues, expenses and rate base from the historic period, after regulatory adjustments as approved by the Commission in Docket No. 42516 and previous rate cases, for the year ended December 31, 2021, to the test period ending July 31, 2023. The exhibit also displays the adjusted retail cost of service amounts and balances for the test period ending July 31, 2023, taking into account previously approved and proposed regulatory adjustments. The exhibit provides explanations for the corresponding changes between periods, as well as the regulatory adjustments within each period.
* **Exhibit\_\_\_(APA/SPA/ADH/MBR-3)** displays the details and the calculation of the 7.70% weighted average cost of capital ending July 31, 2023, including the Company’s projected capital structure and cost of debt, proposed cost of equity as supported by Mr. Coyne in his testimony, and a reconciliation of the budgeted balances to the adjusted balances used in calculating the retail revenue requirements. In addition, we have included the components and calculations of the 13-month weighted average cost of capital for the calendar years ending 2023, 2024, and 2025.
* **Exhibit\_\_\_(APA/SPA/ADH/MBR-4)** contains various schedules that provide detailed support for amounts included in projected retail rate base included in the Company’s revenue requirement for the test period.
* **Exhibit\_\_\_(APA/SPA/ADH/MBR-5)** contains various schedules that provide detailed support for amounts included in projected retail expenses included in the Company’s revenue requirement for the test period.
* **Exhibit\_\_\_(APA/SPA/ADH/MBR-6)** contains various schedules that provide detailed support for amounts excluded from projected retail rate base and expenses in the Company’s revenue requirement for the test period.
* **Exhibit\_\_\_(APA/SPA/ADH/MBR-7)** contains detailed information regarding the distribution investment packages.
* **Exhibit\_\_\_(APA/SPA/ADH/MBR-8)** contains detailed information regarding the transmission investment packages.

V. ECCR, DSM, AND MFF TARIFFS

EnvironmentalComplianceCostsRecovery

Q. What is the Company requesting related to ECCR costs?

A. The Company is requesting an increase of $63 million to be collected through the ECCR tariff in 2023. This amount includes a decrease of $1 million of the levelized traditional ECCR tariff revenue requirements, designed to provide stable rates for customers over the three-year period, and an increase of $64 million corresponding to CCR ARO revenue requirement deficiency in 2023. The levelized revenue requirement is reflected in Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 3 ECCR), which also shows the projected required environmental investments and expenses associated with the ECCR tariff (excluding CCR ARO) in 2023, 2024, and 2025. The costs supporting these projections are consistent with the Environmental Compliance Strategy set forth in the Company’s 2022 IRP. The annual CCR ARO revenue requirements for 2023, 2024, and 2025 are reflected in Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 3 ECCR), which also provides the annual projected expenditures.

**Q.** **Is the Company proposing to recover CCR ARO compliance costs using the same methodology approved in the 2019 BASE Rate Case?**

A. Yes. The Company proposes to continue the recovery of CCR ARO costs under the methodology that was approved by the Commission in the 2019 base rate case. As set forth in the Company’s 2022 IRP filing, as updated, the projected annual spend on compliance activities necessary to comply with federal and state CCR environmental regulations, are estimated to be $320 million, $408 million, and $510 million for 2023, 2024, and 2025, respectively, on a retail basis. The contingency included in these amounts is $47 million, $50 million, and $105 million for 2023, 2024, and 2025, respectively. Based on the methodology approved in the 2019 base rate case, the Company excluded these contingency costs from the annual recovery requested in this filing. In addition, the ARO regulatory balance related to CCR AROs is projected to be cumulatively under-collected by $282 million as of December 31, 2022.

**Q. Please elaborate on the Company’s proposed process for the annual rate adjustments for CCR ARO compliance costs.**

A. The Company proposes to continue the annual rate adjustment process as approved by the Commission in the 2019 base rate case. Following the increase effective January 1, 2023, the Company proposes to submit a filing by October 1, 2023, for recovery of the projected incremental increase in CCR ARO compliance cost for 2024. The proposed adjustments would be based on the most current CCR ARO Semi-Annual Program Status Report, with new rates effective January 1, 2024. By October 1, 2024, the Company would submit an additional filing for the recovery of the projected incremental increase in CCR ARO compliance costs for 2025, with new rates effective January 1, 2025.

Demand Side Management

**Q.** **What costs are to be recovered by the Company’s proposed DSM tariffs?**

A. The Company has included an increase of $30 million. This amount reflects recovery of the program costs and additional sum filed in the Company’s 2022 DSM Certification application, partially offset by the return of prior period over collections to be recovered through the DSM tariffs, effective January 1, 2023, as detailed on Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 4 DSM).

**Q.** **How is the Company proposing to recover revenue requirements associated with the DSM tariffs?**

A. Consistent with the 2019 base rate case Order, the proposed DSM tariffs will be set to collect program costs and additional sum as approved in the Company’s 2022 DSM Certification Application filed in connection with the 2022 IRP. The Company’s annual compliance filings in 2023 and 2024 will reflect the budget approved by the Commission in the 2022 DSM Certification proceeding.

**Municipal Franchise Fee**

**Q. What are the terms of the current MFF tariff?**

A. In the Commission’s Final Order in the 2007 base rate case, Docket No. 25060, the Commission ordered the establishment of the MFF tariff in accordance with the Commission’s MFF Order in Docket No. 21112. The MFF tariff reflects 50% of MFF revenues being collected from customers located within municipal areas covered by a franchise agreement and 50% being collected from all customers, regardless of location. Because the tariff is a percentage rate and is calculated based on each customer’s bill before sales taxes are applied, the percentage rate does not have to be adjusted even if revenues change.

**Q. If the MFF tariff is based on percentage rates, what could cause the MFF tariff to change?**

A. The primary driver that could cause the MFF tariff to change from year to year is the proportion of revenues collected from customers receiving service within the municipalities’ boundaries, due to load growth within and/or expansion of municipal boundaries. The MFF tariff is designed to recover the amount of franchise fees paid pursuant to our franchise agreements with the cities across the Company’s service territory. Under those agreements, the cities charge, and we pay, 4% of total revenues generated inside the respective city, which includes amounts collected from all of the tariffs: traditional base; NCCR; ECCR; DSM; and Fuel Cost Recovery (“FCR”). Therefore, as customer demographics (proportion of electric sales revenues generated inside versus outside municipalities) as well as customer usage patterns change from year to year, so will the amounts of our franchise fee payments and so should the MFF tariff. Therefore, we propose adjusting the MFF tariff annually, if needed, to align revenues with costs.

**Q. How is the Company proposing to recover revenue requirements associated with the MFF tariff?**

A. The Company is requesting approval of the $20 million increase shown on Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 5 MFF) in connection with this proceeding, to be effective January 1, 2023. The Company will continue to evaluate changes in the proportionate share of revenues collected within municipalities and, if necessary, file an update to the MFF tariff by submitting an annual filing by November 1st as provided for in the current MFF tariff.

VI. REVENUE REQUIREMENT

**Q.** **What periods ARE COVERED BY THE information in this filing cover?**

A. The historical data in this filing is based on the Company’s actual performance for the twelve-month period that ended December 31, 2021. The projected test period for the traditional revenue requirement is for the twelve-month period ending July 31, 2023. In addition, the Company has provided projected data for each of the twelve months ending December 31, 2023, 2024, and 2025 to meet the requirements of the 2019 base rate case Order and to support the basis for a levelized revenue requirement.

**Q. Please summarize the result of your revenue requirement calculations for the traditional test period ending July 31, 2023.**

A. The revenue requirement calculation in Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 1 Total Company) shows a revenue deficiency, excluding MFF, of $448 million for the period ending July 31, 2023 to be collected through the base tariffs. The jurisdictional allocations are based on an allocated cost-of-service study for the projected test period ending July 31, 2023 as discussed in Mr. Evans’ testimony.

**Q. Please describe the development of the retail revenue deficiency amount for the traditional test period ending July 31, 2023.**

A. Revenue collected from customers must cover all costs of service, including O&M expenses, taxes, depreciation, and the cost of capital (including an appropriate ROE). Retail rates must be sufficient to satisfy the interest requirements of the Company’s debt, while providing an opportunity for a fair and reasonable return on common equity invested. These cost of capital requirements are weighted by the mix of long-term debt and common equity, and reflect certain Commission rate-making adjustments, to produce an overall required retail rate of return. This rate of return is then applied to the retail rate base to yield the Company’s retail earnings requirement.

The retail earnings requirement is then compared to earnings projected under the Company’s current base rates to determine the retail earnings deficiency amount during the test period. This earnings deficiency is then adjusted to cover income taxes by using an “income expansion factor.” This factor, 74.606%, reflects a federal income tax rate of 21% and a state income tax rate of 5.75%. The income expansion factor also includes a reduction for uncollectible accounts, slightly offset by compensation for collection of sales tax. The retail earnings deficiency is then divided by the income expansion factor to determine the total revenue deficiency from retail customers, excluding MFF.

The computation of the income expansion factor is shown in Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 1 Total Company), page 2.

**Q. What is the source of the projected costs used in the filing?**

A. The projected costs used to calculate the revenue deficiency and rate base come from the Company’s 2022 annual budget. The preparation of the Company’s annual budget is a cyclical process of planning, resource identification, review, revision and approval. The process involves all functional areas throughout the Company. This process results in a comprehensive financial budget, which reflects the Company’s best estimate of the resources required to serve our customers’ evolving needs, while effectively managing costs.

**Q. What is the retail rate base upon which the Company is basing its revenue deficiency for the traditional test period ending July 31, 2023?**

A. The projected retail rate base is $24.0 billion and is based on the 13-month average from July 31, 2022 through July 31, 2023, as shown in the revenue deficiency calculation in Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 1 Total Company) page 1.

**Q. What rate of return is applied to the retail rate base in the revenue requirement calculation for the traditional test period ending July 31, 2023?**

A. The Company’s requested overall retail cost of capital is 7.70% for the period ending July 31, 2023, as determined in Exhibit\_\_\_(APA/SPA/ADH/MBR-3, Schedule 1), which is lower than the 7.91% that was approved for 2022 in the 2019 base rate case.

**Q.** **How is the Company’s overall cost of capital determined?**

A. The Company’s overall cost of capital of 7.70% is based on the 13-month average of the estimated capitalization from July 31, 2022 through July 31, 2023. The long-term debt proportion of capitalization is multiplied by its average estimated embedded cost for each month through July 31, 2023. The required return on common equity of 11.00% is described by Mr. Coyne in his testimony. Exhibit\_\_\_(APA/SPA/ADH/MBR-3, Schedule 1) shows the capital structure components for the test period, together with associated costs.

**Q. How has the Company presented the revenue requirement calculations for the three-year period identified in the proposed ARP?**

A. The attached exhibits focus on the test period ending July 31, 2023, as required by the Commission’s 2019 base rate case Order. The Company has also filed revenue requirement information for the calendar years 2023, 2024, and 2025, consistent with the intent of the 2019 base rate case Order and with respect to the three-year ARP. This information is intended to support the Company’s requested adjustment to the test period revenue requirement for those periods. The 2023, 2024, and 2025 revenue requirements for traditional base rates, ECCR tariff including incremental ARO costs related to CCR compliance, and DSM tariff are shown separately in Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 3 ECCR), and Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 4, DSM), respectively.

**Q.** **Why is the Company choosing to base the revenue requirement on a test period ending July 31, 2023 with a levelized adjustment for calendar years 2023, 2024, and 2025?**

A. There are two primary reasons the Company has chosen to present the requested revenue requirement based on a test period ending July 31, 2023 with a levelized adjustment for calendar years 2023, 2024, and 2025. First, the test period ending July 31, 2023 only partially recognizes the increase in rate base and expenses that the Company will incur in the first full year following an approved rate increase. By presenting an adjusted revenue requirement for the entire period ending December 31, 2023, the Company is demonstrating the first full year revenue deficiency, which mitigates the amount of time between incurring the cost and recovering the cost (regulatory lag). Second, by using the three calendar years ending December 31, 2025, the Company reflects the annual revenue deficiencies used in determining a levelized revenue requirement in order to provide more stable base rates during the three-year period.

VII. SUMMARY OF PROJECTIONS FOR THE TEST PERIOD

ENDING JULY 31, 2023

**Q.** **Please describe the rate-making adjustments previously allowed or required by the Commission that are reflected in the Company’s requested revenue requirements.**

A. The Company has made the following adjustments as reflected in Exhibit\_\_\_(APA/SPA/ADH/MBR-2):

1. Pursuant to the Commission’s Order in Docket No. 3270, the corporate headquarters lease was reflected as an operating lease rather than as a capital lease.
2. Pursuant to the Commission’s Order in Docket No. 3840, institutional and goodwill advertising expenses have been removed from retail expenses.
3. Pursuant to the Commission’s Order in Docket No. 3840, 75% of economy energy profits were returned to retail customers through the fuel clause with 25% retained by the Company.
4. Pursuant to the Commission’s Order in Docket No. 18300, 80% of profits from short-term capacity sales were returned to retail customers with 20% retained by the Company.
5. Pursuant to the Commission’s Order in Docket No. 3673, expenses associated with the Nuclear Energy Institute have been excluded from retail expenses.
6. Wholesale revenues and expenses associated with non-territorial power marketing transactions have been removed from retail income.
7. Pursuant to the Commission’s Orders in Docket Nos. 4900, 22528, 25036, 34218, 37854, 38877, 41596, 41734, and 42625, the approved additional sum has been added to expenses for certain Purchase Power Agreements (“PPA”).
8. The carrying charge on over or under-recovered fuel costs added to revenues has been removed since they are credited to customers through the fuel clause.
9. Pursuant to the Commission’s Order in Docket No. 3936, revenues and costs associated with Unregulated Outdoor Lighting have been removed from retail operations.
10. Accumulated Deferred Income Taxes (“ADIT”) related to Construction Work In Progress (“CWIP”) have been removed.
11. Income tax expense has been adjusted to reflect, as a tax deduction, only the interest expenses applicable to the retail rate base.
12. The reserve held by the external trustee for nuclear decommissioning has been removed from the ARO regulatory liability balance.
13. Pursuant to Commission’s Order in Docket No. 3397, nuclear fuel stock related to Plant Vogtle Units 3 and 4 has been removed from retail rate base and Allowance for Funds Used During Construction is recorded on the related balance.
14. Nuclear Construction Cost Recovery tariff revenues and associated rate base items have been removed.
15. DSM additional sum has been added to expenses, and the carrying charge on over- or under-recovered DSM tariffs has been adjusted to revenues. The ADITs associated with the DSM over/under-recovery have also been removed.
16. Pursuant to the Commission’s Order in Docket No. 25060, any shoreline maintenance costs in excess of licensing fees collected from lake lot lessees in association with FERC Boundary Land have been removed.
17. Pursuant to the Commission’s Orders in Docket No. 25322 and No. 36989, 50% of any revenues net of program expenses associated with the Co-location Wireless Equipment program on the transmission tower assets, and 40% of any revenues net of program expenses associated with the co-location programs associated with small cell installations or macro cell development on retail facilities such as telecom towers and land leases on the Company’s regulated assets have been removed for retail regulatory purposes.
18. Pursuant to the Commission’s Order in Docket No. 26550, the market differential adjustment was applied to retail revenues relating to certain wholesale assets transferred to retail rate base.
19. Pursuant to the Commission’s Order in Docket No. 36989, the interest portion of the capacity payments associated with capital lease PPAs was removed.
20. The cumulative impact of these regulatory adjustments has been reflected on cash working capital.

All of these adjustments are consistent with the treatment reflected in the Company’s previously filed ASR.

**Q.** **What other adjustments are included in the Company's filing that have been included in previous cases?**

A. As described more fully below, the Company is proposing the following adjustments:

1. Depreciation expense to reflect new depreciation rates.
2. Nuclear Decommissioning expense.
3. Storm Damage expense.
4. Environmental Remediation expense.
5. Staff consultant fees paid by the Company.
6. Proration of federal ADITs.
7. Test Period Normalization items.
8. Unprotected Excess Deferred Taxes.

**Q.** **How have the new depreciation rates been reflected in the revenue requirement for the period ending July 31, 2023?**

A. The depreciation rates used by the Company are reviewed in every base rate case to ensure that they continue to reflect the current cost of providing service to our customers. The Company’s most recent depreciation study filed in this proceeding shows that current depreciation rates, which were approved in the 2019 base rate case, need to be adjusted to reflect updated estimates of generating unit retirements and unavailability dates, asset service lives, cost of removal, and to recognize the additional investments in new facilities and retirements that have been made since the previous depreciation study. The proposed revenue requirement in this filing reflects the depreciation rates set forth in the new depreciation study. Please refer to Exhibit\_\_\_(APA/SPA/ADH/MBR-5, Schedule 1) and the depreciation study, which can be found in Appendix\_\_\_Exhibit 2 of this filing.

**Q. Who prepared the new depreciation study and on what principles is it based?**

A. The depreciation study was developed by Alliance Consulting Group. In addition, Southern Company Services and Brandenburg, a national demolition firm, updated the dismantlement study through 2020, which was used by Alliance Consulting Group for certain assumptions in their study. The key principles reflected in depreciation rates are the average life group procedure, the remaining life technique, and the traditional net salvage approach. The current depreciation study is consistent with the general principles and processes followed in the 2019 base rate case with one exception. For assets within the Steam Function, the depreciation rates have been adjusted to account for the typical 2-year difference in timing between the balances used to calculate the new rates December 31, 2020 and when the new rates are implemented January 1, 2023.

**Q.** **Why did the Company conclude that this two-year adjustment was appropriate?**

A. In the Company’s 2022 IRP, specific decertification, retirement, or unavailability dates have been requested for Plant Bowen Units 1-2 and Plant Scherer Units 1-3 and Common. Because there is a two-year lag between the balances used to calculate the new depreciation rates and when those rates become effective, an undepreciated balance will remain upon the retirement of the asset. In order to reduce the amount of this undepreciated balance projected at retirement, the depreciation rates for steam generating units were adjusted to address the two-year lag.

**Q.** **Why did the Company assume in the current depreciation study that Scherer Units 1-2 should be fully depreciated by 2028?**

A. The Company’s request in the 2022 IRP filing assumes, for planning purposes, that Scherer Units 1-2 will be unavailable after 2028. This useful life assumption also reduces the projected net book value in rate base (undepreciated balance) upon the physical retirement of the units.

**Q.** **How is the Company proposing to recover the depreciation associated with the retirement of Plant Bowen Units 1-2 and Scherer Units 1-3?**

A. The Company proposes to recover the depreciation related to the reduction in the useful lives of Plant Bowen Units 1-2 and Plant Scherer Units 1-3 over a nine-year period beginning January 1, 2023. Based on the depreciation study filed in this case, Plant Bowen Units 1-2 are scheduled to be depreciated through 2027 and Plant Scherer Units 1-3 are scheduled to be depreciated through 2028 in accordance with the retirement dates proposed in the 2022 IRP. For these units, the Company requests the Commission to defer the difference each year between the amount of depreciation expense recommended under the rates provided in the Company’s new depreciation study and the amount depreciation expense would be assuming a nine-year remaining life into a regulatory asset account beginning January 1, 2023. Once the generating units are retired, the deferred regulatory asset balance, including any remaining undepreciated balance at the retirement date, would be amortized over the remainder of the nine-year recovery period ending December 31, 2031.

**Q.** **Why is the Company proposing a nine-year recovery period for these generating units?**

A. There are several reasons. First, a nine-year recovery period reduces the revenue requirement by extending the recovery period of the remaining investment in assets that have reliably served customers for decades. Also, a nine-year recovery period aligns evenly with the three-year accounting order periods. Lastly, this period ensures recovery does not extend beyond the current estimated useful life for Plant Bowen Units 3 and 4 (the last coal units expected to be in-service).

**Q. Has the Company included an adjustment for funding nuclear decommissioning?**

A. Yes. The Company has updated funding amounts in the budget for the nuclear decommissioning trust accounts for existing units (Plant Hatch Units 1 and 2 and Plant Vogtle Units 1 and 2) to reflect the treatment approved by the Commission since 2001. External trust fund balances were updated as of December 31, 2021 to calculate the projected fund contributions until decommissioning. Based on the Company’s calculation, an annual funding is not projected to be required during the proposed ARP, which results in revenue requirement savings for customers of $4.3 million from the current nuclear decommissioning accrual.

The proposed level of nuclear decommissioning funding is currently expected to meet Nuclear Regulatory Commission minimum funding requirements for decommissioning structures and equipment. This will also provide funding for the storage and eventual removal of spent nuclear fuel. Consistent with the Commission’s previous orders, the Company also excluded any costs related to site restoration of the facilities. Information supporting the funding requirement calculation can be found in Exhibit\_\_\_(APA/SPA/ADH/MBR-5, Schedule 4).

**Q.** **Please describe the change in the storm damage regulatory asset balance since the 2019 BASE Rate Case.**

A. The storm damage regulatory asset balance has decreased from $410.0 million as of December 31, 2019 to $48.4 million as of December 31, 2021. Since the Commission approved the annual storm damage expense of $213.3 million in the 2019 base rate case, there have been fewer significant storms than anticipated impacting Georgia Power’s service territory. The amount approved in the 2019 base rate case has allowed the Company to recover the storm balance deficiency.

**Q.** **Please explain the change in storm damage expense as included in the Company’s revenue requirement.**

A. As stated above, the Commission set the amount of annual storm damage expense at $213.3 million in the 2019 base rate case Order, which consisted of $63.5 million for projected annual storm costs and $149.8 million for annual recovery of prior storm costs. Consistent with the 2019 rate case, the Company has used a 10-year historical average to project annual storm costs in this filing. As a result, the Company projects average annual storm costs of $64.8 million. Since the 2019 base rate case, the regulatory asset associated with storm restoration costs will have been fully recovered and it is estimated that by the end of this year will become a regulatory liability of $100.2 million. Therefore, there is no recovery of prior storm costs required in this case, and the requested annual storm damage expense is a decrease of $148.5 million. The methodology used to develop the projected annual storm damage expense is shown in Exhibit\_\_\_(APA/SPA/ADH/MBR-5, Schedule 2).

**Q.** **Please explain the change in environmental remediation expense as included in the Company’s revenue requirement.**

A. The environmental remediation regulatory balance has decreased from a net regulatory asset of $37.4 million as of December 31, 2019 to a projected net regulatory asset of $14.6 million at December 31, 2022. The requested annual environmental remediation expense included in this filing is $5.1 million, or a decrease of $7.2 million from the $12.2 million annual expense set in the 2019 base rate case Order. This decrease is primarily driven by the recovery of the December 2019 environmental remediation net regulatory asset balance as noted above. The requested expense reflects the Company’s request to recover the projected net regulatory asset balance for environmental remediation over the proposed three-year rate period. The methodology used to develop the annual accrual is the same as approved by the Commission in previous cases and is shown in Exhibit\_\_\_(APA/SPA/ADH/MBR-5, Schedule 3).

**Q. Please explain the adjustment for the fees paid by the Company for consultants retained by the Commission Staff.**

A. Based on O.C.G.A. § 46-2-33(a) and the April 7, 2022 Commission Procedural Scheduling Order in Docket No. 44280, the Company is required to provide up to $785,405 per case per year toward fees for reasonably necessary specialized testimony and assistance in certain proceedings initiated by the Company, with escalation provided on an annual basis based on the Consumer Price Index. This adjustment reflects the Company’s projection of such costs not included in the Company’s budget.

**Q. Please explain the adjustment for the proration of federal ADITs.**

A. The Company’s calculations to determine federal ADITs conforms with Internal Revenue Code Section 167(l), which requires the federal ADITs provided under its normalization rules to be prorated or weighted by the number of days in each month instead of a 13-month average, when included in the revenue requirement for setting rates.

**Q. Please explain the test period normalization adjustments in the filing.**

A. The test period normalization adjustments provide for certain revenues and expenses to be normalized in the test period to align the revenue requirement impact of those adjustments with the effective date of the proposed base rates. Therefore, customers are not charged for costs or credited for revenues that are included in the test period but are eliminated effective January 1, 2023; likewise, the adjustments include revenues or costs that begin January 1, 2023 and should be included for the full year in the test period revenue requirement. These normalization items primarily consist of changes in expenses including changes in depreciation rates and recovery of AROs, changes in the amortization of existing regulatory assets and liabilities such as those related to storm damage and tax reform, and new amortization of regulatory assets or liabilities such as those related to the net book value associated with retirement of certain generating units and software and cloud computing costs.

These adjustments are consistent with the Commission’s prior precedent and in accordance with general rate-making principles. All of the costs were incurred in order to provide service to customers and under the approval of the Commission.

**Q. Please explain the change in the TCJA benefits in the Company’s revenue requirement in this filing?**

A. During the current ARP period (2020-2022), the Company was able to offset a portion of its revenue requirement by recording a regulatory liability and amortizing a portion of the benefits from the TCJA, which reduced customers’ rates by $220 million annually. By the end of 2022, Georgia Power’s customers will have fully realized the approximate $660 million total in benefits related to unprotected excess deferred taxes. As such, the regulatory liability related to these benefits will be zero at December 31, 2022, and no longer exist to put downward pressure on rates, which results in an increase to the requested revenue requirement in this case. Customers continue to benefit from the impact of lower federal and state income tax rates in the Company’s income tax calculations, resulting from the TCJA.

**Q. What new adjustments or accounting items are included in the filing that have not been included in previous cases?**

A. The Company has included the following adjustments:

1. Amortization of Net Book Values (“NBV”) of Plant Wansley Units 1-2 and 5A and Plant Boulevard Unit 1.
2. Amortization of Deferred Software Costs.
3. Amortization of Incremental COVID Costs.
4. Amortization of Customer Usage Data Access Costs.

**Q.** **How is the remaining NBV of Plant Wansley Unit 1-2 and 5A and Plant Boulevard Unit 1 reflected in this filing?**

A. As proposed in the 2022 IRP, the Company has deferred the NBV of Plant Wansley Units 1, 2, and 5A and Plant Boulevard Unit 1 to regulatory asset accounts upon the projected retirement dates of the units to be amortized at the current approved depreciation rate through December 31, 2022. Effective January 1, 2023, the Company proposes to amortize these NBVs over their remaining useful lives as approved in Docket No. 42516. Please see Section VIII for further discussions on other accounting items requested in the 2022 IRP.

**Q.** **What amount is the Company seeking to recover regarding software and cloud computing costs in this filing?**

A. As approved in the 2019 base rate case, the Company changed its accounting for software and cloud computing projects and now defers to a regulatory asset certain costs expensed under Generally Accepted Accounting Principle (“GAAP”) which, prior to 2020, were capitalized. The Company has deferred $33.0 million of software and cloud computing costs as of December 31, 2021 and is projected to defer an additional $15.9 million through December 31, 2022, for a total of $48.9 million. The Company is requesting to recover the $48.9 million over a five-year amortization period ending December 31, 2027, which is consistent with the allowed five-year GAAP depreciation period for capitalized software. This represents an annual amortization expense of $9.8 million.

**Q.** **What incremental costs related to the COVID-19 pandemic has the Company deferred, and over what period does the Company propose recovery of these costs?**

A. As approved by the Commission in Docket No. 42516, the Company has deferred $105,000 of incremental bad debt expense and $20.9 million of other costs related to the COVID-19 pandemic to a regulatory asset as of December 31, 2021. The incremental other costs include additional expenses impacting the Company’s operations of the business, such as cleaning supplies and personal protective equipment, overtime labor hours, and meal vouchers deployed to front line workers in order to help protect employee's health while performing critical operations. The Company projects an additional $4.2 million of incremental other costs to be deferred to the regulatory asset in 2022. The Company is requesting a three-year amortization period ending December 31, 2025 to recover these costs. This represents an annual amortization expense of $8.4 million. Beginning January 1, 2023, the Company will no longer defer costs it will incur related to its COVID-19 pandemic response.

**Q.** **Has the Company incurred costs related to providing hourly usage data to customers as directed by the Commission in Docket No. 42516?**

A. Yes. The Company has deferred $238,000 of incremental costs incurred in its efforts to provide hourly usage data to customers through December 31, 2021 and projects to defer an additional $548,000 related to its efforts in 2022.

**Q.** **What amount is the Company seeking to recover regarding HOURLY usage data access costs in this filing?**

A. The Company is requesting to recover a regulatory asset balance of $786,000 as of December 31, 2022 over a three-year amortization period ending December 31, 2025. This represents an annual amortization expense of $262,000. Beginning January 1, 2023, the Company will no longer defer costs it will incur related to hourly usage data access costs.

VIII. GEORGIA POWER’S 2022 INTEGRATED RESOURCE PLAN

**Q.** **In addition to the items noted in Section VII, please explain the accounting requests related to the Company’s pending decertification requests in the 2022 IRP.**

A. As proposed in the 2022 IRP, the Company projects to reclassify $19 million of estimated unusable material and supplies inventory from Plant Wansley to a regulatory asset upon the projected retirement date. Considering the uncertainties around the salvage value of the inventory, the Company is not proposing to amortize the unusable inventory regulatory asset at this time and requests the amortization to be addressed in the next base rate case. Consistent with unusable inventory of previously decertified units, the regulatory asset amount has been included in the ECCR revenue requirement.

**Q.** **Is the Company offering any Wholesale capacity to retail customers in the 2022 IRP?**

A. Yes. The Company is offering 88 MWs of wholesale block capacity to the retail jurisdiction associated with Plant Yates Units 6 and 7 and Combustion Turbines (“CT”) at Plant McManus and Plant Wilson. If approved by the Commission, 65 MWs from Plant Yates Units 6 and 7 and 23 MWs from Plants McManus and Wilson CTs will be transferred to retail cost of service on January 1, 2024 and January 1, 2025, respectively.

**Q.** **How is the Wholesale capacity to retail offer reflected in the filing?**

A. Consistent with the 2022 IRP filing, the Company has included the rate base components associated with the capacity offer and the related allocation of the expenses in retail cost of service at the proposed dates of the transfer. Consistent with prior wholesale offers, the Company has also included a market differential adjustment (“MDA”) in this filing to meet the requirement that the transaction be offered at then-current wholesale market terms, which serves to reduce the revenue requirement in this filing. The MDA represents the difference between the levelized market value and the levelized revenue requirement of the net asset over its remaining useful life.

**Q.** **Are any of the Purchase Power agreements from the 2022 IRP scheduled to begin during this ARP period?**

A. Yes. As part of the 2022 IRP, the Company requested certification of six PPAs for a combined annual contract capacity of 2,356 MW (winter rating). Of the 2,356 MW, 1,671 MW are scheduled to begin in 2024 and 429 MW are scheduled to begin in 2025, with the remaining 256 MW scheduled to begin in 2028. The Company has included the related capacity costs of these PPAs in this ARP.

**IX. GRID INVESTMENT PLAN PROGRESS AND UPDATE**

**Q.** **Mr. Robinson, please briefly summarize the Grid Investment Plan approved in the 2019 BASE rate case.**

A. Georgia Power’s Grid Investment Plan, approved by the Commission in the 2019 base rate case, is a 12-year program that focuses on improving distribution reliability and replacing aging transmission assets. The Commission specifically approved the Company’s request to invest $1.3 billion for the 2020-2022 period. The Grid Investment Plan consists of investment packages that target underperforming feeders (also referred to as circuits) and aging transmission lines and substations that deliver electricity from generation to our customers throughout the state. Importantly, for investments focused on improving customer reliability, the Company performed an extensive economic benefit study that evaluated and determined the optimal investment range for the Grid Investment Plan to improve customer reliability across the system.

**Q. What approval is the Company seeking in this proceeding regarding the Grid Investment Plan?**

A. Consistent with the 2019 base rate case, the Company requests that the Commission approve dollars associated with the next three-year period of the Grid Investment Plan. For 2023-2025, the Company will invest approximately $2.2 billion. Exhibit \_\_\_(APA/SPA/ADH/MBR-7) contains the distribution packages for the 2023-2025 period and Exhibit\_\_\_(APA/SPA/ADH/MBR-8) contains the transmission packages for the 2023-2025 period. These refined plans align with the Company’s overall commitment to improve reliability and system performance efficiently and cost effectively.

**Q.** **Have the Grid Investment Plan objectives remained consistent with those approved in the 2019 BASE Rate Case?**

A. Yes. The Grid Investment Plan objectives remain unchanged: distribution investments focusing on improving reliability for customers and transmission investments focusing on replacing aging system assets. As mentioned above and reflected in Exhibits\_\_\_(APA/SPA/ADH/MBR-7-8), Georgia Power refined certain program components and assumptions based on positive insights, learnings, and data gathered during the initial three-year period of the Grid Investment Plan.

**Q.** **Please address the preliminary results of the 2020-2022 investments and distribution system performance improvements since the last rate case.**

A. The results from the projects completed to date have produced positive reliability benefits for Georgia Power customers. It is important to highlight that the Company tracks results of feeders selected for investment that have a full year of reliability data post-construction completion. Tracking in this manner ensures that the results reflect improvements across all seasonal variations within a full calendar cycle. These preliminary results continue to reinforce the Company’s confidence in the overall strategy and execution to date of the Grid Investment Plan.

Given that only a subset of projects have been completed and in-service for a full calendar cycle, the Company determined that revising benefit estimates for distribution investment packages is not warranted at this time. The benefit assumptions for these investment packages for the 2023-2025 period remain consistent with those applied in the 2019 Grid Investment Plan.

**Q. Earlier in the testimony you stated that the Company refined certain components of the Grid Investment Plan based on positive insights and lessons learned. please explain.**

A. During the 2020-2022 period, the Company acquired valuable knowledge about the overall program strategy and the structure required to successfully transition a program of this scale on paper to projects on the ground. The list below highlights examples of distribution investment insights and learnings the Company gained from this experience:

* **Program Strategy & Rationale:** Georgia Power confirmed that the overall strategy and economic rationale supporting the Grid Investment Plan is optimal for Georgia Power customers. The specific investment packages being deployed are producing expected benefits and delivering positive results.
* **Investment Packages Scope & Cost:** The total cost required to deliver individual investments are higher than the Company originally projected, driven by increases in both scope and cost of work. To realize the target benefits for customers, the Company refined the scope of the investment packages. As the Company learned more about existing feeder conditions, the Company made these refinements after concluding that additional work was necessary to ensure that grid investment projects operate and deliver as planned. Regarding costs, the Company has experienced increases driven by several factors, including land acquisition, traffic management and escalation in costs related to contractor labor and materials.
* **Undergrounding:** Undergrounding remains the most effective solution for improving customer reliability. However, in developing and executing projects during the 2020-2022 timeframe, the Company learned that these projects are costing more than initially expected and require longer construction times, which causes significant public disruption.

Given the learnings discussed above, the Company reassessed and refreshed the Grid Investment Plan, within the bounds of the original core strategy, to confirm which specific investment packages will continue to provide reliability improvements that benefit Georgia Power customers.

**Q.** **Will the refined Grid Investment Plan packages and strategy benefit from lessons learned from the first three years of implementation?**

A. Yes. The Company incorporated learnings and positive insights gained during initial execution of the Grid Investment Plan. The Company only made refinements that aligned with the overarching strategy and economic rationale underpinning the Grid Investment Plan approved in the 2019 base rate case.

The Company made two key changes based on the learnings to date; these changes have driven the refresh of the Grid Investment Plan:

* Updated the cost of distribution investment packages to match the costs observed through the work to date.
* Reevaluated distribution investment packages selected for each feeder to ensure that the Grid Investment Plan is still delivering reliability improvements at an optimum cost/benefit return for Georgia Power customers.

The outcome of these refinements is a distribution plan that continues to deliver, where it is economically beneficial, strong reliability benefits for customers. For example, the Company no longer leverages a hierarchy that defaults to undergrounding if a feeder qualifies, but instead allows the cost benefit analysis to determine the most cost-effective solution (e.g., hardening, sectionalizing) to achieve reliability improvements. In addition, the Company refined transmission package criteria to ensure that the appropriate scope of work continues to be considered for investment. For example, the condition of relays, which are devices that protect the system when faults and other abnormal conditions are detected, is now considered in transmission substation investment decisions instead of regulators.

**Q.** **Please provide an update on other Transmission and distribution related spending.**

A. As discussed in the Company’s most recent IRP filing, the state of Georgia has experienced positive customer growth over the last ten years and is expected to continue its robust economic growth and population trends above U.S. averages. As a result, the Company must continue to make the investments necessary to serve these new customers. The Company must also make transmission and distribution investments to support the transition of the generation fleet to more economical and cleaner resources. Importantly, these investments will ensure the Company is able to continue to provide reliable, affordable, and safe electric service to meet the long-term needs of Georgia Power customers.

X. TAXES

**Q. What taxes does the Company pay?**

A. The Company pays federal and state income taxes, local property taxes, sales and use taxes, payroll taxes and several other miscellaneous taxes. Taxes other than income taxes are shown on Exhibit\_\_\_(APA/SPA/ADH/MBR-5, Schedule 5) and the computation of income taxes is shown on Exhibit\_\_\_(APA/SPA/ADH/MBR-5, Schedule 6, Workpaper 1).

**Q. What timing differences result in deferred income taxes?**

A. Exhibit\_\_\_(APA/SPA/ADH/MBR-4, Schedule 6) identifies the categories of timing differences that result in deferred income taxes. It also shows both the provision for deferred income taxes and the reversal of income taxes deferred in prior years for each specific item.

**Q. What does the Company propose in the event legislation is passed that alters the current federal or state corporate income tax rates?**

A. If federal or state legislation is passed altering the federal or state corporate income tax rates that would impact the Company’s revenue requirement calculations, the Company would work with the Commission to appropriately address such changes at that time.

XI. WHOLESALE SALES

**Q.** **Please describe any changes to the treatment of wholesale sales in regard to retail cost of service since the 2019 Rate Case.**

A. The only change to the treatment of wholesale sales in regard to retail cost of service since the 2019 base rate case is related to the Transmission Service Agreement (“TSA”) to facilitate the transfer of energy generated at Plant Scherer Unit 4 to its owners, Jacksonville Electric Authority and Florida Power and Light. This contract was terminated at the end of 2021 due to the retirement of Scherer Unit 4. Therefore, the allocation of transmission investments and expenses associated with the contract will no longer be excluded from retail cost of service beginning in 2022.

XII. WORKING CAPITAL

**Q.** **Please explain the concept of working capital as it relates to a regulated utility.**

A. Working capital for a regulated utility can be described as the average amount of capital (in excess of that used to finance net utility plant and other separately identified rate base components) necessary to operate the business. This working capital bridges the gap from the time costs are incurred by the Company to provide electric service until the payments are received from customers for that service. Additionally, it covers other assets that must be financed by investors pending recovery from customers. This definition of working capital as applied to a regulated utility is different from the definition of working capital as used in the ordinary business or accounting sense. Working capital, as applied to commercial enterprises, is defined as current assets less current liabilities and is used for purposes of evaluating the liquidity of a commercial business at a given point in time.

**Q.** **What is included in the Company’s working capital requirement?**

A. The working capital requirement included in this filing consists of 13-month average balances of materials and supplies inventories, minimum bank balances, and prepayments. A provision for cash working capital (i.e., the cash necessary to pay operating expenses prior to collection of revenues) is included in overall working capital. Exhibit\_\_\_(APA/SPA/ADH/MBR-4, Schedule 4, Workpaper 1) provides a summary of the Company’s working capital components included in this filing. In addition, Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 5 MFF) provides the estimated cash working capital requirement related to municipal franchise fees.

**Q.** **What method was used in computing the Company’s cash working capital requirement for the test period?**

A. The Company performed a lead-lag study to determine the estimated cash working capital requirement for the test period. The study method used in this filing is consistent with studies approved by the Commission in prior rate case proceedings. The lead-lag methodology performed involves a study of the time lag between the date customers receive service from the Company and the date they pay for such service. This is reduced by any offsetting lead time between the date suppliers and employees render service to the Company and the date the Company pays for such services. This lead-lag methodology is generally accepted as the most reliable method for determining a cash working capital requirement and has historically been the stated preference of the Commission. One of the most important aspects of this methodology is that it provides specific analysis of day-to-day operations of the Company, and the results are applied to specific Company cost of service accounts. It does not rely on point-in-time balances from historical accounting records; rather, it provides a picture of the average flow of funds a utility requires in its operating cycle which can be applied to projected expenses to determine cash working capital. Although this approach is much more time-consuming than some other methods, it produces a more refined analysis. A complete description of the lead-lag study is included in Appendix Exhibit 3.

**Q.** **Does this conclude your testimony?**

A. Yes.

1. Table 1 is supported by the following exhibits: Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base) Page 1; Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 1; Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 6; Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 4 DSM) Page 1, and Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 5 MFF) Page 1.

   [↑](#footnote-ref-2)
2. Table 2 is supported by the following exhibits: Traditional Base: Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base) Page 3; ECCR Traditional: Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 2; ECCR CCR ARO: Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 6;DSM: Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 4 DSM) Page 1; MFF: Exhibit\_\_\_(APA/SPA/ADH/MBR-1, Schedule 5 MFF) Page 2 [↑](#footnote-ref-3)