STATE OF GEORGIA

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re: Georgia Power Company's Application to Adjust Rates to Include Reasonable and Prudent Plant Vogtle Units 3 and 4 Costs	)))))	Docket No. 29849

GEORGIA POWER COMPANY'S APPLICATION TO ADJUST RATES TO INCLUDE REASONABLE AND PRUDENT PLANT VOGTLE UNITS 3 AND 4 COSTS

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Georgia Power Company ("Georgia Power" or the "Company") hereby files its Application to Adjust Rates to Include Reasonable and Prudent Plant Vogtle Unit 3 and 4 costs ("Application"). As provided in the Georgia Public Service Commission's ("Commission") January 11, 2018, Order on the Seventeenth Semi-Annual Vogtle Construction Monitoring ("VCM") Report in Docket No. 29849 ("VCM 17 Order"), "once the fuel load of Unit 4 is reached, the Company may make a filing with the Commission to determine the adjustment to retail base rates necessary to include the remaining amounts of Units 3 and 4 into retail base rates. During this review, the Commission will determine the remaining issues pertaining to prudence of Units 3 and 4 costs."[1] The Company's Application is consistent with the Commission's intent and directives as stated in the VCM 17 Order, the Commission's January 3, 2017, Supplemental Information Review ("SIR") Order Adopting Stipulation in Docket No. 29849 ("SIR Final Order"), and the Commission's November 15, 2021, Order Adopting Stipulation in Docket No. 43838 regarding Georgia Power's Application to Adjust Rates to Include Certain Plant Vogtle Unit 3 and Common Costs ("Unit 3 Rate Adjustment Order").

This Application sets forth the basis for the Company's requested cost recovery. The purpose of this Application, along with the Minimum Filing Requirements ("MFRs") and supporting external testimony, is to present the remaining costs related to Vogtle Units 3 and 4 and

[1] *VCM 17 Order*, Docket 29849 at 19.

common facilities for the Commission's prudence and reasonableness review. Consistent with the Commission's VCM 17 Order, those costs deemed reasonable and prudent will go into rates the month after Unit 4 achieves Commercial Operation as recommended by the Company and ultimately approved by the Commission.

I. EXECUTIVE SUMMARY

Vogtle Units 3 and 4 Will Provide Substantial Benefits to Customers, the State of Georgia, and the Nation.

The completion of Vogtle Units 3 and 4 (the "Project") is monumental for customers, the state of Georgia, the nation, and the entire nuclear industry. These 1,102 MWe nuclear units, located at the existing Vogtle nuclear site in Burke County, Georgia, are the first new nuclear generation units to be built in the United States in over 30 years. Building new nuclear units is a complex process, and the path to completing Vogtle Units 3 and 4 faced numerous and unprecedented challenges – including the bankruptcy of the Project's contractor and the COVID-19 global pandemic. Nevertheless, the team persevered, never wavering in their commitment to complete the Project. The successful completion of Vogtle Units 3 and 4 will be the culmination of this journey—which involved tens of thousands of American craft workers and engineers, millions of labor hours, the development of a global nuclear supply chain, and a group of committed Co-Owners[2] and regulators who had the courage and foresight to support new nuclear power when others did not. Vogtle Units 3 and 4 are a testament to the fact that, when there is a common vision and a shared commitment, we can accomplish monumental things.

As Georgia's economy and population continue to grow and thrive, Vogtle Units 3 and 4 will be critical to Georgia Power's ability to continue meeting the evolving energy needs of our 2.7 million customers. Georgia is one of the fastest growing states in the country, adding more than one million new residents over the past decade – the fourth highest population gain in the country. This tremendous growth has been driven, in large part, by the fact that Georgia has consistently been recognized as one of the best states in the country in which to do business. The addition of Vogtle Units 3 and 4 will provide businesses and industries with the confidence to stay,

[2] Vogtle Units 3 and 4 are co-owned by Georgia Power (45.7%), Oglethorpe Power Corporation (30%), MEAG (22.7%), and the City of Dalton through Dalton Utilities (1.6%) (collectively, the "Co-Owners").

expand, or locate in our state, which will help ensure Georgia's economy continues to grow. Once completed, Vogtle Units 1 through 4 are expected to produce more carbon-free electricity each year than any other energy facility currently operating in the United States. Vogtle Units 3 and 4 will add two reliable, carbon-free, baseload units to the Georgia Power generation fleet, providing fuel diversity and protecting customers from unpredictable fluctuations in fuel prices.

At Georgia Power, customers are at the center of everything we do, and we are unwavering in our commitment to meet the energy needs of our 2.7 million customers and the communities we are privileged to serve. Georgia Power is grateful to the thousands of men and women who made this Project possible, and we are proud and excited for Vogtle Units 3 and 4 to join our generation fleet for the next 60-80 years.

Georgia Power and Southern Nuclear are Committed to Safety, Quality, and Compliance.

Since the Project's inception, safety has been the number one priority in the design, construction, and testing of Vogtle Units 3 and 4. Throughout construction, the Project maintained an OSHA Recordable Incidence Rate below the heavy construction industry average. Throughout construction of the Project, the Company complied with the Nuclear Regulatory Commission's ("NRC") Construction Reactor Oversight Process – an in-depth oversight and review process that enables the NRC to confirm the reactors are built according to NRC design and allows the NRC to objectively evaluate Southern Nuclear's effectiveness in assuring construction quality while communicating performance assessment results to the public. As discussed in this report and numerous VCM proceedings, the Company ensured that the priorities of safety, quality, and compliance were never outweighed by factors such as cost or schedule. As the Units transition to operations, safety and quality will remain the top priority, consistent with Southern Nuclear and Georgia Power's industry-leading operational standards. With Unit 3 commercially operable, and Unit 4 having received the 103(g) finding, both units are now under the NRC's Reactor Oversight Process ("ROP"). The ROP was designed and implemented to help ensure public health and safety in the operation of commercial nuclear power plants. Through the ROP program, the NRC communicates plant performance and assessments to the public, providing greater transparency in the process. Since moving to the ROP, neither Unit 3 nor Unit 4 has received a Notice of Violation, and both remain in favorable standing with the NRC.

Completing Units 3 and 4 Involved Numerous Challenges with Stringent Standards that Georgia Power and Southern Nuclear Strategically Navigated without Compromising Safety or Quality.

Building the country's first new nuclear generating units in more than 30 years has been a massive and complicated undertaking. In completing Vogtle Units 3 and 4, the Project Team encountered numerous challenges, including:

- Significant headwinds associated with re-establishing a nuclear construction infrastructure and workforce after 30 years of dormancy;
- Licensing delays resulting from the Fukushima-Daiichi event;
- The impacts of an immature nuclear construction industry, including shortfalls in first-time construction quality, which led to substantial rework and oversight from the NRC;
- The stringent application and implementation of a new NRC licensing approach to nuclear plant design and construction (10 CFR Part 52 ("Part 52"));
- The addition and application of nuclear standards to new U.S.-based nuclear suppliers;
- The bankruptcy of the Project's Engineering, Procurement and Construction ("EPC") contractor (i.e., Westinghouse Electric Company ("Westinghouse")) and the subsequent transition of those responsibilities to new entities;
- The decision of whether to continue the Project midstream without the protection of the EPC Agreement with Westinghouse ("EPC Agreement");
- The impacts from the COVID-19 global pandemic; and
- Startup and testing challenges on a first-of-a-kind ("FOAK") reactor and turbine design in the United States.

These, as well as numerous other obstacles, led to setbacks, delays, and cost increases. Nevertheless, because of the shared and steadfast commitment of the Company, Co-Owners, contractors, and this Commission, Unit 3 is now operating for the benefit of customers, and Unit 4 will likewise soon be complete and producing valuable power for Georgians.

Georgia Power and this Commission have Worked to Mitigate the Cost Impact of Units 3 and 4.

The Company understands and acknowledges the magnitude of the cost to build these new units, which have resulted in additional costs for customers. Accordingly, from certification through completion, the Company and the Commission have consistently taken steps to mitigate the cost impact to customers. For example:

- **EPC Agreement and Toshiba Parent Guaranty --** In 2008, Georgia Power entered into what was essentially a fixed-price contract for the Project. Under this contract, the Company only paid for completed engineering, procurement, or construction milestones, thereby protecting customers from potential cost increases during the initial stages of the Project. The EPC Agreement also included a performance guarantee from Toshiba (Westinghouse's parent company), which the Company and Co-Owners called upon following Westinghouse's bankruptcy in 2017. This performance guarantee led to $1.7 billion being returned to Georgia Power's customers in the form of bill credits and a reduction in the total capital costs to construct the Project.
- **Nuclear Construction Cost Recovery Tariff --** In 2009, to help minimize the impact of construction financing costs on customers, the state legislature passed a statute that enabled the Company to recover a portion of the Project's financing costs during construction through the Nuclear Construction Cost Recovery ("NCCR") tariff. The statute was established to help minimize the impact of construction financing costs on customers and has supported Georgia Power's access to lower financing costs for construction of the new nuclear units and other critical infrastructure.
- **Production Tax Credits and Department of Energy Loan Guarantees --** To further mitigate costs for customers, the Company proactively pursued federal incentives such as Production Tax Credits ("PTCs"), which were introduced in the 2005 Energy Act and extended in the 2017 Tax Cuts and Jobs Act. PTCs are expected to save customers approximately $1.5 billion over the first eight years of operations. The Company also pursued and secured $5.1 billion in loan guarantees from the U.S. Department of Energy ("DOE"), which is estimated to save customers more than $500 million in financing costs.

- **Return on Equity Reductions --** In 2016, to further protect customers as costs and the risk of delays increased on the Project, the Commission imposed significant return on equity ("ROE") reductions for cost increases and schedule delays from the original certification. These ROE reductions translated to lower bill impacts for customers during construction and decreased allowance for funds used during construction ("AFUDC"), ultimately lowering costs for customers once the units are included in retail rates. As a part of the SIR Final Order and VCM 17 Order, the Commission implemented significant ROE reductions as an incentive to complete the Project as expeditiously as possible. In all, these ROE reductions will have reduced impacts to customers by over $1.5 billion.
- **The Company's Election to *Not* Seek Recovery of $2.626 Billion in Project Costs from Customers --** As a part of VCM 19, following the Company's 2018 reforecast and increase in projected total Project costs, the Company elected not to seek recovery of $694 million from customers. As part of this request and as discussed later, the Company has elected not to seek recovery of $1.362 billion in prudently incurred construction costs. Further, as a result of the stipulated agreement between the Company, Commission Public Interest Advocacy Staff ("Staff"), and several intervenors, the Company will forgo recovery of an additional $1.264 billion in prudently incurred costs. In total, the Company will forgo recovery of a total of $2.626 billion in prudently incurred costs to bring Vogtle Units 3 and 4 through construction, testing, and startup and into operations to serve our 2.7 million customers.

Georgia Power's Requested Recovery of Construction and Capital Cost is Reasonable and Prudent.

By order dated January 3, 2017, in Docket No. 29849, the Commission deemed prudent the $3.569 billion incurred by Georgia Power on the Project through the VCM 14 reporting period ending December 31, 2015 (which included the settlement amounts paid or to be paid to Westinghouse). Of this amount, pursuant to the Commission's Unit 3 Rate Adjustment Order, $2.1 billion was placed in rate base the month after Unit 3 reached Commercial Operation. The Commission must now determine the reasonableness and prudence of Georgia Power's share of the remaining construction and capital cost.

As of June 30, 2023, Georgia Power's total Project construction and capital cost was $9.823 billion, including $25 million expended for Staff's construction monitoring fees and after accounting for the Toshiba Parent Guaranty funds, net of customer refunds, applied to reduce the construction and capital cost. The completion of Vogtle Units 3 and 4 has been challenged and taken longer than anticipated at the Project's outset. Through the completion of Unit 4, the Company expects to incur $10.188 billion in total Project construction and capital cost[3] and, as a part of this filing, has elected *not* to request recovery of all these reasonable and prudent costs. Instead, of the $10.188 billion the Company expects to incur, the Company has put forth the necessary support to justify the reasonableness, prudence, and recovery of $8.826 billion in total construction and capital cost. The Company's Application and the established record in Docket No. 29849, which has been built over the course of 14 years in the VCM proceedings, demonstrate that all costs incurred on the Project to date were prudently invested in compliance with the Project's certificate and the Commission's orders, and the amount the Company requests for recovery is reasonable and prudent.

Notwithstanding the Company's position that $8.826 billion would be a reasonable amount to recover for the Project, Georgia Power, Staff, and several intervenors, including Georgia Association of Manufacturers, Georgia Interfaith Power & Light, Georgia Watch, and Partnership for Southern Equity, have reached a stipulated agreement that provides for the Company to recover a total of $7.562 billion in construction and capital cost. The terms and conditions of the stipulation are a fair and reasonable resolution for how to recover the agreed to costs for Vogtle Units 3 and 4.

If the stipulation is approved, and after considering the $2.626 billion in costs that the Company will forgo for recovery, the total rate impact to Georgia Power retail customers from the construction and initial operation of Vogtle Units 3 and 4 would be approximately 10%, of which approximately 5% is already in retail rates; accordingly, the month after Unit 4 achieves Commercial Operation, average retail rates would be adjusted by approximately 5%. Notably, this estimated impact to average retail rates does not reflect the inherent fuel savings and the value of

[3] The $10.188 billion projection excludes approximately $407 million of costs associated with the cost-sharing and tender provisions of the joint ownership agreement for which Georgia Power will not seek recovery from retail customers. Of this estimated $407 million, $121 million was incurred as of June 30, 2023, related to Georgia Power's cost-sharing with Oglethorpe Power Corporation and Dalton Utilities and the September 29, 2022 settlement agreement with MEAG Power.

decreased fuel pricing volatility resulting from the Project. When fuel savings are taken into account, the total rate impact to retail customers from Vogtle Units 3 and 4 is approximately 8%.

Completion of Units 3 and 4 Represents the Culmination of a Long-Standing Commitment by Numerous Parties for the Benefit of Customers and the State.

Georgia Power and the other Co-Owners of Vogtle Units 3 and 4—Oglethorpe Power Corporation, Municipal Electric Authority of Georgia ("MEAG"), and the City of Dalton through Dalton Utilities—have actively and consistently supported this Project through extensive oversight of the Project and recognition of the value the Project will bring to Georgia for the next 60 to 80 years.

As a result of the constructive regulatory environment fostered by this Commission, Georgia's long-term energy future is sound, and Georgia Power has been able to invest in a diverse energy mix—that includes nuclear energy—to generate and deliver clean, safe, reliable, and affordable energy for customers. Nuclear energy is a necessary and critical component of a reduced carbon future for our customers, the state of Georgia, and the country. The completion of Vogtle Units 3 and 4 is not only about benefitting customers today, but also about serving customers nearly a century from now with carbon-free, baseload energy.

The successful completion of the Project is a direct result of Georgia Power's partnership with the thousands of craft workers at the site, our teammates at Southern Nuclear, our construction partners and Co-Owners, and the foresight of state and local leadership. Georgia Power is proud to have brought online the first new nuclear unit built in the United States in more than 30 years, and the Company looks forward to both units' long and productive future and the numerous benefits they will provide to our customers and the state.

II. PROJECT HISTORY AND REGULATORY BACKGROUND

A. Project Certification

1. <u>The 2007 IRP and 2016-2017 Baseload Need RFP Identified Nuclear as a Cost-Effective Baseload Resource</u>

On January 31, 2007, Georgia Power filed its 2007 Integrated Resource Plan ("IRP") with the Commission in Docket No. 24505 and identified a baseload need beginning in 2016. The IRP fully evaluated nuclear resources as a baseload option and initiated the need for a 2016-2017 Baseload Request for Proposals ("RFP"). The IRP also showed that new nuclear units performed well under many of the planning scenarios evaluated, and presented the best option to meet the Company's baseload needs in the 2016 and 2017 timeframe. On July 13, 2007, the Commission issued its Final Order approving the Company's 2007 IRP and found that it was reasonable for Georgia Power to further investigate opportunities to build new nuclear resources.

In compliance with the 2007 IRP Order, the Company issued a baseload RFP on November 6, 2007, to meet its 2016-2017 capacity needs. The RFP was conducted with the active participation of Staff and the Independent Evaluator ("IE"), the Accion Group. No bids were received in response to the 2016-2017 RFP, leaving the Company's proposal to construct Vogtle Units 3 and 4 as the only viable baseload option resulting from the RFP.

As part of the 2016-2017 RFP bid evaluation process, the Company conducted an extensive economic evaluation of the alternatives to Vogtle Units 3 and 4. Alternative technologies considered included the baseload generating plant options of pulverized coal and Integrated Gasification Combined Cycle, as well as Natural Gas Combined Cycle units. Alternative technologies were evaluated with varying fuel forecasts to represent the range of possible future fuel costs. In all, the Company evaluated economics over a range of fuel forecasts and potential carbon control cases. The results of the economic evaluation demonstrated the cost-effectiveness of Vogtle Units 3 and 4 across a broad range of possible future costs and risks. Although building Vogtle Units 3 and 4 was not the most cost-effective in *all* cases evaluated, it was the most cost-effective choice when compared to natural gas and coal alternatives within the majority of the fuel and carbon cases.

2. Consortium and EPC Agreement

The Company evaluated various technologies for the Project including the Westinghouse AP1000 reactor, the General Electric Economic Simplified Boiling Water Reactor, the General Electric Advanced Boiling Water Reactor, and the AREVA Evolutionary Power Reactor. An interdisciplinary group within Georgia Power and Southern Company conducted a technical evaluation that considered the then-current state of design and engineering and regulatory approvals of the various technologies. The group ultimately concluded that the AP1000 was the preferred choice. Several factors led to the selection of the AP1000 technology. Westinghouse had obtained NRC design certification of an earlier version of the AP1000 and was actively pursuing construction contracts to build the AP1000, both domestically and internationally. Similarly situated utilities also selected the AP1000 and were pursuing contracts with Westinghouse. The Company, as agent for the Co-Owners, was able to negotiate favorable terms and conditions in an EPC Agreement with a consortium consisting of Westinghouse and Stone & Webster, Inc. (the "Consortium" or "Contractor").

On March 21, 2008, the Georgia Power Board of Directors authorized Georgia Power management to enter into the EPC Agreement with the Consortium and on March 28, 2008, Southern Nuclear submitted the Combined Operating License ("COL") Application to the NRC. The EPC Agreement was essentially a turnkey agreement whereby the Consortium was responsible for the engineering, procurement, and construction of Units 3 and 4. The Company, together with the Co-Owners, as entities with the ultimate financial responsibility for the plant, provided oversight and were integrally involved in the day-to-day development of the Project.

3. Vogtle Units 3 and 4 Certification and Commission Consideration of Risk Factors

On August 1, 2008, the Company filed its Application for the Certification of Vogtle Units 3 and 4 and updated IRP with the Commission in Docket No. 27800. Specifically, the Company requested that the Commission: (1) certify Vogtle Units 3 and 4; (2) approve the 2008 IRP; (3) allow Construction Work in Progress ("CWIP") in rate base for Vogtle Units 3 and 4; and (4) institute Quarterly Construction Monitoring and Treatment of Indexed Costs. Staff hired Dr. William Jacobs to serve as construction monitor and assist the Staff in evaluating Georgia Power's Application for Certification of Vogtle Units 3 and 4.

At the outset of the Project, the Company and Staff both identified various Project risk categories, including: (1) price escalation; (2) regulatory issues; (3) financial issues; (4) supply chain; (5) professional labor; (6) craft labor; (7) project execution and oversight; (8) technology risks; (9) external risks; and (10) other miscellaneous risks.

The Commission carefully considered these risks among other factors that could impact Project cost and schedule. In weighing the Project risks and benefits, the Commission ultimately granted the Company a certificate to build the Project, finding the EPC Agreement reasonable and selection of the AP1000 technology to be reasonable and prudent. On March 26, 2009, the Commission issued an Order granting Georgia Power's certificate request ("Certification Order").[4] The Certification Order provided that:

- Georgia Power's Application for Certification of Vogtle Units 3 and 4 as modified by the Stipulation between the Staff and Georgia Power was approved.
- The certified in-service cost of Georgia Power's interest in Plant Vogtle Units 3 and 4 would be $6,446,564,927.[5]
- Georgia Power's selection of the AP1000 technology was reasonable and prudent.
- The EPC Agreement was reasonable.
- Georgia Power would file with the Commission semi-annual construction and monthly monitoring reports.

In finding the selection of the AP1000 technology to be reasonable and prudent, the Commission based its finding on a number of findings of fact, including: (1) the Westinghouse AP1000 was the only new-generation nuclear design certified by the NRC at the time, so it was preferable to those designs still seeking design certification; (2) the AP1000 passive design technology incorporates the necessary safeguards in the event of a design-basis accident and improves the safety of the plant; and (3) the AP1000's passive safety systems improve on the technologies of other pressurized water reactors because their simplified design requires significantly fewer pumps, valves, cable, and piping.[6] In finding the EPC Agreement to be reasonable, the Commission concluded that "[a]lthough the risk to ratepayers is not eliminated entirely, the contract contains provisions that effectively mitigate the risk."[7] The Commission further found "that by placing the risks for any additional costs related to activities requiring more

[4] *Certification Order*, Docket No. 27800 (March 26, 2009).
[5] *Id.* at 12. The certified in-service cost was later revised to $6.11 billion when Senate Bill 31 was signed into law.
[6] *Order on Remand,* Docket No 27800 at 9-11.
[7] *Id.* at 12.

man-hours or material than estimated upon the Consortium, the EPC Agreement has reasonably balanced the risks between the Company and the Consortium."[8]

4. Post-Certification Modifications

Following the Certification Order, Senate Bill 31 was signed into law, which permitted CWIP to be included in rate base during construction of Vogtle Units 3 and 4. As a result, the certified in-service amount, which included both capital costs and financing costs, was amended from $6.45 billion to $6.11 billion ($4.418 billion capital plus $1.695 billion financing costs incurred during construction).

B. Vogtle Construction Monitoring

1. Construction Monitoring Reports

In accordance with the Certification Order and pursuant to O.C.G.A. § 46-3A-7(b), since 2009, the Company has provided Staff with monthly status reports and filed semi-annual construction monitoring reports with the Commission. Through these reports, the Company provided the Commission with information it could rely on to confirm that the standards of convenience and necessity continued to be met in compliance with the Project's certificate. The construction monitoring process helped ensure that the Commission received the most up-to-date construction information for Vogtle Units 3 and 4. In addition, the VCM process provided transparency, oversight, and regular review of the Project as it progressed.

The semi-annual progress reports included any proposed revisions in the Project cost estimates, construction schedule, or project configuration, as well as a report of the actual costs incurred in the period covered by the report. Semi-annual reports were filed on February 28th for the preceding July 1 through December 31 reporting period and on August 31st for the preceding January 1 through June 30 reporting period, unless otherwise approved by the Commission.

Pursuant to the terms of the Certification Order and subsequent VCM Orders as identified below, each semi-annual construction monitoring report was required to include the following:

- The reasons for any additional change in the estimated costs of the units since the process began (Certification Order)

[8] *Id.*

- A description of any cooperative actions between other builders of nuclear units in the southeast to address labor, crafts, engineering, and management requirements (Certification Order; removed in VCM 18 Report and Final Order)
- An explanation of how the indices used in the EPC contract are tracking (Certification Order; removed in VCM 18 Report and Final Order)
- Any updated estimate of onsite fuel storage costs, including the costs for dry storage of spent fuel for an extended period of time after shutdown, and any updated calculation of spent fuel storage costs assuming Yucca Mountain is never available (Certification Order; removed in VCM 9/10 Final Order)
- The status of the Company's loan guarantee application at the DOE and, to the extent that application is granted, the impact it has or would have on the final expected in-service cost of the units (Certification Order)
- Whether the Company is using trust preferred financing and the impact it has or would have on the expected in-service cost of the units (Certification Order; removed in VCM 18 Report and Final Order)
- The extent to which the Company is using short term debt and the impact it has or would have on the expected in-service cost of the units (Certification Order; removed in VCM 18 Report and Final Order)
- An update of the estimated in-service cost and projected date of Commercial Operation of both Units (Certification Order)
- A description of all major sources of change (both increases and decreases) to the in-service cost and sources of change in Commercial Operation dates, if any (Certification Order)
- The status of the Company's combined construction and operating license application at the NRC (Certification Order; removed in VCM 9/10 Final Order)
- The status of all other significant permits and licenses required from other government agencies (Certification Order)

- The status of procurement, engineering, fabrication, transportation, and erection of major equipment (Certification Order; removed in VCM 9/10 Final Order)
- The status of transportation links for heavy forgings and modules (Certification Order; removed in VCM 18 Report and Final Order)
- An updated comparison of the economics of the certified Project to other capacity options (Certification Order, removed in VCM 23 Order)
- An update to Project financing provided in response to Staff data request STF-TN-1-2, including copies of the most current information shared with rating agencies (Certification Order)
- An estimate of the Total Project Cost (which consist of Total Construction and Capital Cost plus Construction Schedule Financing Costs) (VCM 9/10 Order)
- An estimate of the revenue requirements that the Company expects customers will incur both during construction and over the operating life of each unit for each delay scenario (VCM 9/10 Order)
- Up to date analysis of contingency (VCM 18 Order)
- A reasonably estimated quantification of Project risks (VCM 18 Order)
- Variances to the cost and schedule, quantified in dollars and days and fully explained (VCM 18 Order)

Since certification, Georgia Power has filed 28 semiannual construction monitoring reports in compliance with this requirement in Docket No. 29849. This represents 14 years of supporting data, information, and progress reports on the Project on file and reviewed by the Commission and its Staff. This includes 250 sets of data requests with more than 6,900 questions and responses filed in Docket No. 29849 to date. In addition, the VCM Reports provide evidence of the Company's management of the Project from start to finish, as well as in response to and throughout each major challenge encountered during construction and testing of Vogtle Units 3 and 4. The Company has made additional documentation available for Staff review and coordinated site visits and technical meetings between Staff and Project personnel. As the Commission has previously found, through the VCM process, the Staff and Construction Monitor have been actively and diligently monitoring the decisions and actions of the Company and reporting their observations to the Commission since the beginning of the Project. The Commission has further found that their review and monitoring of the Project has been thorough and reasonably critical of the Company's actions and decisions, performing exactly as the Commission directed.[9]

In each VCM Report, until the VCM 25 Report (as described later), the Company identified the Project expenditures incurred during the respective six-month reporting period. In accordance with O.C.G.A. § 46-3A-7(b), in each VCM Order, the Commission then verified and approved whether such expenditures were made pursuant to the Project's certificate as well as any proposed revisions. Verification of expenditures by the Commission through this process forecloses subsequent exclusion of such costs from rate base absent fraud, concealment, failure to disclose a material fact, imprudence, or criminal misconduct. O.C.G.A. § 46-A-7(c).

2. Oversight by the Independent Construction Monitor

The Commission selected Dr. William Jacobs to serve as the Independent Construction Monitor ("Construction Monitor"). In that role, Dr. Jacobs assisted Lead Analyst Steve Roetger and the rest of Staff with all aspects of the Project. Staff reviewed the Company's weekly and monthly metrics report and submitted data requests to the Company for additional information. Dr. Jacobs and Mr. Roetger attended Monthly Project Review Meetings for the Project and, for many years, maintained an office onsite at the Project. Dr. Jacobs, Mr. Roetger, and other Staff members attended multiple Vogtle site visits and daily planning meetings, even attending remotely throughout the COVID-19 pandemic. In addition, following the reforecast of costs in VCM 19, Georgia Power and Staff agreed to increase the Commission monitoring costs up to $3.8 million per year to provide Staff with resources to continue to monitor the Project in light of changing circumstances. Staff hired the Vogtle Monitoring Group ("VMG") to assist with monitoring the Project, including stationing a representative at the Project to attend meetings and oversee progress at Units 3 and 4 on site. In addition to Dr. Jacobs' role, VMG has conducted schedule and cost analyses, provided testimony, and supported Staff in its prudence review and oversight of the Project. Moreover, as part of each VCM proceeding, Staff Analyst Shemetha Jones provided the Commission with an update on her review and analysis of the Company's Construction

[9] *See SIR Final Order*, Docket No. 29849, at 6.

Management Costs and Co-Owners' Costs, internal and external audits, and the Company's controls and procedures to ensure Project costs are properly accounted for and recorded. In most VCM proceedings, Staff also filed testimony providing economic analyses, finance analysis, and/or analysis of rate impacts of the Project, most often led by the Commission's Director of Utility Finance, Tom Newsome, and supported by additional consultants. Through June 30, 2023, Georgia Power has paid $25 million for the independent Construction Monitor's services and additional consulting services rendered to Staff.

C. Supplemental Information Review

On December 31, 2015, the parties to the EPC Agreement entered into a settlement agreement (the "Definitive Settlement Agreement") that resolved pending litigation between the Co-Owners and the Contractor as well as several other issues, including an increase in Westinghouse's limit of liability, and consequently the Toshiba Guarantee, of almost $1 billion. On January 21, 2016, the Company filed with the Commission an Application for Review and Approval of the Definitive Settlement Agreement[10] for Plant Vogtle Units 3 and 4 and Amendment 7 to the EPC Agreement. As part of that Application, the Company requested Commission review and approval of the Definitive Settlement Agreement and Amendment 7 to the EPC Agreement as prudent, reasonable, and in the best interest of the Company's customers. On February 5, 2016, in response to that request, the Commission issued an order creating a process to receive and review supplemental information from the Company, the Co-Owners, and intervenors (the "SIR PSO").[11]

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[10] The Definitive Settlement Agreement was an agreement between the Co-Owners and Westinghouse to settle certain major claims and disputes and modify the EPC Agreement. These major claims revolved around requests for change orders, which led to delays in issuing various licenses and work authorizations. Westinghouse and Stone & Webster asserted that design changes and licensing delay were a result of NRC actions that were compensable under the EPC Agreement. The Co-Owners denied that the change orders were within the scope of their obligation to pay. The dispute resulted in litigation in federal court in the Southern District of Georgia.

The Definitive Settlement Agreement focused the contractor's responsibilities on Westinghouse as a single prime contractor and resolved the "contentious and distracting" litigation between the Co-Owners, Westinghouse, and CB&I Stone & Webster. *See Georgia Power Company's Application for Review and Approval of the Definitive Settlement Agreement*, Docket No. 29849 (Jan. 21, 2016) at 2-3.

[11] *Order Regarding Supplemental Information, Staff Review, and Opportunity for Settlement*, Docket No. 29849 (February 5, 2016).

On April 5, 2016, the Company filed a report as part of the Commission's SIR. The SIR report was filed in support of the Company's request that the Commission approve the Company's settlement with the Contractor, and in support of a finding that all costs incurred on Vogtle Units 3 and 4 through December 31, 2015, were prudently incurred and in compliance with the Project's certificate. The SIR report demonstrated that all costs on the Project had been prudently invested, that the newly proposed cost and schedule forecast was reasonable, and that the settlement of claims with contractors was justified and in the best interests of customers and the Company.

The Co-Owners each filed comments in support of the Company's SIR report. Additional comments were filed by intervenors Resource Supply Management ("RSM"), Georgia Watch, and Southern Alliance for Clean Energy ("SACE"). On October 20, 2016, Staff filed a Stipulation with the Commission—signed between Staff, the Company, the Georgia Association of Manufacturers ("GAM"), and the Georgia Industrial Group ("GIG")—resolving all issues from the SIR PSO. On December 6, 2016, the Commission held hearings to consider the Stipulation and, on December 20, 2016, voted to approve the Stipulation.

The SIR Final Order resolved prudency determinations for the Project from certification through the end of the reporting period for VCM 14. As part of the approved Stipulation, $3.569 billion in costs incurred through December 31, 2015, and to be incurred through the settlement with the Consortium were deemed prudent. Additionally, $5.68 billion was deemed reasonable and presumed prudent, such that a party challenging costs incurred above $3.569 billion and up to $5.68 billion would bear the burden of proving such costs were imprudent. For any and all costs above $5.68 billion, the Company retained the burden to show that any such costs are reasonable and prudent. The NCCR statute was deemed to apply only to the certified capital amount of $4.418 billion and financing costs recovered through the NCCR were deemed prudent if incurred prior to December 31, 2019, for Unit 3 and December 31, 2020, for Unit 4. The Commission also ordered a reduction of the ROE on the entire Project cost estimate from 10.95% to 10% effective January 1, 2016, saving customers approximately $185 million through the end of construction. Additionally, if the Project was not completed by December 31, 2020, the Commission ordered that the Company automatically reduce its NCCR ROE by 300 basis points and its AFUDC ROE to its average cost of long-term debt.

D. Westinghouse's Bankruptcy and the Interim Assessment Agreement

At the end of 2016, Toshiba announced it would write off several billion dollars in connection with its investment in Westinghouse. In early 2017, Toshiba further announced that it would exit the nuclear construction business. By March 2017, it had become apparent that Westinghouse would seek bankruptcy protection, and the Co-Owners began planning for contingencies to continue the Project in the event of a Westinghouse bankruptcy.

Westinghouse filed for bankruptcy on March 29, 2017. On the same day, Westinghouse entered into the Interim Assessment Agreement ("IAA") with Georgia Power (acting for itself and as agent for the other Co-Owners). The IAA allowed work on the Project to continue after Westinghouse declared bankruptcy while the Co-Owners decided the best path forward for the Project. On March 30, 2017, the Bankruptcy Court entered an order approving the IAA.

During the interim assessment period, the Co-Owners agreed to pay all costs related to construction and supplies for the Project. While the IAA was in effect, Georgia Power ceased making payments under the EPC Agreement and instead incurred liabilities pursuant to the IAA. The EPC Agreement between Westinghouse and the Co-Owners was rejected in bankruptcy. The duration of the IAA – from March 30, 2017 to July 27, 2017 – allowed time to negotiate a long-term agreement for Westinghouse to continue supporting the Project. During the IAA period, the Co-Owners coordinated with Westinghouse and its subcontractors and vendors to transfer to the Co-Owners primary responsibility for most of Westinghouse's prior scope of work under the EPC Agreement, including construction and project management.

Following the bankruptcy, the Company negotiated with Westinghouse to set forth the terms and conditions for Westinghouse's required long-term participation on the Project, which culminated in the execution of the Services Agreement on June 9, 2017. Among other things, the Services Agreement:

- Clarified intellectual property licenses given Westinghouse's status as sole provider of the AP1000 technology;
- Delineated the division of responsibility given the change modification in the scopes of work of the Project;
- Created flexibility in ownership for certain scopes of work to provide opportunities for the Project to diversify and optimize resources; and

- Established limitations on the amount of risk Westinghouse could incur given its bankruptcy proceeding.

Execution of the Services Agreement was subject to conditions, including approvals by the DOE, debtor-in-possession ("DIP") lenders, and the Bankruptcy Court. On July 20, 2017, the Services Agreement was amended and restated to incorporate modifications requested by DOE and DIP lenders, but no material modifications were made. The Amended and Restated Services Agreement was approved by the Bankruptcy Court on July 20, 2017, pending DOE approval. The Services Agreement became effective on July 27, 2017, at which time the IAA expired. The Bankruptcy Court also approved Westinghouse's request to reject the EPC Agreement.

Pursuant to the Services Agreement, Westinghouse (1) supported the transition to the Co-Owners of primary responsibility for most of its scope under the EPC Agreement, including construction and project management, (2) provided design and engineering services for the balance of the Project, and (3) provided other engineering, procurement, and technical support and staff augmentation services to support Co-Owners' completion of the Project through startup. As part of the change in overall Project leadership, and consistent with the rejection of the EPC Agreement, the Co-Owners assumed many of Westinghouse's previous subcontracts and purchase orders and either executed, or continued negotiating, new agreements with certain subcontractors and vendors. The Services Agreement maintained and further expanded the Co-Owners' rights to the AP1000 intellectual property and access to Westinghouse's engineering expertise.

E. Construction Contractor Transition and Project Completion Analysis

The IAA provided the Co-Owners with direct access to detailed information associated with Westinghouse's cost to complete analysis and schedule, which informed the Co-Owners' assessment of the best path forward for the Project and customers. After reviewing this information, the Company determined that the December 2019 and September 2020 forecasted in-service dates for Units 3 and 4 previously provided by Westinghouse were not achievable. In addition, after receiving access to the contracts that Westinghouse held with subcontractors and vendors for substantial scopes of work, Southern Nuclear commenced an in-depth review of the subcontracts both to inform the Estimate to Complete ("ETC") process and to determine how to proceed with respect to each contract. As part of this review, Southern Nuclear examined numerous factors for each contract, including items such as the scope of work being performed, the total contract price, the amount left to be spent on the contract, the terms and conditions of the contract, outstanding invoices, and the sequencing of the remaining work to be performed.

In parallel with the efforts to continue work on the Project, to protect the Co-Owners' rights in the Westinghouse bankruptcy proceeding, to establish a new Project structure, and to negotiate agreements with the contractors for continued support of the Project, the Company undertook several efforts to analyze whether the Project should continue or, alternatively, be cancelled. These analyses included:

- Southern Nuclear's ETC;
- Kenrich's analysis of cost and schedule;
- Bechtel's assessment of cost and schedule;
- Pegasus-Global's analysis of the costs to cancel one or both units;
- Black and Veatch's estimate of the costs of demobilizing and securing the site; and
- PwC's quantitative risk analysis for the three options presented for consideration.

The Company, Southern Nuclear, and the independent consultants continued to develop and refine these analyses over the summer of 2017. In parallel, the Co-Owners independently considered their specific non-shareable costs, such as financing costs, and their specific circumstances, such as their need for capacity.

In addition to analyzing the cost and schedule, the Project Team's organizational structure was reviewed and aligned around an integrated project execution focus, with a singular point of accountability for all Southern Nuclear and contractor resources. As part of and in addition to those organizational efforts, the Company received bids from both Fluor and Bechtel to serve as the construction contractor. Upon careful review of the bids and discussions with both firms, the Company selected Bechtel as the construction contractor, ultimately agreeing to contract terms on October 23, 2017.

Bechtel brought to the Project a reputation for engaging well-qualified, talented teams with strong leadership and senior-level engagement. Bechtel promised to bring to the Project its strong relationship with the building trades, having just recently completed the Watts Bar Unit 2 construction for the Tennessee Valley Authority. Bechtel also developed its own risk-informed plan to complete the Project on the revised schedule and reviewed and substantiated portions of the Southern Nuclear ETC. The Bechtel Agreement, entered into between the Project Co-Owners and Bechtel, aligned Bechtel with the Co-Owners on the goals of completing the Project in the safest and most efficient manner with the highest level of quality. The Bechtel Agreement is a cost-reimbursable contract that uses an at-risk fee mechanism to incentivize Bechtel based on Bechtel's costs and schedule performances measured against certain commercial targets.

Given Bechtel's experience on the Project, an efficient transition to a single construction contractor was possible with minimal disruption to the Project. Under the Services Agreement, Westinghouse continued to provide engineering and procurement support as well as access to the AP1000 technology. After entering into the Bechtel Agreement, the Company continued to work closely with Southern Nuclear to provide oversight on the Project and ensure quality and compliant construction.

F. VCM 17 – The Go / No-Go Decision

As required by the VCM process, the Company filed its revised costs, schedule, and project configuration following the Westinghouse bankruptcy for Commission review in the VCM 17 Report on August 31, 2017. The Company sought (1) Commission approval and verification of expenditures incurred during the reporting period, (2) Commission approval of the Company's proposed revisions in cost estimates, construction schedule, and project configuration, and (3) a Commission determination as to whether such proposed costs were reasonable. In addition, as directed by the Commission,[12] the Company included within its VCM 17 Report its recommendation to continue construction of Units 3 and 4.

Based on the information available and its estimates at the time, the Company identified the most reasonable schedule for Unit 3 and Unit 4 Commercial Operation Dates ("CODs") to be November 2021 and November 2022, respectively. In relation to the then-current schedule, the requested schedule revision represented an additional 29 months for each unit. When the VCM 17 Report was filed, Georgia Power's share of the total Project construction and capital cost was forecasted to be $8.77 billion. The Company provided the Commission with the most complete

[12] *Order Requiring Georgia Power Company to File Certain Information*, Georgia Public Service Commission, Review of Proposed Revisions and Verification of Expenditures Pursuant to Georgia Power Company's Certificate of Public Convenience and Necessity for Plant Vogtle Units 3 and 4, Docket No. 29849 (August 23, 2017).

analysis possible, which included the Southern Nuclear ETC, Kenrich ETC, Bechtel Cost and Schedule Assessment, and PwC quantitative risk analysis. The Company sought Commission approval of its new project management structure whereby Georgia Power, along with Southern Nuclear acting as the project manager, would manage the Project on behalf of the Co-Owners pursuant to a revised Ownership Participation Agreement and Bechtel would serve as the primary construction contractor. As described above, the Company evaluated the risk and uncertainties on the Project in determining whether to proceed to Project completion. Based upon the best information available at the time of filing the VCM 17 report, the Company recommended that completing the Project was in the best interests of customers.

In the Commission's VCM 17 Order, the Commission approved a revised capital and construction cost forecast of $7.3 billion, net of the Toshiba Parent Guaranty payments and customer refunds. The Commission found that any cost spent up to this amount would be deemed reasonable and was not to be considered a cost cap. The Commission made no determination as to prudence or cost recovery at that time, deciding to hold all cost recovery decisions until after a prudence review following the completion of construction for both units. To further incent the Company to bring Units 3 and 4 online, the Commission ordered tiered reductions to the Company's allowed ROE for the Project beyond those that had been approved in the SIR Final Order. The Commission approved a revised schedule that established the regulatory-approved in-service dates as November 2021 and November 2022 for Units 3 and 4, respectively.[13] The Commission also provided that, effective the first month after Unit 3 achieves Commercial Operation, retail base rates shall be adjusted to include the costs related to Unit 3 and common facilities deemed prudent in the SIR Stipulation.[14]

G. VCM 19 – Revised Estimate of the Cost to Complete the Project

At the time the VCM 17 Report forecast was approved as reasonable by the Commission, it included, among other things, a category of unallocated funds that the Company expected to be specifically allocable within a reasonably short period of time, but which was not yet allocated to specific line items. Over the following year, as Southern Nuclear assigned those dollars to specific

[13] *VCM 17 Order*, Docket No. 29849, at 17.
[14] Id. at 18.

line items, it undertook significant efforts to manage the Project within the forecast presented in the VCM 17 Report, while maintaining Project momentum and transitioning Project management to Southern Nuclear without the fixed/firm price EPC Agreement.

Notwithstanding these efforts, Southern Nuclear determined that certain categories of cost estimates contained in the Southern Nuclear ETC were insufficient because they did not fully anticipate or address certain costs, circumstances, and events that the Project experienced. Southern Nuclear determined that it would be necessary to implement changes to lower Project risks, maintain its schedule, and address cost estimates that were included in the Southern Nuclear ETC. Accordingly, Southern Nuclear developed a core team of project controls and support personnel to re-perform a full cost estimate for the Project. The core team met with functional area budget owners to update assumptions associated with staffing and procurement needs to complete the Project. They also reviewed the Project's contractual obligations, including the Westinghouse Services Agreement and the Bechtel Construction Completion Agreement, to update the forecasts for these agreements, and continued efforts to firm up other estimated costs, such as the 60-plus subcontracts that had not yet been negotiated at the time of the Southern Nuclear ETC. Many of these new subcontracts reflected changes in market conditions and, in some cases, scope adjustments. Finally, the team assessed project risks to determine the appropriate forecast for various cost components and additional needed contingency.

After reviewing and assessing costs and schedule based on a year's worth of experience managing the Project, Southern Nuclear revised its estimate of the cost to complete the Project. The increase in Project estimate was a result of management decisions by Southern Nuclear intended to lower project risks and maintain the target schedule. These cost drivers included an expansion of Bechtel's scope and fee structure, increased field supervision and engineering support, and the implementation of incentives to recruit and retain adequate staffing.

The Company's VCM 19 Report reflected the revised estimate of the cost to complete the Project, showing an increase in Georgia Power's projected share of the total cost from $7.3 billion to $8.4 billion, net of the Toshiba Parent Guaranty and customer refunds. This increase of approximately $1.1 billion included $694 million in base capital forecast and a project contingency estimate of $366 million. The Company stated it would not seek rate recovery from customers of the $694 million increase to the base capital forecast, as reflected in Table 1.1 in the VCM 19

Report. The Company reserved the right to return to the Commission to seek cost recovery of the remaining $366 million at a later date, as appropriate.

H. VCM 24 – Modification of the VCM Process

In addition to verifying and approving expenditures incurred during the VCM 24 reporting period, the Stipulation between the Company and Staff resolving the VCM 24 proceeding set forth the agreed treatment for how the Commission should review actual costs in excess of the $7.3 billion previously deemed reasonable in the VCM 17 Order. The VCM 24 Stipulation provided:

1. All Commission decisions regarding the prudence of investments not already deemed prudent through the SIR Stipulation shall be made after a prudence review as contemplated in the VCM 17 Order. The Company retains the burden of proof on prudency for all capital costs above $5.68 billion.
2. Beginning with the VCM 25 reporting period, the Project exceeded the $7.3 billion capital cost forecast previously deemed reasonable by the Commission in its VCM 17 Order.
3. Beginning with VCM 25 and for each VCM thereafter, the Commission should no longer verify and approve costs incurred on the Project, but rather only review costs above $7.3 billion without making any determination as to reasonableness or prudence until the prudence review contemplated in the VCM 17 Order.
4. The Company should continue to report on the progress and cost of the Project, the Company should continue to file semi-annual VCM reports, and the VCM proceedings and process should continue through Project completion.

In accordance with the VCM 24 Order, the Company did not seek verification and approval of Project expenditures in excess of $7.3 billion in VCM 25 or any subsequent VCM proceeding to date.

I. Financial Penalties and Costs Absorbed by the Company

The Commission and its Staff have closely monitored the construction progress and costs incurred on Units 3 and 4 throughout the VCM process. In response to cost overruns and schedule delays, the Commission has acted throughout the life of the Project to implement periodic financial penalties to incent the Company to complete the Units faster and on budget without compromising safety and quality. In its SIR Final Order, the Commission reduced the Project's ROE from 10.95% to 10%. The Commission also directed that additional financing costs related to investment above the certified amount would be collected in AFUDC, rather than through the NCCR tariff, and any AFUDC ROE calculated on total Project cost above $5.44 billion would be calculated at the Company's average cost of long-term debt. As a further incentive, if the Units did not achieve Commercial Operation by December 31, 2020, the Commission approved an automatic 300-basis point ROE reduction to the NCCR ROE and reduction of all AFUDC ROE to the Company's average cost of long-term debt without any additional action required by the Commission or its Staff.

In the VCM 17 Order, and as an added inducement to bring the Units online, the Commission modified its prior ROE reductions by reducing the NCCR ROE from 10% to 8.3% beginning January 1, 2020, with an additional NCCR ROE reduction beginning January 1, 2021, from 8.3% to the higher of (1) 5.3% or (2) the average cost of long-term debt. Beginning in 2018, the Commission also set the AFUDC ROE at the Company's average cost of long-term debt. Moreover, if Unit 3 did not achieve Commercial Operation by June 1, 2021, the Commission ordered the NCCR ROE to be further reduced by 10-basis points each month (but no lower than the long-term cost of debt) until Commercial Operation. The Commission also ordered that if Unit 4 was not commercially operational by June 1, 2022, the NCCR ROE for Unit 4 would be reduced by 10 basis points each month, but not lower than the long-term cost of debt, until Commercial Operation. The Commission's ROE reductions have saved customers over $1.3 billion and resulted in negative earnings impacts to the Company of approximately $1 billion through June 2023 and continue to have negative earnings impacts with each month of delay.

In addition, the Company has voluntarily absorbed a portion of the cost overruns incurred to date. As previously discussed, the Company reforecast the cost to complete the Project in VCM 19, which resulted in a $1.1 billion forecasted cost increase to the Project. The Company is not seeking to recover $694 million of this $1.1 billion increase from customers and, with this filing and as a result of the stipulated agreement in this docket, is foregoing potential cost recovery of an additional $1.9 billion. In total, the company is foregoing construction and capital cost recovery of $2.6 billion dollars.

J. Unit 3 Rate Adjustment

On June 15, 2021, Georgia Power submitted its Application to Adjust Rates and supporting MFRs to include costs related to Unit 3 and common facilities that were previously deemed prudent in the SIR Stipulation. The Unit 3 Rate Adjustment proceeding identified those costs recoverable through an adjustment to the base revenue requirement and base rates, the costs that were to remain eligible for recovery through the NCCR tariff, the costs that were to be recovered through the Fuel Cost Recovery tariff, and the costs, if any, that would be eligible for deferral and consideration in a future ratemaking proceeding. No prudency determinations were made in the Unit 3 Rate Adjustment proceeding.

The Commission approved the settlement reached by the Company and Staff, which resolved all outstanding issues in the Unit 3 Rate Adjustment proceeding. As a result, of the $3.569 billion in construction costs incurred, verified, and approved through VCM 14 and deemed prudent in the SIR Stipulation, the Commission authorized the inclusion of $2.1 billion in rate base after Unit 3 reached Commercial Operation. The Unit 3 Rate Adjustment Order also provided that, following the conclusion of the prudency proceeding, the total amount found reasonable and prudent by the Commission to be placed into rate base would be net of the $1.493 billion remaining balance for the Toshiba Parent Guaranty.

All remaining costs for Vogtle Units 3 and 4 and common facilities not previously deemed prudent in the SIR Stipulation are subject to the Commission's reasonableness and prudence review in this Prudence and Unit 4 Rate Adjustment proceeding.

III. COST RECOVERY

A. Legal Standard

Under Georgia law, costs incurred in the construction of the Project may be included in base rates if they are found to be *prudent* and *reasonable*.[15] In *Review of Georgia Power Co.'s*

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[15] O.C.G.A. § 46-3A-7(a) ("Inclusion of costs in excess of 100 percent of those approved by the commission shall not be permitted unless shown by the utility to have been reasonable and prudent."); see also *In Re: Application of Georgia Power Co. for Auth. to Increase Retail Elec. Serv. Rates*, Georgia Public Service Commission, Docket No. 3673-U (Nov. 12, 1987) ("Utility rates may only reflect those costs which were prudently incurred, reasonable and not unlawful.").

Rocky Mountain Pumped Storage Facility, Docket No. 6739 (Jan. 14, 1998), the Commission defined the prudence standard as follows:

> A decision must not be judged as correct or incorrect in the light of perfect hindsight. Rather, a decision must be judged as to whether it was reasonable given the facts and circumstances which were known or which reasonably should have been known at the time the decision was made. In applying this standard, it must be recognized that in any decision making process there may exist a range of choices, any or all of which could have been adopted by reasonable management in good faith and under the same set of circumstances. If the Company has made a decision which falls within that "zone of reasonableness," that decision must be found to have been prudent, irrespective of whether others may have selected another alternative, and irrespective of whether in hindsight another decision may now appear in hindsight to have been a more correct decision.

The test for prudence is an objective legal test based on a specific factual inquiry. The prudency standard evaluates whether decisions and actions were reasonable under the circumstances, given what was known or should have been known at the time the decision was made. The standard is one of reasonableness that must be based on a contemporaneous view of the action or decision under question, <u>without</u> the benefit of hindsight. Essentially, the prudence standard, as defined by the law and previously by this Commission, asks the Commission to put itself in the shoes of the project managers at the time critical decisions were being made, and ask itself "what would a reasonable manager have done and was what the Vogtle Project managers did within an acceptable zone of reasonableness?"

The concept of prudence implies a standard or duty of care owed to others. In building a nuclear power plant, the NRC requires the utility to exercise a high standard of care to protect the public health and safety. Similarly, given the costs involved and the rate impact of those costs on customers, the Commission holds the utility to a high standard of care in making decisions and taking actions in its planning and constructing such a project. Thus, while the standard to be applied is reasonableness under the circumstances, where the risk of harm to the public and ratepayer is greater, the standard of care expected from the reasonable person is higher.

Prudence goes to the decision-making process; reasonableness goes to the cost of that prudent decision. Thus, when a utility seeks to add costs over the certified amount to rate base (which is when the reasonableness test comes into play) the utility must not only establish that the costs above the certified amount are the product of judicious and prudent decision-making, it must also establish that the amounts of those costs are reasonable.[16] That is, the utility must show that the costs were not only the result of prudent decisions but that there were no less costly ways to implement the prudent decision. Reasonableness is itself an objective and factual standard. It is not defined by how much one thinks he or she should pay, it is defined by whether the cost incurred implementing a prudent decision was reasonable compared to the available options. In other words, while the decision to incur a certain cost may have been prudent, the total amount of that cost may be excessive and not properly chargeable to the ratepayer. The determinative issue for reasonableness is not whether the decision to incur the costs was prudent, but whether the prudent decision was implemented appropriately.

Both the reasonableness and prudence standards are satisfied by the reasonable manager standard (i.e., what a reasonable manager would have done under the same or similar circumstances). Given this standard of care, a reasonable person is one who is qualified by education, training, and experience to make the decision or take the action, using available information and applying logical reasoning processes. Utility rates may only reflect those costs that were prudently incurred, reasonable, and not unlawful. Consequently, costs that are incurred because of imprudent action or inaction, or are unreasonable, excessive, or unlawful, are disqualified from rate recognition.

B. Reasonable and Prudent Project Costs

1. Construction and Capital Cost

Through the VCM 29 reporting period, Georgia Power's forecasted total construction and capital cost for Vogtle Units 3 and 4 is $10.188 billion, including $33 million allocated for Staff's construction monitoring fees and after accounting for the Toshiba Parent Guaranty funds, net of customer refunds, applied to reduce the construction and capital cost. Consistent with prior testimony in the VCM process, while all costs incurred on the Project were prudent, the Company agrees that it is not reasonable for all costs incurred on the Project to be paid for by Georgia Power's customers. As such, the Company offers the following support for the reasonableness and prudence of $8.826 billion in total construction and capital cost, which is $1.362 billion less than

[16] O.C.G.A. § 46-3A-7(a).

the $10.188 billion the Company expects to incur throughout construction and startup of the Project and greater than the $7.562 billion the Company has agreed to in the signed stipulation.[17]

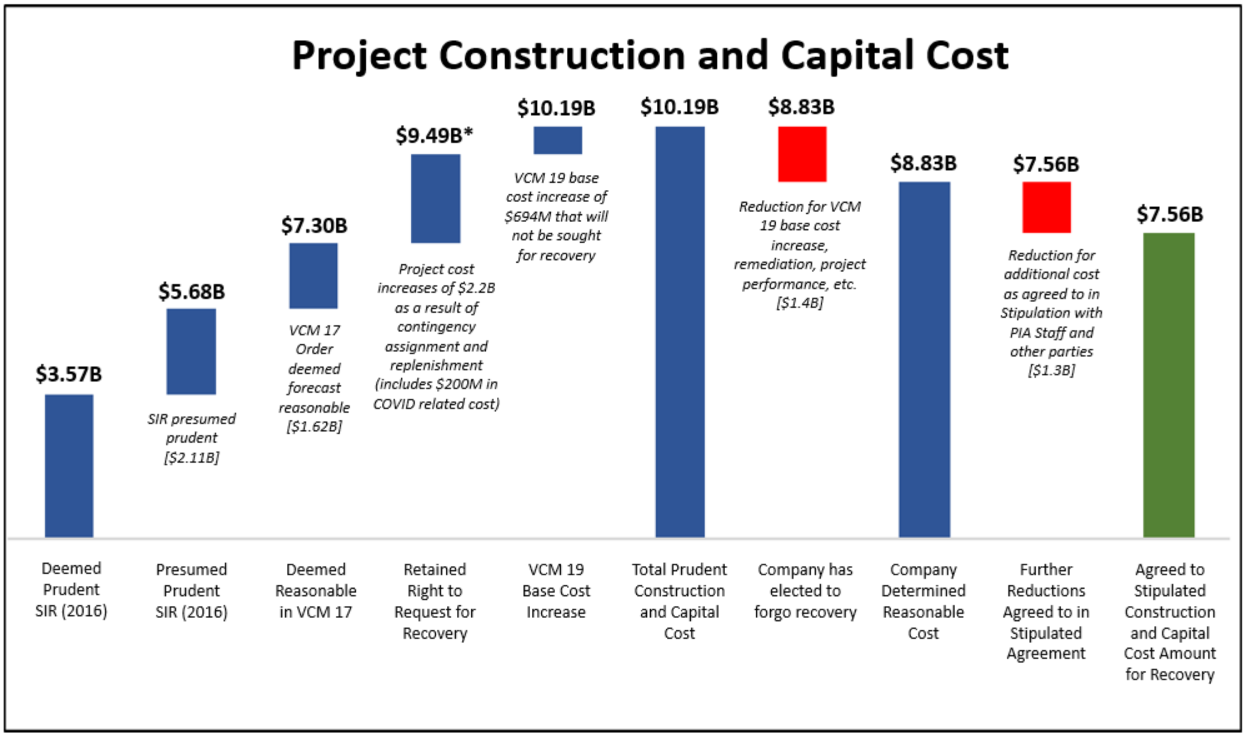
As previously described in Section III(A), to recover construction and capital cost, Georgia Power must demonstrate that such costs were both reasonable and prudent. The record of Georgia Power's expenditures on the Project to date has been provided and reviewed by the Staff and Commission throughout the VCM proceedings. In addition, at various points throughout the construction of the Units and as part of the VCM docket (No. 29849), the Commission has already found that certain categories of costs were reasonable or prudently incurred:

- As part of the SIR Final Order, the Commission deemed prudent the $3.569 billion incurred by Georgia Power on the Project through the VCM 14 reporting period ending December 31, 2015 (including settlement costs paid or to be paid to Westinghouse).
- Also, in the SIR Final Order, the Commission found that costs up to $5.68 billion were presumed prudent, thereby shifting the evidentiary burden to intervening parties to show that costs incurred over $3.569 billion and up to $5.68 billion were *not* prudently incurred.
- In VCM 17, the Commission deemed that construction and capital cost up to $7.3 billion were deemed reasonable.
- Through the VCM process, the Commission has verified and approved all expenditures up to the revised, approved construction and capital cost of $7.3 billion and has reviewed, but not verified and approved, all expenditures above that amount.

A graphical representation of the Project costs and portions of those costs already found to be reasonable or prudent is included in Figure 1 below:

[17] Notwithstanding the stipulated agreement reached with Staff and several intervenors, the Company submits its support for the reasonableness and prudence of $8.8 billion in total construction and capital cost, along with the accompanying financing and operating costs. The Company acknowledges that it has agreed to recover less from customers as part of a reasonable resolution to this case via the stipulated agreement signed with Staff and several intervenors.

Figure 1: Project Construction and Capital Cost



* Excludes Co-Owner sharing and tender

Considering the Commission's prior findings, and as further described below, Georgia Power supports the reasonableness and prudence of $8.826 billion of total Project construction and capital cost for Vogtle Units 3 and 4. The construction and capital cost included within the $8.826 billion are identified in Table 1 and described below.

Table 1: Reasonable and Prudently Incurred Costs Included in the $8.826 Billion

Cost	**Amount (millions)**[18]
VCM 17 Previously Deemed Reasonable Amount	$7,293
COVID-19 Costs (Schedule and Mitigation)	$200
Change in Scope	$142
Procurement of Materials and Equipment	$105
Additional Engineering Resources (headcount and duration)	$48
Direct Construction Productivity/Performance	$413
Schedule Changes (non-COVID) Driven by Scope Increases	$517
Miscellaneous (Taxes, Regulatory Support Costs, and IT)	$75
Construction Monitor	$33
Total	**$8,826**

- **Previously deemed reasonable amount**. In VCM 17, the Commission approved the revised construction and capital cost forecast of $7.3 billion and found that any costs spent up to the revised cost forecast were deemed reasonable. At the time of the VCM 17 filing the Company's total investment in the Project was $4.444 billion, including the costs verified and approved in VCM 15 and 16 and costs incurred during the IAA.
- **COVID Costs (Schedule Impacts and Mitigation)**. The Project incurred $200 million in costs related to the impacts of the COVID-19 pandemic. This amount includes approximately $40 million incurred to establish and staff the onsite medical village, vaccines, testing, masks, hand sanitizer and cleaning stations, and the cost of keeping the workforce safe, healthy, and offsite when diagnosed with COVID-19 (or had been in close proximity to someone who was), among other mitigation measures. The Project's COVID-19 costs also include $160 million in schedule impacts due to productivity challenges from higher-than-normal absenteeism for craft and non-manual personnel, social distancing requirements, and disruption to planned and ongoing work (direct construction, subcontracts, testing) due to mandatory isolation restrictions. Finally, these costs incorporate the impacts from the Project's reduction in force measures taken at the onset of the pandemic to create greater physical separation and less workspace congestion on site. The Project Team's estimate of COVID-19 costs was shared with the Staff in response to Staff Data Request STF-199. The impacts from the COVID-19 pandemic were the result

[18] All dollars represent Georgia Power's share of Project costs.

of circumstances outside the Project Team's direct control. Company management acted prudently in its management of the COVID-19 pandemic and was able to keep the Project moving forward while keeping the safety of the workforce at the forefront of all decisions.

- **Change in Scope**. Following the transition to Southern Nuclear site leadership in January 2018, the Project Team worked diligently to manage the Project within the VCM 17 cost forecast. As Southern Nuclear, Bechtel, and subcontractors gained more time on the Project, certain scopes of work, primarily subcontractor scopes, were determined to be inadequately estimated. Prior estimates were based on information known at the time from prior contractors or based on industry practices for estimating scopes of work. To accurately forecast the remaining work on the Project, Southern Nuclear routinely led walkdowns of the entire site to evaluate progress, status, and work to be completed, which, since January 2018, led to documented adjustments to the work scopes for Bechtel and other subcontractors to account for the differences. The Company identified many of the increases in civil construction, subcontractor, and unscheduled electrical commodity installation scope during the VCM 20/21 report as Bechtel and Southern Nuclear performed a quantity verification effort during the May 2019 schedule re-baseline. Additional examples of scope estimate adjustments included: coatings and fireproofing; concrete and rebar commodity increases for building completion; instrumentation in the plant; and commodity fabrication. The addition of quantities (scope) and thus craft and field non-manual hours to complete the required scope for the Project is a prudent and reasonable cost as it was necessary to complete the Project.
- **Procurement of materials and equipment**. Procurement needs of a Project the size of Vogtle Units 3 and 4 are vast and vary widely. Estimations of required materials differ based on design specifications and field routing estimates. During the Project, the Project Team incurred \$105 million in additional procurement costs above the amount deemed reasonable in VCM 17. The additional procurement costs are prudent and reasonable costs as they were required to complete the Project.
- **Additional Engineering Resources (headcount and duration)**. Engineering resources beyond those forecasted in VCM 17 were required to support Project closeout of the documentation needed to support Inspection, Test, Analysis, and Acceptance Criteria

("ITAAC"), Engineering Service Requests, and Non-Conformances among other requirements. Estimates in these areas were adjusted, as needed, throughout the construction, testing, and startup process as more resources were required to ensure both Units would operate as designed, as well as to ensure successful completion of construction, documentation closure, and necessary testing. These costs are reasonable and prudent as they were necessary to ensure the plant was built in accordance with design and licensing basis requirements and would operate safely for the benefit of customers.

- **Direct Construction Productivity / Performance**. The Direct Construction Cost Performance Index ("CPI") measures the ratio of hours spent on an activity relative to hours earned. The cumulative Bechtel Direct Construction CPI for the Project at the end of direct construction was approximately 1.66. The Project Team managed many challenges in its attempts to manage and achieve a CPI closer to a baseline of 1.0. Mitigation efforts and actions included changing craft staffing levels, minimizing non-productive work, and improving first-time quality. Southern Nuclear conducted multiple craft productivity assessments and held site-wide staff stand downs related to productivity, production, and quality improvements. While performance was not consistent with the VCM 17 or 19 estimates, given the FOAK nuclear construction for this Project and the evolution of the craft labor workforce, this category of costs is also reasonable and prudent.
- **Schedule Changes (non-COVID) Driven by Scope Increase**. As mentioned above in the Change in Scope cost driver, additional scope on the Project occurred through civil construction and unscheduled electrical commodity installation (i.e., coatings and fireproofing; concrete and rebar commodity increases for building completion; instrumentation in the plant; and commodity fabrication). Each of these upward adjustments in scope had an impact on the duration of the Project schedule. As the schedule was extended, the Project Team faced increases in cost that were dependent on the time added to the schedule as well as external factors in the economy that increased labor rates such as competition and availability of skilled resources. The schedule changes due to scope change are reasonable and prudent as the increases in scope manhours and time to complete were necessary for completion of the scope changes.

- **Miscellaneous**. This cost category includes items such as increases in Ad Valorem tax assessments as the installed cost of the Project increased, regulatory support cost increases, and IT infrastructure cost increases. These cost increases are the time-related cost from Ad Valorem tax being capitalized and regulatory support resources being utilized for a longer period of time that are associated with the other reasonable and prudent costs previously described above.

Importantly, even in the absence of the stipulated agreement, the Company would not seek cost recovery for every cost incurred on the Project. The construction and capital cost incurred on the Project but not included in the $8.826 billion reasonable and prudent amount identified by the Company are included in Table 2 and described below.

Table 2: Excluded Cost Categories

Cost	**Amount (millions)**[19]
VCM 19 Reforecast	$694
Schedule Changes	
Rework Driven (Electrical and Inspection Record Backlog)	$165
Rework	
Electrical Quality Issues (IEEE 384)[20]	$8
Inspection Records Backlog	$22
Construction work performed before Bechtel	$12
Penetration Seal Breaches and Re-seals	$2
Non-Segregated Busbar Rework/Redesign	$21
Valve rework	$11
Extraction steam piping rework	$4
Other tracked rework items identified by Staff or GPC	$22
Project Performance Costs Above Best Sustained Productivity	$319
Lost and Damaged Items	$28
Miscellaneous - Testing Support Labor & Other	$54
Total	**$1,362**

- **VCM 19 Reforecast**. As reflected in the VCM 19 Report, the total Project cost estimate at the time included a projected $1.1 billion increase in Georgia Power's share of the total cost (from $7.3 billion to $8.4 billion). This increase included $694 million in the base

[19] All dollars represent Georgia Power's share of Project costs.
[20] IEEE stands for the Institute of Electrical and Electronics Engineers.

capital forecast and a Project contingency estimate of $366 million. As reiterated throughout the VCM process, Georgia Power will not seek rate recovery from customers of the $694 million increase to the base capital forecast.

- **Schedule Changes – Rework Driven**. A certain amount of rework and remediation is expected on mega projects the size of Vogtle Units 3 and 4. As remediation was required on the Project, to the extent that work was beyond what was anticipated in the Project schedule, the schedule was extended. As discussed below, there were several instances in which rework drove the need to extend the schedule beyond the regulatory-approved dates of November 2021 and November 2022. These rework-specific categories included rework identified by Southern Nuclear as above and beyond the typical rework expected on a major construction project. Therefore, in addition to not requesting recovery for the cost of the rework described below, the Company is also not requesting cost recovery for the corresponding schedule impacts. Southern Nuclear identified these rework items and had Bechtel and other subcontractors track the manhours spent on these tasks to appropriately account for such rework. The duration to remediate these rework scopes was identified in the schedule and the associated delay was quantified to be excluded from the Company's rate request.
- **Rework – Electrical Quality Issues**. In December 2020, an adverse trend was identified for Electrical Installation Quality. An extent of condition (i.e., the determined impact of the electrical installation issue on the Project) was performed and identified approximately 600 issues within 64 rooms related to IEEE 384 physical cable separation requirements. Further investigation determined the root cause to be inadequate enforcement of construction standards and behaviors related to electrical installations. Southern Nuclear required Bechtel to separately track manhours spent on IEEE 384 electrical remediation work. The weekly reports populated by construction management and associated Project Controls data were used to identify the entirety of the hours expended to remediate the issues, and the total cost of this remediation effort was determined by combining the costs of those craft labor hours with the engineering and support staff costs needed to support completion of the remediation.

- **Rework – Inspection Records Backlog**. In the fourth quarter 2021, the Project Team became aware of a large backlog of incomplete Inspection Records ("IRs") on Unit 3. IRs are typically included in and completed as work packages are developed and closed, and therefore were not tracked separately. Once Southern Nuclear became aware that IRs were not being closed, Southern Nuclear began tracking IR closures and put measures in place to mitigate potential and similar impacts on Unit 4. The weekly reports populated by construction management and associated Project Controls data were used to identify the hours expended to remediate the issues and quantify the cost to the Project, including engineering and support resources.
- **Rework – Construction Work Performed Before Bechtel**. Since the start of construction, several different contractors have performed work on the Project. As previously discussed, upon Bechtel's arrival onsite, Bechtel was better able to review work completed, or assumed completed, in their estimates. In some cases, this review identified required remediation of work previously completed by others to support testing or meet the technical specifications necessary to complete the Units as designed. The weekly reports developed with Project Controls data were used to identify the population of hours expended to remediate the issues and quantify the cost to the Project, including engineering and support resources.
- **Rework – Penetration Seal Breaches and Re-seals**. Penetration seals are passive fire protection systems used to maintain the fire resistance of a wall or floor that has cables or pipes passing through it. In the event of a fire, the penetrations caused by these cables or pipes can undermine the integrity of the building's fire safety precautions. During construction, subcontractors installed these seals to support testing on the Units. In some cases, the penetration seals required breaching and re-sealing to support additional cable and pipe runs to complete construction or to finish testing. The weekly reports developed with Project Controls data to specifically track the performance of breaches and re-seals were used to identify the hours expended to remediate the issues and quantify the cost to the Project, including engineering and support resources.
- **Rework - Non-Segregated Busbar**. Construction on each Unit included a bus system to provide operational power throughout the plant. During installation, but before completion,

it was discovered that the non-segregated bus duct portion of the system was defective and did not conform to Project requirements. As a result, the original non-segregated busbar design and installation was abandoned and replaced with a conductor cable design. The total dismantling and replacement cost to Southern Nuclear of the busbar system that was initially designed, manufactured, and installed is included in this cost category.

- **Rework – Valve Rework**. During construction and testing, valves and other components became part of the preventative maintenance program. The program performed routine inspections and maintenance prior to and after installation of valves. At times, valve maintenance required use of replacement gaskets, seals, or other consumables such as grease, the costs for which were expected and routine for the Project. Beyond those expected and routine costs, some valves sustained damage during installation. A few examples of these include damage to valve bodies, actuators, stems, or switches. The costs associated with repairing or replacing the damaged valves are captured within this cost category and excluded from the Company's calculation of reasonable and prudent construction and capital cost for the Project.
- **Rework – Extraction Steam Piping Rework**. The extraction steam piping from the Moisture Separator Reheater to the low-pressure turbines on both Units had to be cut and the pipe had to be re-formed and re-welded to provide a stress-free condition on the turbine casings. This contractor rework was tracked and is included in this category along with the estimated cost of the support resources necessary to complete the rework.
- **Rework – Other Tracked Rework Items Identified by Staff or Georgia Power**. In addition to the items identified in the list above, Staff has previously identified other components or equipment that required remediation or replacement, and Georgia Power has identified others. These items include jacking oil pumps, the Spent Fuel System and Liquid Radiation Waste demineralization tanks, Unit 3 turbine building roof membrane replacement, and other items identified through the data request process. All tracked rework items on the Project are included in this category of cost, including the craft cost and support costs for the craft.
- **Project Performance Costs Above Best Sustained Productivity.** The Company reviewed the CPI performance on the Project for Units 3 and 4. In the review, Southern

Nuclear and Georgia Power looked at CPI performance to determine the best sustained levels of productivity to estimate what could have been the best possible performance achieved on the Project, barring any rework, staffing, or other impediments to productivity, and applied that CPI to determine the resulting cost of lost productivity. Georgia Power has excluded those lost productivity costs from this calculation.

- **Lost and Damaged Items.** Lost and damaged material is a common component of a large and complex construction project. Vogtle Units 3 and 4 were not immune to the typical lost and damaged materials; however, on this Project some of the materials lost or damaged were designated with very specific purposes and had to be replaced by materials that met the same design and quality requirements as the original piece of equipment or material. For example, special types of piping had been prefabricated to a specific design; numerous supports were fabricated for a specific purpose, location, and according to the required design; and predetermined cable types and lengths were cut to specific design requirements. Southern Nuclear tracked and trended the material replacements, the costs for which are included in this category. Georgia Power is not seeking recovery of costs for these lost and damaged items.
- **Miscellaneous**. This cost category primarily includes labor utilized to support testing.

2. AFUDC Financing Costs

Throughout the construction of Units 3 and 4, the Company collected financing costs upfront from customers through the NCCR tariff based on the $4.418 billion certified amount. Financing costs on construction and capital cost above this amount were accrued through AFUDC. As part of the Company's request, the Company seeks to include in rate base the associated AFUDC financing costs on the construction and capital cost above the $4.418 billion certified cost up to the total construction and capital cost to be approved by the Commission in this case. The total projected AFUDC through a March 2024 estimated in-service date for Unit 4 is $505 million based on the $8.826 billion of construction and capital cost deemed reasonable and prudent by the Company. Based on the stipulated agreement between the Company, Staff, and several intervenors, the associated total AFUDC projected through March 2024 is $437 million based on the $7.562 billion of total construction and capital cost. These amounts have been calculated in accordance with the VCM 17 Order, which required the AFUDC ROE to be equal to the Company's average cost of long-term debt starting in 2018.

3. Operating Costs

The Company also proposes to recover the following costs related to its full operation and commensurate output of Units 3 and 4 and common facilities upon Commercial Operation: (1) depreciation expense; (2) operation and maintenance ("O&M") expenses; (3) property taxes; (4) nuclear decommissioning costs; (5) nuclear fuel plant; and (6) materials and supplies inventory. The operating cost profile of Units 3 and 4 will be significantly reduced during the first eight years of each Unit's operations as customers will benefit from the Federal PTCs Georgia Power will be awarded for generating electricity from Vogtle Units 3 and 4. To avoid confusion, nuclear fuel plant and materials and supplies inventories are costs necessary to operate the business (i.e., operating costs) that are rate based and included within the capital costs identified in Table 3 below. In contrast, depreciation expense, O&M expense, property taxes, and nuclear decommissioning costs are all operating costs recorded as operating expenses.

4. Summary of Reasonable and Prudent Costs

Georgia Power requests cost recovery for the reasonable and prudent construction and capital cost, financing costs, and operating costs associated with the completion of Vogtle Units 3 and 4 and common facilities. As noted above, some of these costs are already being recovered in rates. Specifically, pursuant to the Commission's November 15, 2021, Order in Docket No. 43838, $2.100 billion previously deemed prudent and reasonable by the Commission as well as the operating costs for Unit 3 have already been placed into rates. Table 3 below summarizes the Company's request in this case.

Table 3: Summary of Reasonable and Prudent Costs

Capital Cost & other Rate Base Items Requested for Recovery	**Amount (millions) 13-Month Average**
Construction and Capital Cost	$8,826
AFUDC Financing Costs	505
(less) Capital Accumulated Reserve	(142)
Nuclear Fuel (net of Accumulated Reserve)	232
Regulatory Assets	215
Spare Parts Inventory	54
Accumulated Deferred Income Taxes	206
Total	**$9,896**

Operating Expense Requested for Recovery	**Amount (millions)**
O&M Expense	$155
Depreciation Expense	156
Property Taxes	59
Nuclear Decommissioning	15
Regulatory Assets Amortization	23
(less) Production Tax Credits	(137)

Section IV below analyzes the Project's cost and schedule challenges and describes how the Company managed various risks presented and events that occurred on site. Thus, as presented herein, the Company sets forth its case for the reasonableness and prudence of $8.826 billion in construction and capital cost, as well as the associated financing and operating costs for Vogtle Units 3 and 4.

Importantly, as a result of the stipulated agreement reached between Georgia Power, Staff, and some intervenors, the Company has agreed that it is reasonable to recover less than the amount described in Table 3 from customers. Section V summarizes the terms and conditions of the stipulation and Section VI outlines the proposed retail rate adjustments to recover in base rates the revenue requirement associated with the remaining construction and capital cost, financing costs, and operating costs for Vogtle Units 3 and 4, as agreed to in the stipulation.

IV. ASSESSMENT OF COST AND SCHEDULE

Following the VCM 17 Order and Southern Nuclear's transition to a construction management and oversight role, Southern Nuclear stood up a dedicated organization to manage and review the Project's costs and schedule. This organization worked with each functional area and Bechtel to provide the most accurate estimates of cost and schedule utilizing the information available to the Project Team at the time the estimates were made. Through its monthly budget and forecast review process, Southern Nuclear engaged with Georgia Power and the Co-Owners to inform them of changes in schedule, cost pressures, and potential risks that would require allocation of or addition to contingency. Changes in schedule, cost pressures, and potential risks were also reported to, and discussed with, Staff and the Construction Monitor on a regular basis.

As part of Southern Nuclear's schedule responsibilities, adjustments to the site working schedule were made on a regular basis to incorporate the most current information available. These re-baselines were a critical component of the Project's ongoing efforts to review and assess the schedule and ensure that the site working schedule supported the regulatory-approved and risk adjusted in-service dates. Each of the Project's schedule adjustments and enhancements were performed when necessary and appropriate to meet Project objectives. By providing regular cost and schedule updates to Staff and Co-Owners, Southern Nuclear and the Company helped ensure that they had the most comprehensive and current information available regarding the cost and schedule to complete the Project.

A. Project Cost Review

The Company's total construction and capital cost for the Project is approximately $10.188 billion. Throughout the Project lifecycle, Southern Nuclear has presented the Commission with its best cost estimate given the information known at the time of each VCM filing. The cost control process that was established following the cost reforecast in VCM 19 has been, and will continue to be, used until Project completion. Southern Nuclear utilized a monthly cost forecasting process to evaluate costs and cost risks to the Project. This process included regular monthly meetings with each functional area to review actual spend to date, budgets, forecasted costs, and areas of risk or concern. Southern Nuclear also utilized this monthly cost control process to ensure timely updates to the Project's estimate to complete, forecast assumptions, and cost risks associated with staffing, procurement, Bechtel's remaining scope of work, subcontracts, and Westinghouse services, as well as other engineering and support activities. By combining its monthly cost control process with the risk management program, change control process, Project metrics development, and weekly schedule updates, the Project Team evaluated and communicated the Project's cost risk and cost contingency profile on a monthly basis to the Co-Owners and Staff.

At a summary level, the Project's forward-looking cost risk profile included the following cost categories: Bechtel Direct Construction; Subcontracts; Procurement; Engineering; and Other Staffing. Using its suite of tools and analyses, and taking into account the Project's forward-looking risk profile, as well as progress to date, Southern Nuclear developed a range of cost risk to the Project, which was highly influenced by Bechtel Direct Construction's "to-go" CPI, Bechtel Direct Construction's "to-go" hours or effort to completion, and the projected in-service dates for Units 3 and 4. Further—and equally important to estimating the range of cost risk remaining on the Project—Southern Nuclear considered the existing contingencies embedded in the Project's current ETC. Together, the estimated range of cost risk and available contingencies provided Southern Nuclear with estimates of potential cost scenarios on the Project. Southern Nuclear and the Company provided this cost data monthly to Co-Owners and Staff and engaged in monthly meetings with Co-Owners and Staff to review the cost data and answer any questions.

B. Project Schedule Review

After assuming control of the planning process, and to improve production and provide schedule margin, Southern Nuclear planned to complete the Project ahead of the regulatory-approved in-service dates of November 2021 and November 2022 for Units 3 and 4, respectively. Southern Nuclear continually acknowledged that this site working schedule was aggressive and believed working towards a challenging schedule was necessary to help the Project Team maintain focus and drive toward completion of the Project.

The aggressive site work plan not only enabled the Project Team to gain a better understanding of the risks that were in front of them, but also helped identify those risks earlier than they otherwise would have. A key process for identifying risks sooner rather than later was the Partial Release to Test ("PRT") approach, which provided Initial Test Program ("ITP") personnel with access to early testing of components and equipment. This process for early testing was valuable in applying lessons learned from Unit 3 to Unit 4 in the testing and startup processes. When a PRT was utilized, it required signoff from Bechtel that the system, structure, or component had been completed, was ready for testing, and that the release of jurisdiction to ITP would not cause construction delays.

To ensure all stakeholders were apprised of progress to less aggressive and more risk-adjusted workplans, the Project Team also developed regulatory-approved and risk-adjusted schedules. Used in conjunction with the site's more aggressive working schedule, these risk-adjusted schedules provided points of comparison and valuable risk management for the site working schedule. These schedules also provided forecasted production levels needed to meet the regulatory-approved and risk-adjusted in-service dates. By creating and reviewing these benchmark schedules, the Project Team, Co-Owners, and Staff were able to compare the production levels and milestone dates forecasted to meet the in-service dates beyond the site working schedule.

Adjustments to the site working schedule were made on a regular and as needed basis during the Project to ensure that Project management could effectively use the site working schedule to drive efficiencies, improve production, and reduce risk. Whenever it was determined that the site working schedule no longer supported Project planning requirements, the Southern Nuclear and Bechtel Project Controls teams performed a re-baseline to calibrate both schedule and cost, incorporating the most current information available based on construction progress and risks ahead. These re-baselines were part of the Project's ongoing efforts to review and assess cost and schedule and assure the site working schedule supported the regulatory-approved and risk adjusted in-service dates.

To update the site working schedule through a re-baseline effort, the Project Team utilized an iterative, phased approach to develop schedule scenarios that considered resource constraints, logic and sequence, and milestone dates. Functional groups across the site – working both independently and collectively – evaluated each scenario. This approach enabled leadership from Bechtel, Southern Nuclear, Georgia Power, and the other Co-Owners to remain informed and engaged throughout the process and to assess the progress of the re-baseline effort.

The Project completed several schedule re-baselines after VCM 17. The re-baseline process was a comprehensive and coordinated effort among personnel from all organizations on the Project, including the Construction, Subcontracts, Southern Nuclear ITP, Engineering, and Procurement organizations. In preparation for the re-baseline effort, each functional organization was tasked with validating its schedule scope while also performing specific actions and reviews relevant to the organization's function. For example:

- The construction organization was responsible for quantity verification of all commodities for the updated site working schedule to reflect a current and accurate assessment of quantities remaining to install. Construction was also responsible for identifying current resource constraints and assessing the potential to ramp those resources when necessary to support Project needs;
- The subcontracts organization was responsible for supporting the integration of the subcontracted scope in the updated site working schedule;
- Engineering was responsible for evaluating design constraints and reviewing logistics in the updated site working schedule; and
- The procurement organization coordinated services and material availability with other functional organizations to support their need date.

Each organization was responsible for identifying potential construction impacts and, when necessary, developing mitigation plans to support the schedule.

After analyzing the initial data and, where applicable, mitigating potential impacts, the construction schedules were resource loaded and levelized. Bechtel construction and the Southern Nuclear ITP organizations also reviewed the schedule logic connecting construction system completion to system testing. The ITP organization then built a detailed testing schedule to support testing and system turnover milestones up to fuel load. Post fuel load, the simulator-tested startup plan would be incorporated into the schedule. With all major schedule re-baselines, the Company provided Staff with updated schedule files in native formats so they could perform an independent analysis and review the Company's progress.

As has been discussed throughout the VCM proceedings, the Company's approach of targeting earlier in-service dates in the site work plan was a strategic decision by Southern Nuclear and the Company to incentivize productivity, manage production, and provide schedule margin against the regulatory-approved in-service dates for the Project.

The Project Team continued to work toward an aggressive site working schedule even after the Company recognized the regulatory-approved in-service dates were no longer achievable. Using the aggressive site working plan enabled the Project Team to pull risk forward and maintain margin to the risk-adjusted schedules developed by the Project Team. Project leadership continuously evaluated the site working schedule for opportunities to move the Project through testing and turnover, and believed that while aggressive, the site working schedule was still the most appropriate plan to complete the Project as safely, quickly, and efficiently as possible.

C. Challenges Mitigated by Project Management since the VCM 17 Report

As previously acknowledged, constructing and achieving Commercial Operation of Units 3 and 4 has not been without challenges. As discussed in detail in the Company's SIR Report, VCM 17 Report, and subsequent Semi-Annual VCM Reports, the Company anticipated several challenges in building the first new nuclear units in the United States in more than 30 years. Many of these challenges were known and identified in advance; numerous other challenges, however, were unknown at the outset and required real-time responses and corrective action from Georgia Power and Southern Nuclear. For example, managing through contractor turnover, a global pandemic, and unexpected rework were risks unknown when construction began that only became apparent as the Project progressed and more information became available.

Nevertheless, the Company successfully navigated many of these risks through proactive management to avoid significant impact to Project completion. Below are some of the actions taken to mitigate different risk impacts to customers.

1. <u>The Project Management team applied lessons learned from other units, utilized modularization techniques, and navigated the NRC's new Part 52 licensing process to overcome FOAK challenges.</u>

The AP1000 nuclear units at Plant Vogtle Units 3 and 4 make up the first new nuclear construction project in the nation in more than 30 years. Prior to Vogtle, Westinghouse had not yet built an AP1000 reactor in the United States. As with any FOAK project, numerous execution risks existed on the Project, many of which were anticipated. To mitigate some of the FOAK Project risks, the Company entered into an arrangement with China's Sanmen Nuclear Operator to receive construction and testing lessons learned during the construction of four similar Westinghouse units in China. This arrangement allowed Company personnel to gain first-hand experience and knowledge at the Sanmen site in exchange for Southern Nuclear's guidance related to its world-class best practices in operations, training, and maintenance programs. This mutual exchange of information saved time in Vogtle's construction schedule and Project management was able to credit the experience gained from the Chinese units towards Vogtle's licensing basis from the NRC.

Further, the Project management team took advantage of modularization techniques to overcome FOAK challenges. The standard AP1000 was designed to be constructed with both structural and mechanical modules. These modules were fabricated off-site and then transported to the site for assembly and outfitting. Upon receipt at the site, the sub-modules were assembled into completed modules, moved to their final location in the AP1000 plant, and sealed in place with concrete.

The modularization process itself presented some FOAK challenges. To facilitate the modularization process, contractors needed to build a fabrication facility with a nuclear quality assurance program ("NQA-1") to ensure the modules met all code requirements. Additionally, early in the Project timeline, the Project Team encountered various challenges related to modularization that needed rework and redesign. In response, the Project Team implemented several additional programs and processes to provide the oversight necessary to ensure the modules were built with quality and met regulatory requirements. These programs led to the successful installation of many large modules and sub-modules in both Units.

The modularization process also presented opportunities to take lessons learned from Unit 3 and apply them to Unit 4. For example, experience from Unit 3 promoted the modularization of the Unit 4 Annex Building steel floors. The use of modularization for this component allowed for greater efficiency in installing the supplemental steel that supports piping, HVAC equipment, electrical conduit, and cable trays. As seen on Unit 4, the modularization approach produced economies of scale, enhanced quality control in the supply chain, and resulted in shorter onsite construction schedules than those experienced during the prior generation of nuclear plant construction in the U.S.

Finally, the NRC's new licensing process presented both FOAK benefits and challenges. The first generation of nuclear plants constructed in the United States were often forced to re-litigate safety issues after billions of dollars of construction work had been completed. In part to address that situation, the NRC established a new licensing process. Under Part 52, the NRC certified the AP1000 reactor design in a rulemaking proceeding. This procedure effectively resolved all design safety issues associated with the AP1000 design before construction began,[21] which in turn limited the issues that could be raised during the subsequent COL process. Further, Southern Nuclear was able to reference the certified AP1000 design in its COL application and thereby avoid any review or challenges to the AP1000 design during licensing and for the remainder of the Project. Finally, the resolution of these issues under Part 52 prevented design or safety issues from being raised in post-construction litigation regarding operation of the facility.

Part 52 also presented challenges, particularly with respect to changes during construction. In many cases, design changes brought about by constructability or other issues required license amendment requests ("LARs") or exemptions from the certified design. This added time to what were often minor and non-safety related departures from the certified AP1000 design. Despite this timing challenge, Southern Nuclear mitigated Part 52 delays in two ways. First, during initial licensing, Southern Nuclear proposed a Preliminary Amendment Request Process ("PAR"), which would allow certain non-safety related LARs to be implemented based on a preliminary review by NRC Staff, rather than waiting on the full LAR process. The NRC approved this proposal in February 2012. Second, Southern Nuclear sought and received an NRC-approved exemption from a requirement to seek a LAR for changes that had no significant safety impacts on plant structure, systems, or components. This exemption permitted Southern Nuclear to forego the LAR process altogether for those changes in favor of a more focused and less time-consuming internal safety review. These two licensing actions by Southern Nuclear helped to mitigate the delays from necessary changes during construction.

[21] *See* 10 C.F.R. Part 52, Appendix D (VI) (A) ("The Commission has determined that the structures, systems, components, and design features of the AP1000 design comply with the provisions of the Atomic Energy Act of 1954, as amended, and the applicable regulations identified in Section V of this appendix; and therefore, provide adequate protection to the health and safety of the public. A conclusion that a matter is resolved includes the finding that additional or alternative structures, systems, components, design features, design criteria, testing, analyses, acceptance criteria, or justifications are not necessary for the AP1000 design.")

2. <u>Southern Nuclear minimized the time between the closure of regulatory items by collaborating directly with the NRC and consolidating items needed for approval of fuel load.</u>

Under Part 52, the only possible post-construction hearings are challenges to ITAAC closure. Thus, there was a risk of delay from challenges in closing one or more ITAACs, or contentions by intervenors that an ITAAC had not been met. Either scenario could have delayed fuel load. However, by satisfying the Part 52 licensing requirements, the Project limited this risk because the safety of the AP1000 design was resolved by the NRC and all ITAACs were identified and agreed upon in advance. Nevertheless, it was possible that the NRC would take longer than anticipated to approve fuel load due to ITAAC closure, or that license amendments would be required to modify ITAAC or design requirements.

With these potential challenges in mind, Southern Nuclear worked diligently and proactively to collaborate with the NRC to minimize the time between ITAAC closure and the NRC's 10 CFR 52.103(g) finding authorizing fuel load. Southern Nuclear also worked with the NRC to determine in advance what information would be required for the closure of an ITAAC through the Uncompleted ITAAC Notification ("UIN") process. In the UIN process, each testing methodology and process was submitted to the NRC for prior approval pending final test execution, thus reducing the amount of information to be reviewed during the final review process. Finally, Southern Nuclear consolidated ITAACs to promote efficient approval while still meeting all required criteria.

At the end of July 2022, Southern Nuclear submitted to the NRC an "All ITAACs Complete" Letter for Unit 3, which was the final submission to support the NRC's issuance of the 103(g) finding required for fuel load and demonstrated that the Unit met the NRC's strict nuclear safety and quality standards. On August 3, 2022, Unit 3 received the historic 103(g) finding from the NRC, signifying that no further NRC findings were necessary and allowing Southern Nuclear to load fuel and begin the Unit 3 startup sequence. Southern Nuclear then continued to work with the NRC to further reduce and consolidate the ITAACs required for Unit 4, based on lessons learned during the Unit 3 process. On July 20, 2023, Southern Nuclear submitted the All ITAACs Complete letter to the NRC and, on July 28, 2023, the NRC issued the 103(g) finding required for Unit 4 fuel load. Ultimately, the NRC denied the only petition to intervene to challenge the completion of ITAACs for Unit 3 and there were no challenges to the ITAAC completion for Unit 4.

3. The Company obtained letters of credit and financial protections from Westinghouse and Toshiba to protect customers from harm.

Toshiba's obligation to the Project originated during the EPC Agreement negotiation, during which the Co-Owners insisted that the Consortium counterparties provide security to the Co-Owners in the form of a financial guaranty. The executed EPC Agreement included parent guarantees from Toshiba and Shaw Group, Inc. for Westinghouse and Stone & Webster, respectively. In connection with the settlement of claims by Westinghouse in 2015, Georgia Power negotiated an increase in Westinghouse's limit of liability for abandonment of the Project, and therefore an increase in Toshiba's parent guarantee from 30% to 40% of the contract price. This change added almost $1 billion to the protection of the parent guaranty. At the time, the Co-Owners were not aware of any reason that Toshiba would be unable to fund any shortfalls due to the Co-Owners under the EPC Agreement. Nonetheless, the Co-Owners further insisted on the requirement that Westinghouse produce letters of credit if Toshiba's credit rating fell below a certain threshold.

Following the downgrade of Toshiba's credit rating in December 2015, the Company, on behalf of the Co-Owners and to insulate ratepayers from financial harm, demanded that Westinghouse post letters of credit for the exposure on the Project. These letters of credit were received in January 2016 and the Company held the letters of credit as security against the risk that Toshiba was unable to pay the amounts for which it was liable. Westinghouse petitioned for bankruptcy protection on March 29, 2017. In response to the bankruptcy filing, Georgia Power entered the IAA to continue Project progress, but also initiated negotiations with Toshiba for what the Co-Owners viewed as a breach of contract and abandonment of the Project – which entitled the Co-Owners to call on the Toshiba Parent Guaranty.

The collection of the Toshiba Parent Guaranty was later identified as a risk during the VCM 17 reporting period, after Westinghouse declared bankruptcy and Toshiba's shedding of Westinghouse nuclear assets created uncertainty as to its corporate financial stability. Relying on the letters of credit, the Company sought to ensure that customers would be somewhat insulated from financial harm and receive a benefit if Toshiba was unable to satisfy its obligations under the

EPC Agreement. To that end, on June 9, 2017, Georgia Power, the other Co-Owners, and Toshiba entered into the Guaranty Settlement Agreement. Toshiba acknowledged its parent guaranty obligation as $3.68 billion, of which Georgia Power's share was approximately $1.68 billion. The Guaranty Settlement Agreement provided for a schedule of payments for Toshiba's obligations beginning in October 2017 and continuing through January 2021. Toshiba made the first three payments as scheduled.

On December 8, 2017, the Company and the other Vogtle Co-Owners and Toshiba entered into Amendment No. 1 to the Guaranty Settlement Agreement, which provided that Toshiba's remaining payment obligations under the Guaranty Settlement Agreement were due and payable in full on December 15, 2017, which Toshiba satisfied on December 14, 2017. The satisfaction of the Guaranty Settlement Agreement ultimately resolved the risk associated with the Toshiba Parent Guaranty. Consistent with the Commission's VCM 17 Order, the Company applied its portion of the Toshiba Parent Guaranty—approximately $1.493 billion ($1.68 billion less the costs associated with securing the payment, and less the customer refund totaling approximately $188 million)—to the total construction and capital forecast filed in the VCM 17 Report.

4. <u>The Company diligently pursued lower cost financing opportunities by entering into the DOE loan guarantee agreement despite uncertainty around the future of the Project.</u>

At the time of VCM 17, DOE loan guarantees were expected to save customers approximately $400 million, based on the current capacity of the original commitment. When the VCM 17 Report was filed, the Company and the DOE were in discussions to expand the program for the Project in the form of additional capacity through an Amended and Restated Loan Guarantee. The magnitude of the DOE's credit facility through this program was uncertain at a time in the Project's history when the decision of whether to move forward was up for debate.

In March 2019, the Company executed an Amended and Restated Loan Guarantee Agreement with the DOE. The proceeds of borrowings from this Agreement could be used to reimburse Georgia Power for eligible Project costs, up to approximately $5.1 billion. By December 31, 2021, Georgia Power had borrowed all $5.1 billion. These amounts benefit customers by allowing Georgia Power access to lower credit spreads during construction and future operation. Georgia Power customers are estimated to save over $500 million through the loan guarantees, which has already been secured through draws against the credit facility. The Company's persistent and diligent pursuit of lower cost financing opportunities has tangibly saved customers money in a high-cost environment.

5. Southern Nuclear adjusted CPI assumptions rather than resetting unit rates to ensure the integrity of performance comparisons during construction.

During several VCM proceedings, and in numerous meetings regarding Project metrics, Staff and VMG asserted that unit rates should be adjusted each time the Project schedule is re-baselined because unit rates directly impact planned schedule durations. By utilizing unit rates that do not reflect the durations achieved onsite, Staff and VMG argued that schedule durations were unachievable and did not provide a meaningful baseline upon which to measure performance. In contrast, the Company and Southern Nuclear believed that adjusting unit rates, which were established when Bechtel took over as prime Contractor, would alter the view that site leadership, Co-Owners, and external stakeholders had of past performance and negatively impact comparisons of past performance to current performance.

Thus, instead of revising unit rates, Southern Nuclear determined that the best way to plan work and establish necessary staffing levels was to target earned hours while applying an estimated CPI factor. In addition, as part of the cost forecasting process, contingency allocations were made to address areas experiencing higher CPIs and account for the risk of insufficient unit rates. Using CPI assumptions to account for staffing and costs related to observed production rates better maintained the integrity and cohesiveness of the Project's performance metrics. This approach provided the Project with a more appropriate and comparable view of both historical and current production and performance.

6. The Company navigated a major contractor change and re-assessed hundreds of subcontracts with minimal disruption to schedule.

Following the Westinghouse bankruptcy, the Company solicited bids from both Fluor and Bechtel to serve as the construction contractor. Upon careful review of the bids and discussions with both firms, the Company selected Bechtel as the construction contractor. Given its experience on the Project, Bechtel transitioned efficiently to serving as the Project's single construction contractor during the second half of 2017, with minimal disruption to the Project. Bechtel brought to the Project an experienced team with an excellent reputation in the industry and promised senior-level engagement to the Project. Bechtel also had a strong relationship with the building trades. Bechtel developed a comprehensive, risk-informed plan for Project completion and participated in the review of substantial portions of the Southern Nuclear ETC. Further, the Bechtel Agreement aligned Bechtel with the Co-Owners on the goal of completing the Project in the most efficient manner. The Bechtel Agreement was a cost-reimbursable contract with a performance incentive component, under which Bechtel accepted some risk on Project execution.

Once Bechtel was selected as the primary contractor, Project management's focus turned to the supporting subcontractors and vendors. The Company undertook the arduous task of reviewing each Westinghouse subcontract to determine which should be retained and which should be renegotiated or terminated during the transition of the Project. Each of the contracts and vendors were reviewed based on numerous factors, including impact to the Project timeline, complexity, material lead times, and other factors. Additionally, Southern Nuclear and Bechtel negotiated construction subcontracts for new work as part of the transition from Westinghouse. As part of the subcontracts review effort, Southern Nuclear, Bechtel, and Georgia Power worked together to structure the alignment of the subcontracts to determine which entity should own and manage the contracted scopes of work to most efficiently complete the Project.

7. <u>Southern Nuclear assumed responsibility for coordinating engineering activities to finalize engineering design and more efficiently address changes.</u>

Throughout the Project, engineering design and engineering support of construction operated at different paces. As of the VCM 17 Report filing, engineering design was reported to be approximately 95% complete, based on information that Westinghouse used to determine the activities remaining for completion according to the initial design of the Project. Following VCM 17, engineering design completion activities concentrated on targeted activities including unscheduled electrical design. The design portion of the electrical scope commonly described in the construction industry as "unscheduled" includes commodities such as lighting, communication systems, and fire detection. These remaining work scopes were planned to be "field run," which means the electrical craft identify a commodity installation route onsite in real time and mark-up drawings for later incorporation. By VCM 24, engineering design was reported 100 percent complete.

While engineering *design* was reported complete, that designation did not mean that all engineering *support* of the Project was complete. Rather, it signaled that engineering had transitioned into a support role for the construction and testing activities remaining for Project completion. Further, during installation and construction, the Project management team identified issues that required design changes, the resolution of which required continued support from engineering teams. After VCM 17 and through completion of Unit 3, design changes represented more of a refinement than a significant scope change and, therefore, had minimal impact on the overall Project.

To address the transition from engineering design to engineering support, Southern Nuclear assumed responsibility for coordinating all the engineering activities, including implementation of the engineering service request process. Southern Nuclear reviewed, prioritized, and coordinated engineering support, interfacing daily with the testing and construction organizations on the Project. This oversight ensured the focus of engineering resources remained on the activities that were deemed most critical to the Project as a whole.

8. Site leadership addressed numerous productivity challenges.

Site leadership was forced to contend with productivity challenges in a variety of contexts. Since the very beginning of the Project, labor force and craft productivity was a challenge. Productivity improvements were achieved in the short term but were not maintained for the long term. The inability to capitalize on productivity improvements persisted during the Project, having been identified in the VCM 17 Report and subsequent reports as a top Project risk. This risk could have resulted in an inability to meet or sustain the productivity rates incorporated in the Project schedules, higher than anticipated rates of rework, or greater than expected design changes. However, as described in the following three examples, Project management's responsive and attentive efforts helped minimize the impacts of these productivity risks.

a) Spent Fuel Pool Remediation

In March 2021, after the Spent Fuel Pool ("SFP") racks were installed and the SFP was filled, a leak was discovered through the Plant Leak Detection System. Resources had to be diverted from their planned and scheduled work fronts to address this structural issue, resulting in Project delays. The Project Team performed a full repair of the SFP floor to ensure quality standards were met for the longevity of the plant. The SFP floor was removed, and the underlying surface was remediated. The SFP floor was then redesigned to decrease the number of floor plates required, which also reduced the number of required seam welds and the potential for weld distortion. The floor plates were custom measured, laser cut for fit, and then welded in place. The SFP repairs were completed in October 2021. Post-repair testing of the SFP was completed, and fuel receipt resumed in November 2021.

While this remediation required delays and diversion of resources that affected other Unit 3 construction and completion efforts, the remediation was necessary and serves as evidence of the Project Team's consistent commitment to safety and quality. Further, applying lessons learned from this experience, the Project Team proactively checked for leaks in the Unit 4 SFP and reactor cavity. Minor issues were found and remediated, thus avoiding similar issues and potential delays on Unit 4.

b) IEEE 384 – Electrical Cable Separation

Southern Nuclear self-identified IEEE 384 cable separation concerns in late 2020 and initiated an Extent of Condition ("EOC") investigation. In January 2021, the EOC effort was included in a Root Cause Determination ("RCD") following the discovery of additional cable separation issues. The Project Team worked diligently to identify the extent of the issues and to uncover the cause of the cable separation issues through the RCD process. As the contributing causes of the cable separation were identified, Project management immediately took actions to curtail the issues. The issues identified during the RCD were documented through the Corrective Action Program in Condition Reports, and the management team established a remediation plan that included joint walkdown evaluations and increased inspections.

The management team expanded electrical training, increased oversight, and emphasized the importance and use of the Corrective Action Program. The management team also implemented leadership changes in the Quality Control organization, placing Southern Nuclear in charge of this contractor-led organization. Additionally, the Project Team engaged the Engineering organization to evaluate the issues and identify actions to ensure that remediation work met Southern Nuclear's quality standards and expectations. Finally, Project leadership extended the cable separation evaluation to Unit 4 to ensure that any separation issues on Unit 4 were identified and remediated, and that process improvements and lessons learned were implemented to minimize similar potential issues on Unit 4.

Ultimately, thanks to these actions, the NRC inspections of the Main Control Room IEEE 384 work were successful, and all IEEE 384 construction-related ITAACs were closed prior to the All ITAACs Complete submission.

c) Impacts of the COVID-19 Pandemic

COVID-19 was declared a pandemic by the World Health Organization on March 12, 2020, and immediately impacted productivity on the Project. The onsite Project Team immediately began to navigate the effects of the pandemic on the Project's workforce, schedule, and cost. Protecting the health and safety of the Vogtle Units 3 and 4 workforce, as well as the surrounding community, became the highest priority for the Project. To ensure the safety of the workforce, Project leadership assembled a COVID-19 response team inclusive of medical doctors and epidemiologists to provide guidance to all work practices and health actions the Company took in response to the pandemic. The Project Team took proactive measures to respond, including creating onsite medical facilities, deep cleaning workspaces, reducing the number of workers in given areas, and supplying and requiring facial coverings in certain areas of the plant where social distancing was not possible. Additionally, Project management worked with the state of Georgia to classify the Vogtle Units 3 and 4 Project as a "critical infrastructure project," which enabled site personnel to travel to and from work during any travel bans, including during curfew hours. The Project also established an onsite medical village to provide testing and vaccinations to personnel to help curb the spread of COVID and minimize its impact on productivity. The Project Team continued to monitor these actions and adjusted them as necessary to reduce the potential for further impacts of the pandemic on the Project.

There were thousands of positive cases onsite, which resulted in higher-than-normal absenteeism for both craft and non-manual personnel, while causing sudden disruptions to planned or ongoing work due to the required isolation of personnel who tested positive or who had been in close contact with someone who tested positive. These performance challenges contributed to schedule delays and increased costs on the Project. Further, disruptions in the global supply chain due to COVID-19 impacted the Project as suppliers navigated the pandemic's effects and related local, state, and national government restrictions.

In July 2021, the Project demobilized the onsite medical village after vaccines became available and were offered onsite. Thereafter, the Project Team continued to monitor the pandemic, including the evolution of variants, and adjusted protocols as appropriate to reduce the potential for further impacts on the Project. The Company estimated that the height of the pandemic consumed approximately three to four months of schedule margin previously embedded in the site work plans for both Units, with a total direct and indirect cost of $200 million.

Significant uncertainty surrounded COVID-19 globally, and Vogtle Units 3 and 4 were no exception. Georgia Power, Southern Nuclear, and Bechtel continued to monitor and address these and other risks as the pandemic evolved. Despite the significant challenges and uncertainty, Project leadership, supported by the Vogtle Units 3 and 4 workforce, safely continued progress on the Project and achieved major accomplishments during the COVID-19 pandemic.

9. <u>Southern Nuclear proactively identified potential scope growth and appropriately adjusted schedules and baselines as additional information became available.</u>

Unidentified scope includes any work not addressed in Southern Nuclear's ETC that must be performed to finish the Project. Examples of unidentified scope include design changes that cause the need for rework, make work more difficult than initially projected, or change the amount of work required to complete the Project. These design changes outside the initial scope of work may have arisen due to constructability concerns or because NRC requirements necessitated changes to the Project design. Additionally, various parties may have interpreted applicable codes differently, which could have required the Project Team to perform work differently, undertake more extensive inspections, or redo already completed work.

As discussed in detail above, during the transition following Westinghouse's bankruptcy, Southern Nuclear was forced to rely on the information available to it at the time, without the full benefit of being in control of construction activities on the Project. After reviewing and assessing costs and schedule based on a year's worth of experience managing the Project, Southern Nuclear revised its estimate of the cost to complete the Project as part of the VCM 19 proceeding. The increased ETC was a result of management decisions by Southern Nuclear that were intended to lower project risks and maintain the target schedule considering the additional work scope. Ultimately, the Company determined that it was not reasonable to seek rate recovery for the $694 million increase to the base capital forecast resulting from these decisions, thus saving customers significant costs from the increased scope of work identified during the re-baselining effort.

10. The Company limited testing and startup risks through proactive training, collaboration with Chinese unit operators, and the application of Unit 3 lessons learned to improve performance on Unit 4.

Testing and startup risks were and will remain a challenge to the Project until Unit 4 achieves Commercial Operation. As Vogtle Units 3 and 4 are the only two AP1000s being built in the United States, the possibility remains that the AP1000 reactor might not function as designed. Additionally, pre-operational or startup testing might reveal operational problems. However, the risks associated with startup and testing are low probability. As discussed above, the Southern Nuclear Operations organization spent significant time at four Chinese AP1000 units learning about the primary side of the units (reactor side), identifying and implementing lessons learned from the Chinese operators, and simulating various operations. Southern Nuclear operators were also embedded in the Project's ITP organization to support testing so that they would be aware of any technical issues, challenges, and design modifications to the system. In addition, the Southern Nuclear operators continue to receive training in the simulator as Unit 3 is operating and Unit 4 nears completion.

Further, lessons learned from Unit 3 construction and testing drove various improvements on Unit 4's successful completion of Hot Functional Testing ("HFT"), including: turnover of all required systems prior to start; closure of more Construction Work Packages; completion of more

Component and Pre-Operational tests; and reduction in Work To Go items. These lessons learned provided obvious and marked improvements in Unit 4 startup and testing, completing HFT four days ahead of the 46-day testing schedule and 52 days faster than HFT on Unit 3. Overall, Unit 4 has completed major testing 30 – 50% faster than experienced on Unit 3. Unit 4 ultimately received its 103(g) finding from the NRC 88 days after completing HFT, five times faster than Unit 3. Table 4 below compares timelines and durations of major milestones on each Unit, proving that the application of lessons learned from Unit 3 has had a dramatic impact on the successful construction of Unit 4.

Table 4: Lessons Learned as Shown in Unit 3 and Unit 4 Milestones

Days between Major Milestones	Unit 3 July 2023 COD	Unit 4
Cold Hydro Start	10/16/20	12/7/22
Cold Hydro to Hot Functional Test Start	**191 days** 4/25/21	**103 days** 3/20/23
Hot Functional Test Duration	**94 days** 7/28/21	**42 days** 5/1/23
Hot Functional Test Complete to 103(g)	**371 days** 8/3/22	**88 days** 7/28/23
103(g) to Fuel Load	**71 days** 10/13/22	**20 days** 8/17/23
Fuel Load to Substantial Completion	**291 days** 7/31/23	**TBD**

V. THE STIPULATED AGREEMENT

On August 29, 2023, Georgia Power, Staff, and several intervenors signed a stipulation resolving all remaining issues for determination by the Commission regarding the reasonableness, prudence, and cost recovery for the remaining costs associated with the Project. The stipulating parties agree that $7.562 billion is a reasonable and prudent *total* construction and capital cost for the Project to be included in rate base. The agreed-to reduction from Georgia Power's total construction and capital cost takes into consideration the length of time to construct the Project, replacement energy costs incurred during the extended construction time, and other issues such as the amount of rework required, scheduling of activities, testing, and productivity. Upon Unit 4 achieving Commercial Operation, Georgia Power will include in rate base the remaining $5.462 billion[22] of Project construction and capital cost, less the deferred accumulated depreciation on the remaining balance of Unit 3. Retail base rates will be adjusted to include the revenue requirement associated with the $5.462 billion balance the month after Unit 4 achieves Commercial Operation.

When the rate adjustment occurs, the NCCR tariff will cease to be collected and financing costs will be included in general revenue requirements. To protect customers from further cost overruns, Georgia Power has agreed that if Commercial Operation for Unit 4 is not reached by March 31, 2024, the Company's ROE used to determine the NCCR and calculate AFUDC will be reduced to zero until Commercial Operation for Unit 4 is achieved. The stipulation provides that it is reasonable and prudent to include in rate base the associated AFUDC financing cost above $4.418 billion (the certified amount) up to $7.562 billion. The stipulation also provides for the recovery of projected O&M expenses, depreciation expense, nuclear decommissioning accrual, and property taxes, net of projected PTCs, as well as nuclear fuel plant and materials and supplies inventory.

Consistent with the stipulation approved in the Unit 3 Rate Adjustment Order, the stipulating parties agree that as of each Units' respective first refueling outage, the Commission may order the Company to credit customers for O&M expenses or disallow costs associated with the repair or replacement of any system, structure, or component found to have caused a material deviation in performance resulting from imprudent engineering, construction, procurement, testing, or startup. Finally, Georgia Power has agreed to continue to file semi-annual VCM reports until Unit 4 achieves Commercial Operation.

The stipulation is a reasonable resolution of the outstanding issues regarding cost recovery for Vogtle Units 3 and 4. As with any settlement, no single party received everything it sought as a proposed resolution. The stipulation considers many of the issues raised by Staff and intervenors in the VCM proceedings throughout the Project. The stipulating parties worked hard to look

[22] $7.562 billion total project construction and capital cost minus the $2.1 billion already included in rates equals $5.462 billion.

beyond single issues to reach an agreement. The resulting stipulation strikes a reasonable balance among complex, technical issues and provides for the recovery of reasonable and prudent costs for the Project while recognizing the affordability needs of customers.

VI. PROPOSED RETAIL BASE RATE ADJUSTMENT TO RECOVER THE REMAINING COSTS FOR UNITS 3 AND 4 AND COMMON FACILITIES IN ACCORDANCE WITH THE STIPULATION

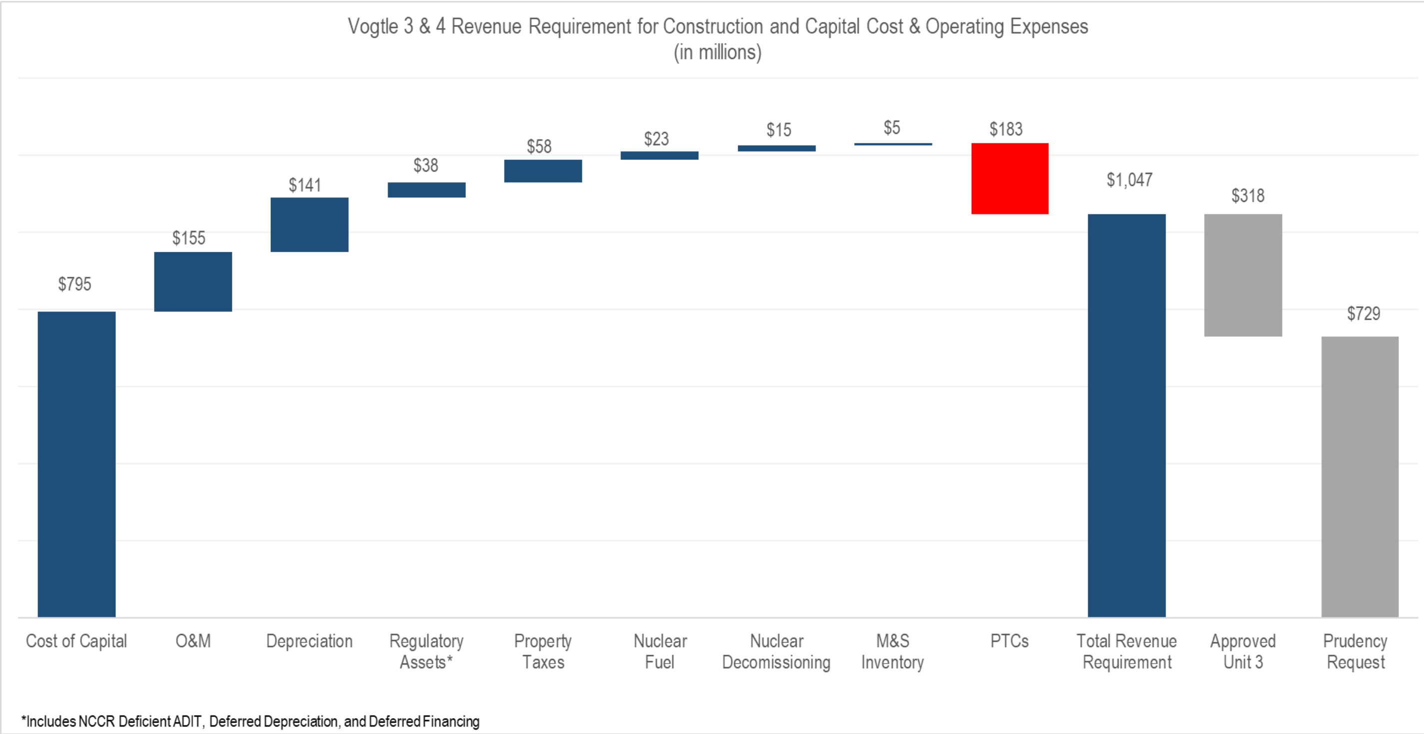
A. Revenue Requirement to be Recovered from Customers

To recover the remaining construction and capital cost, as well as the costs of operating Unit 4 upon reaching Commercial Operation, the Company proposes to increase base rates by $729 million on an annual basis. In determining the incremental increase in revenue requirement to recover the remaining construction and capital cost of Units 3 and 4 from customers, the Company calculated the full revenue requirement for Vogtle Units 3 and 4 and common facilities and then subtracted out the revenue requirement amount already approved in rates through the Unit 3 Rate Adjustment Order. The proposed increase does not include estimated fuel savings attributed to Vogtle Units 3 and 4 that are already incorporated into the current Fuel Cost Recovery (FCR-26) rates effective June 1, 2023. The proposed increase also does not include the reduction of the NCCR tariff through its elimination the month following Unit 4 Commercial Operation. (See Schedule 1 of Exhibit 1.) The components of the 13-month average rate base amount are presented on Schedule 2, pages 2 and 4 of Exhibit 1, which includes requested construction and capital cost including the associated AFUDC, accumulated deferred income taxes ("ADITs"), nuclear fuel plant, materials and supplies inventory, and regulatory assets related to the deferred depreciation, financing costs, and deficient ADITs. The Company's projected weighted-average cost of capital applied to this 13-month average rate base amount is calculated on Schedule 2, page 5 of Exhibit 1.

The Company also proposes to recover the following reasonable and prudent costs related to the full operation and commensurate output of Units 3 and 4 and common facilities upon Commercial Operation: (1) depreciation expense; (2) O&M expenses; (3) property taxes; and (4) nuclear decommissioning costs (based on the current 40-year operating license of Vogtle Units 3 and 4). Because Units 3 and 4 will be generating electricity, they will be awarded federal PTCs during the first eight years of each Unit's operation. The projected operating cost profile and ultimate costs to customers will be significantly reduced thanks to the benefit of the PTCs related to the Company's share of Vogtle Unit 3 and 4's generation output. These projected operating costs and PTC amounts are presented on Schedule 2, page 4 of Exhibit 1.

For the calculation of depreciation expenses, the Company has agreed to depreciate Vogtle Units 3 and 4 based on the annual rate of 1.677%, which was approved by the Commission in the Vogtle Unit 3 Rate Adjustment Stipulation in Docket No. 43838, until the Company's next base rate case. The Company will calculate depreciation on the allowed construction and capital cost and associated AFUDC for the Project. The Company and Staff have agreed to re-evaluate the depreciation rate for Vogtle Units 3 and 4 in the Company's depreciation study in the next base rate case. For the regulatory assets related to the deferred depreciation and financing costs on Unit 3 capital that was deferred since Unit 3 was placed in service, the Company proposes to include such costs in retail base rates and amortize the costs ratably over 10 years. Likewise, the Company proposes to amortize ratably the deficient Vogtle Units 3 and 4 ADITs resulting from the Tax Cuts and Jobs Act over 10 years. The full revenue requirement is presented in Figure 2 below.

Figure 2: Revenue Requirement for $7.562 Billion of Construction and Capital Cost



If the stipulation is approved, retail rates will increase by approximately 5%. The bill increase tied to the stipulated $7.562 billion in construction and capital cost equates to approximately $8.95 per month for the typical residential customer using an average of 1,000 kWh per month and includes the elimination of the NCCR tariff effective in the same month.

B. Rate Design

The Company will adjust base rates to recover the remaining Units 3 and 4 and common facilities revenue requirements beginning in the month after Unit 4 achieves Commercial Operation. The proposed increase will be allocated equally across all base tariffs. The Company will design the Unit 4 price changes after completing the rate design for the October 1, 2023, rate case compliance filing as specified in the Commission's Order in Docket No. 44280.

In conjunction with the November 1, 2023, NCCR filing, the Company will provide a set of tariffs that includes the combined effect of the rate case compliance filing and the Units 3 and 4 and common facilities revenue requirements. The tariffs filed for the rate case compliance filing will take effect January 1, 2024. If Unit 4 achieves Commercial Operation in March 2024, the tariffs reflecting the combined effects of the rate case compliance filing and Units 3 and 4 and common facilities revenue requirements will go into effect on April 1, 2024. However, if Unit 4 achieves Commercial Operation before or after March 2024, the Company will provide a revised set of tariffs to account for any necessary changes to the revenue requirements and schedule, and these tariffs will go into effect the month following Unit 4 Commercial Operation. All noted changes to the Company's revenue requirements and tariffs will be subject to Commission and Staff review.

C. NCCR and Remaining Financing Costs

Pursuant to O.C.G.A. § 46-2-25, Georgia Power recovers the cost of financing the construction of Units 3 and 4 during construction through a separate rider on customer bills, the NCCR tariff. The SIR Stipulation provided that, consistent with O.C.G.A. § 46-2-25, the NCCR tariff will continue until the Units are in base rates, but the NCCR will only be collected on the certified capital cost of $4.418 billion. As provided by law, Georgia Power shall continue to recover the allowed financing costs pursuant to the NCCR tariff until the effective date of the rate adjustment described above, at which time the financing costs shall be included in Georgia Power's general revenue requirements and collected through base rates. For the year 2024, rather than increase the NCCR tariff for three months, the Company proposes to keep the 2023 NCCR tariff in place until Unit 4 achieves Commercial Operation. As agreed to in the stipulated agreement, any over or under-recovered balance resulting from the NCCR tariff at its termination date will be included in rate base and addressed in the next base rate case.

D. Replacement Fuel Costs

The Company has provided a table of replacement energy costs in accordance with the VCM 12 stipulation for the time period beyond the Vogtle Units 3 and 4 certification in-service dates of April 2016 and April 2017 for Unit 3 and 4, respectively. Following the Westinghouse bankruptcy, the Company, Co-Owners, and Commission all had to decide to continue construction or abandon the Project and build alternative generation. With the approval to continue construction in the VCM 17 Order, the Commission found reasonable the Company's updated schedule of

November 2021 and 2022 for the Units. The Company has recalculated the total replacement fuel costs based upon these reasonable in-service dates and presents this information in the table below:

Table 5: Replacement Fuel Costs

Replacement Energy Costs and Deferred Operating Costs

Millions of Dollars

	Deferred Benefits		Deferred Operating Costs				
Date	Replacement Energy Cost	Deferred PTCs	O&M	Depreciation	Ad Valorem	Total Deferred Operating Costs	Net Cost
Dec-21	**7.9**	8.7	(4.7)	(6.3)	(2.1)	(13.1)	3.6
Jan-22	**8.3**	8.7	(4.2)	(6.3)	(2.2)	(12.7)	4.4
Feb-22	**6.9**	8.7	(4.2)	(6.3)	(2.9)	(13.4)	2.3
Mar-22	**8.6**	8.7	(4.3)	(6.3)	(2.5)	(13.1)	4.2
Apr-22	**14.7**	8.7	(8.0)	(6.3)	(2.2)	(16.5)	6.9
May-22	**26.1**	7.6	(10.1)	(6.3)	(2.4)	(18.8)	14.9
Jun-22	**30.4**	7.6	(9.9)	(6.3)	(2.4)	(18.6)	19.4
Jul-22	**35.8**	7.6	(10.0)	(6.3)	(2.5)	(18.8)	24.6
Aug-22	**34.5**	7.6	(10.3)	(6.4)	(2.5)	(19.2)	23.0
Sep-22	**25.3**	7.6	(11.5)	(6.4)	(2.5)	(20.4)	12.6
Oct-22	**15.9**	7.6	(11.5)	(6.4)	(2.5)	(20.4)	3.2
Nov-22	**14.0**	7.6	(18.0)	(6.4)	(2.1)	(26.5)	(4.8)
Dec-22	**59.4**	14.2	(12.6)	(10.9)	(3.9)	(27.3)	46.3
Jan-23	**15.4**	14.2	(12.5)	(10.9)	(2.8)	(26.2)	3.3
Feb-23	**7.8**	14.2	(13.7)	(10.9)	(3.7)	(28.3)	(6.3)
Mar-23	**9.5**	14.2	(12.4)	(10.9)	(3.3)	(26.6)	(3.0)
Apr-23	**5.6**	14.2	(10.7)	(10.9)	(3.3)	(24.9)	(5.1)
May-23	**8.3**	14.2	(12.3)	(11.0)	(3.3)	(26.5)	(4.1)
Jun-23	**11.1**	14.2	(9.3)	(11.0)	(3.3)	(23.5)	1.7
TOTAL:	**345.5**	**196.4**	**(190.4)**	**(152.3)**	**(52.2)**	**(394.8)**	**147.0**

**costs re-based using Nov 2021 (U3) and Nov 2022 (U4) inservice*

E. Unit 3 Commercial Operation

As provided in the Unit 3 Rate Adjustment Stipulation, Georgia Power agreed that, as of the date it filed this Unit 4 Prudence Review and Rate Adjustment, if Unit 3 had materially deviated from its expected performance, the Commission had the right to review the O&M expenses embedded in the tariffs for Unit 3. Georgia Power would retain the burden to prove that any outage or derating resulting in lower than anticipated electricity production by Unit 3 was not the result of unreasonable or imprudent construction, testing, or startup activities.

Unit 3 achieved Commercial Operation on July 31, 2023. The Company notified the Commission on July 31, 2023, in Docket No. 43838 that Unit 3 achieved Commercial Operation. Since then, Unit 3 has remained operational and dispatchable as the Unit is serving Georgia customers with 24-hour a day, 7-day a week carbon free electricity.

F. Process to Determine that Unit 4 has Achieved Commercial Operation.

Per the terms of the Unit 3 Rate Adjustment Stipulation, the parties agreed that the definition of "Commercial Operation," as defined in the SIR Stipulation and Order in Docket No. 29849, would not be altered or amended for Unit 4. As part of the Unit 3 Rate Adjustment Stipulation, the parties reserved the right to make any arguments regarding what process will be used to determine that Unit 4 is "fully dispatchable on demand at the stated Net Electrical Output of 1,102 Mwe" as that term is used in the SIR Stipulation.

For Unit 3, the parties agreed that Commercial Operation would not be declared for rate recovery purposes unless and until Unit 3 successfully completed all appropriate pre-operational tests and power ascension testing and any necessary remediation required for safe and reliable operation. Once Georgia Power certified to the Commission that Unit 3 had successfully completed all such testing and was fully dispatchable at the stated net electrical output of 1,102 MWe, no further action or proceeding was required for Georgia Power to adjust retail base rates. In accordance with this process, rates were adjusted on August 1, 2023, following the achievement of Commercial Operation of Unit 3 on July 31, 2023.

Georgia Power proposes that the process for determining whether Unit 4 has achieved Commercial Operation be the same as and consistent with the process used for determining whether Commercial Operation was achieved for Unit 3. A simple notification process was all that was necessary for the Commission to determine that Unit 3 achieved Commercial Operation. At the conclusion of Unit 4 testing and startup procedures, Southern Nuclear will determine when Unit 4 is "fully dispatchable on demand at the stated Net Electrical Output of 1,102 MWe" as that phrase is used in the SIR Stipulation. Once this determination is made, the Company, along with the other Co-Owners, will declare that Unit 4 has achieved Commercial Operation, Unit 4 will be available to dispatch in accordance with Fleet Operations for the benefit of customers, and the Company will notify the Commission of that declaration. At that time, the Commission then has sole discretion to determine whether the Company's declaration meets the Commission's criteria for the purpose of placing the remaining Project costs in rates.

VII. PRUDENCE PACKAGE OVERVIEW

In addition to this Application, the Company's Prudence Filing will include the following supporting testimony and reports:

(1) Direct Testimony of Aaron Abramovitz, Jeremiah Haswell, and John Williams on behalf of Georgia Power. Witnesses Abramovitz, Haswell, and Williams identify, explain, support, and prove the reasonableness and prudence of the construction and capital cost, financing costs, and operating costs for which the Company seeks cost recovery. The Company panel also discusses the accounting mechanics and recovery logistics for the Company's request.

(2) HKA Expert Reports and the Direct Testimony of Tim Chitester, Mark Gentry, and Kim Reome. The HKA panel submits reports and supporting testimony outlining the results of their detailed analysis and independent opinion of the reasonableness of the Vogtle Units 3 and 4 cost and schedule.

(3) Direct Testimony of Joe Miller and Mike Skaggs. Witnesses Miller and Skaggs are former electric utility executives with megaproject and nuclear construction experience who analyzed the management decisions made throughout the life of the Project. Witnesses Miller and Skaggs rely on their decades of experience in the industry to offer independent opinions and provide the "reasonable manager" perspective as a point of reference for the prudence of the Company's decisions on Vogtle Units 3 and 4.

Similar to the Company's Unit 3 Rate Adjustment Application, Exhibit 1 to this Application includes the MFR Schedules detailing the Company's revenue requirements to support its request to adjust rates for the remaining amounts of Units 3 and 4 and common facilities costs. The MFRs, as filed, assume a Unit 4 Commercial Operation date in March 2024. If Unit 4 does not achieve Commercial Operation in March 2024, or should there be changes to the tax code that impact the federal income tax rate or availability of PTCs, the Company will revise the MFRs and schedules in Exhibit 1 to reflect such changes.

VIII. CONCLUSION

The Company's Application is consistent with the Commission's intent and directives as stated in the VCM 17 Order, the SIR Final Order, the Unit 3 Rate Adjustment Order, and the stipulated agreement reached in settlement of this proceeding. The completion of Vogtle Units 3 and 4 will be a monumental accomplishment, representing the only newly constructed nuclear units built in the United States in decades. The addition of Vogtle Units 3 and 4 will add at least 1,007 MWe of reliable, carbon free generation capacity to the Georgia Power fleet. Units 3 and 4 will be able to power up to 1,000,000 homes and businesses and will serve Georgia Power customers for 60-80 years. Notwithstanding the high upfront capital costs, nuclear energy remains one of the lowest cost and most reliable energy sources for our state and our customers. Vogtle Units 3 and 4 will provide necessary baseload energy to the system and provide an inherent hedge against unpredictable fluctuations in fossil fuel prices. The addition of these units will continue to give businesses and industries the confidence to stay, expand, or locate in our state – generating thousands of jobs and enormous capital investments in Georgia.

Building new nuclear units is a complex process and the path to completion of Vogtle Units 3 and 4 has not been without challenges. The Project faced unprecedented challenges that led to setbacks, delays, and cost increases. Georgia Power and the other Co-Owners actively supported this Project, oversaw its construction and development, and recognized the value of this Project to Georgia's future. With the support of the Commission, both Units will soon be complete, online, and producing carbon-free electricity for Georgia Power's customers and the state of Georgia. Thanks to the Commission's long-term view of the state's energy future, Georgia Power has been able to invest in a diverse energy mix—that includes nuclear energy—to maintain high levels of reliability for our customers. The Commission and Staff have remained steadfast in ensuring that Georgia Power honors its commitment to seeing these Units completed and getting it done right. Georgia Power is committed to constructively working with the Georgia Public Service Commission in planning for our customers' needs today and for decades to come. This constructive regulatory construct has allowed, and will continue to allow, Georgia Power to provide clean, safe, reliable, and affordable energy to our customers as Georgia continues to grow.

The Company's Application demonstrates that all costs incurred on the Project to date and requested for cost recovery are reasonable and have been prudently incurred on behalf of customers. The Company proposes to recover the remaining Units 3 and 4 costs found reasonable and prudent by the Commission, which include the corresponding financing costs. In addition, the Company proposes to recover the following costs related to its full ownership in Units 3 and 4 and common facilities upon Commercial Operation: (1) depreciation expense; (2) O&M expenses; (3) property taxes; (4) nuclear decommissioning costs; (5) nuclear fuel plant; and (6) materials and supplies inventory; as well as to provide customers with the full benefit of the PTCs. The month after Unit 4 achieves Commercial Operation, the Company proposes to increase base rates by $729 million on an annual basis. Combined with the $207 million reduction to retail rates resulting from the elimination of the NCCR tariff, retail rates will increase by approximately 5%, which equates to a bill increase of approximately $8.95 per month for the typical residential customer using an average of 1,000 kWh per month. The proposed increase will be allocated proportionally across all base tariffs. In addition, once fully implemented, the expansion of the Income Qualified Senior Discount included in the stipulated agreement with Staff and other intervenors will qualify 96,000 additional customers for the monthly $33.50 discount (including fuel) and will increase the typical residential customer's bill by approximately $1.00 per month. Georgia Power will prepare revised tariffs as described above and will provide those to the Commission alongside the Company's planned NCCR filing in November in Docket No. 44280.

The Company's requests are reasonable and consistent with the Commission's VCM 17 Order, SIR Final Order, and Unit 3 Rate Adjustment Order. As such, the Commission should approve Georgia Power's prudence request and rate adjustment plan for the Project as reflected in the stipulation and presented herein.