

**BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

In the Matter of:)	
GEORGIA POWER COMPANY'S)	DOCKET NO. 42516
2019 RATE CASE)	

**DIRECT TESTIMONY
AND EXHIBITS
OF
RALPH C. SMITH
AND
ROBERT L. TROKEY**

**ON BEHALF OF THE
GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF**

PUBLIC VERSION

October 17, 2019

**BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

TABLE OF CONTENTS

I.	INTRODUCTION	1
II.	SCOPE AND PURPOSE OF TESTIMONY	2
III.	CASE OVERVIEW AND STRUCTURE OF TESTIMONY	5
IV.	TRADITIONAL REVENUE REQUIREMENT SUMMARY	23
	Test Year and Plan Years	23
	Traditional Case Summary	24
	Staff Test Year and Plan Year Adjustments-Estimated Revenue Requirement Impacts	27
V.	ECCR TARIFF REVENUE DEFICIENCY SUMMARY	32
VI.	DSM TARIFF REVENUE DEFICIENCY SUMMARY	39
VII.	MUNICIPAL FRANCHISE FEE TARIFF (“MFF”)	41
VIII.	COAL COMBUSTION RESIDUALS (CCR) ASSET RETIREMENT OBLIGATIONS (ARO) REVENUE REQUIREMENT	45
IX.	ORGANIZATION OF STAFF’S REVENUE REQUIREMENT AND ADJUSTMENT SCHEDULES	59
X.	STAFF ADJUSTMENTS	64
	Overall Rate of Return	64
	E-1, Company Errata - Rate Base Adjustments	64
	E-2, Company Errata - Operating Income Adjustments	67
	E-3, Interest Credits on Minimum Bank Balances	68
	E-4, Electric Vehicle Charging Facilities	70
	E-5, Cash Working Capital	75
	E-6, Miscellaneous Items / Executive Financial Planning	75

E-7, Property Tax Adjustment	76
E-8, Interest Synchronization Adjustment	79
E-9, Stock-Based Compensation.....	80
E-10, Payroll Tax Expense.....	81
E-11, Uncollectibles Expense	81
E-12, Storm Damage Regulatory Asset Amortization and Storm Damage Accrual ...	83
Sharing of Responsibility for the CCR ARO Amount for Plant Kraft and the Benefits of Donating Plant Kraft Land to the Georgia Ports Authority.....	87
Sales Forecast and Projection of Revenue at Current Rates	92
Plant Held for Future Use	93
Gain Sharing on Land Sales.....	97
Stewart County "Future Nuclear" Site Investigation Cost.....	98
Production Tax Credits	100
F-1, Depreciation Expense and Accumulated Depreciation - Depreciation Rates - ..	102
F-2, Accumulated Deferred Income Taxes - Impact of Depreciation Rates.....	103
 XI. AFFILIATE CHARGES TO GEORGIA POWER COMPANY AND GEORGIA POWER COMPANY CHARGES TO AFFILIATES	 105
Overview of Affiliate Charges from Southern Company Services and Southern Nuclear Operating Company to Georgia Power Company.....	105
Southern Company Services Charges to Georgia Power Company	106
SCS Allocation Factors Using 2019 Statistics	107
Southern Nuclear Company Charges to Georgia Power Company	111
Georgia Power Company Charges to Other Affiliates.....	116
Georgia Power Company Charges to Southern Power	117
 XII. TAX CUTS AND JOBS ACT OF 2017	 121
 XIII. INCENTIVE COMPENSATION	 131
Stock Based Compensation.....	132
Performance Pay Plan	139
 XIV. RATE PLAN PRINCIPLES AND RECOMMENDATIONS	 142
Multi-Year Rate Plans Versus Traditional Test Year Based Ratemaking	142
Earnings Test and Earnings Band-History	144

Staff Rate Plan Recommendations	146
Step Increase Approach.....	148
Sharing of Gains on Disposition of Land and Utility Property.....	151
Application of Earnings Above Top End of Band	152
XV. SUMMARY OF STAFF RECOMMENATIONS	155

<u>Exhibit</u>	<u>Description</u>
RCS-1	Ralph C. Smith Background and Qualifications
RLT-1	Robert L. Trokey Background and Qualifications
RS/RT-2	Traditional Revenue Requirement and Adjustment Schedules
RS/RT-3	ECCR Revenue Requirement
RS/RT-4	DSM Revenue Requirement
RS/RT-5	Municipal Franchise Fee Revenue Requirement
RS/RT-6	CCR ARO Compliance Revenue Requirement
RS/RT-7	Georgia Power's responses from Docket No. 42310 (2019 IRP) to STF-L&A-1-65, STF-L&A-5-15, and the supplemental response to STF-L&A-5-16 concerning certain transmission and substation projects which the Company had included in prior IRP filings but which are not included in the Company's 2019 IRP.
RS/RT-8	Georgia Power's 2018 FERC Form 1, pages 214, account 105, Plant Held for Future Use.
RS/RT-9	Identification of amounts in the PHFFU for which the projected "use" date in providing electric service is (1) 2030 or beyond or (2) 2040 or beyond.
RS/RT-10	Annual cost of PHFFU, including the annual financing costs.
RS/RT-11	Georgia Power's Trade Secret attachments to its responses in Docket No. 42310 (2019 IRP) to STF-L&A-1-23 and STF-L&A-1-25 relating to details of the CCR spending by year and by plant ash pond and landfill.
RS/RT-12	Georgia Power's responses to STF-L&A-1-13 and STF-L&A-1-16 Docket No. 42310 (2019 IRP) relating to the ECCR.
RS/RT-13	Georgia Power's Trade Secret response to STF-L&A-1-11 and STF-PIA-9-4 Docket No. 42310 (2019 IRP) relating to the ECCR.
RS/RT-14	Georgia Power Trade Secret response to STF-L&A-12-1 and Trade Secret informal follow-up responses concerning contingency amounts for the ECCR
RS/RT-15	Georgia Power responses to STF-L&A-1-47, STF-L&A-1-47 Supplemental Attachment, and STF-RCS-1-35 (from Docket No. 36989) regarding Property Tax True-Up
RS/RT-16	Georgia Power response to STF-L&A-1-129 and STF-L&A-5-33 regarding EV Charging Facilities

- RS/RT-17 Georgia Power response to STF-L&A-1-60 regarding Miscellaneous Items/Executive Financial Planning
- RS/RT-18 Georgia Power responses to STF-L&A-1-32 and STF-L&A-4-47 regarding Minimum Bank Balance Interest Credits
- RS/RT-19 Georgia Power Trade Secret response to STF-L&A-11-19 regarding Minimum Bank Balance Interest Credits
- RS/RT-20 Georgia Power responses to STF-L&A-1-125, STF-L&A-1-126, STF-L&A-1-127 and its Trade Secret response to STF-L&A-13-4 concerning Production Tax Credits
- RS/RT-21 Commission's Order on the Tax Cuts and Jobs Act in Docket No. 36989, including Exhibit 1, 2018 TCJA Base Rates Settlement between Staff and Georgia Power Company
- RS/RT-22 Georgia Power responses to STF-L&A-1-20, STF-L&A-1-106, STF-L&A-1-107, STF-L&A-1-119, STF-L&A-11-9 and STF-L&A-13-6 concerning Tax Cuts and Jobs Act and Excess ADIT classification as Protected or Unprotected
- RS/RT-23 Selected pages of Southern Company Services FERC Form 60 dated December 31, 2018 (Cover, pages 307, 402.1, 402.2)
- RS/RT-24 Georgia Power responses to STF-L&A-1-115 and STF-L&A-1-116 (with selected attachment pages) and STF-L&A-1-117 regarding SCS Use of Updated Statistics for Allocation Factors
- RS/RT-25 Selected pages of Southern Nuclear Operating Company FERC Form 60 dated December 31, 2018 (Cover, pages 307, 402.1, 402.2)
- RS/RT-26 Georgia Power responses to STF-L&A-1-122 and STF-L&A-13-3 concerning impact of Southern Nuclear Operating Company allocations of cost to Georgia Power Company including how the SNOG nuclear-units-based cost allocation to the Company will change relating to Plant Vogtle Units 3 and 4 going into commercial operation.
- RS/RT-27 Georgia Power responses to STF-L&A-1-83, STF-L&A-3-38, STF-L&A-3-41, and STF-L&A-11-30 regarding Stock-Based Compensation
- RS/RT-28 Georgia Power Trade Secret response to STF-L&A-1-82 regarding Stock-Based Compensation
- RS/RT-29 Georgia Power response to STF-L&A-1-39 regarding Storm Damage Accruals

- RS/RT-30 Georgia Power responses to STF-PIA-10-3 through STF-PIA-10-9 regarding Uncollectible Expense
- RS/RT-31 Georgia Power response to STF-PIA-13-3 regarding DSM
- RS/RT-32 Georgia Power Trade Secret response to STF-PIA-14-4 regarding CCR ARO Compliance Costs
- RS/RT-33 Georgia Power response to STF-L&A-11-1 concerning Georgia Power Company charges to Southern Power.

**BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

In the Matter of:)	
GEORGIA POWER COMPANY'S)	DOCKET NO. 42516
2019 RATE CASE)	

DIRECT TESTIMONY OF RALPH C. SMITH AND ROBERT L. TROKEY

I. INTRODUCTION

Q. MR. SMITH, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Ralph C. Smith, 15728 Farmington Road, Livonia, Michigan 48154.

Q. WHAT IS YOUR OCCUPATION?

A. I am a certified public accountant and a senior regulatory utility consultant with the firm Larkin & Associates, PLLC, certified public accountants and regulatory consultants.

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit__(RCS-1). This exhibit summarizes my regulatory experience and qualifications.

Q. MR. TROKEY, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Robert L. Trokey, 244 Washington St. SW, Atlanta, Georgia 30334.

Q. WHAT IS YOUR OCCUPATION?

A. I am a Utilities Analyst in the Electric Section of the Georgia Public Service Commission (“Commission”).

Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. It is presented in Exhibit RLT-1. This exhibit summarizes my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. We are testifying on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff (“Staff”).

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY?

A. The scope and purpose of our testimony is to present the Staff’s overall traditional case revenue requirement position for Georgia Power Company (“Georgia Power” or “Company”), as well as Staff’s recommended position regarding the Company’s proposed Alternative Rate Plan (“ARP”), and Environmental Compliance Cost Recovery (“ECCR”). We also show the Company’s Demand Side Management (“DSM”) revenue requirement, Municipal Franchise Fee (“MFF”) revenue requirement, and Coal Combustion Residuals (“CCR”) Asset Retirement Obligation (“ARO”) Compliance revenue requirement, as well as Staff’s corresponding recommendations on each of those. We also address the Company’s proposal for a three-year alternative rate plan covering

1 the years 2020, 2021 and 2022, the history of previous Company rate plans, and
2 recommendations for the principles and sharing mechanisms that should be applied, if the
3 Commission chooses to allow for an alternative rate plan in the current rate cases, versus
4 allowing a revenue requirement based on adjusted test year results.

5
6 **Q. IN CALCULATING THE STAFF'S RECOMMENDED OVERALL**
7 **TRADITIONAL RATE CASE REVENUE REQUIREMENT POSITION, DID**
8 **YOU INCORPORATE RECOMMENDATIONS MADE BY THESE OTHER**
9 **STAFF WITNESSES?**

10 A. Yes. We have incorporated the following recommendations of other Staff witnesses at
11 this time:

- 12 • Ms. Barber's and Messrs. Brown, Dietchman, and Faryniarz's recommendations
13 concerning the Company's *DSM revenue requirement* and adjustments thereto.
- 14 • Mr. Michael Gorman's recommended *capital structure, return on equity and*
15 *cost rates for long-term debt*.

16
17
18 **Q. THE COST OF DEBT USED TO CALCULATE STAFF REVENUE**
19 **REQUIREMENTS IS SLIGHTLY HIGHER THAN COST OF DEBT**
20 **RECOMMENDED BY MR. GORMAN. DOES THIS BENEFIT THE COMPANY?**

21 A. Yes. Staff witness Gorman's final recommended debt rates were not used to calculate
22 revenue requirements due to time constraints. The use of higher debt rates benefits the
23 Company by increasing revenue requirements by approximately \$6 million per year.
24

1
2
3
4
5
6
7
8
9

**Q. WHAT INFORMATION HAVE YOU RELIED UPON IN THE DEVELOPMENT
OF YOUR TESTIMONY?**

A. In developing this testimony, we have relied upon our review and analysis of the Company's direct testimonies and accompanying exhibits; Minimum Filing Requirements; workpapers; responses to "STF-L&A" and "STF-PIA" and other Staff data requests; transcripts from the September 30-October 2, 2019 hearings; and other relevant financial documents and data.

III.CASE OVERVIEW AND STRUCTURE OF TESTIMONY

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THIS CASE.

A. This case was filed by the Company on June 28, 2019, in accordance with the requirements of the Accounting Order approved by the Commission in its Order dated December 23, 2013, in Georgia Power's 2013 rate case, Docket No. 36989, and the May 12, 2022 Order Adopting Settlement Agreement in Docket No. 39971.¹ Georgia Power filed the instant rate case to obtain a Commission decision regarding its base rates prior to the expiration of the Accounting Order on December 31, 2019.

Q. WHAT TEST PERIOD AND PLAN YEARS ARE USED IN THE COMPANY'S FILING?

A. The Company's rate filing includes financial projections for the traditional, Commission-ordered test year of August 1, 2019 through July 31, 2020, as well as for an Alternative Rate Plan that encompasses the three calendar years 2020, 2021 and 2022.

Q. WHAT DOES THE COMPANY SHOW AS THE REVENUE DEFICIENCY APPLICABLE TO BASE RATES?

A. Company Exhibit __ (DPP/SPA/MBR-1, Schedule 1 Total Company) page 1 of 10 shows Georgia Power's computation of the retail revenue deficiency applicable to base rate tariffs, excluding the Municipal Franchise Fees ("MFF") for the test year and each plan year as follows:

¹ Joint Application Of Atlanta Gas Light Company, AGL Resources, Inc., and The Southern Company for a Finding that Southern Company's Acquisition of Atlanta Gas Light Resources Complies With Applicable Law.

Test Period: \$195.263 million

2020: \$351.749 million

2021: \$711.156 million

2022: \$1.1174 billion

Q. HOW DID THE COMPANY PROPOSE TO RECOVER THE REVENUE DEFICIENCY FOR THE TEST YEAR ENDING JULY 31, 2020?

A. The rate filing indicates that the Company requests a revenue requirement increase of approximately \$367 million rather than the \$195 million revenue deficiency associated with the test year. The \$367 million is based on a \$209.224 million "levelized" revenue deficiency which the Company calculated based on calendar 2020 through 2022 projected results and \$158.110 million for a 2020 revenue deficiency for CCR ARO compliance. This is shown on Company Exhibit__(DPP/SPA/MBR-1, Schedule 2 Traditional Base), page 1 of 5. As shown there, Georgia Power first calculated a retail jurisdictional revenue excess for the test year of approximately \$144 million. To that amount the Company added a "2020-2022 Levelization Adjustment Less CCR ARO Compliance" amount of \$353 million, to derive its requested Levelized Revenue Deficiency Applicable to Traditional Base Rate Tariffs less CCR ARO Compliance of \$209.224 million, as shown on Company Exhibit__(DPP/SPA/MBR-1, Schedule 2 Traditional Base), page 1, lines 1-3. The Company adds to that amount its requested 2020 revenue requirement deficiency for CCR ARO Compliance of \$158 million, to derive its proposed total Revenue Deficiency Applicable to Traditional Base Rate Tariffs

1 of \$367 million, as shown on Company Exhibit__(DPP/SPA/MBR-1, Schedule 2
2 Traditional Base), page 1, lines 4-5.

3
4 **Q. IS THE COMPANY'S PROPOSED RECOVERY OF A REVENUE DEFICIENCY**
5 **BASED ON THE TRADITIONAL TEST YEAR APPROACH?**

6 A. No. The Company's rate request in this case is not based on the traditional ratemaking
7 approach. Rather, it is based on an Alternative Rate Plan that uses projected data from an
8 alternative test year, calendar year 2020, as well as projections for calendar years 2021
9 and 2022. While the proposed Alternative Rate Plan has no termination date, the rate
10 filing presents projected revenue requirement and associated rate change data for the first
11 three years of the Plan, i.e., the years 2020, 2021 and 2022. This approach is very
12 beneficial to the Company as it eliminates regulatory lag. The Company is only entitled
13 to rates being set under the test year. Any alternative rate plan must be approved by both
14 the Company and the Commission. Of course, if rates are set on a test year the Company
15 may stay out as long as it wants and may file a rate case at any time. The Commission has
16 the authority to order the Company to file a rate case at any time.

17
18 The revenue deficiency calculated by the Company (excluding the MFF) for the test year
19 is \$195 million as shown on Company Exhibit __ Exhibit __ (DPP/SPA/MBR-2,
20 Schedule 1 Total Company), page 1 of 10.

21
22 The revenue deficiencies calculated by the Company (excluding the MFF) under the
23 Alternative Rate Plan amount to approximately \$364 million for 2020, \$732 million for

1 2021 and \$1.147 billion for 2022 as shown on Company Exhibit __ (DPP/SPA/MBR-2,
2 Schedule 1 Total Company), page 1 of 10.

3
4 As shown on Company Exhibit __ (DPP/SPA/MBR-2, Schedule 2, Traditional Base),
5 page 3 of 5, the Company has calculated a traditional base rate tariff revenue excess of
6 \$4.3 million for 2020; a \$229.5 million deficiency for 2021 and a \$434.2 million revenue
7 deficiency for 2022.

8
9 As shown on Company Exhibit __ (DPP/SPA/MBR-1, Schedule 2 Traditional Base),
10 page 2 of 5, the Company proposes to "levelize" the traditional base rate tariff revenue
11 excess of \$4.3 million for 2020; a \$229.5 million deficiency for 2021 and a \$434.2
12 million revenue deficiency for 2022, using a discount rate of 7.51%, to produce a
13 "levelized" annual revenue deficiency of \$209.2 million for 2020, 2021 and 2022.

14
15 As shown on Company Exhibit __ (DPP/SPA/MBR-1, Schedule 2 Traditional Base),
16 page 1 of 5, the Company proposes to adjust its calculated test year revenue requirement
17 excess of \$144 million under traditional base rate tariffs (less CCR ARO Compliance)
18 upward by \$353 million to get to the 2020, 2021 and 2022 "levelized" revenue deficiency
19 of \$209.2 million per year. This is shown on Company Exhibit __ (DPP/SPA/MBR-1,
20 Schedule 2 Traditional Base), page 2 of 5, lines 1 through 3. This means that, under
21 Georgia Power's proposal, the traditional base rates (excluding the CCR ARO
22 Compliance revenue requirement) to become effective on January 1, 2020 will be
23 designed to recover a revenue deficiency of \$209.2 million per year, which is \$353.2

1 million more than the \$144 million revenue excess that the Company calculated for the
2 test year.²

3
4 **Q. HAS THE COMPANY CALCULATED AN AMOUNT FOR CCR ARO**
5 **COMPLIANCE IN DERIVING THE \$144 MILLION ITS PROPOSED**
6 **TRADITIONAL BASE RATE REVENUE REQUIREMENT FOR THE TEST**
7 **YEAR?**

8 A. Yes. For the test period, as shown in Company Exhibit__ (DPP/SPA/MBR-1, Schedule 2
9 Traditional Base), page 3 of 5, column (3), line 5, and on page 4 of 5, line 7, the
10 Company shows a test year CCR ARO Compliance revenue deficiency of \$151.3 million.

11
12 **Q. HOW DOES THAT COMPARE WITH THE CCR ARO COMPLIANCE**
13 **REVENUE DEFICIENCY AMOUNTS THAT THE COMPANY HAS**
14 **CALCULATED FOR PLAN YEARS, 2020 THROUGH 2022?**

15 A. The test year CCR ARO Compliance revenue deficiency amount of \$151.3 million is
16 lower than the Company's calculated CCR ARO Compliance revenue deficiency amounts
17 for 2020 of \$158.1 million, for 2021 of \$297.7 million and for 2022 of \$525.2 million.

18
19 **Q. WHAT AMOUNT OF BASE RATE REVENUE DEFICIENCY, INCLUSIVE OF**
20 **THE CCR ARO COMPLIANCE REVENUE DEFICIENCY, HAS THE**

² The Company's calculated test year revenue excess of \$144 million for traditional base rate tariffs (excluding CCR ARO Compliance) is shown on Company Exhibit__ (DPP/SPA/MBR-1, Schedule 2 Traditional Base), page 1 of 5, line 1; on page 2 of 5, line 3, and on page 3 of 5, column (3), line 6. The CCR ARO revenue requirement deficiency amount that was excluded in the Company's derivation of the \$144 million test year revenue excess is \$151.3 million, as shown on Company Exhibit__ (DPP/SPA/MBR-1, Schedule 2 Traditional Base), page 3 of 5, line 5.

**COMPANY PROPOSED FOR NEW RATES TO BECOME EFFECTIVE ON
JANUARY 1, 2020, AND HOW DOES THAT COMPARE WITH THE TEST
YEAR AMOUNT?**

A. As shown in Company Exhibit__ (DPP/SPA/MBR-1, Schedule 2 Traditional Base), page 1 of 5, a CCR ARO Compliance revenue deficiency of \$158.1 million on line 4 has been added to the 2020-2022 “Levelized Revenue Deficiency” applicable to traditional base rates of \$209.2 million (from line 3) to produce a combined revenue deficiency of \$367.3 million.

That \$367.3 million is \$360 million higher than the \$7.3 million test year revenue deficiency applicable to traditional base rates that the Company shows on Exhibit__ (DPP/SPA/MBR-1, Schedule 2 Traditional Base), page 3 of 5, line 4.

**Q. WHAT AMOUNT OF REVENUE DEFICIENCY HAS THE COMPANY
CALCULATED FOR THE TEST YEAR AND EACH PLAN YEAR?**

A. Company Exhibit __ (DPP/SPA/MBR-1, Schedule 1 Total Company) page 1 of 10 shows Georgia Power's computation of the retail revenue deficiency applicable to base rate tariffs, excluding the Municipal Franchise Fees ("MFF") for the test year and each plan year as follows:

- Test Period: \$195.263 million
- 2020: \$351.749 million
- 2021: \$711.156 million
- 2022: \$1.1174 billion

With the MFF included, the Company's calculated revenue requirement deficiency amounts by year for the 2020 through 2022 plan years is summarized from Table 2 at page 17 of the Poroach/Adams/Robinson panel testimony as follows:

Table A - Company As-Filed Projected Revenue Requirement Deficiency

Company As-Filed Projected Revenue Requirement Deficiency by Year			
(In Millions of Dollars)			
Effective Date	2020	2021	2022
Traditional Base			
Not Levelized (a)	\$ (4)	\$ 230	\$ 434
CCR ARO (b)	\$ 158	\$ 298	\$ 525
ECCR (c)	\$ 184	\$ 167	\$ 141
DSM* (d)	\$ 14	\$ 16	\$ 17
MFF	\$ 12	\$ 21	\$ 30
Total (\$)	\$ 364	\$ 732	\$ 1,147
* As determined by the Commission through annual DSM filings.			
Note: Amounts may not sum to total due to rounding			
Source: Poroach/Adams/Robinson Direct Testimony, page 17, Table 2			
<i>See the following exhibits supporting Table 1:</i>			
(a) Exhibit__ (DPP/SPA/MBR-1, Schedule 2 Traditional Base) Page 3			
(b) Exhibit__ (DPP/SPA/MBR-1, Schedule 2 Traditional Base) Page 4			
(c) Exhibit__ (DPP/SPA/MBR-1, Schedule 3 ECCR) Page 3			
(d) Exhibit__ (DPP/SPA/MBR-1, Schedule 4 DSM) Page 1			

Q. DOES TABLE A REPRESENT THE RATE INCREASES THAT THE COMPANY IS SEEKING?

A. No. The rate increases for the 2020, 2021 and 2022 plan years that the Company is seeking are summarized below from Table 1 from page 9 of the Poroach/Adams/Robinson panel testimony:

1 **Table B - Company As-Filed Proposed Rate Adjustments**

Company Proposed Rate Adjustments (in millions) - Company As-Filed			
Effective Date	1/1/2020	1/1/2021	1/1/2022
Traditional Base			
Levelized (a)	\$ 209	\$ -	\$ -
CCR ARO (b)	\$ 158	\$ 140	\$ 227
ECCR (c)	\$ 165	\$ -	\$ -
DSM* (d)	\$ 14	\$ 2	\$ 1
MFF (e)	\$ 17	\$ 3	\$ 5
Total (\$)	\$ 563	\$ 145	\$ 234
Cumulative (\$)	\$ 563	\$ 708	\$ 942
* As determined by the Commission through annual DSM filings.			
Note: Amounts may not sum to total due to rounding			
Source: Poroach/Adams/Robinson Direct Testimony, page 9, Table 1			
See the following exhibits supporting Table 1:			
(a) Exhibit__ (DPP/SPA/MBR-1, Schedule 2 Traditional Base) Page 1			
(b) Exhibit__ (DPP/SPA/MBR-1, Schedule 2 Traditional Base) Page 4			
(c) Exhibit__ (DPP/SPA/MBR-1, Schedule 3 ECCR) Page 1			
(d) Exhibit__ (DPP/SPA/MBR-1, Schedule 4 DSM) Page 1			
(e) Exhibit__ (DPP/SPA/MBR-1, Schedule 5 MFF) Page 1			

2

3

4 **Q. HAS THE COMPANY FILED ERRATA THAT HAVE CHANGED ITS**

5 **REVENUE DEFICIENCY AMOUNTS?**

6 A. Yes. On September 24, 2019, the Company filed errata that had the overall net effect of

7 reducing the Company's proposed January 1, 2020, 2021 and 2022 rate adjustments by

8 approximately \$3 million (from \$563 million for 2020 to \$560 million); by \$1 million for

9 2021 (from \$145 million to \$144 million) and by \$1 million for 2022 (from \$234 million

10 to \$233 million). The Company's corrected rate changes are summarized in the following

11 table:

Table C - Company Updated Proposed Rate Adjustments

Company Proposed Rate Adjustments (in millions) - Company Errata			
Effective Date	1/1/2020	1/1/2021	1/1/2022
Traditional Base			
Levelized	\$ 210	\$ -	\$ -
CCR ARO	\$ 158	\$ 139	\$ 227
ECCR	\$ 163	\$ -	\$ -
DSM*	\$ 12	\$ 1	\$ 1
MFF	\$ 17	\$ 3	\$ 5
Total (\$)	\$ 560	\$ 144	\$ 233
Cumulative (\$)	\$ 560	\$ 704	\$ 937
Cumulative (\$) Company As-Filed	\$ 563	\$ 708	\$ 942
Change from Company As-Filed	\$ (3)	\$ (4)	\$ (5)
* As determined by the Commission through annual DSM filings.			
Note: Amounts may not sum to total due to rounding			
Source: Errata Transmittal Letter Dated September 24, 2019, Page 2			

Q. HAS THE COMPANY INDICATED WHAT CAUSED THE ERRATA CHANGES?

A. Yes. As discussed in the Company's Errata transmittal letter, the Company's Errata filing reflects the revenue requirement impacts from various items included in the amended Stipulation that was approved by the Commission in Georgia Power's 2019 Integrated Resource Plan ("2019 IRP") and DSM Certification proceedings in Docket Nos. 42310 and 42311.

Q. WHAT SPECIFIC CORRECTIONS ARE REFLECTED IN GEORGIA POWER'S ERRATA FILING?

A. The Company's transmittal letter lists the following revenue requirement impacts in its Errata filing:

- Transmission interconnection investments related to the 2,000 MW of renewable capacity to be procured through two utility scale renewable request for proposals ("RFP")
- 25 MW of Plant Scherer Unit 3 capacity remaining in wholesale jurisdiction
- Annual limits on Plant Bowen Units 1 and 2 capital expenditures
- Removal of capital expenditures for certain hydro modernization projects but included the associated impact to operation and maintenance expenses
- Increase in battery energy storage system project capacity from 50 MW to 80 MW
- Adjustments to Demand Side Management ("DSM") costs and additional sum as agreed to in the Stipulation as amended and the associated impacts of increasing kWh savings by 15%
- Reasonably necessary specialized assistance to Commission Staff of up to \$500,000 annually

In addition, the errata transmittal letter also states that the Company identified a correction related to its projected depreciation expense and associated impacts for general plant.

Q. HAVE THE ALL THE IMPACTS FROM THE COMPANY'S ERRATA FILING BEEN REFLECTED IN STAFF'S CALCULATIONS?

A. Yes. Since Staff's analysis used as a starting point the Company's original filing, the Company's errata filing corrections have been reflected by Staff as adjustments.

1 **Q. HOW IS THE REST OF YOUR TESTIMONY STRUCTURED?**

2 A. The rest of our testimony is structured into several sections where various issues are
3 addressed.

4
5 Section IV presents a summary of the Company's and Staff's recommended revenue
6 requirement as determined based on the traditional ratemaking approach using the
7 traditional test year August 1, 2019 through July 31, 2020 as well as for each of the plan
8 years, 2020, 2021 and 2022, which are presented in Exhibit__(RS/RT-2).

9
10 Section V discusses the Environmental Compliance Cost Recovery ("ECCR") tariff
11 revenue deficiency proposed by the Company and calculated by Staff. Staff's calculation
12 of the ECCR revenue requirement for the test year and each plan year is shown in
13 Exhibit__(RS/RT-3). This section also discusses how the Company's requested ECCR
14 amount affects the revenue requirement, and Staff's recommended proposal.

15
16 Section VI of our testimony presents a summary of the DSM tariff revenue deficiency
17 amounts for 2020, 2021 and 2022 using information from Docket Nos. 42310 and 42311
18 and supplied to us by Staff witness Jamie Barber. Staff's calculations of the DSM
19 revenue deficiency amounts are shown in Exhibit__(RS/RT-4) and also reflect the
20 application of Staff's recommended cost of capital in the calculation of carrying charges.

21
22 Section VII presents a summary of the Municipal Franchise Fee ("MFF") tariff revenue
23 requirement, which is shown in Exhibit__(RS/RT-4), and the impacts of the pre-tax cost

1 of capital and the traditional base rate, ECCR and DSM revenue deficiency amounts on
2 the MFF revenue requirement deficiency that was proposed by the Company and as
3 calculated by Staff.

4
5 Section VIII discusses the Company's proposed and Staff's adjusted revenue requirement
6 for Coal Combustion Residuals ("CCR") Asset Retirement Obligations ("ARO") which
7 are presented in Exhibit__(RS/RT-6).

8
9 Section IX discusses the organization of Staff's revenue requirement and adjustment
10 schedules which are presented in Exhibit__(RS/RT-2) for the traditional rate case based
11 on the test year ending July 31, 2020 and for each year, 2020-2022, in the alternative rate
12 plan.

13
14 Section X discusses each of Staff's recommended adjustments that are shown in Exhibit
15 __(RS/RT-2) on Schedules E-1 through E-12 and some areas that were reviewed by Staff
16 but for which no adjustment is being made to the Company's filing.

17
18 Section XI addresses affiliate transactions including the charges between Georgia Power
19 Company and its affiliates including Southern Company Services ("SCS") and Southern
20 Nuclear Operating Company ("SNO" or "SNC") charges to Georgia Power; and
21 Georgia Power charges to affiliates.

1 Section XII addresses certain income tax issues relating to the Tax Cuts and Jobs Act of
2 2017 ("TCJA").

3
4 Section XIII addresses the incentive compensation plans of Georgia Power Company and
5 affiliates, which includes stock-based compensation and the Performance Pay Plan.

6
7 Section XIV explains Staff's proposed principles and recommendations for the
8 Alternative Rate Plan. This section includes a discussion of Staff's proposed earnings
9 test, as well as Staff's recommendation that a step increase approach be used instead of
10 the levelization approach that has been proposed by Georgia Power Company.

11
12 Finally, Section XV presents a summary of recommendations.

13
14 **Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?**

15 A. Yes. In addition to our qualifications, which are in Exhibit RCS-1 and RLT-1,
16 respectively, Staff has attached Exhibits RS/RT-2 through RS/RT-33 which contain
17 responses to discovery and other materials referenced in our testimony.

18
19 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-2?**

20 A. Exhibit RS/RT-2 presents Staff's calculations relating to the Traditional Revenue
21 Requirement and Adjustment Schedules.

22
23 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-3?**

24 A. Exhibit RS/RT-3 presents Staff's calculations concerning the ECCR Revenue
25 Requirement.

1
2 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-4?**

3 A. Exhibit RS/RT-4 presents Staff's calculations concerning the DSM Revenue
4 Requirement.

5
6 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-5?**

7 A. Exhibit RS/RT-5 presents Staff's calculations concerning the Municipal Franchise Fee
8 Revenue Requirement.

9
10 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-6?**

11 A. Exhibit RS/RT-6 presents Staff's calculations concerning the CCR ARO Compliance
12 Revenue Requirement.

13
14 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-7?**

15 A. Exhibit RS/RT-7 presents Georgia Power's responses from Docket No. 42310 (2019 IRP)
16 to STF-L&A-1-65, STF-L&A-5-15, and the supplemental response to STF-L&A-5-16
17 concerning certain transmission and substation projects which the Company had included
18 in prior IRP filings but which are not included in the Company's 2019 IRP.

19
20 **Q. WHAT ARE SHOWN IN EXHIBITS RS/RT-8, RS/RT-9, AND RS/RT-10?**

21 A. Exhibit RS/RT-8 presents Georgia Power's 2018 FERC Form 1, pages 214, account 105,
22 Plant Held for Future Use.

23
24 Exhibit RS/RT-9 identifies amounts in the PHFFU account for which the projected "use"
25 date in providing electric service is (1) 2030 or beyond or (2) 2040 or beyond.
26

1 Exhibit RS/RT-10 presents the estimated annual cost of PHFFU, including the annual
2 financing costs.
3

4 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-11?**

5 A. Exhibit RS/RT-11 presents Georgia Power's Trade Secret attachments to its responses in
6 Docket No. 42310 (2019 IRP) to STF-L&A-1-23 and STF-L&A-1-25 relating to details
7 of the CCR spending by year and by plant ash pond and landfill.
8

9 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-12?**

10 A. Exhibit RS/RT-12 presents Georgia Power's responses to STF-L&A-1-13 and STF-
11 L&A-1-16 Docket No. 42310 (2019 IRP) relating to the ECCR.
12

13 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-13?**

14 A. Exhibit RS/RT-13 presents Georgia Power's Trade Secret response to STF-L&A-1-11
15 and STF-PIA-9-4 Docket No. 42310 (2019 IRP) relating to the ECCR.
16

17 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-14?**

18 A. Exhibit RS/RT-14 presents Trade Secret response to STF-L&A-12-1 and Trade Secret
19 informal follow-up responses concerning contingency amounts for the ECCR.
20

21 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-15?**

22 A. Exhibit RS/RT-15 presents Georgia Power's responses to STF-L&A-1-47, STF-L&A-1-
23 47 Supplemental Attachment, and STF-RCS-1-35 (from Docket No. 36989) regarding
24 Property Tax True-Up.
25

26 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-16?**

1 A. Exhibit RS/RT-16 presents Georgia Power's response to STF-L&A-1-129 and STF-L&A-
2 5-33 regarding EV Charging Facilities.

3
4 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-17?**

5 A. Exhibit RS/RT-17 presents Georgia Power's response to STF-L&A-1-60 regarding
6 Miscellaneous Items/Executive Financial Planning.

7
8 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-18?**

9 A. Exhibit RS/RT-18 presents Georgia Power's responses to STF-L&A-1-32 and STF-L&A-
10 4-47 regarding Minimum Bank Balance Interest Credits.

11
12 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-19?**

13 A. Exhibit RS/RT-19 presents Georgia Power's Trade Secret response to STF-L&A-11-19
14 regarding Minimum Bank Balance Interest Credits.

15
16 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-20?**

17 A. Exhibit RS/RT-20 presents Georgia Power's responses to STF-L&A-1-125, STF-L&A-1-
18 126, STF-L&A-1-127 and its Trade Secret response to STF-L&A-13-4 concerning
19 Production Tax Credits.

20
21 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-21?**

22 A. Exhibit RS/RT-21 presents Commission's Order on the Tax Cuts and Jobs Act in Docket
23 No. 36989, including Exhibit 1, 2018 TCJA Base Rates Settlement between Staff and
24 Georgia Power Company.

25
26 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-22?**

27 A. Exhibit RS/RT-22 presents Georgia Power's responses to STF-L&A-1-20, STF-L&A-1-

1 106, STF-L&A-1-107, STF-L&A-1-119, STF-L&A-11-9 and STF-L&A-13-6 concerning
2 Tax Cuts and Jobs Act and Excess ADIT classification as Protected or Unprotected, as
3 well as amortization periods being used by the Company.
4

5 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-23?**

6 A. Exhibit RS/RT-23 presents Selected pages of Southern Company Services FERC Form
7 60 dated December 31, 2018 (Cover, pages 307, 402.1, 402.2).
8

9 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-24?**

10 A. Exhibit RS/RT-24 presents Georgia Power's responses to STF-L&A-1-115 and STF-
11 L&A-1-116 (without attachments) and STF-L&A-1-117 regarding SCS Use of Updated
12 Statistics for Allocation Factors.
13

14 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-25?**

15 A. Exhibit RS/RT-25 presents Selected pages of Southern Nuclear Operating Company
16 FERC Form 60 dated December 31, 2018 (Cover, pages 307, 402.1, 402.2).
17

18 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-26?**

19 A. Exhibit RS/RT-26 presents Georgia Power's responses to STF-L&A-1-122 and STF-
20 L&A-13-3 concerning impact of Southern Nuclear Operating Company allocations of
21 cost to Georgia Power's Company including how the SNOC nuclear-units-based cost
22 allocation to the Company will change relating to Plant Vogtle Units 3 and 4 going into
23 commercial operation.
24

25 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-27?**

26 A. Exhibit RS/RT-27 presents Georgia Power's responses to STF-L&A-1-83, STF-L&A-3-
27 38, STF-L&A-3-41, and STF-L&A-11-30 regarding Stock-Based Compensation.

1
2 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-28?**

3 A. Exhibit RS/RT-28 presents Georgia Power's Trade Secret response to STF-L&A-1-82
4 regarding Stock-Based Compensation.

5
6 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-29?**

7 A. Exhibit RS/RT-29 presents Georgia Power's response to STF-L&A-1-39 regarding Storm
8 Damage Accruals.

9
10 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-30?**

11 A. Exhibit RS/RT-30 presents Georgia Power's responses to STF-PIA-10-3 through STF-
12 PIA-10-9 regarding Uncollectible Expense.

13
14 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-31?**

15 A. Exhibit RS/RT-31 presents Georgia Power's response to STF-PIA-13-3 regarding DSM.
16

17 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-32?**

18 A. Exhibit RS/RT-32 presents Georgia Power's Trade Secret response to STF-PIA-14-4
19 regarding CCR ARO Compliance Costs.
20

21 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-33?**

22 A. Exhibit RS/RT-33 presents Georgia Power's response to STF-L&A-11-1 concerning
23 Georgia Power Company charges to Southern Power Company and other affiliates.
24
25

IV. TRADITIONAL REVENUE REQUIREMENT SUMMARY

Test Year and Plan Years

Q. WHAT TEST YEAR SHOULD BE USED TO DETERMINE THE COMPANY'S TRADITIONAL REVENUE REQUIREMENT IN THIS CASE?

A. Under the Commission's May 9, 2016 Order in Docket No. 39971, the test period to be used in this case is from August 1, 2019 to July 31, 2020. The May 9 Order also required the Company to file testimony and exhibits required in a general rate case along with supporting schedules required by the Commission to support a "traditional" rate case by July 1, 2019, so that the Commission may consider whether to continue, modify, or discontinue the Alternative Rate Plan established in Georgia Power Company's 2013 Rate Case, Docket No. 36989 ("2013 Rate Case").

Both the Company and Staff have presented revenue requirement calculations using the test year ending July 31, 2020, as well as for calendar years 2020, 2021 and 2022, which comprise the Company's Alternative Rate Plan presentation in the current rate case.

Q. WHAT IS THE DIFFERENCE BETWEEN THE COMPANY'S CALCULATED REVENUE DEFICIENCY FOR THE TEST YEAR ENDED JULY 31, 2020 AND FOR CALENDAR YEAR 2020?

A. The Company's calculated revenue excess of \$144 million for the test year ended July 31, 2020 is approximately \$353.2 million less than its calculated revenue deficiency for

the calendar year 2020 of \$209.2 million, as shown on Company Exhibit__
(DPP/SPA/MBR-1, Schedule 2 Traditional Base), page 1 of 5, lines 1 through 3.

After considering the Company's requested CCR ARO Compliance revenue requirement of approximately \$158.1 million the Company is proposing a 2020 revenue deficiency of \$367.3 million as shown on Company Exhibit__ (DPP/SPA/MBR-1, Schedule 2 Traditional Base), page 1 of 5, on lines 4 and 5, respectively. That \$367.3 million is \$360 million more than the amount of the Company's calculated test year revenue deficiency applicable to traditional base rate tariffs of \$7.3 million, which is shown on Company Exhibit__ (DPP/SPA/MBR-1, Schedule 2 Traditional Base), page 3 of 5, column 3, line 4.

Traditional Case Summary

**Q. PLEASE SUMMARIZE STAFF'S FINDINGS AND CONCLUSIONS
REGARDING GEORGIA POWER'S TRADITIONAL REVENUE
REQUIREMENT BASED ON THE COMMISSION-ORDERED TEST YEAR
ENDING JULY 31, 2020.**

A. Our findings and conclusions are as follows:

1. The traditional revenue requirement for Georgia Power in this rate case should be determined based on the use of the Commission-ordered test year ending July 31, 2020.

- 1 2. The appropriate traditional test year average retail rate base is \$20.063 billion
2 which is \$33.9 million lower than the Company's proposed traditional test year
3 average retail rate base of \$20.097 billion as shown on Staff Exhibit__(RS/RT-2),
4 Schedule A, line 1 and Schedule B.³
- 5 3. The appropriate traditional test year retail operating income is \$1.477 billion,
6 which is \$28.028 million higher than the Company's proposed test year traditional
7 test year retail operating income of \$1.449 billion as shown on Staff
8 Exhibit__(RS/RT-2), Schedule A, line 4 and Staff Exhibit__(RS/RT-2), Schedule
9 C.
- 10 4. The traditional test year overall rate of return for Georgia Power we used in this
11 case is 6.69% as summarized on Staff Exhibit__(RS/RT-2), Schedule D and
12 includes a fair return on equity of 9.2% and the 4.07% cost of debt as
13 recommended by Staff witness Michael Gorman.⁴ Staff's overall cost of capital of
14 6.69% for the test year compares to Georgia Power's proposed overall rate of
15 return of 7.93%, which includes a requested return on equity rate of 10.9%.
- 16 5. The appropriate income expansion factor (aka Gross Revenue Conversion Factor
17 or GRCF) to be used for ratemaking purposes in this case is 74.616%, as shown
18 on Staff Exhibit__(RS/RT-2), Schedule A-1. This percentage compares with the
19 Company's proposed factor of 74.602%. This factor reflects a federal income tax
20 rate of 21% and a state income tax rate of 5.75%. The same income tax rates

³ The rate base difference is impacted by various adjustments.

⁴ Please note that Mr. Gorman's final recommended cost of debt for the test year is slightly lower than the 4.07% we used to calculate the revenue requirement.

1 were used by both Georgia Power and Staff; however, Staff's factor is lower than
2 the Company's because Staff reflects a lower component for uncollectibles.

3 6. The recommended traditional test year ratemaking components outlined above
4 would produce an annual Traditional Base Rate Tariff decrease (i.e., a revenue
5 excess amount) of approximately \$181.1 million. This is \$376.3 million lower
6 than Georgia Power's proposed traditional test year Traditional Base Rate Tariff
7 deficiency of \$195.2 million. These amounts are shown on Staff Exhibit
8 __ (RS/RT-2), Schedule A, line 7, in columns C, A, and G, respectively.

9 7. Georgia Power's proposed ECCR Tariff rider revenue deficiency has been
10 adjusted by Staff as shown on Staff Exhibit __ (RS/RT-3), and discussed in Section
11 V of our testimony. While Georgia Power has proposed an ECCR Tariff revenue
12 deficiency of \$173.6 million for the test year, Staff recommends a test year ECCR
13 Tariff revenue deficiency of \$112.7 million. The Company also proposed a
14 "levelization" adjustment for the ECCR. Staff does not recommend a levelization
15 adjustment for the ECCR. Without the levelization adjustment, Staff's
16 recommended ECCR revenue deficiency of \$112.7 million is about \$60.9 million
17 lower than the Company's proposed amount of \$173.6 million. See Staff
18 Exhibit __ (RS/RT-2), Schedule A, line 8, columns A and C, and Staff
19 Exhibit __ (RS/RT-3).

20 8. Georgia Power has proposed continuation of its DSM Tariff rider with an
21 associated DSM Tariff revenue deficiency of \$14.33 million for the traditional
22 test year. Staff calculated a \$11.87 million DSM revenue deficiency, which is

about \$2.46 million lower than the Company amount. See Staff Exhibit__(RS/RT-2), Schedule A, line 9 and Staff Exhibit__(RS/RT-4).

9. For the CCR ARO Compliance revenue requirement, Staff calculated \$102.6 million for the test year and \$104.6 million for 2020, as shown on Exhibit__(RS/RT-6). These amounts compare with, and are lower by \$48.7 million and \$53.5 million, respectively, than the Company's proposed test year amount of \$151.3 million and the Company's proposed 2020 amount of \$158.1 million. See Exhibit__(RS/RT-2), Schedule A, line 11, and Exhibit__(RS/RT-6). For CCR ARO Compliance, Staff recommends using the 2020 revenue deficiency amount of \$104.6 million, as shown on Exhibit__(RS/RT-2), Schedule A, column C, line 15.

10. Staff recommends that the Company's proposed 2020-2022 levelization revenue requirement adjustment of \$353.2 million to derive a levelized revenue deficiency amount of \$209.2 million per year for 2020-2022 (not including CCR ARO Compliance) not be adopted. Rather, Staff recommends that a step-increase approach be used for a three-year rate plan. Staff Exhibit__(RS/RT-2), Schedule A, line 13.

Staff Test Year and Plan Year Adjustments-Estimated Revenue Requirement Impacts

**Q. HAVE YOU PREPARED A TABLE OUTLINING THE APPROXIMATE
REVENUE REQUIREMENT IMPACT OF EACH OF STAFF'S
RECOMMENDED ADJUSTMENTS TO THE COMPANY'S PROPOSED**

TRADITIONAL REVENUE REQUIREMENT IN THIS CASE FOR THE TEST YEAR AND EACH PLAN YEAR?

A. Yes, Table D is presented on the next page of this testimony from amounts that are shown in more detail on Staff Exhibit__(RS/RT-2), Schedule A-2, pages 1 through 4:

Table D - Summary of Staff Traditional Base Rate Revenue Requirement Adjustments

Georgia Power Company

Revenue Requirement Impact Summary (Also See Exhibit __ (RS/RT-2), Schedule A-2)

Summary of Staff Adjustments and Adjusted Revenue Deficiency (Sufficiency)

(Thousands of Dollars)

Line No	Description	Staff Exh__(RS/RT-2) Detail Adjustment Schedules	Forecasted Test Year Ending 7/31/2020	Calendar 2020	Calendar 2021	Calendar 2022
1	Company Calculated Revenue Requirement Deficiency		\$ 195,263	\$ 351,749	\$ 711,156	\$ 1,117,391
Staff Adjustments:						
2	Return on Equity (9.20% vs 10.9%), Capital Structure and Cost of Debt	D	\$ (335,708)	\$ (348,685)	\$ (385,197)	\$ (424,125)
3	Adjustments and Corrections from GPC Errata/Update Filing*	E-1 & E-2	\$ 2,803	\$ 4,858	\$ (2,117)	\$ (10,345)
4	Stock-Based Compensation	E-9	\$ (19,505)	\$ (19,425)	\$ (21,308)	\$ (22,670)
5	Storm Damage Accrual	E-12	\$ (5,122)	\$ (5,034)	\$ (4,746)	\$ (4,455)
6	Property Tax Refunds	E-7	\$ (2,579)	\$ (2,579)	\$ (2,579)	\$ (2,578)
7	Uncollectibles Expense	E-11	\$ (1,429)	\$ (1,981)	\$ (1,981)	\$ (1,981)
Fall-Out Impacts from Other Adjustments:						
8	Interest Synchronization	E-8	\$ (11,681)	\$ (10,724)	\$ (6,243)	\$ (793)
9	Cash Working Capital	E-5	\$ (323)	\$ (279)	\$ (154)	\$ 45
10	Payroll Tax Expense	E-10	\$ (1,492)	\$ (1,486)	\$ (1,631)	\$ (1,734)
11	Difference Due to Staff using a different Gross Revenue Conversion Factor	A-1, A-2	\$ (37)	\$ (92)	\$ (185)	\$ (289)
Other Staff Adjustments:						
11	Executive Financial Planning	E-6	\$ (410)	\$ (410)	\$ (410)	\$ (410)
12	Interest Credits on Minimum Bank Balances	E-3	\$ (272)	\$ (272)	\$ (272)	\$ (272)
13	EV Charging Facilities	E-4	\$ (587)	\$ (702)	\$ (906)	\$ (1,099)
14	Staff Adjusted Rate Base Revenue Deficiency (Sum of lines 1 through 13 above)		\$ (181,078)	\$ (35,063)	\$ 283,428	\$ 646,684
15	Staff Adjusted Base Rate Revenue Deficiency (Excess)	A, A-2	\$ (181,078)	\$ (35,063)	\$ 283,428	\$ 646,685
16	Difference (rounding)		\$ (0)	\$ (0)	\$ (0)	\$ (1)

* These adjustments do not include the interest synchronization or rate of return impacts

Based on Staff's calculations the Company has excess revenues of \$181 million and \$35 million in the test year and calendar year 2020, respectively. For calendar 2021 and 2022

the Company has revenue deficiencies of \$283 million and 647 million, respectively.⁵

Each Staff adjustment is discussed in additional detail in Section X of our testimony.

Q. DOES STAFF RECOMMEND A LEVELIZED APPROACH FOR THE 2020–2022 PLAN YEAR REVENUE REQUIREMENT, AS PROPOSED BY GEORGIA POWER?

A. No. As explained in more detail elsewhere in our testimony, Staff recommends a step-increase approach for years 2021 and 2022, not a levelization.

Q. PLEASE SUMMARIZE STAFF’S RECOMMENDED REVENUE REQUIREMENT FOR THE TRADITIONAL TEST YEAR ENDING JULY 31, 2020 AND CALENDAR 2020, 2021 AND 2022.

A. As shown on Exhibit __ (RS/RT-2), Schedule A, page 1, line 7, Staff’s analysis shows the Company has excess revenue at current rates for the traditional test year, and for calendar year 2020. Staff’s analysis also shows the Company has a revenue deficiency for calendar years 2021 and 2022 at current rates. This is shown in detail on Staff Exhibit __ (RS/RT-2), Schedule A, and Schedule A-2, pages 1 through 4.

Q. IF STAFF’S ANALYSIS REFLECTS EXCESS REVENUE FOR TEST YEAR AND 2020, THEN WHY IS STAFF NOT RECOMMENDING A RATE DECREASE FOR 2020?

⁵ These values do not include MFF. Staff’s calculated MFF revenue deficiencies are shown on Exhibit __ (RS/RT-5) and are \$7.4 million for the test year, \$10.5 million for 2020, \$20.1 million for 2021 and \$32.1 million for 2022. If MFF is included, the Staff excess revenue amounts for the test year and 2020 would be reduced by the \$7.4 million and \$10.5 million MFF amounts, and the revenue deficiency amounts for 2021 and 2022 would be increased by the 2021 and 2022 MFF revenue deficiency amounts., respectively.

1 A. This is primarily based on considerations for rate stability. To avoid a reduction in rates
2 on January 1, 2020 followed by what (other things being equal) would be a larger step
3 increase in rates on January 1, 2021, Staff concluded that less fluctuation in rates would
4 benefit ratepayers and the Company in this particular situation. Therefore, Staff
5 recommends current rates be maintained through 2020. A step increase to be effective on
6 January 1, 2021 should be addressed in a compliance filing to be made by the Company
7 on October 1, 2020.

8
9 If the Company earns above the top end of the earnings band in 2020, as would be
10 evaluated in the context of the Company's 2020 Annual Surveillance Report ("ASR"),
11 Staff recommends that the excess should be used to recover deferred costs. Staff's
12 proposed rate plan earnings band and sharing is addressed in additional detail in a
13 subsequent section of our testimony.

14
15 **Q. WHAT IS STAFF'S RECOMMENDATION FOR ADDRESSING THE EXCESS**
16 **REVENUES IN THE TRADITIONAL TEST YEAR AND CALENDAR 2020?**

17 A. If the Commission concludes that the Company has excess revenue for the traditional test
18 year and/or for calendar year 2020, as Staff shows, Staff recommends that the revenue
19 excess be used for accelerated recognition of deferred costs in 2020 up to the amount of
20 the revenue excess. As an illustration, Staff shows a revenue excess of approximately
21 \$181 million for the test year and \$35 million for calendar year 2020.⁶ On
22 Exhibit__(RS/RT-2), Schedule B, pages 1 through 4, lines 34, 35, 38 and 39 there are

⁶ See, e.g., Exhibit__(RS/RT-2), Schedule A, columns C and D, respectively, line 7.

1 deferrals for Environmental CWIP (\$21.2 million retail jurisdictional rate base amount
2 for the test year), retired units remaining net book value (\$588.5 million), and unusable
3 inventory regulatory assets (\$37 million). Some portion of these deferrals could
4 potentially be recognized on an accelerated basis up to the amount of the revenue
5 requirement excess associated with the excess earnings. That is, the excess revenues
6 could be applied in 2020 to increase the amortization of the assets identified above. This
7 could be done in the current rate case by making an adjustment, or determining the
8 amount of excess earnings in 2020 could be reviewed in the context of the Company's
9 2020 ASR report, as described above.

10

V. ECCR TARIFF REVENUE DEFICIENCY SUMMARY

Q. WHAT HAS THE COMPANY REQUESTED FOR THE ECCR?

A. The Company is requesting a "levelized" revenue deficiency of \$165 million to be collected through the ECCR tariff effective January 1, 2020 through December 31, 2022. The ECCR amount requested by the Company is based on a levelized amount for the three-year period of 2020 through 2022 and thus, under the Company's proposal, the ECCR revenue requirement would not be expected to change from January 1, 2020 through December 31, 2022.

Q. WHAT IS THE BASIS FOR THE COSTS INCLUDED IN GEORGIA POWER COMPANY'S PROPOSED ECCR?

A. The Company's ECCR revenue requirements for the plan years 2020 through 2022 are reflected on Exhibit___(DPP/SPA/MBR-1, Schedule 2 ECCR). The Company's Poroach/Adams/Robinson panel direct testimony indicates that those are based on the projected environmental investments and expenses associated with the ECCR tariff in 2020, 2021 and 2022. Those projections are described as being consistent with the Company's environmental strategy that was filed with the Commission in the Company's 2019 IRP proceeding, Docket No. 42310. The Company states that the projected costs it proposes to be recovered through the ECCR tariff are set based on the compliance strategy that was approved in the 2019 IRP process. Further, changes in those cost projections will not impact the ECCR tariff rate unless such changes are approved by the Commission.

1
2
3 **Q. WHAT AMOUNTS OF ANNUAL ECCR REVENUE DEFICIENCIES HAS THE**
4 **COMPANY CALCULATED FOR EACH YEAR?**

5 A. Page 2 of Company Exhibit____(DPP/SPA/MBR-1, Schedule 3 ECCR) shows the revenue
6 deficiencies for the ECCR tariff as \$183 million, \$167 million and \$141 million in
7 calendar years 2020, 2021, and 2022, respectively. However, the amounts Georgia
8 Power has requested in the proposed Alternate Rate Plan for the ECCR tariff would begin
9 recovery of the combined 2020 through 2022 levelized calendar year amounts on January
10 1, 2020. Thus, the Company proposed to begin charging ratepayers for \$164.9 million on
11 January 1, 2020, which is about \$8.7 million below the \$173.6 million Company-
12 calculated ECCR revenue requirement for the forecast test year ending July 31, 2020.
13

14 **Q. DOES STAFF AGREE WITH GEORGIA POWER'S PROPOSED ECCR TARIFF**
15 **REVENUE DEFICIENCY FOR THE TRADITIONAL TEST YEAR ENDING**
16 **JULY 31, 2020 OR FOR THE PLAN YEARS 2020 THOROUGH 2022?**

17 A. Staff agrees with the continuation of the existing ECCR Tariff rider. However, Staff does
18 not agree with the Company's proposed traditional test year ECCR Tariff revenue
19 deficiency amount of \$173.6 million, or with the Company's proposed ECCR revenue
20 deficiency amounts for plan years 2020, 2021 or 2022.

21 **Q. WHAT AMOUNT OF ECCR REVENUE DEFICIENCY DOES STAFF**
22 **RECOMMEND FOR THE TEST YEAR?**

1 A. As shown on Exhibit ____ (RS/RT-2), page 2 of 12, Staff shows traditional test year ECCR
2 Tariff revenue excess amounts of approximately \$113 million, which is \$61 million
3 lower than Georgia Power's proposed deficiency amount of \$174 million. Staff is not
4 recommending a levelized adjustment for the ECCR.

5
6 **Q. HOW DO STAFF'S RECOMMENDED ECCR REVENUE DEFICIENCY**
7 **AMOUNTS FOR THE PLAN YEARS 2020 THROUGH 2022 COMPARE WITH**
8 **THE COMPANY'S REQUEST?**

9 A. As shown on Exhibit ____ (RS/RT-2), page 3 of 12, Staff's recommended ECCR revenue
10 deficiency amounts for the plan years 2020 through 2022 are lower than the Company's
11 requested amounts in each year.

- 12 • For 2020, the Staff ECCR recommended revenue deficiency is \$121 million,
13 which is about \$62 million lower than the Company's calculated amount of
14 \$183.6 million.
- 15 • For 2021, the Staff ECCR recommended revenue deficiency is \$107 million,
16 which is about \$60.5 million lower than the Company's calculated amount of
17 \$167.5 million.
- 18 • For 2022, the Staff ECCR recommended revenue deficiency is \$82.7 million,
19 which is about \$57.9 million lower than the Company's calculated amount of
20 \$140.6 million

21
22 **Q. WHY ARE THE STAFF RECOMMENDED AMOUNTS OF ECCR DEFICIENCY**
23 **LOWER THAN THE COMPANY CALCULATIONS?**

1 A. As detailed on Exhibit __ (RS/RT-3):

- 2 • Staff used a lower overall cost of capital based on the recommendations of Mr.
- 3 Gorman;
- 4 • Staff reflected the impacts from the Company's errata filing;
- 5 • Staff removed amounts for contingency built into projected costs;
- 6 • Staff's Income Expansion Factor differs from the Company's due to an adjustment
- 7 Staff has made to uncollectibles.

8 The calculations underlying Staff's recommended ECCR Tariff revenue deficiency
9 amounts, and how they compare with Georgia Power's proposed amounts for the test
10 year and for each plan year, 2020 through 2022, are shown on Staff Exhibit __ (RS/RT-3).

11
12 **Q. IS THE ECCR REVENUE REQUIREMENT AFFECTED BY THE RETURN ON**
13 **EQUITY AND COST OF CAPITAL?**

14 A. Yes. The cost of capital is an important input to the ECCR revenue requirement
15 calculation.

16
17 **Q. DOES STAFF'S PROPOSED COST OF CAPITAL DIFFER FROM THE COST**
18 **OF CAPITAL REQUESTED BY GEORGIA POWER COMPANY?**

19 A. Yes. As described in the testimony of Staff witness Gorman, Staff has recommended a
20 9.2% cost of equity and a lower cost of long-term debt than requested by the Company.
21 Mr. Gorman is recommending a capital structure that is different than the one requested
22 by the Company. Each of these items affect the cost of capital. The result is that Staff is

recommending an overall cost of capital for the future test year and for each rate plan year, 2020 through 2022, that is lower than Georgia Power has requested.

Q. IS THE ECCR REVENUE REQUIREMENT IMPACTED BY OTHER ADJUSTMENTS?

A. Yes. The ECCR revenue requirement is also impacted by adjustments that affect environmental plant, depreciation, and O&M expense, as well as income taxes related to ECCR components, as shown on Exhibit __ (RS/RT-3).

Q. HOW HAVE YOU INCORPORATED THOSE IMPACTS INTO THE ECCR REVENUE REQUIREMENT?

A. While the largest impact on the ECCR revenue requirement results from Staff's recommended cost of capital, other items affecting the ECCR have also been incorporated where such items could be readily identified from the details of the Company's errata filing and Staff's recommended adjustments. Staff has removed the estimated contingency amounts that were projected by the Company from the test year and plan year ECCR rate base and depreciation expense based on information provided by the Company. The Company's formal and informal responses to Staff data requests concerning ECCR components are presented in Exhibit __ (RS/RT-14).

Q. WHAT REVENUE REQUIREMENTS DOES STAFF SHOW FOR THE ECCR FOR THE FUTURE TEST YEAR AND FOR 2020, 2021, AND 2022?

A. As shown on Exhibit__(RS/RT-3), we have recalculated the ECCR revenue requirements for the future test year and for each calendar year, 2020, 2021 and 2022 in the Company-proposed rate plan period. Staff's recalculated ECCR revenue requirements, and how they compare with the Company's request, are summarized below:

Table E: ECCR Revenue Requirement Deficiency - Staff and Company Compared

COMPUTATION OF RETAIL REVENUE DEFICIENCY APPLICABLE TO ENVIRONMENTAL COMPLIANCE COST RECOVERY (ECCR) TARIFF (Thousands of Dollars)				
	<u>Test Year</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>
Per Staff	\$ 112,688	\$ 121,090	\$ 106,974	\$ 82,683
Per Company	\$ 164,926	\$ 183,581	\$ 167,475	\$ 140,623
Difference	<u>\$ (52,237)</u>	<u>\$ (62,491)</u>	<u>\$ (60,501)</u>	<u>\$ (57,940)</u>
Source: Staff Exhibit__(RS/RT-3), pages 1 and 2				

Q. DOES STAFF PROPOSE TO LEVELIZE THE ECCR REVENUE REQUIREMENTS?

A. No. Staff has not reflected a "levelization" of the 2020 through 2022 ECCR revenue requirements, similar to the Company's proposed \$8.7 million decrease. Rather, Staff recommends that annual ECCR revenue deficiency (or excess) amounts for 2021 and 2022 be established based on compliance filings to be made by the Company on October 1, 2020 and 2021, respectively. Because the ECCR is a separately identifiable tariff component, annual adjustments can be made for the annual changes in the ECCR revenue requirement. Thus, Staff proposes that the ECCR revenue requirement be reflected as annual rate changes, rather than a levelized approach that includes significant amounts for an estimated construction cost contingency.

Q. PLEASE EXPLAIN WHAT AN EARNINGS TEST IS.

1 A. An earnings test reviews the Company's earnings, typically calculated with various
2 adjustments to reflect ratemaking treatments. In the current alternative rate plan, for
3 example, the Company reports its results for each year in an Annual Surveillance Report
4 ("ASR"), which is reviewed by Staff. The Company's earnings are reviewed to determine
5 if they were below, within or above an established earnings band. Staff's specific
6 recommendations for resetting the earnings band are addressed in a Section XIII of our
7 testimony.

8
9 **Q. DOES THE COMPANY'S ECCR PROPOSAL INCLUDE AN EARNINGS TEST?**

10 A. No.

11
12 **Q. DOES STAFF PROPOSE TO INCLUDE AN EARNINGS TEST AS PART OF ITS**
13 **ECCR AND RATE PLAN RECOMMENDATIONS?**

14 A. Yes. We discuss Staff's proposed earnings test for the Rate Plan period in Section XIII
15 of our testimony.

VI. DSM TARIFF REVENUE DEFICIENCY SUMMARY

Q. HOW HAS STAFF REFLECTED THE DSM TARIFF REVENUE DEFICIENCY FOR THE TRADITIONAL TEST YEAR ENDING JULY 31, 2020 AND FOR CALENDAR YEAR 2020?

A. Staff supports the continuation of the existing DSM Tariff rider since the DSM program costs will be different each year and will vary by participation levels. For the test year and for calendar years 2020 through 2022, Staff has reflected a DSM tariff revenue deficiency in the following amounts, for which detailed calculations are shown on Exhibit ____ (RS/RT-4);

- \$11.9 million for the test year, which is about \$2.5 million lower than the Company's requested \$14.3 million.
- \$11.9 million for 2020, which is about \$2.5 million lower than the Company's requested \$14.4 million.
- \$13.2 million for 2021, which is about \$3.2 million lower than the Company's requested \$16.4 million.
- \$14.0 million for 2022, which is about \$3.4 million lower than the Company's requested \$17.4 million.

Requiring the Company and Staff to agree on final program plans was part of a stipulation approved by the Commission in Docket No. 42310/42311. We are advised by Staff witness Barber that these program plans will also drive the DSM

1 revenue requirement for the plan years. The amounts for 2021 and 2022 will ultimately
2 be determined by the Commission through the Company's annual DSM filings.

3 **Q. DOES THE DSM TARIFF REVENUE REQUIREMENT INCLUDE A**
4 **COMPONENT FOR CARRYING COSTS ON DEFERRALS?**

5 A. Yes. The Company's calculation of DSM carrying costs has been reproduced on Exhibit
6 __ (RS/RT-4), pages 9 and 10 of 17. The Staff's calculation of DSM carrying costs has
7 been reproduced on that Exhibit on pages 11-12. Pages 13-17 show the derivation of the
8 Revenue Requirement carrying cost rate used by the Company and the comparable rates
9 used by the Staff for the test year and for 2020, 2021 and 2022, respectively. The Staff
10 carrying cost rates reflect Staff's recommended cost of capital.

11

VII. MUNICIPAL FRANCHISE FEE TARIFF (“MFF”)

Q. PLEASE PROVIDE SOME BACKGROUND ON THE COMPANY’S MFF TARIFF.

A. In the 2007 Georgia Power Rate Case Order, the Commission ordered the establishment of the MFF tariff in accordance with the Commission’s Order in Docket No. 21112. The MFF tariff initially reflected 50 percent of MFF revenues being collected from customers located within municipal areas covered by a franchise agreement and 50 percent being collected from all customers, regardless of location. However, over the years, the Company has experienced a shift with more of its total revenue coming from customers within municipalities. Currently, the Company estimates that approximately 63.36% of its revenues are from customers within municipalities. Because the tariff is a percentage rate and is calculated based on each customer’s total bill before sales taxes are applied, the percentage rate does not have to be changed even if revenues change.

Q. WHAT CAUSES THE MFF TARIFFS TO CHANGE?

A. As described on pages 28-29 of the Poroach/Adams/Robinson Direct Testimony, the primary components of the MFF tariff that could change from year to year are the amount of revenues collected relative to whether or not customers are receiving service within a municipality’s boundaries. As customer demographics change, so would the respective MFF tariff. The Company indicates that since the Company last updated the MFF tariff in the 2016 Compliance Filing, a number of new municipalities have been incorporated in Georgia Power's service territory. The Company expects the trend of new municipalities

1 to continue, which could increase revenues from customers receiving service within
2 municipal boundaries and thus the Company's MFF expense going forward.

3
4 **Q. WHAT HAS THE COMPANY REQUESTED FOR AN MFF TARIFF REVENUE**
5 **REQUIREMENT?**

6 A. The Company's Poroach/Adams/Robinson panel's direct testimony at page 29 states that
7 the Company is requesting approval of a \$17 million increase to be effective January 1,
8 2020. The Company's calculation shown on Exhibit____(DPP/SPA/MBR-1, Schedule 5
9 MFF) shows a total MFF revenue deficiency of \$16.802 million for 2020. The
10 Poroach/Adams/Robinson panel also stated that the Company would also propose to
11 update the MFF tariff with an annual November 1 compliance filing, if needed, as
12 provided in the current MFF tariff.

13
14 **Q. IS THE MFF TARIFF REVENUE REQUIREMENT INCREASE THAT THE**
15 **COMPANY REQUESTED IMPACTED BY THE LEVEL OF THE BASE RATE**
16 **AND ECCR REVENUE DEFICIENCY PROPOSED BY THE COMPANY?**

17 A. Yes.

18
19 **Q. IS STAFF'S RECOMMENDATION ON THE AMOUNTS OF BASE RATE AND**
20 **ECCR REVENUE DEFICIENCY DIFFERENT THAN THE AMOUNTS**
21 **INCLUDED IN THE COMPANY'S DIRECT CASE?**

22 A. Yes.

1 **Q. ARE THERE ANY OTHER DIFFERENCES BETWEEN THE STAFF AND**
2 **COMPANY CASES RELEVANT TO THE CALCULATION OF THE MFF**
3 **TARIFF REVENUE REQUIREMENT?**

4 A. Yes. Staff also shows a different amount of DSM revenue deficiency than was
5 incorporated in Georgia Power's filing, as described above in Section VI of our
6 testimony. In addition, Staff's recommended weighted average cost of capital is lower
7 than Georgia Power's request. This translates into a lower pre-tax weighted average cost
8 of capital.

9
10 **Q. HAVE YOU CALCULATED THE MFF REVENUE REQUIREMENT**
11 **DEFICIENCY TO REFLECT THE IMPACT OF THE DIFFERENCES IN PRE-**
12 **TAX COST OF CAPITAL AND THE BASE RATE, ECCR AND DSM REVENUE**
13 **DEFICIENCY AMOUNTS?**

14 A. Yes. On Exhibit__(RS/RT-5), page 3 of 4, we have reproduced the Company's MFF
15 Revenue Requirement deficiency calculations. Exhibit__(RS/RT-5), page 4 of 4, which
16 shows the Staff's calculations. The Staff calculations use the Staff's pre-tax weighted
17 average cost of capital, base rate, ECCR and DSM revenue deficiency amounts. Staff's
18 calculations produce an MFF revenue deficiency of \$7.4 million for the test year, and
19 \$10.5 for 2020, as calculated on Exhibit__(RS/RT-5), page 4. Differences between
20 Company and Staff revenue deficiencies for MFF are summarizes on Exhibit__(RS/RT-
21 5), page 2.

1 **Q. DOES STAFF AGREE WITH THE COMPANY'S PROPOSAL THAT THE MFF**
2 **CAN BE UPDATED BY FILINGS BY THE COMPANY WITH AN ANNUAL**
3 **NOVEMBER 1 COMPLIANCE FILING, IF NEEDED, AS PROVIDED IN THE**
4 **CURRENT MFF TARIFF?**

5 **A. Yes.**
6

**VIII. COAL COMBUSTION RESIDUALS (CCR) ASSET RETIREMENT
OBLIGATIONS (ARO) REVENUE REQUIREMENT**

**Q. WILL YOU BE USING CERTAIN ABBREVIATIONS FOR THE DISCUSSION
IN THIS SECTION OF YOUR TESTMONY?**

A. Staff will be referring to the Asset Retirement Obligation as "ARO" and to the Coal
Combustion Residuals as "CCR" - which are the same abbreviations used by the
Company in its direct testimony and in responding to Staff discovery.

**Q. HOW IS THE OBLIGATION FOR CCR COMPLIANCE RECORDED FOR
ACCOUNTING PURPOSES AND RECOVERED FROM CUSTOMERS IN
RATES?**

A. For accounting purposes, the Company's obligation for compliance with CCR regulations
is recorded as an Asset Retirement Obligation. A related liability is also recorded to
recognize the legal obligation to incur such costs. Historically, costs related to the
remediation of ash ponds and landfills that have been used to store coal ash at plants that
were still operational would have generally been included in the cost of removal/negative
net salvage component of depreciation rates and would have been recovered over the
estimated remaining life of the coal-fired generating plants. CCR compliance costs for
coal-fired generating plants that have already been retired or are being retired before their
previously estimated useful lives will need to be addressed in some form of an
amortization. Both the Company and Staff have calculated revenue requirements related
to the recovery of CCR costs in the current rate case proceeding. On Exhibit __ (RS/RT-
6) we have replicated the Company's calculated CCR ARO Compliance revenue
deficiency amounts for the test year and for each plan year, 2020 through 2022, and also

1 present Staff's calculated revenue deficiency amounts for each period for the CCR ARO
2 Compliance.

3
4 **Q. DID THE COMPANY RECORD INCREASES TO ITS ASSET RETIREMENT**
5 **OBLIGATIONS TO REFLECT CCR COSTS?**

6 A. Yes. In December 2018, Georgia Power recorded an increase of approximately \$3.1
7 billion to its AROs related to the CCR Rule and the related state rule.⁷ As noted above,
8 the Company estimates a total CCR ARO compliance cost of \$7.585 billion.

9
10 **Q. HAS THE COMPANY IDENTIFIED ITS ANTICIPATED EXPENDITURES FOR**
11 **COAL COMBUSTION RESIDUALS COMPLIANCE?**

12 A. Yes. In the 2019 IRP case, the Company identified a total estimated amount of \$7.585
13 billion for CCR ARO costs that the Company has estimated for all of its coal-fired
14 generating plant ash ponds and landfills.

15
16 **Q. OVER WHAT PERIOD DOES THAT \$7.585 BILLION OF TOTAL CCR ARO**
17 **COSTS RELATE?**

18 A. The \$7.585 billion of total CCR ARO costs relates to spending that the Company has
19 incurred through 2018 and estimated for the years 2019 through 2075. Details of the
20 spending by year and by plant ash pond and landfill are shown in the Company's Trade
21 Secret attachments to data requests STF-L&A-1-23 and STF-L&A-1-25 in the 2019 IRP
22 case, Docket Nos. 42310 & 42311. Copies of those responses are included in Exhibit
23 RS/RT-11 to our testimony.

⁷ Southern Company 2018 Annual Report, p. 141.

1
2 **Q. WHAT CCR COST DOES THE COMPANY EXPECT TO INCUR DURING 2019**
3 **- 2022?**

4 A. In the 2019 IRP case, the Company estimated it would incur CCR costs of “\$0.2 billion
5 for 2019, \$0.3 billion for 2020, \$0.4 billion for 2021, and \$0.7 billion for 2022.”⁸ In the
6 2019 rate case, as stated on page 25 of the Poroach/Adams/Robinson panel's direct
7 testimony, the Company anticipates having an under-collected balance at December 31,
8 2019 of \$241 million, and anticipates spending of \$277 million in 2020, \$395 million in
9 2021 and \$655 million in 2022, respectively.

10
11 **Q. DID THE COMPANY PROVIDE A DETAILED BREAKOUT OF CCR COST**
12 **EXPECTED TO BE INCURRED DURING 2019 – 2022?**

13 A. Yes. The following table summarizes the Company's projected CCR cost for the years
14 2019 through 2022 using the Trade Secret information that was provided in the
15 attachment to the response to STF-LA-1-23 in the 2019 IRP case, Docket Nos. 42310 &
16 42311:
17 [BEGIN CONFIDENTIAL]

⁸ Southern Company and Georgia Power Company 2018 10-K filing to the SEC. Page II-121.

Ash Ponds					
<u>Facility</u>	2019	2020	2021	2022	Total
Arkwright					
Bowen					
Branch					
Hammond					
Kraft					
McDonough					
McIntosh					
McManus					
Mitchell					
Scherer					
Wansley					
Yates					
Ash Pond Subtotal					
Landfills					
<u>Facility</u>	2019	2020	2021	2022	Total
Arkwright					
Bowen					
Branch					
Hammond					
Kraft					
McIntosh					
Scherer					
Wansley					
Yates					
Landfill Subtotal					
Total					

[END CONFIDENTIAL]

Additionally, in response to Staff discovery in the rate case, the Company provided additional information, including identification of amounts of contingency that are

1 included in its CCR ARO estimates. Copies of the Company's responses to Staff rate
2 case discovery on the CCR ARO are included in Exhibit ____(RS/RT-32).

3
4 **Q. WHAT WAS STAFF'S GENERAL RECOMMENDATION IN THE 2019 IRP**
5 **PROCEEDING CONCERNING THOSE CCR ARO COSTS?**

6 A. Staff's general recommendation in the 2019 IRP proceeding was that the Commission not
7 approve specific cost recovery for CCR ARO costs, or other costs, in that IRP
8 proceeding, but rather for the Commission to reserve judgment concerning cost recovery
9 and to make decisions about cost recovery in other proceedings such as the Company's
10 upcoming 2019 general rate case and/or in ASR review proceedings where the
11 Company's costs are being reviewed.

12
13 **Q. HAS STAFF IDENTIFIED CONCERNS WITH THE COMPANY'S ESTIMATED**
14 **COSTS FOR CCR ARO?**

15 A. Yes. Staff has identified concerns related to the accuracy of the Company's CCR ARO
16 estimate. The Company acknowledged that the \$7.585 billion is its best estimate at this
17 point, and that it will be evaluating the most qualified contractors, through an RFP
18 process, to make sure competitive bids are selected for the work.⁹ Thus, the cost
19 estimates are not final and are subject to change.

20
21 **Q. WHAT OTHER FACTORS INDICATE THE ESTIMATED CCR ARO COSTS**
22 **ARE NOT FINALIZED?**

⁹ Docket No. 42310, Hearing transcript dated April 9, 2019, p. 787-788.

1 A. The Company's CCR ARO cost estimates include a significant amount of contingency.
2 According to the Company's response to Staff's informal request for clarification of
3 Hearing Request HR-1-10 in Docket Nos. 42310 & 42311, the \$7.585 billion total cost
4 estimate includes [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] in
5 contingency. This represents approximately [BEGIN CONFIDENTIAL] [REDACTED] [END
6 CONFIDENTIAL] of the Company's estimated CCR ARO costs. Contingency is
7 included in both closure costs and post-closure costs.
8

9 **Q. IS IT KNOWN WHETHER THE COMPANY WILL INCUR COSTS**
10 **REPRESENTED BY THE CONTINGENCY?**

11 A. No. Although there are risks that cost will increase with any project, there are
12 opportunities to adapt and mitigate the drivers and offset cost increases. The amount of
13 contingency needed, or actually incurred, is not known until the costs are incurred at
14 some point in the future. With any unforeseen circumstance, the Company and its
15 contractors will have the opportunity to assess cost challenges and work to mitigate cost
16 increases. It is not known at this time what the future cost overruns for these projects will
17 be, if any. Ideally, the contracts for ash pond closures, landfill construction and post-
18 closure care will accurately reflect the expected costs and the work will be implemented
19 in a way such that actual costs are either at or below the projected costs, without the need
20 for contingency.
21

22 **Q. IS THERE A PROBABILITY THAT COSTS WILL COME IN LOWER THAN**
23 **THE COMPANY'S PROJECTIONS?**

1 A. Yes. Staff's understanding is that the contingency amount included in the Company's
2 CCR ARO cost estimate was developed such that there is a high probability that actual
3 costs for this work will be below the total estimated project cost because some portions of
4 the Company's contingency estimates have a low probability of being incurred.

5
6 **Q. SHOULD THE COMMISSION APPROVE THE CONTINGENCY INCLUDED**
7 **WITHIN THE COMPANY'S CCR ARO COST ESTIMATES?**

8 A. No. Staff recommends that the Commission not approve contingency dollars included by
9 the Company in the estimates that the Company used to derive its requested CCR ARO
10 compliance revenue requirements for the test year, and for plan years 2020 through 2022.

11
12 **Q. WAS THE COMPANY REQUIRED TO PROVIDE ITS COST ESTIMATES TO**
13 **THE COMMISSION IN THE IRP?**

14 A. Yes. The IRP Rule requires that Environmental Compliance Strategy to evaluate the
15 utility's plans, including technologies and forecasted incremental capital and operation
16 and maintenance expenditures for compliance.¹⁰

17
18 **Q. IS THE COMPANY REQUESTING APPROVAL OR RECOVERY OF ITS**
19 **PROJECTED CCR ARO COMPLIANCE COSTS IN THE CURRENT RATE**
20 **CASE?**

21 A. Yes. As described in the Poroach/Adams/Robinson direct testimony at pages 24-27 (and
22 elsewhere) the Company proposes to recover its estimated CCR ARO costs for 2019

¹⁰ Commission Rule 515-3-4-.04(1)(c)

1 through 2022 over a three-year period, wherein the 2019 and 2020 costs are recovered
2 over the three-year period, 2020 through 2022; the 2021 costs are recovered over the
3 three-year period 2021-2023; and the 2022 costs are recovered over the three-year period
4 2022-2024. The Poroach/Adams/Robinson direct testimony has a colored bar chart on
5 page 25 which illustrates the Company's proposal. For purpose of the three years
6 included in the Company's alternative rate plan, the 2020 calendar year includes cost
7 recovery for one-third of the estimated \$241 million December 31, 2019 under-recovered
8 balance and one-third of the \$277 million estimated 2020 CCR ARO compliance
9 spending. The 2021 calendar year includes cost recovery for one-third of the estimated
10 2019 ending balance, and one-third of the estimated 2020 and 2021 CCR ARO
11 compliance spending. The 2022 plan year includes cost recovery for one-third of the
12 estimated 2019 ending balance, and for one-third of the estimated 2020, 2021 and 2022
13 CCR ARO compliance cost spending. The Company estimates 2020, 2021 and 2022
14 CCR ARO compliance spending to be \$277 million, \$395 million, and \$655 million,
15 respectively. The Company's proposed alternative rate plan reflects step increases, as the
16 CCR ARO spending is being rolled into rates over the three-year period, January 1, 2020
17 through December 31, 2022.

18
19 As summarized in the Poroach/Adams/Robinson testimony on page 9 in Table 1, the
20 Company is requesting a CCR ARO increase of \$158 million effective January 1, 2020,
21 another \$140 million increase effective on January 1, 2021 and another \$227 million step
22 increase on January 1, 2022 for CCR ARO cost recovery.

1 **Q. DOES THE COMPANY'S PROPOSED ALTERNATIVE RATE PLAN INCLUDE**
2 **A SPECIFIC PROVISION TO DECREASE THE CCR ARO REVENUE**
3 **REQUIREMENT ON JANUARY 1, 2023, WHEN THE DECEMBER 31, 2019**
4 **BALANCE AND THE COMPANY'S ESTIMATED 2020 CCR ARO**
5 **COMPLIANCE SPENDING WOULD HAVE BEEN RECOVERED?**

6 A. No. While the Company has proposed a three-year rate plan for the period 2020 through
7 2022, it would not necessarily terminate on January 1, 2023. If it did not terminate on
8 that date and if the CCR ARO revenue requirements that the Company is requesting in
9 the current case continued beyond December 31, 2022, without being recalibrated to
10 reflect the dropping off of December 31, 2019 and 2020 amounts and reflection of 2023
11 CCR ARO amounts, that could lead to a mis-match in the costs being incurred and the
12 related rate recovery.

13
14 **Q. DOES STAFF RECOMMEND AN ANNUAL FILING BY THE COMPANY EACH**
15 **YEAR RELATED TO ARO COST RECOVERY?**

16 A. Yes. Staff agrees conceptually with the Company's proposal to recover CCR ARO costs
17 over a three-year period, i.e., based on the one-third amortization approach proposed by
18 the Company. Since actual costs could vary from the Company's estimates, Staff
19 recommends that the Commission not pre-approve a level of cost recovery for years 2021
20 and 2022 in the current rate case, but rather that the Company making an annual
21 compliance filing to update the CCR ARO spending and estimates each year on October
22 1, for CCR ARO rates to become effective the following January 1. Additionally, Staff

1 recommends that the contingency amounts not be included in the CCR ARO revenue
2 requirement.

3
4 **Q. HAS STAFF CALCULATED REVENUE REQUIREMENTS FOR THE CCR ARO**
5 **RECOVERY FOR THE TEST YEAR?**

6 A. Yes. Staff's calculations are presented in Exhibit __ (RS/RT-6). As shown on page 2 of
7 10, for the test year, Staff has calculated a CCR revenue requirement of \$102.6 million,
8 which is \$48.7 million lower than the \$151.3 million in the Company's application.

9
10 **Q. HAS STAFF ALSO CALCULATED CCR ARO REVENUE REQUIREMENT**
11 **AMOUNTS FOR PLAN YEARS, 2020 THROUGH 2022?**

12 A. Yes. As shown on Exhibit __ (RS/RT-6), page 3 of 10, for 2020 Staff calculated a CCR
13 ARO revenue requirement deficiency of \$104.6 million, which is \$53.5 million lower
14 than the Company's proposed amount of \$158.1 million. Staff has also calculated CCR
15 ARO revenue requirement deficiencies of \$202.8 million and \$362.0 million for 2021
16 and 2022, respectively, as shown on Exhibit __ (RS/RT-6), page 3 of 10.

17
18 **Q. WHAT ADJUSTMENTS HAS STAFF MADE TO THE COMPANY'S PROPOSED**
19 **CCR ARO REVENUE DEFICIENCY CALCULATIONS?**

20 A. As shown on Exhibit __ (RS/RT-6), page 10 of 10, Staff has reflected adjustments per the
21 Company's errata filing. As shown on Exhibit __ (RS/RT-6), page 9 of 10, Staff has
22 removed contingency amounts that the Company provided in its Trade Secret Attachment
23 to the response to STF-PIA-14-4. The removal of the contingency amounts reduced the

1 three-year based amortizations for the December 31, 2019 under-recovered balance, as
2 well as the amortizations and Company proposed rate base amounts for the Company's
3 projected 2020, 2021 and 2022 projected expenditures.

4
5 Staff recommends that the Company receive a carrying cost allowance based on the cost
6 of long-term debt with no ROE component, rather than a full rate base return (including
7 an equity return and income tax gross-up) on the CCR ARO amounts while they are
8 being recovered for the following reasons. First, these expenditures are not providing
9 energy or capacity. Second, over the course of making the expenditures (currently
10 estimated to exceed \$7.5 billion) a burden is being placed on ratepayers with no
11 offsetting benefits. Third, Staff is recommending timely recovery (3 years) of the
12 Company's coal ash pond and landfill remediation cost spending. Given the large
13 magnitude of these costs and the lack of benefit to customers, it would be unreasonable
14 for the Company to earn a profit (ROE) on these costs.

15
16 As shown on Exhibit __ (RS/RT-6), pages 2 and 3, to effectuate this recommendation,
17 Staff has removed the rate base return in column B on page 2 for the test year and on
18 page 3, lines 8-10 for plan years, 2020, 2021 and 2022. As shown on page 9 of 10, lines
19 32-34, Staff has taken what would have been the Staff-adjusted rate base (line 11), and
20 multiplied it by Staff's recommended cost rate for long-term debt (see line 33) to derive
21 an annual carrying cost allowance amount for the test year and each plan year (see line
22 34). Staff included the carrying cost allowance in the calculation of the operating income
23 deficiency for the test year and each plan year.

1
2 As shown on Exhibit __ (RS/RT-6), page 2 of 10, line 6, and page 3 of 10, line 13, in
3 computing the CCR ARO revenue requirement, Staff also applied its adjusted Income
4 Expansion Factor. Staff's Income Expansion Factor differs from the Company's proposed
5 factor because of an adjustment Staff has made to the uncollectibles component.
6

7 **Q. REFERRING TO EXHIBIT __ (RS/RT-6), PAGE 9 OF 10, PLEASE BRIEFLY**
8 **EXPLAIN THE CALCULATIONS SHOWN ON THAT PAGE.**

9 A. Exhibit __ (RS/RT-6), page 9 of 10, shows the Staff's adjusted Operating Income
10 Deficiency, which is shown on line 17. Those amounts carry forward to pages 2 and 3
11 and are used in calculating the Staff recommended CCR ARO revenue requirement.
12

13 Exhibit __ (RS/RT-6), page 9 of 10, lines 1 through 11 show how Staff used the Trade
14 Secret information from the Company's response to STF-PIA-14-4 to remove the
15 contingency amounts from the Company's projected CCR ARO beginning balances for
16 each plan year, and from the one-third recovery amounts applicable to each year. What
17 would be the Staff's adjusted ARO CCR rate base is shown on line 11. However, as
18 described above, Staff is not recommending a full rate base return on deferred CCR ARO
19 costs during the recovery period. A three-year recovery period is relatively short,
20 providing timely recovery to the Company. Staff has calculated a carrying cost
21 allowance using the long-term debt cost rate that is slightly higher, due to timing, than
22 what was recommended in this case by Staff witnesses Gorman. This produced the
23 carrying cost allowance amounts for the test year and each plan year shown on page 9 of

10, line 34. The carrying costs are included in the calculation of the operating income deficiency, as shown on line 13a. Amounts on page 9 of 10, lines 12 through 16 are summed to derive the operating income deficiency amounts, which are shown on line 17. The state and federal income tax calculations are shown on lines 18 through 31, and parallel the Company's calculations. The operating income deficiency amount for the test year on page 9 of 10, column A, line 17, of \$76.531 million, is carried forward to page 2 of 10, column B, line 4, and is used to calculate the test year revenue deficiency for CCR ARO Compliance.

Similarly, the operating income deficiency amounts for each plan year shown on page 9 of 10, line 17, in columns B, C and D, of \$78.05 million, \$151.35 million, and \$270.11 million, for 2020, 2021 and 2022, respectively, are carried forward to page 3 of 10, lines 11 and 12, and are used to calculate the revenue deficiency for CCR ARO Compliance for each plan year.

Q. PRIOR TO REQUESTING COST RECOVERY IN EACH YEAR, SHOULD THE COMPANY CONTINUE TO FINALIZE AND REFINE ITS CCR ARO ESTIMATES?

A. Yes. The Company should refine the estimate as much as possible prior to making such a request for cost recovery. Given that this work will take place over the next six decades, i.e., CCR costs are estimated through 2075, the Company will continue to refine and revise cost estimates for this work. As estimates are revised over time, the Commission

will have an opportunity to review and approve these costs in conjunction with future rate cases.

Q. DOES STAFF RECOMMEND THAT THE COMMISSION APPROVE 2021 AND 2022 CCR ARO REVENUE DEFICIENCY AMOUNTS FOR THE COMPANY AT THIS TIME?

A. No. As noted above, Staff recommends that the Commission approve a 2020 revenue deficiency amount for CCR ARO costs. The Company should continue to refine its estimates and should make a compliance filing prior to the 2021 and 2022 step increases for CCR ARO cost recovery.

**IX. ORGANIZATION OF STAFF'S REVENUE REQUIREMENT AND
ADJUSTMENT SCHEDULES**

**Q. HOW ARE STAFF'S REVENUE REQUIREMENT AND ADJUSTMENT
SCHEDULES ORGANIZED?**

A. Staff's revenue requirement and adjustment schedules for the traditional rate case, and each calendar year in the three-year plan are presented in Exhibit__(RS/RT-2). They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, A-2, B, B.1, C, C.1 and D. Exhibit__(RS/RT-2) also contains adjustment Schedules E-1 through E-12. Additionally, Exhibit__(RS/RT-2) contains Schedules F-1 and F-2 for an adjustment related to the Company's proposed depreciation rates that was calculated by Staff, but which Staff has not reflected in computing the test year or rate year revenue requirement deficiencies.

Q. WHAT DOES EXHIBIT__(RS/RT-2), SCHEDULE A SHOW?

A. Exhibit__(RS/RT-2), Schedule A presents a revenue requirement summary. Georgia Power's calculation of its proposed rate year revenue deficiency of \$195.263 million is shown in column A, line 7. Column A, lines 8 and 9, show Georgia Power's proposed revenue deficiency amounts of \$173.625 million and \$14.330 million for the ECCR and DSM tariffs, respectively. Georgia Power's Application shows a traditional base rate revenue deficiency of approximately \$7.3 million after accounting for the ECCR and DSM tariff revenue deficiencies, as shown in column A, line 10. Exhibit__(RS/RT-2), Schedule A, Column B, presents summary information for the Company proposed Alternative Rate Plan, which covers calendar years 2020 through 2022. As shown in

1 Columns A and B, line 11, the Company also proposes an \$151.292 million revenue
2 deficiency for CCR ARO Compliance. As shown on Exhibit__(RS/RT-2), Schedule A,
3 Columns A and B, line 13, the Company also has requested an additional revenue
4 deficiency of \$353.207 million in arriving at its requested \$209.224 million for the
5 levelization of its calculated 2020 through 2022 revenue requirements, which is shown on
6 line 14. The total requested by the Company of \$367.334 million is shown in Column B,
7 on line 16. That includes \$209.224 million for the levelization of its calculated 2020
8 through 2022 revenue requirement deficiencies and \$158.110 million for its calculated
9 CCR ARO Compliance revenue requirement.

10
11 Columns C through F show the revenue requirement calculation that results from our
12 recommendations and the recommendations of other Staff witnesses. Staff's base rate
13 revenue deficiency for the future test year, and for each calendar year, 2020 through
14 2022, are shown on line 7. Staff's adjusted ECCR and DSM revenue deficiencies
15 (excess) are shown on lines 8 and 9, respectively.¹¹ Line 10 shows Staff's traditional
16 base rate revenue deficiency. Line 11 shows Staff's recommended revenue requirement
17 for CCR ARO Compliance. As noted elsewhere, Staff is not proposing a levelization of
18 2020–2022 results. Staff total recommended base rate revenue deficiency is shown on
19 line 16.

20
21 **Q. WHAT IS SHOWN ON SCHEDULE A-1 OF EXHIBIT__(RS/RT-2)?**

¹¹ As noted in Section VI, the DSM revenue requirements are subject to change.

1 A. Schedule A-1, page 1, shows the derivation of the gross revenue conversion factor
2 (“GRCF”) for the test year ending July 31, 2020. This factor is used on Schedule A, line
3 6, to convert the net operating income deficiency or sufficiency into an equivalent
4 revenue requirement amount. As shown on Exhibit__ (RS/RT-2), Schedule A-1, page 1,
5 we have used a GRCF of 1.340447 to convert the earnings sufficiency for the 2020 rate
6 year into a revenue deficiency amount. This GRCF is the equivalent of what the
7 Company refers to as an Income Expansion Factor. The GRCF of 1.340447 on line 15,
8 in column B, is essentially the same as the Income Expansion Factor of 74.602% shown
9 on line 14. Both reflect the use of a 21% federal income tax rate and a 5.75% state
10 income tax rate.

11
12 As shown on Schedule A-1, page 1 of 2, in column C, Staff's GRCF of 1.340195 or
13 74.616% is slightly different than the Company's proposed GRCF because Staff has
14 adjusted the uncollectibles factor. Staff's adjustment to the uncollectibles factor is shown
15 on lines 4 through 8 of Schedule A-1, page 1 of 2, in column C.

16
17 Schedule A-1, page 2, shows the derivation of the GRCF used for each plan year. The
18 GRCFs used by Staff for each period are similar to the Company's proposed Income
19 Expansion Factors for each period. As noted above, Staff's proposed GRCFs for each
20 year differ from the Company's proposed Income Expansion Factors because of Staff's
21 adjustment for uncollectibles.

Q. WHAT IS SHOWN ON SCHEDULE A-2?

A. Schedule A-2 consists of 4 pages and shows a detailed reconciliation of the Company's requested and Staff's adjusted revenue requirements. Page 1 shows the reconciliation for the test year ending July 31, 2020. Pages 2-4 show the reconciliation for calendar years 2020, 2021 and 2022, respectively.

Q. PLEASE BRIEFLY EXPLAIN SCHEDULES B AND C OF STAFF EXHIBIT__(RS/RT-2).

A. The adjustments presented on Schedule A that impact rate base are shown on Schedule B. Schedule B.1 summarizes the Staff's recommended rate base adjustments. Exhibit__(RS/RT-2) contains a Schedule B and B.1 for the test year ending July 31, 2020 as well as for each plan year, 2020, 2021 and 2022.

Schedules C presents adjusted net operating income. Schedule C.1 summarizes Staff's recommended adjustment to revenue and expenses applicable to the ratemaking analysis. Schedule C.1 also presents the impact on income tax expense resulting from each of Staff's recommended adjustments. Exhibit__(RS/RT-2) contains a Schedule C and C.1 for the test year ending July 31, 2020 and for each calendar year (2020, 2021 and 2022) in the Company's proposed alternative rate plan.

Q. WHAT IS SHOWN ON SCHEDULE D?

A. Schedule D presents the capital structure and cost rates that I used to calculate Staff's recommended revenue requirement in this case. The Company's proposed cost of capital

1 is shown for comparative purposes. The return on common equity of 9.2 percent on
2 Schedule D is based on the recommendations of Staff witness Michael Gorman. Staff's
3 recommended capital structure and the cost rates for long-term debt are sponsored by
4 Staff witnesses Gorman. Mr. Gorman recommended a lower cost of long-term debt than
5 was requested by the Company. Schedule D has four pages. Page 1 shows the cost of
6 capital for the test year ending July 31, 2020. Pages 2-4 show the cost of capital for each
7 calendar year, 2020 through 2022, that is included in the Company's proposed alternative
8 rate plan.
9

10 **Q. HOW ARE STAFF'S ADJUSTMENTS TO RATE BASE AND NET OPERATING**
11 **INCOME PRESENTED?**

12 A. Staff's adjustments to rate base and net operating income for the test year ending July 31,
13 2020 and for each plan year (2020, 2021 and 2022) are summarized on Exhibit__(RS/RT-
14 2), Schedules B.1 and C.1, respectively, as noted above. Each Staff adjustment is also
15 shown on Exhibit__(RS/RT-2) on Schedules E-1 through E-12, and is discussed in
16 Section X of our testimony.
17

X. STAFF ADJUSTMENTS**Overall Rate of Return****Q. HOW HAVE YOU REFLECTED THE OVERALL RATE OF RETURN
RECOMMENDED BY STAFF WITNESSES MICHAEL GORMAN?**

A. On Staff Exhibit__(RS/RT-2), Schedule D, we have replicated Georgia Power's requested capital structure, capital cost rates, and resulting overall rate of return (from the Company's original filing before adjustments). The primary change to the Company's proposed overall rate of return determination is Mr. Gorman's recommended return on equity rate of 9.2% as opposed to Georgia Power's proposed return on equity of 10.9%. Staff has also used a and different cost rates for long-term debt, as recommended by Mr. Gorman. Staff's recommended overall cost of capital for the test year is 6.69%, compared with Georgia Power's request of 7.93%. This is shown on Staff Exhibit__(RS/RT-2), Schedule D, page 1 of 4. Staff's recommended overall cost of capital for the 2020, 2021 and 2022 plan years is summarized on Schedule D, pages 2 through 4 of 4, respectively.

E-1, Company Errata - Rate Base Adjustments**Q. DID GEORGIA POWER FILE AN ERRATA FILING SUBSEQUENT TO ITS
INITIAL FILING THAT WAS MADE ON JUNE 28, 2019?**

A. Yes. On September 24, 2019, the Company filed an Errata filing to supplement its initial rate case filing that was filed on June 28, 2019. Specifically, as discussed in the Company's Errata transmittal letter, the Errata filing reflects the revenue requirement impacts from various items included in the amended Stipulation that was approved by the

Commission in Georgia Power's 2019 Integrated Resource Plan ("2019 IRP") and DSM Certification proceedings in Docket Nos. 42310 and 42311.

Q. WHAT SPECIFIC REVENUE REQUIREMENT IMPACTS ARE REFLECTED IN GEORGIA POWER'S ERRATA FILING?

A. The Company's transmittal letter lists the following revenue requirement impacts in its Errata filing:

- Transmission interconnection investments related to the 2,000 MW of renewable capacity to be procured through two utility scale renewable request for proposals ("RFP")
- 25 MW of Plant Scherer Unit 3 capacity remaining in wholesale jurisdiction
- Annual limits on Plant Bowen Units 1 and 2 capital expenditures
- Removal of capital expenditures for certain hydro modernization projects but included the associated impact to operation and maintenance expenses
- Increase in battery energy storage system project capacity from 50 MW to 80 MW
- Adjustments to Demand Side Management ("DSM") costs and additional sum as agreed to in the Stipulation as amended and the associated impacts of increasing kWh savings by 15%
- Reasonably necessary specialized assistance to Commission Staff of up to \$500,000 annually

The Errata transmittal letter also states that the Company identified a correction related to its projected depreciation expense and associated impacts for general plant.

Q. DID THE COMPANY FILE AN EXHIBIT WITH ITS ERRATA FILING WHICH REFLECTS THE REVENUE REQUIREMENTS LISTED ABOVE?

A. Yes. The Company filed Errata Exhibit 1, which summarizes the incremental revenue requirement impacts that it made to its initial proposed revenue requirement as shown on

1 Company Exhibit__(DPP/SPA/MBR-1 Schedule 1 Total Company). Page 5 of Errata
2 Exhibit 1 reflects the adjustments which impact the Company's retail rate base.
3 Specifically, page 5 of Errata Exhibit 1 reflects various adjustments to reduce electric
4 plant in service, accumulated depreciation, accumulated deferred income taxes ("ADIT")
5 as well as other rate base items including (1) fuel and materials and supplies inventory,
6 (2) minimum bank balances and prepayments, (3) operating reserves, and (4) ARO
7 regulatory liability. These adjustments reduce retail rate base for the forecasted test year
8 and the plan years by \$18.002 million (test year), \$34.914 million (2020), \$112.455
9 million (2021) and \$211.362 million (2022).

10
11 **Q. PLEASE EXPLAIN THE RATE BASE ADJUSTMENTS SHOWN ON STAFF**
12 **EXHIBIT__(RS/RT-2), SCHEDULE E-1.**

13 A. Our adjustments reflect the retail rate base adjustments that are shown on the Company's
14 Errata Exhibit 1, page 5. As shown on Staff Exhibit__(RS/RT-2), Schedule E-1, our
15 adjustments reduce the Company's retail rate base by \$18.002 million, \$34.914 million,
16 \$112.455 million and \$211.362 million for the forecasted test year and plan years 2020,
17 2021 and 2022, respectively.

18
19 **Q. DID YOU ALSO MAKE ADJUSTMENTS RELATED TO THE COMPANY'S**
20 **ERRATA FILING TO OPERATING INCOME?**

21 A. Yes. We also made adjustments related to the Company's operating income, which are
22 reflected on Staff Exhibit__(RS/RT-2) and discussed in the next section of our testimony.

E-2, Company Errata - Operating Income Adjustments

Q. PLEASE EXPLAIN THE ADJUSTMENTS SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDULE E-2.

A. As discussed in the previous section of our testimony, these adjustments to operating income are made pursuant to the Company's Errata filing that was filed on September 24, 2019. Specifically, page 6 of Errata Exhibit 1 reflects various adjustments to (1) operating revenues, (2) O&M expense, (3) depreciation and amortization expense, (4) taxes other than income taxes and, (5) income taxes. The total of these Errata adjustments reduces retail operating income for the forecasted test year and the plan years by \$3.295 million (test year), \$5.973 million (2020), \$6.016 million (2021) and \$6.537 million (2022).

Q. PLEASE EXPLAIN THE OPERATING INCOME ADJUSTMENTS SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDULE E-2.

A. Our adjustments reflect the retail operating income adjustments that are shown on the Company's Errata Exhibit 1, page 6. As shown on Staff Exhibit__(RS/RT-2), Schedule E-2, our adjustments reduce the Company's retail operating income by \$3.295 million, \$5.973 million, \$6.016 million and \$6.537 million for the forecasted test year and plan years 2020, 2021 and 2022, respectively.

E-3, Interest Credits on Minimum Bank Balances

Q. HAS THE COMPANY INCLUDED PROJECTED AVERAGE MINIMUM BANK BALANCES IN THE FORECASTED TEST YEAR AND THE PLAN YEARS 2020 THROUGH 2022?

A. Yes. According to the response to STF-L&A-4-47, the Company's filing includes projected average minimum bank balances totaling \$47.9 million. This projected three-year average is based on using calendar years 2016 through 2018.¹²

Q. DOES THE COMPANY EARN INTEREST ON ITS AVERAGE MINIMUM BANK BALANCES?

A. Yes. As discussed in the response to STF-L&A-1-32, Georgia Power earns interest credits on minimum bank balances, which offset its bank fees. For example, in 2018, the Company earned interest credits provided by its bank's earning credit rates, which offset approximately \$600,000 in bank fees, which was recorded above-the-line in FERC account 923-00010.

Q. DID THE COMPANY BUDGET FOR INTEREST CREDITS ON IT MINIMUM BANK BALANCES IT THE FORECASTED TEST YEAR OR THE PLAN YEARS 2020-2022?

A. No. The Company did not budget for interest credits on its minimum bank balances in the forecasted test year or the plan years 2020-2022. In its response to STF-L&A-11-19, the Company stated that the forecasted interest rates which relate to the interest credits on

¹² See the response to STF-L&A-11-19.

1 minimum bank balances fluctuate based on market conditions and the minimum bank
2 balance on a total system basis. Based on this, the Company did not include any interest
3 credits for the forecasted test year or the plan years.

4
5 **Q. DID THE COMPANY PROVIDE THE ACTUAL INTEREST CREDITS FOR A**
6 **RECENT 12-MONTH PERIOD?**

7 A. Yes. In its response to STF-L&A-11-19, the Company stated that the actual amount of
8 interest credits for the 12-month period ended June 30, 2019 totaled approximately
9 \$275,000.

10
11 **Q. SHOULD AN AMOUNT FOR INTEREST CREDITS BE REFLECTED IN THE**
12 **COMPANY'S FORECASTED TEST YEAR AND EACH PLAN YEAR 2020-2022?**

13 A. Yes. As stated above, the Company has included projected average minimum bank
14 balances totaling approximately \$47.9 million in the forecasted test year and for each
15 plan year. In addition, the Company has stated that it earns interest credits on its average
16 minimum bank balances, which offset bank fees and that these interest credits are
17 recorded above-the-line in FERC account 923-00010. Therefore, an adjustment to reflect
18 interest credits in the Company's forecasted test year and each plan year is appropriate
19 and should be made.

20
21 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT.**

22 A. As stated above, the Company's interest credits for the recent 12-month period ended
23 June 30, 2019 totaled approximately \$275,000. Therefore, Staff has used this amount as

1 the basis for our adjustment. As shown on Staff Exhibit__(RS/RT-2), Schedule E-3, we
2 recommend that interest credits of approximately \$272,000 on a retail jurisdictional basis
3 be reflected for the forecasted test year, as well as for each plan year. This adjustment
4 increases after tax operating income by \$203,000 in the test year and each plan year.

5
6 **E-4, Electric Vehicle Charging Facilities**

7 **Q. HAS GEORGIA POWER INCLUDED COSTS RELATED TO ELECTRIC**
8 **TRANSPORTATION ACTIVITIES IN ITS FILING?**

9 A. Yes. As discussed on pages 48-49 of the Direct Testimony of Company witnesses
10 Porocho, Adams and Robinson, the Company's filing reflects projected capital and O&M
11 costs for electric transportation activities, including (1) net investment of all existing
12 community electric vehicle ("EV") charging facilities located on and off Company
13 property) as well as related revenues and expenses, (2) residential and commercial
14 rebates for installing EV chargers, and (3) costs related to EV education and awareness.
15 Specifically, the Company's filing includes \$6 million of capital investment over the term
16 of the alternative rate plan.

17
18 **Q. HAS THE COMPANY'S PREVIOUS INVESTMENT IN EV CHARGING**
19 **FACILITIES BEEN ALLOWED IN COST OF SERVICE?**

20 A. Generally, no. As stated on page 49 of the Direct Testimony of Company witnesses
21 Porocho, Adams and Robinson, of the approximately \$3 million of capital investment the
22 Company has made in EV charging facilities since 2014, the bulk of such investment has
23 not been allowed in cost of service.

1
2 **Q. HAS THE COMPANY PROVIDED WHAT IT CLAIMS IS ITS BUSINESS CASE**
3 **FOR ELECTRIC TRANSPORTATION ACTIVITIES?**

4 A. Yes. In its response to STF-L&A-5-33, the Company stated that its on-road and non-road
5 electric transportation activities enables and supports residential, commercial and
6 industrial customers transitioning into EV transportation and charging facilities. The
7 Company broke its business case strategy for EV transportation into three focus areas,
8 including: (1) customer education, (2) EV charging infrastructure (e.g., rebates and public
9 (Company-owned and partnerships), and (3) fleet electrification.
10

11 **Q. HAS THE COMPANY PROVIDED DETAILS RELATED TO ITS PROPOSED**
12 **INVESTMENT OF \$6 MILLION IN EV CHARGING FACILITIES DURING**
13 **EACH PLAN YEAR 2020 THROUGH 2022?**

14 A. Yes. In its response to STF-L&A-5-33b, the Company stated in part:

15 Georgia Power's proposed investment of \$6 million over the term of the
16 ARP in 2020, 2021 and 2022 will result in significant infrastructure
17 improvements. Assuming \$75,000 per new direct current fast charger
18 ("DCFC") installation, the program can result in roughly 25 additional
19 chargers per year for a total of 75 DCFC chargers over three years.
20 Georgia Power plans to meet the increasing need for charging
21 infrastructure - EV registrations increased 135% in 2018 from 2017 and
22 Lyft EV drivers logged in more than 1,100,000 miles over a six-month
23 span in 2019 - with a three-pronged approach.
24

25 **Q. SINCE THE END OF THE TWO-YEAR EV PILOT PROGRAM IN DECEMBER**
26 **2016, HAS THE COMPANY COMPLETED ANY STUDIES OR DONE ANY**
27 **EVALUATION AND/OR REDESIGN OF THE EV PROGRAM TO STRUCTURE**
28 **IT SO THAT IT PROVIDES BENEFITS TO CUSTOMERS?**

1 A. No, the Company has not completed additional studies beyond the pilot program.

2 Specifically, in response to STF-L&A-5-33c, the Company stated:

3 Georgia Power has not completed any additional studies beyond the Pilot
4 evaluation. Nevertheless, the Company applied lessons learned from the
5 Pilot evaluation and continues to closely monitor the usage of the
6 Company's existing charging network as well as broad areas of the EV
7 market including: EPRI's on-road EV sales projections; technology
8 advancements (battery range and cost, decrease in charging time,
9 equipment replacement cost savings, battery storage); the evolution and
10 mass market production of EV models of all sizes and uses; and market
11 disruptors such as ride-share and autonomous vehicles. The Company
12 also plans to participate in research and development efforts through
13 industry membership (EPRI, Edison Electric Institute, Clean Cities
14 Georgia, Alliance for Transportation Electrification and Electric Drive
15 Transportation Association), Southern Company Services research and
16 development and other leadership opportunities.

17
18 **Q. HAS THE COMPANY IDENTIFIED ALL COSTS AND REVENUES FOR EV**
19 **CHARGING FACILITIES THAT ARE INCLUDED IN RATE BASE, REVENUE**
20 **AND OPERATING EXPENSES FOR THE FORECASTED TEST YEAR AND**
21 **FOR CALENDAR YEARS 2020-2022?**

22 A. Yes. In its response to STF-L&A-1-129, the Company provided the amounts
23 summarized in the following table as being included in the forecasted test year and for
24 calendar years 2020 through 2022:

EV Charging Stations (Thousands of Dollars)					
Rate Base	FERC Account	Test Year	2020	2021	2022
(13-Month Average):					
Plant in Service	101	\$ 4,094	\$ 4,933	\$ 6,933	\$ 8,933
Accumulated Depreciation	108	\$ (291)	\$ (342)	\$ (505)	\$ (721)
Materials & Supplies	154	\$ 24	\$ 24	\$ 24	\$ 24
ADIT	282	\$ (639)	\$ (713)	\$ (949)	\$ (1,243)
Net Rate Base		\$ 3,188	\$ 3,902	\$ 5,503	\$ 6,993
Operating Income					
Revenue	456	\$ 108	\$ 115	\$ 120	\$ 123
O&M Expense	908	\$ 325	\$ 334	\$ 342	\$ 351
Depreciation Expense	403	\$ 88	\$ 135	\$ 189	\$ 243
Source: STF-L&A-1-129					

Q. IN YOUR OPINION, SHOULD THE COSTS AND REVENUES ASSOCIATED WITH THE EV CHARGING FACILITIES BE INCLUDED IN GEORGIA POWER'S RATE BASE AND COST OF SERVICE?

A. No, they should not. First, the table above clearly demonstrates the charging stations will not generate enough revenue to cover O&M expense and depreciation much less the return on capital and income taxes associated with the investment. Therefore, this investment would be subsidized by all ratepayers including the vast majority without EVs. Second, there are hundreds of charging stations throughout the state being provided by companies risking their own capital. It would be unfair and inappropriate regulatory policy to allow Georgia Power to use its monopoly status to subsidize its investment in EV charging facilities. If the EV charging stations were "behind the fence" whereby they were being used for the purpose of fueling the Company's fleet of vehicles used in the provision of providing service, such costs may be appropriate for recovery from ratepayers assuming the investment was prudent and economic. However, as discussed

1 above, the Company's plan for the \$6 million investment in EV charging facilities over
2 the term of plan years 2020-2022, is largely centered on making such charging facilities
3 available to the general public including pay-for-hire EV use such as by Lyft drivers who
4 drive EVs and therefore would need to use EV charging facilities. Also, the rates that the
5 Company appears to be charging for EV charging to the customers who are using the EV
6 charging facilities appear to be insufficient to recover the costs. Staff recommends that
7 the costs associated with providing EV charging stations to the general public should not
8 be subsidized by the Company's ratepayers. Staff has therefore made an adjustment to
9 remove the costs and revenues associated with the EV charging facilities.

10
11 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE THE COSTS AND**
12 **REVENUES ASSOICATED WITH THE EV CHARGING FACILITIES.**

13 A. As shown on Staff Exhibit__(RS/RT-2), Schedule E-4 (lines 1-5), our recommended
14 adjustment is in two parts. The first part of our adjustment is to remove the rate base
15 components, which are comprised of plant in service, accumulated depreciation,
16 materials and supplies and accumulated deferred income taxes ("ADIT"). The impact of
17 removing the rate base components of the EV charging facilities results in net rate base
18 being decreased by \$3.188 million, \$3.902 million, \$5.503 million and \$6.993 million for
19 the forecasted test year and plan years 2020, 2021 and 2022, respectively.

20
21 As shown on Staff Exhibit__(RS/RT-2), Schedule E-4 (lines 6-14), the second part of our
22 adjustment is to remove the components of the EV charging facilities that relate to
23 operating income, which includes decreasing jurisdictional revenue by \$107,000,

1 \$114,000, \$118,000 and \$121,000 for the forecasted test year and plan years 2020, 2021
2 and 2022, respectively. In addition, our adjustment reduces jurisdictional O&M expenses
3 by \$321,000, \$330,000, \$338,000 and \$347,000 for the forecasted test year and plan
4 years 2020, 2021 and 2022, respectively. Finally, our adjustment reduces jurisdictional
5 depreciation expense by \$87,000, \$133,000, \$187,000 and \$240,000 for the forecasted
6 test year and plan years 2020, 2021 and 2022, respectively.

7
8 **E-5, Cash Working Capital**

9 **Q. WHAT HAS THE COMPANY REQUESTED FOR CASH WORKING CAPITAL?**

10 A. For the future test year ending July 31, 2020, the Company has reflected negative cash
11 working capital of \$22.482 million, based on an updated lead-lag study that it conducted
12 for purposes of this case.

13
14 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR CASH WORKING CAPITAL.**

15 A. As shown on Exhibit__(RS/RT-2), Schedule E-5, the only adjustments we are
16 recommending to the Company's cash working capital in the current rate case result from
17 adjustments that are being by Staff for certain cash operating expenses. As the result of
18 having adjusted various cash operating expenses, the amount of cash working capital
19 computed in Staff's case differs from the amounts that were presented in the Company's
20 filing.

21
22 **E-6, Miscellaneous Items / Executive Financial Planning**

23 **Q. PLEASE EXPLAIN THE EXECUTIVE FINANCIAL PLANNING ADJUSTMENT**
24 **SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDULE E-6.**

1 A. In its response to STF-L&A-1-60, the Company confirms that the proposed test year and
2 each plan year operating expenses include \$414,374 associated with its executive
3 financial planning program. This amount includes Georgia Power direct charges of
4 \$164,410 as well as charges allocated to Georgia Power by SCS and SNOC of \$180,000
5 and \$69,964, respectively. This program provides personal financial planning, estate
6 planning, investment advice and tax planning and preparation to Georgia Power's Chief
7 Executive Officer, Chief Operating Officer, Vice-Presidents and Directors. We do not
8 believe that the captive ratepayers of Georgia Power should pay for the charges
9 associated with these types of top executive perks. Rather, we believe that the
10 Company's stockholders should be made responsible for these costs. Our recommended
11 removal of these executive financial planning program costs from the forecasted test year
12 and each plan year is reflected on Staff Exhibit__(RS/RT-2), Schedule E-6. A similar
13 adjustment was recommended by Staff in prior Georgia Power rate cases.

14
15 **E-7, Property Tax Adjustment**

16 **Q. DO YOU RECOMMEND AN ADJUSTMENT TO THE COMPANY'S**
17 **PROPOSED PROPERTY TAXES PROJECTED FOR THE TEST YEAR?**

18 A. Yes. Georgia Power books property tax true-ups on a consistent basis each year. The
19 reason for booking such property tax true-ups is that the Company's property taxes are
20 based on budgeted estimates for the applicable budget period. As more actual data
21 becomes available and true millage rates established by assessed values, become
22 available, estimated amounts are adjusted to include as nearly as can be determined the
23 appropriate property taxes applicable to each calendar year. The responses to STF-RCS-

1-35 from Docket No. 36989 and STF-RS/RT-1-47 (original and supplemental) shows that the Company has booked the following property tax true-ups over the last 17 years:

Property Tax True-Ups (Favorable)/Unfavorable		
Property		Amount
<u>Tax Year</u>		<u>(Millions)</u>
2002		\$ (3.171)
2003		\$ 1.139
2004		\$ (1.622)
2005		\$ (2.683)
2006		\$ (5.000)
2007		\$ (10.325)
2008		\$ (8.481)
2009		\$ (0.106)
2010		\$ (0.057)
2011		\$ (0.348)
2012		\$ (1.797)
2013		\$ (5.057)
2014		\$ (4.012)
2015		\$ 0.321
2016		\$ (0.533)
2017		\$ (4.869)
2018		\$ 2.331
17-Year Average		<u>\$ (2.604)</u>
Source: STF-RCS-1-35 (Docket No. 36989) and STF-L&A-1-47 (original and supplemental)		

As shown in the above table, the Company has experienced an average annual favorable tax true-up booking of \$2.604 million over the 17-year period. According to the response to STF-L&A-1-47, the property tax true-up for property tax year 2018 shown in the table above is through May 31, 2019.

Q. DO THE BUDGETED PROPERTY TAX EXPENSES FOR THE FORECASTED TEST YEAR OR PLAN YEARS INCORPORATE PROPERTY TAX VALUATION TRUE-UPS EXPECTED FOR THE PROJECTED TEST YEAR?

1 A. No. As stated in the response to STF-L&A-1-47, the Company's budget that was used by
2 Georgia Power for rate case cost projection purposes does not reflect any property tax
3 valuation true-ups since the true-ups are not known until actual data becomes available.
4

5 **Q. SHOULD THE PROPERTY TAXES FOR THE TEST YEAR AND PLAN YEARS**
6 **BE ADJUSTED?**

7 A. Yes. The property taxes included in the test year and plan years in this case are the
8 originally budgeted taxes for those periods and do not reflect tax true-ups for tax accruals
9 or tax true-ups that may eventually be booked in the test year when more actual data
10 becomes available.
11

12 Based on the foregoing information, we recommend that an average favorable property
13 tax true-up level of \$2.604 million, i.e., approximately \$2.575 million on a retail
14 jurisdictional basis as shown on Exhibit __ (RS/RT-2), Schedule E-7, be reflected for the
15 forecasted test year, as well as for each plan year. It is reasonable to use this historic
16 annual average property tax true-up level as an appropriate proxy for the normalized level
17 of test year property tax true-ups.
18

19 **Q. WHAT IS THE IMPACT OF THIS RECOMMENDED PROPERTY TAX**
20 **ADJUSTMENT ON THE COMPANY'S TEST YEAR AFTER-TAX OPERATING**
21 **INCOME?**

22 A. As shown on Staff Exhibit __ (RS/RT-2), Schedule E-7, the recommended property tax
23 true-up adjustment reduces property tax expense by \$2.575 million and increases the

Company's test year retail after-tax operating income by \$1.924 million for the forecasted test year and each plan year.

E-8, Interest Synchronization Adjustment

Q. PLEASE DESCRIBE GEORGIA POWER'S PROPOSED INTEREST SYNCHRONIZATION ADJUSTMENT SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDULE E-8.

A. The Company is proposing that interest expenses to be used as a deduction in the calculation of the test year pro forma adjusted income taxes be based on the interest expenses that are implicit in its proposed overall rate of return. These pro forma interest expenses (referred to as the so-called "synchronized" interest expenses) are determined by multiplying the weighted cost of debt component of the overall rate of return times the rate base used in this case.

Q. HAVE YOU DETERMINED THE STAFF-RECOMMENDED TRADITIONAL TEST YEAR SYNCHRONIZED INTEREST EXPENSES IN A SIMILAR MANNER?

A. Yes. The Staff-recommended traditional test year synchronized interest expense amount, calculated in the same manner, is shown in the third column of Staff Exhibit__(RS/RT-2), Schedule E-8, page 1. Plan year synchronized interest adjustment amounts are shown on pages 2-4 of Schedule E-8.

1 **Q. WHY IS THE STAFF'S RECOMMENDED SYNCHRONIZED INTEREST**
2 **AMOUNT DIFFERENT FROM GEORGIA POWER'S PROPOSED**
3 **SYNCHRONIZED INTEREST AMOUNT?**

4 A. This disparity is due to the differences in the rate base levels used in Georgia Power's and
5 Staff's respective recommendations and to the difference in the capital structure and cost
6 rate for long-term debt between Staff and the Company. These differences result in
7 different synchronized interest expense amounts.

8
9 **Q. HOW DOES THIS DIFFERENCE IN THE TWO SYNCHRONIZED INTEREST**
10 **EXPENSE LEVELS IMPACT GEORGIA POWER'S PROPOSED**
11 **TRADITIONAL TEST YEAR AFTER-TAX RETAIL OPERATING INCOME?**

12 A. As shown on line 6 of Staff Exhibit__(RS/RT-2), Schedule E-8, page 1, adoption of
13 Staff's recommended synchronized interest amount decreases the Company's traditional
14 test year retail income tax expense by \$8.716 million and increases after-tax operating
15 income by that same amount, i.e., by \$8.716 million.

16
17 The interest synchronization adjustments for each plan year are shown on Schedule E-8,
18 pages 2-4, respectively.

19
20 **E-9, Stock-Based Compensation**

21 **Q. PLEASE EXPLAIN THE ADJUSTMENT FOR STOCK-BASED**
22 **COMPENSATION.**

1 A. This adjustment is shown on Exhibit__(RS/RT-2), Schedule E-9, and decreases operating
2 expenses by the amounts shown and is explained in additional detail in Section XIV of
3 our testimony, which addresses incentive compensation.

4
5 **E-10, Payroll Tax Expense**

6 **Q. PLEASE EXPLAIN THE ADJUSTMENT TO PAYROLL TAX EXPENSE.**

7 A. Staff's adjustment to the Company's payroll tax expense is made in conjunction with the
8 adjustments that are being made to remove stock-based compensation. Based upon those
9 recommended adjustments, as shown on Exhibit No.__(RS/RT-2), Schedule E-10, in
10 column A, Georgia Power's proposed traditional test year payroll tax expense is reduced
11 by \$1.490 million.

12
13 For the years associated with the Company's proposed Alternative Rate Plan, payroll tax
14 expense is reduced by \$1.484 million, \$1.629 million and \$1.732 million in 2020, 2021
15 and 2022, respectively, as shown on Exhibit No.__(RS/RT-2), Schedule E-10, in columns
16 B through D, respectively.

17
18 **E-11, Uncollectibles Expense**

19 **Q. WHAT LEVEL OF PROJECTED UNCOLLECTIBLES EXPENSE HAS THE**
20 **COMPANY INCLUDED IN THE FORECASTED TEST YEAR AND THE PLAN**
21 **YEARS?**

1 A. The Company's filing reflects uncollectibles expense of \$13.445 million in the test year,
2 \$14.003 million in 2020 and 2021 and \$14.004 million in 2022.¹³

3
4 **Q. DO THESE PROJECTED LEVELS OF UNCOLLECTIBLES EXPENSE APPEAR**
5 **TO BE REASONABLE?**

6 A. No, they do not. Staff requested that the Company identify the amount of actual
7 uncollectibles expense that was reflected in its ASRs for 2016, 2017 and 2018. In
8 response to Staff's inquiry, the Company stated that actual uncollectibles expense
9 reflected in its ASR's totaled \$14.476 million, \$11.250 million and \$11.923 million in
10 2016, 2017 and 2018, respectively.¹⁴ Uncollectibles expense in each year, 2017 and 2018
11 was below \$12 million. It appears that the reduction in uncollectibles expense from 2016
12 through 2017 and 2018 was driven by the Company's customers enrolling in prepaid
13 programs, which the Company plans to expand.

14
15 **Q. ARE YOU RECOMMENDING AN ADJUSTMENT FOR UNCOLLECTIBLES**
16 **EXPENSE TO INCLUDE IN THE TEST YEAR AND THE PLAN YEARS 2020-**
17 **2022?**

18 A. Yes. We have adjusted uncollectibles expense for the test year and plan years 2020-2022
19 to \$12 million in each year. As noted above, uncollectibles expense was below \$12
20 million in the two most current full years, 2017 and 2018. Specifically, the Company's
21 actual uncollectibles expense in 2017 and 2018 was \$11.250 million and \$11.923 million,

¹³ See the responses to STF-PIA-10-3, STF-PIA-10-4, STF-PIA-10-5 and STF-PIA-10-6.

¹⁴ See the responses to STF-PIA-10-7, STF-PIA-10-8 and STF-PIA-10-9.

1 respectively. Moreover, as Georgia Power expands its prepaid programs, the expectation
2 would be that increased customer participation in the prepaid programs would continue to
3 reduce uncollectibles expense. Staff is recommending an allowance for uncollectibles
4 expense of \$12 million in the test year and plan years. Staff has also adjusted the GRCF
5 to reflect the uncollectibles recommendation.
6

7 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO UNCOLLECTIBLES EXPENSE.**

8 A. As shown on Exhibit__(RS/RT-2), Schedule E-11, Staff's recommendation to use \$12
9 million for uncollectibles expense reduces the Company's requested O&M expense by
10 approximately \$1.427 million (test year), \$1.978 million (2020 and 2021), and \$1.979
11 million (2022) on a retail jurisdictional basis. Staff's adjustment increases the Company's
12 test year retail after-tax operating income by \$1.066 million for the test year and by
13 \$1.478 million for each of the plan years 2020 through 2022.
14

15 **E-12, Storm Damage Regulatory Asset Amortization and Storm Damage Accrual**

16 **Q. WHAT WAS THE COMPANY'S STORM DAMAGE REGULATORY ASSET**
17 **ACCOUNT BALANCE AS OF DECEMBER 31, 2018 AND HOW DOES THAT**
18 **COMPARE WITH THE DECEMBER 31, 2013 BALANCE?**

19 A. As discussed on page 39 of the Direct Testimony of Company witnesses Poroach, Adams
20 and Robinson, the Company's storm damage regulatory asset account had a balance of
21 \$37.1 million as of December 31, 2013, which increased to \$415.8 million as of
22 December 31, 2018, or an increase of approximately 1,021%.
23

1 **Q. WHAT DOES THE COMPANY ATTRIBUTE TO THIS SUBSTANTIALLY**
2 **LARGE INCREASE IN ITS STORM DAMAGE REGULATORY ASSET**
3 **BALANCE?**

4 A. The Company attributes this substantially large increase to its storm damage regulatory
5 asset balance to a number of significant storms that have impacted Georgia Power since
6 the 2013 rate case. Specifically, Company witnesses Poroach, Adams and Robinson state
7 that costs to the storm reserve included approximately (1) \$75 million related to Ice
8 Storm Pax in 2014; (2) approximately \$240 million related to Hurricane's Matthew and
9 Irma in 2016 and 2017, respectively, and (3) approximately \$130 million related to
10 Hurricane Michael in 2018.

11 **Q. WHAT DID THE COMMISSION AUTHORIZE PURSUANT TO STORM**
12 **DAMAGE COSTS IN ITS ORDER IN THE 2013 RATE CASE IN DOCKET NO.**
13 **38969?**

14 A. As stated in the Direct Testimony of Company witnesses Poroach, Adams and Robinson,
15 the Commission's 2013 rate case Order authorized annual storm damage expense at \$29.9
16 million, which included projected annual storm costs¹⁵ of \$22.8 million and recovery for
17 prior storm costs totaling \$7.1 million. These levels of storm cost recovery were not
18 updated in 2016 when the Company's then-current rate plan was extended for an
19 additional three-year period, 2017 through 2019.

¹⁵ In our testimony the terms "storm damage costs" and "storm costs" are used interchangeably to refer to the costs incurred by the Company to restore power after major storms.

1 **Q. WHAT HAS THE COMPANY REFLECTED IN ITS FILING WITH REGARD**
2 **TO STORM DAMAGE EXPENSE?**

3 A. As discussed on page 40 of the Direct Testimony of Company witnesses Poroach, Adams
4 and Robinson and shown on Company Exhibit__(DPP/SPA/MBR-5, Schedule 2), the
5 Company calculated projected annual storm costs of \$63.5 million, which was based on a
6 10-year historical average. In addition, the Company has included a projected reserve
7 deficiency of \$449.4 million as of December 31, 2019, which it proposes to amortize
8 over a three-year period, or \$149.8 million per year. As shown on Company
9 Exhibit__(DPP/SPA/MBR-5, Schedule 2), the combination of the projected annual storm
10 expense of \$63.5 million and the annual amortization of the reserve deficiency of \$149.8
11 million results in a proposed storm damage accrual of \$213.3 million, or an annual
12 increase of \$183.4 million.

13
14 **Q. HAS STAFF USED THE COMPANY'S PROPOSED \$63.5 MILLION AMOUNT**
15 **FOR THE PROJECTION OF STORM DAMAGE CHARGES FOR THE TEST**
16 **YEAR AND PLAN YEARS?**

17 A. Yes. Staff reviewed the Company's calculation of a ten-year average of storm damage
18 costs, which produced the Company's \$63.5 million estimate. More recent years, such as
19 2016 through 2018 has seen much higher storm damage costs than previous years. Using
20 a shorter period for the average could therefore result in having an increased cost
21 estimate. Staff has accepted the Company's \$63.5 million for purposes of this case. Staff
22 recommends that the Company's storm damage costs be reviewed in detail.

1 **Q. HAS STAFF ADJUSTED THE COMPANY'S ESTIMATE OF THE DECEMBER**
2 **31, 2019 DEFERRED STORM DAMAGE COST BALANCE?**

3 A. Yes. The Company's estimate was based on actual charges for each month through
4 December 2018 and upon estimated monthly amounts for each month of 2019. The
5 Company's response to STF-L&A-1-39a provided actual charges for January through
6 June 2019. As shown on Exhibit ____ (RS/RT-2), Schedule E-12, Staff has used actual
7 charges for January through June 2019 in place of the Company's estimates for those
8 months. That resulted in a slightly lower December 31, 2019 balance, which is being
9 amortized over a three-year period.

10
11 **Q. DOES STAFF RECOMMEND THAT THE COMPANY'S STORM DAMAGE**
12 **COSTS BE REVIEWED IN A SEPARATE INVESTIGATION APART FROM**
13 **THIS RATE CASE?**

14 A. Yes. While a certain level of review of the Company's storm costs is done in this rate
15 case and can be done in conjunction with reviewing the Company's ASR filings, the
16 Company's deferred amount has built up to over \$400 million and most of that from
17 storms occurring in recent years since the Company's 2013 rate case. Several of the
18 Florida electric utilities have been impacted by some of the same hurricanes. Staff is
19 aware that the Florida Public Service Commission has opened up a number of dockets
20 under which the large amounts of storm costs incurred by a number of the Florida electric
21 utilities are being examined in detail. The detailed records underlying storm cost,
22 especially those associated with major hurricanes, can be very voluminous and include
23 vendor receipts, utility payroll and time records, and details of charges from affiliates and

1 from crews from other utilities that are providing assistance with restoring electric service
2 after the storms. Staff accordingly recommends a more detailed investigation into the
3 Company's over \$400 million of deferred storm costs. This would not necessarily require
4 the Commission to open a new docket to investigate the Company's storm costs, as the
5 Florida Commission has done with respect to the electric utilities that it regulates;
6 however, there should be assurance that Staff would have adequate resources sufficient to
7 conduct the investigation in the detail that is warranted by the substantial amount of
8 storm cost deferrals.

9 **Sharing of Responsibility for the CCR ARO Amount for Plant Kraft and the Benefits of**
10 **Donating Plant Kraft Land to the Georgia Ports Authority**

11 **Q. HAS THE COMPANY RETIRED PLANT KRAFT?**

12 A. Yes. Plant Kraft Units 1-4 were decertified in the 2013 IRP and Plant Kraft Unit 1 CT
13 was retired in the 2016 IRP. These units have been retired by the Company.

14
15 **Q. DOES THE COMPANY HAVE AN ASSET RETIREMENT OBLIGATION**
16 **RELATED TO COAL COMBUSTION RESIDUALS (AKA ASH POND CLEAN-**
17 **UP) AT PLANT KRAFT?**

18 A. Yes, it appears that the Company does. The Company's response to STF-L&A-1-23
19 Attachment A from Docket No. 42310 shows a CCR ARO for the Plant Kraft ash pond of
20 [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] as the "project to date
21 2018" amount. It shows no Plant Kraft ash pond CCR ARO costs for any years beyond
22 2018.

1 **Q. DOES THE COMPANY HAVE AN ASSET RETIREMENT OBLIGATION**
2 **RELATED TO COAL COMBUSTION RESIDUALS LANDFILL CLEAN-UP AT**
3 **PLANT KRAFT?**

4 A. Yes. The Company's response to STF-L&A-1-23 Attachment A from Docket No. 42310
5 shows a CCR ARO for the Plant Kraft landfill totaling [BEGIN CONFIDENTIAL] [REDACTED]
6 [REDACTED] [END CONFIDENTIAL]. The "project to date 2018" amount for the Plant Kraft
7 ash pond is [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] and
8 additional amounts are listed for 2019 through 2028. An amount of [BEGIN
9 CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] is listed for "2029 &
10 Beyond." The amounts for the Plant Kraft landfill CCR ARO total [BEGIN
11 CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL].
12

13 **Q. HAS THE COMPANY RECEIVED COMMISSION AUTHORIZATION TO**
14 **DONATE PLANT KRAFT LAND TO THE GEORGIA PORTS AUTHORITY?**

15 A. Yes. Authorization from the Commission in Docket No. 36989 (Order dated October 16,
16 2018) was provided to the Company to donate a parcel of land at the Plant Kraft
17 generating site to the Georgia Ports Authority.
18

19 **Q. WILL ALL OF THE LAND AT PLANT KRAFT BE DONATED TO THE PORTS**
20 **AUTHORITY?**

21 A. No. Some portions of the 73-acre Plant Kraft site will be retained by Georgia Power,
22 including substations, transmission lines, a dissolved oxygen site (for Vogtle 3 and 4),
23 and an access road to the Company's assets.

1
2 **Q. HAS THE COMPANY MADE THE DONATION OF THE PLANT KRAFT LAND**
3 **TO THE GEORGIA PORTS AUTHORITY YET?**

4 A. No, not yet according to the Company's response to recent informal Staff inquiries.
5

6 **Q. DOES THE PLANT KRAFT LAND THAT IS TO BE DONATED INCLUDE THE**
7 **SITE OF THE FORMER ASH POND?**

8 A. Yes. The Plant Kraft land that is to be donated includes the site of the ash pond which
9 appears to have been remediated.
10

11 **Q. WHAT WAS THE MARKET VALUE OF THE DONATED PLANT KRAFT**
12 **PROPERTY?**

13 A. The Company provided a copy of its Plant Kraft appraisal in Docket No. 40161.¹⁶ The
14 Plant Kraft appraisal estimated the market value of Tract-1 to be [BEGIN
15 CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] as of March 7, 2017.
16

17 **Q. DID STAFF PREVIOUSLY RAISE ISSUES ABOUT THE DONATION OF THE**
18 **PLANT KRAFT LAND?**

19 A. Yes. In the 2016 IRP, Staff noted that the Company had collected a return on the book
20 value of the land from ratepayers for the entire time that the land has been owned by the
21 Company. Staff noted that if the appraised market value of the land exceeded the net
22 book value, the Company may be able to realize a gain upon the disposition of such land.

¹⁶ Docket No. 40161, STF-24-6 Attachment

1 If there is a gain realized upon the disposition of utility plant land, it should be evaluated
2 in a context in which the Company's earnings are being reviewed. In the 2019 IRP, Staff
3 encouraged the Commission and Company to consider a sharing of the income tax
4 savings resulting from the Company's donation of the Plant Kraft land to the Ports
5 Authority.

6
7 **Q. WILL THE DONATION OF PLANT KRAFT LAND TO THE PORTS**
8 **AUTHORITY BENEFIT THE COMPANY?**

9 A. Yes. The donation of the Plant Kraft land benefitted the Company by enhancing the
10 Company's reputation as a good corporate citizen and by providing a tax deduction based
11 on the appraised fair market value of the land when it was donated. In response to Staff
12 informal inquiries the Company has stated that:

13 Pursuant to Treas. Reg. 1.170A-13(c), prior to the donation, the Company
14 will obtain a qualified appraisal of the parcel of Plant Kraft land being
15 donated. Pursuant to Treas. Reg. 1.170A-1(c)(1), the amount of a
16 charitable contribution is the fair market value of the property at the time
17 of the contribution; therefore, the tax deduction will be based on the
18 qualified appraisal of the parcel of Plant Kraft land being donated.

19
20 **Q. WILL THE DONATION OF THE PLANT KRAFT LAND BENEFIT THE STATE**
21 **OF GEORGIA?**

22 A. Yes. The Ports Authority which has been an economic engine for growth to the State
23 will benefit by receiving the remediated Plant Kraft land.

24
25 **Q. WILL A GAIN BE RECORDED RELATED TO THE PLANT KRAFT LAND**
26 **DONATION?**

1 A. No. No gain is anticipated to be recorded for the donation of the Plant Kraft land. As the
2 Company explained in response to informal Staff inquiries conducted during the 2019
3 IRP:

4 because this proposed transaction is not a traditional sale, but is actually a
5 donation of an asset, in accordance with FERC's Uniform System of
6 Accounts, the Company will record the donation expense based on the
7 book cost of the land and not the fair market value. Such donation expense
8 will be recorded in account 426.1 (Land Donations). Therefore, there will
9 be no gains or losses in a donation as would be recorded in the case of a
10 typical sale of an asset.

11 If the Company donates the land in 2018, this will result in an approximate
12 [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL]
13 decrease to tax expense (fair market value of the land to be donated
14 multiplied by the blended federal and state tax rate of 25.472%). In
15 following FERC's Uniform System of Accounts, the Company will apply
16 the reduction in tax expense Below-the-Line.

17
18 **Q. WHAT IS STAFF'S PRIMARY RECOMMENDATION RELATED TO THE**
19 **DECREASE TO TAX EXPENSE FROM THE DONATION AND THE COST OF**
20 **REMEDATING THE PLANT KRAFT ASH POND?**

21 A. Staff acknowledges that the income tax benefit from a donation would typically follow
22 the treatment of that donation, and donations are typically recorded as a below-the-line
23 item for ratemaking, and the Company's proposed treatment follows that traditional
24 treatment. However, the situation with the Plant Kraft land value and ash pond clean-up
25 here presents unique facts. Because the value of the Plant Kraft land to be donated
26 appears to have benefitted from the ash pond clean-up, Staff recommends that the
27 Commission and the Company consider applying some of the donation-related tax
28 savings that would otherwise be assigned below-the-line to addressing the Plant Kraft ash
29 pond clean-up cost. Staff is interested in assuring that the Plant Kraft land donation

1 would have a benefit, not only to the Company and the State of Georgia, but also to the
2 Company's customers, and applying the donation tax savings to the ash pond clean-up
3 costs would be one way of providing a benefit to customers.

4
5 **Q. DOES STAFF HAVE AN ALTERNATIVE RECOMMENDATION**
6 **CONCERNING THE PLANT KRAFT CCR COMPLIANCE COSTS?**

7 A. Yes. Since the Plant Kraft ash pond clean-up appears to have increased the market value
8 of the plant land that is to be donated, if the full benefit of donating that land is to be
9 retained by shareholders, Staff's alternative recommendation is that the related ash pond
10 remediation costs also be allocated to shareholders.

11
12 **Sales Forecast and Projection of Revenue at Current Rates**

13 **Q. HAS STAFF USED THE COMPANY'S SALES FORECAST AND PROJECTION**
14 **OF REVENUE AT CURRENT RATES?**

15 A. Yes. John Hutts, a witness for Staff in the Company's 2019 IRP indicated that Staff does
16 not agree with the Company's methodology for projecting sales, particularly with the 38-
17 year period used by the Company for modeling for normal weather. Staff indicated that it
18 supports the use of a 20-year period for modeling for normal weather. As explained in
19 the Direct Testimony of Staff witness John Hutts in the 2019 IRP case, Docket No.
20 42310, the Company used heating degree hours (HDH) and cooling degree hours (CDH)
21 in development of its energy sales forecast. HDH and CDH are measures of temperature
22 and are computed as the absolute value of the difference between average daily
23 temperature and a defined base temperature. The relationship between energy

1 consumption and degree hours is positive, i.e., energy consumption increases with
2 increases in degree hours. In its Budget 2019 sales forecast, the Company used normal
3 HDH and CDH are represented as their respective averages for the 38 years beginning
4 1980 and ending 2017. As indicated by Mr. Hutts in the 2019 IRP proceeding, Staff does
5 not agree with the Company's methodology for quantifying the impact of "normal"
6 weather on the sales forecast. Mr. Hutts recommended that the Company should
7 compute HDH and CDH on a rolling 20-year basis, rather than on the 38-year basis that
8 the Company utilized in producing its sales forecast. However, the Staff consultant who
9 addressed this issue for Staff in the 2019 IRP case evaluated the impact of using 20-year
10 weather information versus the Company's methodology and determined that the impact
11 would be minimal. In other words, Staff concluded that the result was reasonable even
12 though Staff has concerns about the Company's methodology, which were explained in
13 Mr. Hutts' testimony in the 2019 IRP proceeding. Consequently, Staff is using the
14 Company's sales forecast without adjustment in the rate case; however, this should not be
15 interpreted as Staff concurrence with the Company's methodology or underlying
16 assumptions.

17
18 **Plant Held for Future Use**

19 **Q. WHAT AMOUNT OF PLANT HELD FOR FUTURE USE ("PHFFU") HAS THE**
20 **COMPANY REFLECTED IN RATE BASE?**

21 **A.** The Company reflected approximately \$116.7 million of PHFFU in rate base in the test
22 year and in each plan year.

1 **Q. WHAT AMOUNT OF PHFFU IS SHOWN ON THE COMPANY'S 2018 FERC**
2 **FORM 1?**

3 A. The Company's 2018 FERC Form 1 shows \$116,714,221 of PHFFU. A copy of that
4 page is presented in Exhibit __ (RS/RT-8).

5
6 **Q. HAS THE COMPANY INCLUDED TRANSMISSION AND SUBSTATION**
7 **PROJECTS IN IRP PROCEEDINGS AND THEN SUBSEQUENTLY PUSHED**
8 **OUT THE EXPECTED USE DATES?**

9 A. Yes. As examples, Exhibit RS/RT-7 contains the Company's responses to STF-L&A-1-
10 65 and STF-L&A-5-15 from Docket No. 42310, which address certain transmission and
11 substation projects which the Company had included in prior IRP filings but which were
12 not included in the Company's 2019 IRP filing. Exhibit RS/RT-7 also includes the
13 Company's supplemental response to STF-L&A-5-16 from Docket No. 42310, which
14 provided information about Georgia Power's costs for PHFFU.

15
16 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-9?**

17 A. Exhibit RS/RT-9 uses information from the Company's 2018 FERC Form 1 concerning
18 Plant Held for Future Use (see, e.g., Exhibit RS/RT-8) to identify the cost of PHFFU that
19 show an "expected use" date of (1) 2030 or beyond and (2) 2040 or beyond. As shown
20 there, of the \$116.7 million of PHFFU, approximately \$110 million or 94% has an
21 "expected use" date of 2030 or beyond and approximately \$82 million or 70% has an
22 "expected use" date of 2040 or beyond. If PHFFU were to be included in rate base to

1 earn a full return for investors for multi-decade periods, the cost to ratepayers will add up
2 to significant amounts.

3
4
5 **Q. WHAT IS SHOWN IN EXHIBIT RS/RT-10?**

6 A. Exhibit RS/RT-10 is an Exhibit that Staff prepared showing the annual cost of PHFFU,
7 including the annual financing costs, which were estimated using the cost of capital from
8 the Company's 2018 ASR and from Staff's recommendation in the current rate case for
9 the test year, and reflects an income tax gross-up on the equity return to estimate the
10 annual revenue requirement impact. This also includes information that the Company
11 provided in its response to STF-L&A-5-16 in Docket No. 42310 concerning operating
12 expenses and property taxes for PHFFU. As shown on Exhibit RS/RT-10, the annual
13 cost, including financing charges, property taxes and operating expenses for PHFFU is
14 estimated at \$10.9 million per year (using Staff's proposed cost of capital) to \$13.7
15 million per year (using the capital structure from the 2018 ASR and a 12.0% ROE,
16 representing the top end of the current earnings band from Docket No. 36989). At an
17 annual cost of approximately \$11 million per year, over ten years that could grow to \$110
18 million; over 20 years to \$220 million; and over 30 years to \$330 million. The point is
19 that cost to customers of the Company's holding PHFFU for multi-decade periods can
20 become very significant. Staff recommends that a reasonable and balanced approach to
21 PHFFU be applied prospectively, starting with the current rate case.

22
23 **Q. WHAT ARE STAFF'S CONCERNS REGARDING THE COMPANY'S PHFFU?**

1 A. Staff is concerned that the "expected use" dates keep getting pushed off further and
2 further into the future, such that land acquired for future use is sitting in the PHFFU
3 account and being included in rate base to earn a return for investors for extended multi-
4 decade periods in some instances. A large portion of the Company's PHFFU at
5 December 31, 2018 for example has projected use dates of 2030 or beyond, and almost
6 70% of the total PHFFU cost is for projects which have "expected use" dates of 2040.
7 Additionally, the PHFFU includes about \$23.5 million for a future generating plant site in
8 Stewart County, Georgia; however, the Company has no plans to construct generation
9 there, nor has the Commission approved the construction of a new generating plant at that
10 site. To the extent that the Company does not have firm plans at this time to construct a
11 new generating plant on the Stewart County site within a reasonable planning period,
12 Staff recommends that the Company evaluate whether the costs of that site should be
13 transferred to a non-utility property account. To the extent that the Commission has not
14 certified this site for new generation, and finds that the Company does not have firm
15 plans at this time to construct a new generating plant on the Stewart County site within a
16 reasonable planning period, Staff recommends that the Commission direct the Company
17 to evaluate whether the costs of that site should be transferred to a non-utility property
18 account.

19
20 **Q. IS STAFF MAKING A RECOMMENDATION ON RATE BASE INCLUSION**
21 **FOR PHFFU?**

22 A. Yes. Staff recommends that prospectively starting with this rate case that if PHFFU has
23 been held for more than 15 years and has not yet been placed into service, that such

PHFFU be removed from rate base until it is placed into service. Applying this recommendation in the current rate case does not result in any PHFFU being removed from rate base. Staff also proposes that gains (or losses) on disposition of PHFFU be shared between customers and investors, as described below.

Gain Sharing on Land Sales

Q. HAS THE COMPANY MADE A RECOMMENDATION FOR SHARING OF GAINS ON THE SALE OF LAND THAT WAS IN PLANT HELD FOR FUTURE USE?

A. Yes. At pages 49-50 of their direct testimony, the Poroach/Adams/Robinson panel recommends that any net gains or losses on disposition of utility land, including land held in PHFFU, be shared 20% with customers with the remaining 80% to be retained by the Company.

Q. IS STAFF MAKING A RECOMMENDATION ON THE SHARING OF GAINS OR LOSSES ON THE DISPOSITION OF LAND THAT WAS IN PLANT HELD FOR FUTURE USE?

A. Yes. Staff's proposal is discussed in additional detail under Section XIII of our testimony concerning rate plan principles. Staff's proposal is that gains (or losses) on the sale of land that was in PHFFU be shared with ratepayers based on the proportion of the time that the land in PHFFU was included in rate base to the total time the land was held by the Company, subject to a maximum ratepayer sharing of 80%.

1 As an example, if land were included in rate base as PHFFU for 15 years and the
2 Company held it for 15 years and sold it in year 15, ratepayers would get 80% of the gain
3 and the Company would get 20%. (15 of 15 years = 100%, subject to the 80% maximum
4 on ratepayer sharing.)

5
6 As another illustrative example, if land were included in rate base as PHFFU for 10 years
7 and the Company held it for 15 years and sold it in year 15, ratepayers would get 67% of
8 the gain and the Company would get 33%. (10 of 15 years = 67%.)
9

10 **Q. WHY DOES STAFF RECOMMEND THAT THE CUSTOMER SHARING ON**
11 **THE GAINS AND LOSSES FROM THE SALE OF LAND BE LIMITED TO 80%?**

12 A. Allowing the Company to retain 20% should provide incentives to the Company to obtain
13 the best price when selling land, and also to incent the Company to sell land that is not
14 needed within a reasonable period (e.g., within 15 years) for use in providing utility
15 service.
16

17 **Stewart County "Future Nuclear" Site Investigation Cost**

18 **Q. HAS THE COMPANY REQUESTED RECOVERY FROM RATEPAYERS FOR**
19 **SPENDING ON SITE INVESTIGATION COST FOR "FUTURE NUCLEAR"?**

20 A. Yes. In the current rate case, the Company has included these costs in rate and is
21 requesting recovery over a three-year amortization period of the retail jurisdictional
22 portion of the approximately \$49 million that it spent on investigating the Stewart County
23 site for a future nuclear generating unit. The Company's rate base reflects this request on

1 a line labeled as "Future Nuclear" and "Future Nuclear Regulatory Asset" and on its
2 statement of earnings as "Amortization of Future Nuclear." The Company recorded
3 approximately \$49 million in costs to evaluate the Stewart County site for potential new
4 nuclear units. Details about this were presented with the Company's 2019 IRP filing. As
5 shown on page G-130 of the Company's 2019 IRP, amounts of \$5.5 million for Southern
6 Nuclear Operating Company and \$43.252 million for Georgia Power were spent through
7 2018, totaling approximately \$49 million, prior to ceasing such activities and putting the
8 Stewart County site into a "preserved" state pursuant to a Commission Order¹⁷ which
9 stated that "the Company shall not recommence the Stewart County Site Investigation or
10 incur additional related costs beyond the cost necessary to close out and preserve the
11 work performed to date without prior Commission approval."

12 **Q. HAS STAFF MADE ANY ADJUSTMENT TO REMOVE THAT "FUTURE**
13 **NUCLEAR" COST FROM RATE BASE OR TO REMOVE THE**
14 **AMORTIZATION FROM OPERATING EXPENSES?**

15 A. No. For purposes of this rate case, Staff has left the Company's proposed amounts in rate
16 base and as amortization expense, without adjustment.

17 **Q. WHAT HAS STAFF OBSERVED TO DATE CONCERNING THE COMPANY'S**
18 **2018 EARNINGS?**

19 A. Staff has observed that the Company's amended 2018 ASR report shows approximately
20 \$153 million of over-earnings (i.e., earnings above 12.0%, the top end of the earnings
21 band in the current alternative rate plan), of which two-thirds, or approximately \$102
22 million have been designated for customer refunds and approximately \$51 million to be

¹⁷ Order dated March 7, 2017 in Docket No. 40161, at page 3.

1 retained by the Company. Staff is continuing its review of the Company's amended 2018
2 ASR filing and the final amounts of over-earnings may be different after Staff's analysis
3 than what the Company has shown. The existence of the approximately \$153 million of
4 over-earnings in 2018, however, suggests that there may be options available to the
5 Commission if it wants to have the Company's "Future Nuclear" cost item removed from
6 the revenue requirement to be established in the current case that ratepayers would be
7 paying starting January 1, 2020. Three options that present themselves from the 2018
8 ASR over-earnings are:

- 9 • One, recovering the "Future Nuclear" cost from the total 2018 over-earnings
10 amount of approximately \$153 million.
- 11 • Two, recovering the "Future Nuclear" cost only from the ratepayers' two-third
12 share (approximately \$102 million) of the 2018 over-earnings amount.
- 13 • Three, applying the Company's one-third share of the 2018 over-earnings amount
14 for recovery of the "Future Nuclear" cost.

15 If the Commission wants to explore ways in which the Company could be allowed to
16 recover the "Future Nuclear" cost in a manner that would remove it from the prospective
17 revenue requirement in the current rate case, and would terminate the period during
18 which ratepayers are paying the Company a return on those costs, including a shareholder
19 profit on that amount, Staff recommends that the Commission consider approving one of
20 the options identified above.

21 22 **Production Tax Credits**

23 **Q. DID THE COMPANY HAVE PRODUCTION TAX CREDITS IN 2018?**

1 A. Yes. The Company's response to STF-L&A-1-125 indicates that the Company had
2 \$40,534 of Production Tax Credits ("PTCs") related to hydro generation in 2018. The
3 Company's response to STF-L&A-1-127 indicates that the Company had renewable
4 PTCs in a carry-forward position at December 31, 2017 and 2018 of \$703,569 and
5 \$744,193, respectively.
6

7 **Q. DOES THE COMPANY FORECAST PRODUCTION TAX CREDITS?**

8 A. The Company's response to STF-L&A-13-4 indicates that the Company did not forecast
9 any hydro PTCs for the test year, or for 2020, 2021 or 2022. That response also indicates
10 that the \$40,534 hydro PTC amount in 2018 was for 3,378 MWhs of hydro generation,
11 and that the Company anticipates about [BEGIN CONFIDENTIAL] [REDACTED] [END
12 CONFIDENTIAL] of hydro generation in 2019 and had 651 MWhs of hydro generation
13 from January through June 2019. Moreover, the response to STF-L&A-13-4(f) indicates
14 that the Company does not anticipate utilizing any of the hydro PTCs that were in a
15 carry-forward position at December 31, 2018 during the rate case period.
16

17 **Q. DOES THE COMPANY ANTICIPATE PTC'S FROM VOGTLE UNITS 3 AND 4?**

18 A. Yes. The Company's response to STF-L&A-1-126 indicates that it projects receiving
19 PTCs for Vogtle Units 3 and 4 of \$6.5 million and \$70.4 million in 2021 and 2022,
20 respectively. However, that response also indicates that the in-service costs of Vogtle
21 Units 3 and 4, including the PTCs, are excluded from the Company's filing, and the
22 Company does not project to receive any other PTCs for the projected years.
23

1 **Q. HAS STAFF MADE AN ADJUSTMENT TO REFLECT PTC'S IN THE TEST**
2 **YEAR OR PLAN YEARS?**

3 A. No. The amount of hydro PTCs in 2018 was fairly small and the Company's responses to
4 discovery indicate that significantly less is expected in 2019. While an adjustment could
5 potentially be made to reflect some amount of hydro PTCs in the test year and plan years,
6 it appears that the amount would be de minimus, so Staff has not made an adjustment.

7
8 As noted in the Company's response to STF-L&A-1-26, PTCs related to Vogtle Units 3
9 and 4 are expected to be very significant -- the Company projects \$70.4 million for 2022,
10 and will need to be factored in when costs for Vogtle Units 3 and 4 are reflected in base
11 rates, i.e., if the projected in-service dates of November 2021 and November 2022 hold
12 up, likely in the Company's next base rate case. However, in the context of the current
13 rate case, the in-service costs of Vogtle Units 3 and 4 have been excluded. Staff is
14 therefore not proposing an adjustment to reflect PTCs from Vogtle Units 3 and 4 in the
15 2021 or 2022 plan years for purposes of computing the Company's base rate revenue
16 requirement in the current case.

17
18 **F-1, Depreciation Expense and Accumulated Depreciation - Depreciation Rates -**

19 **Q. DID STAFF CALCULATE AN ADJUSTMENT FOR THE COMPANY'S**
20 **PROPOSED TRADITIONAL TEST YEAR DEPRECIATION EXPENSES TO**
21 **REFLECT RECOMMENDATIONS FOR STEAM GENERATION**
22 **PRODUCTION DEPRECIATION RATES PROVIDED TO YOU BY A STAFF**
23 **CONSULTANT?**

1 A. Yes. As shown on Staff Exhibit__(RS/RT-2), Schedule F-1, Georgia Power's proposed
2 traditional test year depreciation expenses would be reduced by approximately \$100.707
3 million if the depreciation rates for certain steam generating plants were kept at their
4 current useful lives, rather than being shortened, as the Company has proposed. The
5 lower rates for production plant associated within maintaining the current useful lives
6 would reduces depreciation expense under the proposed Alternative Rate Plan by
7 \$102.346 million, \$103.716 million and \$104.889 million for 2020, 2021 and 2022,
8 respectively. Details are shown on Exhibit__(RS/RT-2), Schedule F-1.

9
10 **Q. HAVE YOU CALCULATED THE NET RETAIL RATE BASE IMPACT OF**
11 **THOSE ADJUSTMENTS TO DEPRECIATION EXPENSE?**

12 A. Yes. As shown on line 15 of Exhibit__(RS/RT-2), Schedule F-1, the depreciation
13 expense adjustment would decrease the Company's traditional average retail net
14 accumulated depreciation by approximately \$50.819 million for the test year, and by
15 \$51.625 million, \$155.612 million and \$260.850 million in the 2020, 2021 and 2022 plan
16 years, respectively.

17
18 **F-2, Accumulated Deferred Income Taxes - Impact of Depreciation Rates**

19 **Q. PLEASE EXPLAIN THE ADJUSTMENT TO ACCUMULATED DEFERRED**
20 **INCOME TAXES TO REFLECT THE IMPACT OF DEPRECIATION RATES.**

21 A. Exhibit __(RS/RT-2), Schedule F-2, shows the calculation of an adjustment ADIT related
22 to what would be the impact on depreciation rates if the Company's proposed useful lives

1 for selected steam generating plants were continued at their current lives, rather than
2 having their lives shortened as proposed by the Company in this rate case.

3
4 **Q. DID STAFF ADJUST THE TEST YEAR OR PLAN YEAR REVENUE**
5 **REQUIREMENTS FOR THE ADJUSTMENTS TO DEPRECIATION EXPENSE,**
6 **ACCUMULATED DEPRECIATION, OR RELATED ADIT, THAT ARE SHOWN**
7 **ON EXHIBIT __ (RS/RT-2), SCHEDULES F-1 AND F-2?**

8 A. No. Staff did not adjust the test year or plan year revenue requirements for the
9 adjustments to depreciation expense, accumulated depreciation, or related ADIT, that are
10 shown on Exhibit __ (RS/RT-2), Schedules F-1 and F-2. Given current market conditions
11 slightly decreasing coal-fired steam generating plant lives appears reasonable and the
12 resulting increase in depreciation expense provides additional cash flow to support the
13 Company's credit metrics. For these reasons Staff adopted the Company depreciation
14 expense for steam generating plant. However, adoption of the Company's revised
15 depreciation rates in this proceeding does not constitute agreement by Staff of the
16 Company's methods or underlying assumptions in this proceeding or a future proceeding.
17 Staff reserves the right to take a different position concerning depreciation rates in future
18 proceedings.

**XI. AFFILIATE CHARGES TO GEORGIA POWER COMPANY AND GEORGIA
POWER COMPANY CHARGES TO AFFILIATES**

**Overview of Affiliate Charges from Southern Company Services and Southern Nuclear
Operating Company to Georgia Power Company**

**Q. PLEASE DESCRIBE THE COSTS THAT GEORGIA POWER INCURS
INDIRECTLY THROUGH CHARGES FROM SOUTHERN COMPANY
SERVICES AND SOUTHERN NUCLEAR OPERATING COMPANY.**

A. In addition to the charges that it incurs directly, Georgia Power incurs costs from two affiliated centralized service companies, SCS and SNC. These two affiliates provide management and technical services to both regulated and non-regulated Southern Company affiliates. These two affiliates charge Georgia Power and the other Southern Company affiliates directly for services provided specifically to each affiliate and then allocate the remaining indirect costs incurred each year to all appropriate affiliates on the basis of various allocation factors.

The SCS cost and allocation methodologies are detailed in the SCS Cost Control and Accountability Manual ("SCS CAM"), which is revised each year to reflect more recent data and changes in the Southern Company affiliate chart. The Company has designated the SCS CAM as Trade Secret information.

The SNC cost and allocation methodologies are detailed in the SNC Classification of Accounts Manual ("SNC CAM"), which is also revised each year to reflect more recent

1 data and any other accounting or allocation changes. The Company does not consider the
2 SNC CAM to be trade secret information.

3
4 **Southern Company Services Charges to Georgia Power Company**

5 **Q. PLEASE DESCRIBE THE SCS COST ALLOCATION METHODOLOGIES.**

6 A. SCS provides services to numerous Southern Company affiliates pursuant to Service
7 Agreement contracts entered into between SCS and each of those affiliates, including
8 Georgia Power. The SCS Service Agreement with Georgia Power states that SCS will
9 provide to Georgia Power the following services at direct or allocated cost: general and
10 design engineering, purchasing, accounting and statistical analysis, finance and treasury,
11 tax, information resources, marketing, auditing, insurance and pension administration,
12 human resources, systems and procedures, and other services with respect to business and
13 operations and power pool operations.

14
15 The costs incurred by SCS are tracked through work orders. Work orders are unique
16 accounts in which the costs for various SCS work activities are collected. The costs then
17 are charged from these work orders to the Southern Company affiliates that use those
18 specific services or cause those costs to be incurred by SCS. For those costs that are not
19 directly charged to the various affiliates for services provided specifically to an affiliate
20 or affiliates, SCS applies an allocation factor to each work order. These factors are used
21 to allocate the SCS work order costs to each affiliate that caused the costs to be incurred.
22 For calendar year 2018, SCS used 20 basic allocation factors to charge costs to the
23 various affiliates. We have attached a description of these allocation factors provided by

SCS in its Form 60 public filing with the Federal Energy Regulatory Commission (“FERC”) as our Exhibit__ (RS/RT-23). We do not propose any adjustments for the allocation factors selected and applied by SCS as I will discuss below.

Q. DOES SCS REPORT THE COSTS THAT IT CHARGES TO EACH OF THE OTHER SOUTHERN COMPANY AFFILIATES?

A. Yes. SCS files a Form 60 with the FERC each year, which details the costs that it incurred and the amounts that it charged to the other Southern Company affiliates. SCS reported in its 2018 Form 60 at page 307 that it incurred and billed \$1.977 billion in costs. SCS charged Georgia Power \$652.8 million of those costs, or 33.02 percent of the total incurred by SCS:

Description	Amount	Reference
SCS Total Amount Billed in 2018	\$ 1,976,700,465	(1)
Billed to Georgia Power Company	\$ 652,752,558	(1)
Percentage of Total SCS Billed to Georgia Power Company	33.02%	
(1) SCS FERC Form 60 for year 2018, page 307		

Georgia Power charged the \$652.8 million to various capital and expense accounts.

SCS Allocation Factors Using 2019 Statistics

Q. HOW DID THE SCS POPULATE THE ALLOCATION FACTORS IN THE YEARS PRIOR TO 2017?

A. In the years prior to 2017, for Fixed Percentage Allocations, SCS used statistics that were based on a single year with a one-year lag. For example, in Georgia Power's 2013 rate case in Docket No. 36989, the 2014 SCS allocations in the Company's projected test year in that prior rate case were based on 2012 statistics, thus the charges included in the

1 Company's expenses were based on outdated data. As a result, it was necessary to make
2 an adjustment to the SCS allocation factors using more recent data.

3
4 **Q. DOES SCS STILL USE STATISTICS BASED ON A SINGLE YEAR WITH A**
5 **ONE-YEAR LAG IN DETERMING ITS ALLOCATION FACTORS?**

6 A. No. As explained in the SCS FERC Form 60 for 2018 at page 402.1, SCS uses statistics
7 based on previous year statistics. For example, the SCS allocations in 2018 were based
8 on 2017 statistics.¹⁸ In the Company's response to STF-L&A-1-116, which asked
9 whether SCS has updated any of its allocation factors for use in 2019, the Company
10 provided supporting calculations for each SCS allocation factor as of January 1, 2019. In
11 Attachment SCS-L&A-1-116, the data on which the SCS allocation factors for January 1,
12 2019 was calculated was based on 2018 statistics.¹⁹

13
14 **Q. DID THE COMPANY CONFIRM THAT THE ACTUAL SCS CHARGES TO**
15 **GEORGIA POWER AS OF JANUARY 1, 2019 WERE BASED ON**
16 **ALLOCATION FACTORS POPULATED WITH 2018 DATA?**

17 A. Yes. Specifically, at the hearing that was held at the Commission on September 30,
18 2019, Company witness Adams confirmed that this was the case. (Tr. 300). Therefore,
19 actual SCS charges to Georgia Power starting January 1, 2020 will be based on allocation
20 factors populated with 2019 data. As a result of SCS now using prior year statistics in

¹⁸ Similarly, the SCS FERC Form 60 for 2017 states on page 402.1 that the 2017 allocations were based on 2016 statistics.

¹⁹ The Excel file attachment to the response to STF-L&A-1-115 provided supporting calculations for each SCS allocation factor as of January 1, 2018, which was based on 2017 statistics.

determining its allocation factors, it is not necessary to make an adjustment such as the one that Staff had recommended in the 2013 rate case in Docket No. 36989.

Q. HAS THERE BEEN ANY IMPACT ON THE SCS ALLOCATION FACTORS RELATED TO THE SALE OF GULF POWER COMPANY TO NEXTERA ENERGY?

A. No. According to the response to STF-L&A-1-117, NextEra Energy ("NextEra") will replace Gulf Power Company ("Gulf Power") with regard to the allocation criteria related to the services provided and will receive charges and allocations from SCS in the same manner that Gulf Power Company did prior to the sale to NextEra.

Q. ARE THERE ANY SERVICES THAT SCS WILL NOT BE PROVIDING TO NEXTERA?

A. Yes. In its response to STF-L&A-1-117, the Company stated that SCS will not provide the following services to NextEra: (1) insurance; (2) human resources; (3) treasury; (4) banking; (5) system air; (6) legal counsel; (7) financial planning; (8) executive; (9) external affairs; (10) and systems integration. Therefore, NextEra will be excluded from the allocation detail for the charges associated with these services. In addition, the Company stated that the total SCS budget was reduced for the expected impact of the sale of Gulf Power, but that this reduction applied to total SCS charges and not isolated to the services noted above that were excluded from NextEra.

1 **Q. WAS THE COMPANY ABLE TO QUANTIFY THE IMPACT ON THE SCS**
2 **CHARGES TO GEORGIA POWER IN THE TEST YEAR OR PLAN YEARS**
3 **2020-2022 AS IT RELATES TO THE SALE OF GULF POWER?**

4 A. No. According to the response to STF-L&A-1-117, the Company stated that due to the
5 multiple changes in allocation factors, including those not impacted by the sale of Gulf
6 Power, including cost reduction efforts, updated allocation criteria, changes in cost
7 centers, and adjustments for the TSA as well as NextEra's discontinued services, it was
8 not possible to quantify the impact of the Gulf Power sale as it relates to the SCS charges
9 to Georgia Power.

10
11 **Q. DID YOU REVIEW THE SCS CHARGES TO GEORGIA POWER TO ENSURE**
12 **THAT NO LOBBYING EXPENSE, CHARITABLE CONTRIBUTIONS OR**
13 **OTHER BELOW-THE-LINE AMOUNTS WERE INCLUDED IN TEST YEAR**
14 **EXPENSES?**

15 A. Yes. We confirmed through discovery that SCS identifies all such charges and that
16 Georgia Power did not include these below-the-line amounts in test year expenses.

17
18 **Q. DID YOU REVIEW THE SCS CHARGES TO GEORGIA POWER FOR**
19 **CERTAIN INCENTIVE COMPENSATION COSTS?**

20 A. Yes. We address this issue in another section of our testimony. It is not limited to the
21 SCS charges to Georgia Power, and also includes similar costs incurred directly by
22 Georgia Power, and incentive compensation costs charged to Georgia Power Company
23 from Southern Nuclear Operating Company.

Southern Nuclear Company Charges to Georgia Power Company

Q. PLEASE DESCRIBE THE SNOC COST ALLOCATION METHODOLOGIES.

A. SNOC provides services to both Georgia Power and Alabama Power Company in support of the Hatch, Vogtle and Farley nuclear generating facilities in Georgia and Alabama. The Service Agreement between SNOC and Georgia Power states that SNOC will provide the following nuclear-related services to Georgia Power at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations.

Similar to SCS, SNOC collects the costs it incurs in numerous work orders. For many of the work orders, the costs are charged directly to the individual generating facilities because the SNOC activities are performed specifically for certain facilities. The remaining costs are charged two-thirds to Georgia Power and one-third to Alabama Power based on the number of plant sites (see additional discussion below). SNOC has other allocation factors available, but uses the number of plant sites for administrative simplicity.

Q. DOES SNOC HAVE ANY SUBSIDIARIES?

A. Yes. On February 23, 2006, SNOC organized a wholly-owned subsidiary, Southern Nuclear Development, LLC ("SND"), to manage Southern's new nuclear generation

1 development activities. On July 1, 2006, SNOC organized Southern Nuclear Services,
2 LLC (“SNS”), a wholly-owned subsidiary. SNS assumed a contract with Pooled
3 Equipment Inventory Company (“PEICo”) from Southern Management Development,
4 Inc., an affiliated company. The contract provides for SNS to receive a fixed monthly fee
5 from PEICo in exchange for providing the following services: project management;
6 quality assurance; storage, maintenance, and insurance; and administration.
7

8 **Q. ARE SOME OF SNOC’S COSTS ALLOCATED TO THOSE SUBSIDIARIES?**

9 A. Yes.
10

11 **Q. DOES SNOC ALSO REPORT THE COSTS THAT IT CHARGES TO GEORGIA**
12 **POWER AND ALABAMA POWER?**

13 A. Yes. SNOC also files a Form 60 with the FERC each year, which details the costs that it
14 incurred and the amounts that it charged to Georgia Power and Alabama Power and other
15 affiliates such as SCS, and the SNOC subsidiaries, SND and SNS. SNOC reported in its
16 2018 Form 60 at page 307 that it incurred \$1.035 billion in costs. SNOC charged
17 Georgia Power \$780.2 million of those costs, consisting of both capital and expense
18 amounts.
19

20 **Q. HOW DOES SNOC ALLOCATE COSTS?**

21 A. As described on page 402.1 of SNOC’s 2018 FERC Form 60, for SNOC corporate
22 departments and functional areas benefitting all operating plants, the SNOC costs are
23 allocated using a Plant Basis Method, which is determined by dividing one plant by the

1 total number of plants. The use of the number of plant sites allocation factor generally
2 benefits Georgia Power through lower charges compared to alternative allocation factors
3 that are available and could have been used.
4

5 **Q. BASED ON SNOC CHARGES BEING ALLOCATED USING THE PLANT BASIS**
6 **METHOD, DOES GEORGIA POWER CURRENTLY RECEIVE A 2/3RDS**
7 **ALLOCATION OF SNOC CHARGES BASED ON HAVING FOUR OF THE SIX**
8 **OPERATING NUCLEAR UNITS?**

9 A. Yes. As noted above, SNOC provides services to both Georgia Power and Alabama
10 Power Company. Georgia Power owns Hatch Units 1 and 2 and Vogtle Units 1 and 2
11 whereas Alabama Power Company owns Farley Units 1 and 2. As a result, since Georgia
12 Power owns four of the six nuclear units currently operating, it receives a 2/3rds share of
13 the SNOC allocated costs.
14

15 **Q. HAS THE COMPANY INDICATED WHEN IT EXPECTS VOGTLE UNITS 3**
16 **AND 4 TO ACHIEVE COMMERCIAL OPERATION?**

17 A. Yes. In its response to STF-L&A-1-122, the Company stated that the Commission
18 approved November 2021 as the target in-service date for Vogtle Unit 3 and November
19 2022 as the target in-service date for Vogtle Unit 4.
20

21 **Q. WILL THE SNOC PLANT BASIS ALLOCATION FACTOR BE UPDATED**
22 **WHEN VOGTLE UNITS 3 AND 4 ACHIEVE COMMERCIAL OPERATION?**

A. Yes. According to the response to STF-L&A-1-122, upon Vogtle Unit 3 achieving commercial operation, Georgia Power will begin receiving a 5/7ths allocation from SNOC on December 1, 2021. In addition, upon Vogtle Unit 4 achieving commercial operation, Georgia Power will begin receiving a 6/8ths (or 3/4ths) allocation from SNOC on December 1, 2022.

Q. HAS THE COMPANY QUANTIFIED THE IMPACT ON FORECASTED CALENDAR YEARS 2021 AND 2022 FROM THE CHANGES IN THE SNOC PLANT BASIS ALLOCATION FACTOR?

A. Yes. In its response to STF-L&A-1-122, the Company provided the amounts shown in the table below:

GPC Impact 100% Dollars		
Unit	2021	2022
Hatch 1&2	\$ (705,549)	\$ (9,353,657)
Vogtle 1&2	\$ (705,549)	\$ (9,353,657)
Vogtle 3	\$ 2,116,646	\$ 26,092,519
Vogtle 4	\$ -	\$ 1,968,453
Total	\$ 705,549	\$ 9,353,658
Source: STF-L&A-1-122		

As shown in the table above, there is an additional SNOC cost allocation in GPC Impact 100% dollars to Georgia Power of \$705,549 in 2021 and \$9,353,658 in 2022 as a result of the change in the plant basis allocation factor when Vogtle Units 3 and 4 are placed into commercial operation. The Company stated that while the amounts noted above reflect the expected impact to the SNOC allocation of costs to Georgia Power upon Vogtle Units 3 and 4 going into service, the costs related to Vogtle Units 3 and 4 have been excluded from the Company's filing in this proceeding.

1 **Q. WHAT DOES THE "GPC IMPACT 100% DOLLARS" DESIGNATION MEAN?**

2 A. According to the response to STF-L&A-13-3, the Company stated that the "GPC Impact
3 100% Dollars" designation represents the full costs allocated to Georgia Power from
4 SNOC prior to any reductions to the allocated costs for billings to joint owners. As
5 shown in Attachment STF-L&A-13-3, page 1, the Georgia Power percentage of the
6 \$2,116,646 shown in 100% dollars in the table above for Vogtle Unit 3 in 2021 is
7 \$974,872. Of this amount, \$960,940 has been excluded from O&M expense and taxes
8 other than income in the Company's filing while the remaining \$13,932 is reflected
9 below-the-line in FERC account 426.

10 In addition, as shown in Attachment STF-L&A-13-3, page 2, the Georgia Power
11 percentage of the \$26,092,519 shown in 100% dollars in the table above for Vogtle Unit
12 3 in 2022 is \$12,005,991. Of this amount, \$11,855,500 has been excluded from O&M
13 expense and taxes other than income in the Company's filing while the remaining
14 \$150,491 is reflected below-the-line in FERC account 426.

15 For Vogtle Unit 4 in 2022, the Georgia Power percentage of the \$1,968,453
16 shown in 100% dollars in the table above for Vogtle Unit 4 in 2022 is \$906,691. Of this
17 amount, \$893,597 has been excluded from O&M expense and taxes other than income in
18 the Company's filing while the remaining \$13,094 is reflected below-the-line in FERC
19 account 426.

20
21 **Q. IN THE EVENT THAT THERE IS A DELAY IN VOGTLE UNITS 3 AND 4**
22 **ACHIEVING COMMERCIAL OPERATION IN NOVEMBER 2021 AND**
23 **NOVEMBER 2022, RESPECTIVELY, HAS THE COMPANY STATED THAT**

1 **THE PLANT BASED ALLOCATION FACTORS WILL NOT CHANGE AS A**
2 **RESULT OF ANY SUCH DELAY?**

3 A. Yes. Specifically, during the hearing at the Commission on September 30, 2019,
4 Company witness Poroach, responding in the context of the response to STF-L&A-1-122,
5 from which the numbers shown in the table above were provided, stated the following:

6 "...I believe the intent of this discovery request was to look at the costs that
7 are projected to be incurred by the fleet to run those units. So those units --
8 or those costs get incurred when the units reach operation. And we're
9 changing the allocation methodologies based on the units that are incurred.
10 So I think this was a forecast and illustrative example based on our
11 budgets. **But to the extent that the units are not online at that time,**
12 **those fleet costs would not be incurred so the allocation methodology**
13 **wouldn't change.**" (Tr. 297)

14 (Emphasis supplied)

15
16 **Q. DID YOU REVIEW THE SNOC CHARGES TO GEORGIA POWER FOR THE**
17 **TEST YEAR?**

18 A. Yes. The only problem identified with the SNOC charges included in the test year was
19 the stock-based incentive compensation expense. We address the stock-based incentive
20 compensation expense in another section of our testimony.

21 **Georgia Power Company Charges to Other Affiliates**

22 **Q. PLEASE DESCRIBE THE SERVICES PROVIDED BY THE COMPANY TO**
23 **OTHER SOUTHERN COMPANY AFFILIATES.**

24 A. Georgia Power operates and maintains the generating facilities that are owned by
25 Southern Power Company ("Southern Power") and physically located in Georgia. These
26 Southern Power generating facilities are located at Plants Dahlberg, Franklin and
27 Wansley.

1
2 **Q. PLEASE DESCRIBE THE METHODOLOGY EMPLOYED BY GEORGIA**
3 **POWER TO DETERMINE THE COSTS OR PRICES CHARGED TO OTHER**
4 **SOUTHERN COMPANY AFFILIATES FOR THE SERVICES IT PROVIDES.**

5 A. The Company generally charges the cost it incurs to provide the services to the other
6 affiliates, although certain of its service agreement contracts with the other affiliates
7 include a test of that cost against market to guard against subsidization of its non-
8 regulated affiliates. For example, the Company's service agreement with Southern
9 Power states that: "As compensation for such services or the market value thereof,
10 whichever is higher."

11
12 Although the methodology for quantifying cost is not defined in the Company's Service
13 Agreement contracts with the other affiliates, I have reviewed the methodology used by
14 the Company for charges to the other affiliates. The Company determines its "cost" on a
15 comprehensive basis. Cost includes the direct costs to provide the services, including a
16 return of and on all investment costs, and indirect costs, including labor payroll taxes,
17 benefits, and other corporate overheads. The overheads include an allocation of
18 administration and general expenses, which in turn include amounts initially charged to
19 Georgia Power by SCS.
20

21 **Georgia Power Company Charges to Southern Power**

22 **Q. DID YOU REVIEW THE COMPANY'S PROCEDURES FOR CHARGING**
23 **COSTS TO SOUTHERN POWER COMPANY?**

1 A. Yes. The previous agreement between Georgia Power and Southern Power was
2 terminated in August 2007, and replaced with a new service contract. Under the service
3 contract, the Company provides and bills Southern Power for specifically requested
4 services.

5
6 The Georgia Power General Accounting Procedure (“GAP”) 58, which describes
7 accounting for work performed by Georgia Power Company on behalf of other
8 companies, was provided in response to STF-L&A-11-1.²⁰ The methodology used by
9 Georgia Power to charge Southern Power appears to be comprehensive and includes
10 Georgia Power overheads, both those incurred directly by Georgia Power and those
11 incurred indirectly through charges to Georgia Power from SCS.

12
13 GAP 58 at pages 1 and 2 states in part that:

14 Upon request, the Company may provide services to associated companies
15 within Southern Company. Reference “Requesting Services” for the types
16 of services provided. The associated companies are Southern Company
17 Services, Alabama, Gulf²¹ and Mississippi Power Companies, Southern
18 Telecom, Southern Company Management Development, SouthernLINC
19 Wireless, Southern Power, and Southern Nuclear. With the acquisition of
20 Southern Company Gas, the associated companies now also include GAS
21 and its subsidiaries.

22 The Company may also provide resources and employees to companies
23 not part of The Southern Company (non-associated companies). This
24 includes any government agencies, other utilities, industrial businesses,
25 etc.

26 Company policies and guidelines documented in this procedure apply to
27 associated operating companies and non-associated companies. When a

²⁰ A copy of this response is included in Exhibit RS/RT-33.

²¹ Gulf Power Company was sold to NextEra Energy on January 1, 2019.

1 particular process varies between the companies, GAP 58 will be the
2 authority.

3
4 GAP 58 at page 4 states that:

5 In accordance with Georgia Public Service Commission (GPSC)
6 guidelines, Docket No. 9355-U, the Company may provide services,
7 properties and resources to associated companies on an actual cost basis
8 (which includes a provision for applicable overheads).

9 These services to associated companies, excluding SPC, include but are
10 not limited to: website design, sale of materials associated with a service,
11 printing, communication materials, fleet operations, calibration, substation
12 outages, equipment repair, intercompany awards, training activities, etc.

13 Per the Services Agreement between SPC and GPC dated August 1, 2007,
14 services available to SPC include labor, environmental, general
15 construction and advisory, property accounting and other services
16 requested by SPC.

17 For non-associated companies, services available and the cost of those
18 services are in accordance with the contract price & terms.

19 When specifically requested, the Company may also loan employees to
20 other companies. These employees will be under the sole supervision and
21 control of that company until the assigned work is completed.

22
23 GAP 58 at page 5 describes the billing for such services as follows:

24 Under a cost plus basis:

- 25 • The requesting company pays the amount based on actual charges
26 to the job, which may be more or less than the original estimate.
27 For Southern Company Gas, if costs exceed the original estimate
28 by more than 120%, written approval must be obtained from GAS
29 for the extra costs.
- 30 • Construction services for non-associated companies are billed
31 under this method.

32 Under contract price billing:

- 33 • The requesting company pays the estimated amount, regardless of
34 the actual cost.
- 35 • Non-construction services for non-associated companies are billed
36 under this method.

1 The Company has indicated that it is following the above-described guidance; however,
2 this was not reviewed in detail concerning budgeted amounts for the projected test year or
3 rate year costs.

4

XII. TAX CUTS AND JOBS ACT OF 2017

Q. PLEASE DESCRIBE SOME OF THE MAJOR IMPACTS OF THE TCJA ON PUBLIC UTILITIES SUCH AS GEORGIA POWER COMPANY.

A. The major impacts of the TCJA on Georgia Power company include the following:

- The reduction in the corporate federal income tax rate will reduce the Company's income tax expense, which will reduce its cost of service and revenue requirements;
- Excess Accumulated Deferred Income Taxes ("EADIT") result from the revaluation of the Accumulated Deferred Income Tax ("ADIT") balances as of December 31, 2017. The EADIT calculation would transfer the excess tax amounts from the ADIT accounts to net regulatory liability accounts, the amounts of which would be returned to customers over time;
- Some of the EADIT is subject to normalization requirements (the "protected" portion) and some is not subject to normalization requirements (the "unprotected" portion). The "protected" EADIT must follow a specified amortization to company with the normalization requirements. The amortization of the "unprotected" EADIT is up to the discretion of the utility's regulator. For Georgia Power Company, the amortization of "unprotected" EADIT is up to the discretion of the Commission;
- Elimination of the Section 199 manufacturing deduction. This will not impact the Company's calculation of the revenue requirement in the current rate case because although the Company has been able to use this specialized deduction in some past years,²² it has not been able to take advantage of the Section 199 deduction in recent years, and it has not been reflected as an adjustment to income tax expense in recent years ASR reports since the Company did not qualify for the deduction on a separate return basis. In any event, the Section 199 deduction will no longer be available for tax years beyond 2017 because it has been eliminated by the TCJA;
- Elimination of bonus depreciation, as well as the lower corporate income tax rate, will decrease the rate of build-up of ADIT balances in the future compared to what it would have been before the TCJA;
- Retention of net interest expense deductibility. Interest expense will continue to be deductible for public utilities such as Georgia Power Company. The TCJA has limited interest deductibility for other types of businesses.

Q. HAS THE COMMISSION ISSUED AN ORDER CONCERNING THE TCJA FOR THE COMPANY?

²² A Section 199 deduction was reflected in the calculation of income tax expense in the Company's 2013 rate case, for example.

1 A. Yes. In its Administrative Session on April 3, 2018, the Commission adopted a Staff
2 recommendation concerning a settlement dated March 6, 2018 between the Company and
3 Staff concerning various issues related to the TCJA. The Commission issued an Order on
4 the TCJA in Docket No. 36989, Georgia Power Company's 2013 Rate Case, which
5 approved a settlement agreement between the Company and Staff addressing TCJA-
6 related treatments for income tax savings and protected and unprotected EADIT. A copy
7 that Order and the settlement are attached for ease of reference in Exhibit RS/RT-21.

8 Highlights of the settlement include:

- 9 • Refunds to customers of \$185 million in 2018 and \$145 million in 2019 for the
10 reduced federal income tax rate-related reductions in federal income taxes in 2018
11 and 2019.
- 12 • Customers will receive the entire benefit of the federal protected EADIT with no
13 sharing with the Company. The Company is deferring the entire amount as a
14 regulatory liability until the next rate case.
- 15 • Customers will receive the entire benefit of the federal unprotected EADIT with
16 no sharing with the Company. None of the unprotected EADIT will be amortized
17 until the Company's next rate case.
- 18 • Customers will receive the entire benefit of the state EADIT with no sharing from
19 the Company. None of the state EADIT will be amortized until the Company's
20 next rate case and the entire state EADIT will be retained as reduction to rate base
21 until the Company's next rate case.
- 22 • Starting in 2018 for ASR purposes only, the common equity in the rate of return
23 will be set at the lower of (a) actual common equity weighting in the capital

1 structure or (b) 55% until the next rate case. Notably, "[t]his provision is not
2 intended to set a precedent and the parties may take an alternative position in a
3 future proceeding."

4
5 For purposes of applying that Settlement, the Company's "next rate case" specified in the
6 settlement is the Company's current 2019 rate case.

7 **Q. DID THE COMPANY ADDRESS THE TCJA IMPACTS IN ITS DIRECT**
8 **TESTIMONY?**

9 A. Yes. The Poroach/Adams/Robinson panel addresses TCJA impacts at page 42-43 of their
10 direct testimony.

11 **Q. HOW HAS THE COMPANY REFLECTED THE IMPACTS OF THE TCJA IN**
12 **ITS RATE CASE?**

13 A. As described in the response to STF-L&A-1-119, the Company has followed the
14 guidance provided in the Commission's Order in Docket No. 36989 referenced above.
15 The Company re-measured its ADIT balance at December 31, 2017 to reflect the new
16 federal corporate income tax rate of 21% that became effective on January 1, 2018. The
17 Company classified its EADIT into protected and unprotected categories. The Company
18 is using the Average Rate Assumption Method ("ARAM") to amortize its protected
19 EADIT. The Company deferred the protected EADIT amortization occurring in 2018
20 and 2019 into a regulatory liability account. In addition, the Company deferred EADIT
21 and estimated savings related to state income taxes for 2019 based on the new state
22 income tax rate of 5.75% effective January 2019. As explained in the responses to STF-
23 L&A-1-107 and STF-L&A-1-119, the Company has proposed to amortize the regulatory

1 liabilities and the unprotected EADIT for the benefit of customers over the three-year
2 period, 2020 through 2022. In addition, the remaining protected EADIT related to the
3 use of accelerated federal income tax depreciation will continue to be amortized using the
4 ARAM, as required by normalization rules.

5 **Q. WHAT AMOUNT OF PROTECTED AND UNPROTECTED EADIT HAS THE**
6 **COMPANY IDENTIFIED?**

7 A. The Company's response to STF-L&A-1-106 identifies \$480.9 million of unprotected
8 EADIT at December 31, 2017 and \$2.558 billion protected EADIT. The total amount of
9 EADIT at December 31, 2017 is \$3.039 billion. That response also shows the EADIT
10 balances broken out between protected and unprotected as of December 31, 2018 and
11 June 30, 2019.

12 **Q. HOW DID THE COMPANY DETERMINE WHICH PORTIONS OF THE EADIT**
13 **WERE PROTECTED AND WHICH WERE UNPROTECTED?**

14 A. Details of the Company's EADIT classification between protected and unprotected are
15 shown in the Company's response to STF-L&A-1-119. Regulated public utilities such as
16 the Company are required to identify the portions of their ADIT balances that represent
17 "excess" ADIT (i.e., EADIT) based on recalculations using the difference between the
18 old federal income tax rate ("FIT") (typically 35%) under which the ADIT was
19 accumulated and the new federal corporate rate of 21%. Basically, utility ADIT must be
20 revalued at the new FIT rate.

21 All *non-property* related ADIT (accounts 190 and 283) for electric utilities such
22 as Georgia Power Company will be reduced. To ensure that these benefits are passed on

1 to customers, the Commission should require that the reduction be deferred in a net
2 regulatory liability.

3 *Property* related ADIT (account 282 for electric utilities) will also need to be
4 revalued at the new FIT rate. IRS normalization requirements will apply to the portion of
5 the property related ADIT that relates to the use of accelerated tax depreciation
6 (including federal bonus tax depreciation). Regulated public utilities like Georgia Power
7 (as do other business taxpayers) typically compute tax depreciation using the Modified
8 Accelerated Cost Recovery System ("MACRS"), which is the current tax depreciation
9 system in the United States. Under this system, the capitalized cost (basis) of tangible
10 property is depreciated for federal income tax purposes over a specified tax life by annual
11 deductions for depreciation. The differences between the use of accelerated tax
12 depreciation to produce depreciation deductions for federal income tax purposes and the
13 use of book depreciation (typically some form of straight-line depreciation) are accounted
14 for, and the tax impacts are accumulated as ADIT for accounting and ratemaking
15 purposes.

16 The EADIT related to the use of accelerated tax depreciation, specifically for the
17 method and life differences, will result in "protected" EADIT balances for at least a
18 portion of the utility's property related ADIT, e.g., the ADIT recorded in account 282.
19 That protected EADIT will be subject to normalization requirements which will govern
20 how it can be flowed back to ratepayers.

21 **Q. DOES THE TCJA PROVIDE FOR A SPECIFIC METHOD TO BE APPLIED TO**
22 **THE PROTECTED EADIT TO COMPLY WITH IRS NORMALIZATION**
23 **REQUIREMENTS?**

1 A. Yes. The TCJA specifically provides that the ARAM must be used for the protected
2 portion of ADIT, although an alternative method is permitted if adequate records are not
3 available to apply ARAM.

4
5 **Q. DOES THE COMPANY HAVE ADEQUATE RECORDS TO APPLY ARAM?**

6 A. Yes. As described in its response to STF-L&A-11-9, Georgia Power Company is using
7 the PowerTax software and has configured it to calculate ARAM. Because the Company
8 has adequate records to calculate ARAM for its protected EADIT, it is my understanding
9 that the requirements of the Internal Revenue Code as modified by the TCJA require that
10 Georgia Power apply ARAM for that protected EADIT.

11 **Q. PLEASE ELABORATE ON THE NORMALIZATION REQUIREMENT FOR**
12 **PROTECTED EADIT.**

13 A. As described above, the TCJA reduced the federal corporate income tax rate to a flat
14 21%. Public utilities such as Georgia Power are required, as a condition of using
15 MACRS (accelerated tax depreciation) to use normalization accounting under which
16 depreciation for ratemaking purposes does not reflect the accelerated depreciation under
17 MACRS. The normalization requirements address how the "excess" ADIT balances
18 related to the use of accelerated tax depreciation on utility property can be flowed back.
19 Generally, the flow-back of such "protected" EADIT balances must occur over the
20 remaining life of the related utility property.

21 Specifically, the TCJA provides that public utilities subject to the normalization
22 method of accounting are not treated as applying the normalization method for any public
23 utility property for purposes of Internal Revenue Code Sec. 167 or Code Sec. 168 if they

1 reduce their excess tax reserves resulting from the lower tax rate in computing their cost
2 of service for ratemaking purposes, and for purposes of reflecting operating results in
3 their regulated books of account, more rapidly or to a greater extent than the amount the
4 reserve would be reduced under ARAM. (TCJA § 13001(d)(1)). For this purpose, the
5 excess tax reserve is the reserve for deferred taxes, described in Code
6 Sec. 168(i)(9)(A)(ii) in effect on the day before the FIT rate reductions take effect
7 (TCJA §13001(d)(3)(A)(i)), minus the amount that would be the balance in the reserve if
8 the amount of the reserve were determined by assuming that the TCJA corporate rate
9 reductions were in effect for all prior periods. (TCJA §13001(d)(3)(A)(ii)).

10
11 **Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF ARAM THAT IS SPECIFIED**
12 **IN THE TCJA FOR COMPLIANCE WITH NORMALIZATION**
13 **REQUIREMENTS FOR THE PROTECTED EADIT.**

14 A. ARAM is the method under which the protected excess in the reserve for deferred taxes
15 is reduced over the remaining lives of the property as recorded in the utility's regulated
16 books of account. Under this method, if timing differences for the property reverse, the
17 amount of the adjustment to the reserve for the deferred taxes is calculated by multiplying
18 (1) the ratio of the aggregate deferred taxes for the property to the aggregate timing
19 differences for the property as of the beginning of the period in question by (2) the
20 amount of the timing differences that reverse during the period. (TCJA
21 § 13001(d)(3)(B)).

22 The reversal of timing differences generally occurs when the amount of the tax
23 depreciation taken on the asset is less than the amount of the regulatory (i.e., book)

1 depreciation taken on the asset. To ensure that the deferred tax reserve, including the
2 excess tax reserve, is reduced to zero at the end of the regulatory life of the asset that
3 generated the reserve, the amount of the timing difference which reverses during a tax
4 year is multiplied by the ratio of (1) the aggregate deferred taxes as of the beginning of
5 the period in question to (2) the aggregate timing differences for the property as of the
6 beginning of the period in question.

7 **Q. DO YOU AGREE WITH APPLYING AN ARAM-BASED AMORTIZATION TO**
8 **THE EADIT THAT IS PROPERLY CLASSIFIED AS PROTECTED?**

9 A. Yes. We agree with applying ARAM-based amortization to protected EADIT. Protected
10 EADIT is properly limited to tax depreciation method/life differences. Other plant-
11 related EADIT, such as basis differences, is not derived from tax depreciation method/life
12 differences and should therefore appropriately be classified as unprotected.

13 **Q. HOW HAS THE COMPANY CLASSIFIED EADIT RELATED TO REPAIRS**
14 **DEDUCTIONS?**

15 A. The Company's response to STF-L&A-13-6 indicates that the Company treats repairs
16 deductions as a basis difference for income tax purposes. Accordingly, all EADIT
17 related to claimed repairs deductions is treated as unprotected EADIT. This treatment is
18 shown on the "basis differences" component for account 282, which the Company
19 classified as unprotected EADIT.

20 **Q. HAS THE COMPANY PROVIDED DETAILS CONCERNING THE**
21 **REGULATORY LIABILITY AMOUNTS ASSOCIATED WITH THE TCJA?**

1 A. Yes. The Company's response to STF-L&A-1-20 provides monthly balances for the test
2 year ending July 31, 2020 for regulatory liabilities related to the TCJA, and related
3 amortization which the Company shows commencing in January 2020.

4 **Q. WERE ADDITIONAL EXPLANATIONS SOUGHT FROM THE COMPANY**
5 **CONCERNING ITS TREATMENT OF EADIT AND TCJA IMPACTS IN THE**
6 **RATE CASE?**

7 A. Yes. Additional information was sought from the Company on its treatment of TCJA
8 impacts and EADIT in the rate case, including in STF-L&A-11-9 and STF-L&A-13-6.
9 In response to STF-L&A-11-9 the Company provided additional details and explanations
10 related to protected and unprotected EADIT. In response to STF-L&A-13-6, the
11 Company indicated that it has treated EADIT related to repairs deductions as "basis
12 differences" which are included in the unprotected EADIT amounts in account 282. The
13 Company's response to STF-L&A-13-6(d) confirms the Company's agreement that
14 claimed repairs deductions are basis differences and the related EADIT should be treated
15 as unprotected.

16 **Q. ARE YOU SATISFIED THAT THE COMPANY HAS APPROPRIATELY**
17 **CLASSIFIED EADIT BETWEEN PROTECTED AND UNPROTECTED, AND IS**
18 **TREATING THE IMPACTS OF THE TCJA IN ACCORDANCE WITH THE**
19 **COMMISSION'S APPROVED SETTLEMENT BETWEEN STAFF AND THE**
20 **COMPANY IN THE COMMISSION'S ORDER IN DOCKET NO. 36989**
21 **CONCERNING THE TAX CUTS AND JOBS ACT?**

22 A. Yes. We agree with the Company's classification of EADIT between the protected and
23 unprotected categories. Additionally, based on our review of the Company's rate filing

1 information and responses to Staff discovery, we believe that the Company is treating the
2 TCJA impacts in accordance with the Commission-approved Settlement between Staff
3 and the Company in Docket No. 36989. This includes using the 21% federal corporate
4 income tax rate (and the 5.75% state income tax rate) to compute income taxes in the rate
5 case, as well as amortizing the TCJA-related regulatory liabilities and unprotected
6 EADIT for the benefit of customers over the three-year period, 2020 through 2022.
7

XIII. INCENTIVE COMPENSATION

Q. PLEASE IDENTIFY THE SOUTHERN COMPANY INCENTIVE

COMPENSATION PLANS, THE COSTS OF WHICH ARE INCLUDED IN THE COMPANY'S TEST YEAR EXPENSES.

A. Southern Company has one primary incentive compensation plan, the Southern Company Omnibus Incentive Compensation Plan, but three types of incentive compensation programs pursuant to that plan. These programs are the Performance Pay Program ("PPP"), and the Long-Term Incentive Program, which is comprised of Performance Shares Units ("PSU") and Restricted Stock Units ("RSU"). Georgia Power's response to STF-L&A-1-82(a)²³ provided the following descriptions of these plans:

Program Name	Description
Performance Pay Program	The Company's annual performance program rewards achievement of operational goals, earnings per share and GPC net income. A target percentage of base pay is established for each employee based on his/her classification and grade level for target-level performance. All employees except a small number of sales-commission employees are eligible to participate.
Long-Term Incentive Program	The Long-Term Incentive Program is a long-term, target-based, variable pay program for granting equity compensation awards that are paid in shares of common stock of Southern Company. The objective of the Long-Term Incentive Program is to promote strong long-term business results by rewarding continued employment and value drivers that distinguish our performance in the utility industry. Employees classified as exempt under FLSA with a minimum salary range of \$132,299 (Grade 9) or greater are eligible. A long-term performance target percentage of base pay is established for each employee based on his/her grade level. Further, this target percent is allocated between performance shares (70%) and restricted stock units (30%).

²³ See Exhibits RS/RT-27 and RS/RT-28 for copies of Company responses to Staff discovery relating to incentive compensation and stock-based compensation.

Stock Based Compensation

Q. DID THE COMPANY PROVIDE DOCUMENTATION WHICH DESCRIBES ITS LONG-TERM INCENTIVE PROGRAM?

A. Yes. A copy of the 2019 Southern Company Long-Term Incentive Program ("LTIP") was provided in Trade Secret Attachment STF-L&A-82b to the response to STF-L&A-1-82.

Q. WHAT IS THE PURPOSE OF THE LTIP?

A. On page 2 of the LTIP, under the heading "Program Purpose" it states:

[*BEGIN TRADE SECRET*]



[*END TRADE SECRET*]

Q. PLEASE DESCRIBE THE SPECIFIC STOCK BASED COMPENSATION PROGRAMS.

A. The PSUs and the RSUs together constitute the Company's long-term incentive compensation programs for higher level employees at Georgia Power, SCS and SNC. Specifically, as discussed on page 3 of the LTIP, **[*BEGIN TRADE SECRET*]**



1 [REDACTED]
2 [REDACTED]
3 [REDACTED]
4 [REDACTED]
5 [REDACTED]nd
6 [REDACTED]
7 [REDACTED] [*END TRADE SECRET*]

8 Georgia Power's response to STF-L&A-1-82, attached hereto as
9 Exhibit__(RS/RT-28), provided, among other information, the dollar amounts for the test
10 year ending July 31, 2020 as well as for calendar years 2020, 2021 and 2022 for each of
11 the long-term incentive compensation programs.

12
13 **Q. IN PRIOR RATE CASES, THE COMPANY'S LONG-TERM INCENTIVE**
14 **PROGRAM INCLUDED STOCK OPTIONS. ARE STOCK OPTIONS**
15 **INCLUDED IN THE COMPANY'S REVENUE REQUIREMENT IN THE**
16 **CURRENT PROCEEDING?**

17 A. No. According to the Company's response to STF-L&A-3-41, in 2015 the Southern
18 Company discontinued granting stock options and all existing stock option awards were
19 vested as of December 31, 2017. As a result, there are no costs related to stock options
20 included in the Company's revenue requirement in the current proceeding.

1 Q. PLEASE DISCUSS THE PERFORMANCE SHARE UNITS AND HOW THEY
2 FUNCTION RELATIVE TO THE FINANCIAL PERFORMANCE OF
3 SOUTHERN COMPANY.

4 A. Page 7 of the LTIP it states that [*BEGIN TRADE SECRET*]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]²⁴

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[*END TRADE SECRET*]

²⁴ [REDACTED]

1 **Q. PLEASE DISCUSS THE RESTRICTED STOCK UNITS AND HOW THEY**
2 **FUNCTION RELATIVE TO THE FINANCIAL PERFORMANCE OF**
3 **SOUTHERN COMPANY.**

4 A. RSUs became part of the Company's LTIP beginning in 2017.²⁵ As noted above,

5 **[*BEGIN TRADE SECRET*]** [REDACTED]

6 [REDACTED]

7 [REDACTED]

8 [REDACTED]

9 [REDACTED]

10 [REDACTED]

11 [REDACTED]

12 [REDACTED]

13 [REDACTED]

14 [REDACTED]

15 [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 [REDACTED]

19 [REDACTED]

20 **[*END TRADE SECRET*]**

21

²⁵ See the response to STF-L&A-3-41.

1 **Q. HAS GEORGIA POWER REMOVED STOCK-BASED COMPENSATION**
2 **EXPENSE FROM ITS ANNUAL SURVEILLANCE REPORTS IN THE YEARS**
3 **SUBSEQUENT TO THE 2013 RATE CASE?**

4 A. Yes. In Georgia Power's ASR that were filed for calendar years 2014 through 2018, the
5 Company has removed stock-based compensation pursuant to the Commission's Order in
6 Docket No. 36989. The Commission adopted a Settlement Agreement in its Order
7 Adopting Settlement Agreement dated December 23, 2013. In the Findings of Fact
8 section of that Order, the Commission identified adjustments that had been recommended
9 by Staff in Georgia Power's 2013 rate case and included as provisions to the Settlement
10 Agreement. One such adjustment was to remove stock-based compensation from the
11 Company's ASR going forward. Specifically, on page 9 of the Commission's Order, the
12 Commission, referencing Exhibit A to the Settlement Agreement, states in part:

13 Paragraphs 2 and 3 of the Settlement Agreement describe and provide that
14 the Annual Surveillance Report ("ASR") will be filed by the Company by
15 March 15 of the year following the reporting year. The Commission finds
16 that the adjustments to the Company's initial filing agreed to in the
17 Settlement Agreement, itemized in Exhibit A to the Settlement Agreement
18 and further described above, shall be applied for ASR filing purposes for
19 each year of the ARP. Specifically, to be included in the ASR are the
20 Stock Based Compensation adjustment (line 11) and the Miscellaneous
21 Adjustments (line 15). The Stock Based Compensation adjustment would
22 be reported as the actualized amount and the Miscellaneous Adjustments
23 would be reported as the amount agreed to in the Settlement Agreement of
24 \$14,175,000.

25
26 **Q. WHAT DOES STAFF RECOMMEND IN THE CURRENT GEORGIA POWER**
27 **RATE CASE?**

28 A. As is explained below Staff recommends that the PSU expense and the RSU expense be
29 removed from retail jurisdictional operating expenses for purposes of establishing the

1 Company's revenue requirement in the current rate case. Additionally, Staff recommends
2 that the principle noted above be clearly stated for purposes of ASRs that are going to be
3 filed for new rate plan years covered by this case, i.e., for ASRs filed by Georgia Power
4 Company for calendar years, 2020, 2021 and 2022. In summary, the principle that had
5 been applicable specifically that stock-based compensation expenses attributable to
6 Georgia Power Company, Southern Company Services, and Southern Nuclear employees
7 were excluded from retail expenses, should be clearly stated in the current case by
8 including language similar to this in a settlement and/or Order in the current rate case so
9 the following principle will clearly apply in the Company's 2020, 2021 and 2022 ASRs
10 and future ASRs unless specifically removed by Commission Order: "Pursuant to the
11 Commission's Order in Docket No. 42516, Stock Based Compensation Expenses
12 attributable to Georgia Power Company, Southern Company Services, and Southern
13 Nuclear employees are excluded from retail expenses.

14
15 **Q. SHOULD THE COMMISSION INCLUDE THE PSU AND RSU EXPENSE IN**
16 **THE REVENUE REQUIREMENT?**

17 A. No. The stock-based incentive compensation expenses for these programs should not be
18 included in the revenue requirement. The cost of these incentive compensation programs
19 is incurred to improve the Southern Company financial performance for the benefit of
20 shareholders, not to improve customer service or meet other regulated utility service
21 requirements. In fact, the objectives of maximizing shareholder value on the one hand
22 and minimizing costs to ratepayers on the other hand, are generally opposed to each
23 other. In addition, the hypothetical stock performance pursuant to the PSU should not be

1 considered expense for ratemaking purposes because dividends are considered in the
2 determination of the required return on common equity and stock performance is a
3 component of shareholder return.
4

5 **Q. HAVE YOU QUANTIFIED THE EFFECT OF YOUR RECOMMENDATIONS**
6 **TO DISALLOW THE STOCK-BASED INCENTIVE COMPENSATION**
7 **EXPENSE FOR THE PSU AND RSU?**

8 A. Yes. The effect is to reduce Georgia Power's forecasted test year retail operating
9 expenses by \$19.482 million. This quantification includes the costs directly incurred by
10 the Company of \$9.893 million and the affiliate charges of \$6.669 million from SCS and
11 \$2.920 million from SNC for these stock-based compensation programs. The
12 quantifications and the source of the data that I relied on for these quantifications are
13 detailed on my Exhibit__(RS/RT-2), Schedule E-9. In addition, as it relates to the
14 Company's alternative rate plan, the effect of disallowing the expense for the PSU and
15 RSU is to reduce retail operating expenses by \$19.402 million, \$21.283 million, and
16 \$22.644 million for calendar years 2020, 2021 and 2022, respectively. Of these amounts,
17 \$10.020 million, \$10.696 million and \$10.988 million reflect costs directly incurred by
18 Georgia Power. Likewise, \$6.592 million, \$7.689 million and \$7.867 million reflect
19 affiliate charges from SCS and \$2.790 million, \$2.898 million and \$3.789 million reflect
20 affiliate charges from SNC.
21

22 **Q. PLEASE EXPLAIN THE ADJUSTMENT CALCULATION SHOWN ON**
23 **EXHIBIT__(RS/RT-2), SCHEDULE E-29.**

A. Exhibit__(RS/RT-2), Schedule E-9 has four pages, one for the test year and one for each plan year, showing the adjustment amounts. The total amounts, O&M expense ratio and O&M expense for the PSU and the RSU are from (or were derived from) the Company's responses to STF-L&A-1-82, STF-L&A-1-83 and STF-L&A-3-38 as shown in columns B, C, and D, respectively. For the test year, as shown on Exhibit__(RS/RT-2), Schedule E-9, page 1, line 11, the total adjustment reduces retail operating expense by \$19.482 million. Pages 2, 3 and 4 of Schedule E-9 present similar information for plan years, 2020, 2021 and 2022, respectively.

Performance Pay Plan

Q. HAS THE COMPANY INCLUDED AMOUNTS RELATED TO ITS PERFORMANCE PAY PLAN IN THE CALCULATION OF ITS REVENUE REQUIREMENT IN THE FORECASTED TEST YEAR ENDING JULY 31, 2020 AS WELL AS FORECASTED CALENDAR YEARS 2020, 2021 AND 2022?

A. Yes. The Company has included amounts related to its Performance Pay Plan ("PPP") in the calculation of its revenue requirement for the forecasted test year ending July 31, 2020 as well as forecasted calendar years 2020, 2021 and 2022. Specifically, the table below summarizes the amounts of PPP expense included in Georgia Power's retail operating expense for the forecasted test year ending July 31, 2020 as well as the forecasted calendar years 2020, 2021 and 2022:

Description	7/31/2020	2020	2021	2022
GPC Directly Incurred PPP Expense Charged to O&M	\$ 50,749,209	\$ 51,335,604	\$ 52,758,152	\$ 54,298,876
SCS PPP Expense Allocated to GPC Charged to O&M	\$ 24,627,153	\$ 25,143,101	\$ 26,065,989	\$ 26,824,885
SNC PPP Expense Allocated to GPC Charged to O&M	\$ 25,412,482	\$ 25,902,267	\$ 27,976,044	\$ 35,455,637
Total PPP Expense Charged to O&M	\$ 100,788,844	\$ 102,380,972	\$ 106,800,185	\$ 116,579,398
Source: STF-L&A-3-38				

1 As shown in the table above, for the forecasted test year ending July 31, 2020, the
2 Company's revenue requirement includes directly incurred PPP expense in O&M totaling
3 \$100.789 million. Of this amount, \$50.749 million reflects directly incurred PPP
4 expense, \$24.627 million reflects PPP expense allocated from SCS and \$25.412 million
5 reflects PPP expense allocated from SNC.

6 For forecasted calendar year 2020, the Company's revenue requirement includes
7 directly incurred PPP expense in O&M totaling \$102.381 million. Of this amount,
8 \$51.336 million reflects directly incurred PPP expense, \$25.143 million reflects PPP
9 expense allocated from SCS and \$25.902 million reflects PPP expense allocated from
10 SNC.

11 For forecasted calendar year 2021, the Company's revenue requirement includes
12 directly incurred PPP expense in O&M totaling \$106.800 million. Of this amount,
13 \$52.758 million reflects directly incurred PPP expense, \$26.066 million reflects PPP
14 expense allocated from SCS and \$27.976 million reflects PPP expense allocated from
15 SNC.

16 For forecasted calendar year 2022, the Company's revenue requirement includes
17 directly incurred PPP expense in O&M totaling \$116.579 million. Of this amount,
18 \$54.299 million reflects directly incurred PPP expense, \$26.825 million reflects PPP
19 expense allocated from SCS and \$35.456 million reflects PPP expense allocated from
20 SNC.

21 **Q. HOW WAS THE PPP INCENTIVE COMPENSATION EXPENSE ADDRESSED**
22 **IN THE COMPANY'S PREVIOUS RATE CASES?**

1 A. In Georgia Power's 2007 rate case, Docket No. 25060, Staff had recommended that
2 Georgia Power's PPP be reduced to reflect a 100 percent payout, rather than the payout
3 target in excess of 100 percent that Georgia Power had included in the cost of service.
4 The Company's PPP expense was addressed in the base rate proceeding by including the
5 amount proposed by Georgia Power in the cost of service in a settlement. In Georgia
6 Power's 2010 rate case, Docket No. 31958, consistent with the ultimate treatment from
7 Docket No. 25060, Staff accepted the amount proposed for PPP by Georgia Power and
8 did not make an adjustment. Similarly, in Georgia Power's 2013 rate case, Docket No.
9 36989, consistent with the treatment in previous rate cases, Staff accepted the amount
10 proposed for PPP by Georgia Power and did not make an adjustment.

11 **Q. HOW HAVE YOU TREATED THE PPP INCENTIVE COMPENSATION**
12 **EXPENSE FOR PURPOSES OF THE COMPANY'S CURRENT RATE CASE?**

13 A. We have treated the PPP incentive compensation expense consistent with its ultimate
14 treatment in Georgia Power's 2007, 2010 and 2013 rate cases. While we share the
15 concerns regarding the PPP incentive compensation expressed by Staff in Georgia
16 Power's 2007 rate case (which was continued in the 2010 and 2013 rate cases), and
17 generally believe that it is appropriate for ratemaking purposes to have shareholders bear
18 some or all of the cost of incentive compensation programs, in view of the record in that
19 case and the ultimate resolution, which removed stock-based incentive compensation
20 expense but did not reduce the PPP cost, we have not recommended an adjustment to
21 reduce PPP expense in the current Georgia Power rate case. Staff does, of course, reserve
22 the right to examine and, if deemed appropriate, contest the treatment of PPP expense in
23 future Georgia Power rate cases.

XIV. RATE PLAN PRINCIPLES AND RECOMMENDATIONS

Multi-Year Rate Plans Versus Traditional Test Year Based Ratemaking

Q. HOW IS AN ALTERNATIVE RATE PLAN DIFFERENT FROM A TRADITIONAL RATE CASE ORDER IN TERMS OF EARNINGS ABOVE THE ROE BAND?

A. Under a traditional rate case order, the Company could earn in excess of an authorized ROE without the ratepayers receiving any rate reductions or any benefit from the application of earnings above the top of the rate band. While the Commission would have the authority to bring the Company in under a Rule Nisi proceeding to reduce its rates, such a proceeding would take a significant amount of time and any order reducing rates would be prospective in nature.

Q. HOW IS THE ALTERNATIVE RATE PLAN DIFFERENT FROM A TRADITIONAL RATE CASE ORDER IN TERMS OF EARNINGS BELOW THE AUTHORIZED ROE OR LOWER ROE BAND?

A. Under a traditional rate case order, the Company could earn less than the authorized ROE and would not have any recourse except to file a rate case. Any relief would be prospective in nature.

Q. HOW DOES TRADITIONAL RATEMAKING COMPARE WITH A MULTI-YEAR RATE PLAN IN TERMS OF WHEN THE COMPANY FILES RATE CASES?

1 A. Under a traditional rate case order, the Company would be able to file another rate case
2 whenever it deemed appropriate, and the Commission would have the ability to bring
3 Georgia Power in for a Rule Nisi to address any overearnings. That distinction is of
4 particular importance in light of the large amounts of environmental compliance and
5 CCR costs that the Company has been and is projected to continue to be incurring, which
6 are at issue in this proceeding, particularly in the 2021 and 2022 plan years. Although
7 some such costs, such as projected increased costs for 2021 and 2022, did not fall within
8 the test year period for this docket, these costs could have fallen within the test year
9 period of a subsequent rate case filing.
10

11 **Q. HOW CAN A MULTI-YEAR RATE PLAN PROVIDE FOR RATE STABILITY?**

12 A. The accounting order/rate plan can provide ratepayers with rate stability and certain
13 benefits depending on how it is structured. Unless the Company's earnings are projected
14 to drop below the bottom of the earnings band, the Staff proposed alternative rate plan for
15 the current case (similar to previous rate plans) would prohibit Georgia Power from filing
16 for a rate increase until a date provided for in the rate plan. However, the Company
17 would have the option to petition the Commission to increase rates up to lower band if its
18 projected earnings would fall below the lower band. Also, the plan may include step
19 increases which increase rates rather than stabilizing rates. While there are certain
20 advantages in step increases there are tradeoffs including only considering certain cost
21 that are increasing rather than all cost which may include some cost that are decreasing. If
22 a three-year rate plan were to be approved, the Company would be prohibited from filing
23 until July 1, 2022, unless it were projected to earn below the bottom end of the band.

Q. IS HAVING A THREE-YEAR RATE PLAN A BENEFIT TO THE COMPANY?

A. Yes. Having a rate plan that is approved by the Commission and agreed to by the Company benefits the Company. One benefit is that the first-year revenue requirement could be based on calendar year 2020, rather than upon the statutory test year ending July 31, 2020. The Company's filing shows a traditional base rate revenue excess (not including CCR ARO revenue requirements) of approximately \$144 million based on the July 31, 2020 test year,²⁶ and a base rate revenue excess of approximately \$4.3 million²⁷ for calendar year 2020, versus revenue deficiencies of \$229.5 million and \$434.2 million for 2021 and 2022.²⁸ Thus, the time shifting of the revenue requirement basis for the first year of new rates has a monetary benefit to the Company.

Earnings Test and Earnings Band-History

Q. HAVE YOU PREPARED A TABLE SUMMARIZING HOW THE EARNINGS SHARING HAS WORKED FOR RATEPAYERS AND THE COMPANY OVER THE PAST SEVERAL YEARS?

A. Yes. This is summarized in the following table for 2007 through 2018, based on ASR results:

²⁶ See, e.g., Exhibit__ (DPP/SPA/MBR-1 Schedule 1 Traditional Base), page 3 of 5, column (3) line 6.

²⁷ Id. At column (4), line 6.

²⁸ Id. At columns (5) and (6), line 6.

Georgia Power Company Historical Earnings Sharing Based on Annual Surveillance Reports											
Year	ROE Reported in ASR Filing	Lower End of Earnings Band	Upper End of Earnings Band	Adjusted ROE	ROE Above Upper End of Earnings Band	ROE Used to Set Revenue Requirement in Rate Case	Adjusted Earned ROE Above ROE used to Set Revenue Requirement	Accounting Adjustment Related to Preventing Under-Earnings	Earnings Above Top End of Band (\$ millions)	Amount Refunded to Customers (\$ millions)	Amounts of Excess Earnings Retained By Company (\$ millions)
2007	11.36%	10.25%	12.25%	11.52%	N/A	11.25%	0.27%		\$ -		
2008	12.11%	10.25%	12.25%	12.20%	N/A	11.25%	0.95%		\$ -		
2009	9.75%	10.25%	12.25%	9.75%	N/A	11.25%		\$ 1.46 [a]	\$ -		
2010	10.15%	10.25%	12.25%	10.15%	N/A	11.25%		\$ 3.30 [a]	\$ -		
2011	11.72%	10.25%	12.25%	11.72%	N/A	11.15%	0.57%		\$ -		
2012	11.99%	10.25%	12.25%	11.99%	N/A	11.15%	0.84%		\$ -		
2013	11.43%	10.25%	12.25%	11.44%	N/A	11.15%	0.29%		\$ -		
2014	12.12%	10.00%	12.00%	12.14%	0.14%	10.95%	1.19%		\$ 16.96	\$ 11.31	\$ 5.65
2015	11.52%	10.00%	12.00%	11.55%	N/A	10.95%	0.60%		\$ -		
2016	12.46%	10.00%	12.00%	12.49%	0.49%	10.95%	1.54%		\$ 65.40	\$ 43.60	\$ 21.80
2017	11.91%	10.00%	12.00%	12.04%	0.04%	10.95%	1.09%		\$ 3.55	\$ 2.37	\$ 1.18
2018	13.17%	10.00%	12.00%	TBD	1.17%	[b]	2.22%		\$ 153.10 [b]	\$ 102.07	\$ 51.03
								Totals	\$ 239.01	\$ 159.34	\$ 79.67
								Percent of Totals	100.00%	66.67%	33.33%
Notes											
[a] \$0.972 million and \$2.2 million were restored to the accrued removal cost regulatory liability account in 2009 and 2010, respectively, based on Staff's recommended adjustments.											
The Company was allowed to amortize amounts from the regulatory liability account to bring the ROE up to 9.75% and 10.15%, the lower bound of the earnings band in 2009 and 2010, respectively. The agreement Staff reached with the Company was to restore a portion of the regulatory liability amortization to reflect adjustments identified in Staff's review. So instead of amortizations of \$48 million and \$170.8 million, the net amortizations were \$47 million and \$168.6 million.											
[b] The Company's 2018 ASR is under review by Staff; final adjustments are not yet determined.											

As shown in the above table, the Company has consistently earned well above its authorized ROE in every year except during the Great Recession in 2009 and 2010. In recent years, the Company has reported about \$239 million of revenues representing earnings above the top end of the ROE band. Two-thirds of that, or approximately \$159 million are for the benefit of ratepayers, while the Company retains the other third, or approximately \$80 million. It should be noted that the 2018 ASR results are still under review by Staff, and Staff has suggested that the Commission consider alternative applications of the 2018 ASR over-earnings amount of approximately \$153 million.

Staff Rate Plan Recommendations

Q. HAVE YOU PREPARED A COMPARISON OF THE 2020, 2021 AND 2022 PLAN YEAR REVENUE DEFICIENCY (OR EXCESS) AMOUNTS FROM THE COMPANY'S FILING AND STAFF'S CALCULATED AMOUNTS?

A. Yes. The following table shows Staff's calculated amounts for the 2020, 2021 and 2022 plan year revenue deficiency (or excess) and compares those with corresponding amounts in the Company's filing (from Table 2 on the Poroeh/Adams/Robinson direct testimony):

Staff Calculated Revenue Requirement Deficiency/(Excess) by Year					
(In Millions of Dollars)					
Effective Date	1/1/2020 Based on TY	1/1/2020, Based on calendar 2020	1/1/2021	1/1/2022	Total
Traditional Base					
Base Rate Revenue Deficiency (Excess) (a)	\$ (408)	\$ (273)	\$ 233	\$ 228	\$ 188
CCR ARO (b)	\$ 102	\$ 105	\$ 98	\$ 159	\$ 362
ECCR (c)	\$ 112	\$ 121			\$ 121
DSM (d)	\$ 12	\$ 12	\$ 1	\$ 1	\$ 14
Rounding/unidentified	\$ 1		\$ (2)	\$ (1)	\$ (3)
Subtotal prior to MFF (f)	\$ (181)	\$ (35)	\$ 331	\$ 387	\$ 682
MFF (e)	\$ 11	\$ 11	\$ 10	\$ 12	\$ 32
Total (\$)	\$ (171)	\$ (25)	\$ 340	\$ 398	\$ 714
(a) Exhibit __ (RS/RT-2), Schedule A, line 12 annual change					
(b) Exhibit __ (RS/RT-6), Page 3					
(c) Exhibit __ (RS/RT-3), Page 3					
(d) Exhibit __ (RS/RT-4) Page 2					
(e) Exhibit __ (RS/RT-5) Page 2					
(f) Exhibit __ (RS/RT-1), Schedule A, line 7 for TY and 2020; line 17 for 2021 and 2022					
Company As-Filed Projected Revenue Requirement Deficiency by Year					
(In Millions of Dollars) (Poroeh/Adams/Robinson testimony, page 17, Table 2)					
Effective Date		1/1/2020	1/1/2021	1/1/2022	Total
Traditional Base Calculated by Company		\$ (144)			
Levelization Adjustment		\$ 353			
Levelized		\$ 209	\$ -	\$ -	\$ 209
CCR ARO		\$ 158	\$ 140	\$ 227	\$ 525
ECCR (Levelized)		\$ 165	\$ -	\$ -	\$ 165
DSM		\$ 14	\$ 2	\$ 1	\$ 17
Subtotal prior to MFF		\$ 546	\$ 142	\$ 228	\$ 916
MFF		\$ 17	\$ 3	\$ 5	\$ 25
Total (\$)		\$ 563	\$ 145	\$ 233	\$ 941
Differences (In Millions of Dollars) Staff Compared with Company					
Effective Date		1/1/2020	1/1/2021	1/1/2022	Total
Traditional Base					
Base Rate Revenue Deficiency (Excess)		\$ (482)	\$ 233	\$ 228	\$ (21)
CCR ARO		\$ (53)	\$ (42)	\$ (68)	\$ (163)
ECCR		\$ (44)	\$ -	\$ -	\$ (44)
DSM		\$ (2)	\$ (1)	\$ (0)	\$ (3)
Rounding/unidentified		\$ -	\$ (2)	\$ (1)	\$ (3)
Subtotal prior to MFF		\$ (581)	\$ 189	\$ 159	\$ (234)
MFF		\$ (6)	\$ 7	\$ 7	\$ 7
Total (\$)		\$ (588)	\$ 195	\$ 165	\$ (227)

1 **Q. IS STAFF RECOMMENDING THE RATE INCREASES AND DECREASES**
2 **SHOWN IN THE ABOVE-TABLE?**

3 A. No. As shown on Exhibit __ (RS/RT-2), Schedule A, on lines 7 and 16, Staff shows
4 revenue excesses for the test year and for 2020. Staff is recommending no change for
5 2020 and that the Company be required to file compliance filings on October 1, 2020 and
6 October 1, 2021 for the step increases to become effective on January 1, 2021 and
7 January 1, 2022, respectively.

8 **Q. PLEASE EXPLAIN STAFF'S RATE PLAN RECOMMENDATIONS.**

9 A. As described above in our testimony, Staff recommends that revenue changes for January
10 1, 2021 and 2022 for base rates as well as the ECCR rates be applied as step adjustments,
11 rather than charged on a levelized basis to retail ratepayers beginning on January 1, 2020.
12 Staff also recommends that the Company continue to update its estimated costs for ECCR
13 and for CCR ARO Compliance cost recovery, and that the Company file by October 1, of
14 2020 and 2021, respectively, for ECCR and CCR ARO revenue requirements for 2021
15 and 2022, respectively.

16
17 Staff recommends that the plan include specified sharing for the gains or losses on the
18 sale of utility land that had been included in rate base as PHFFU.

19
20 Staff also recommends that an earnings test be applied, with an ROE band of 130 basis
21 points above Staff's recommended 9.2% ROE, as described below.

Staff further recommends that earnings above the top end of the earnings band be applied for the accelerated recovery of deferred costs and regulatory assets, rather than the two-thirds/one-third sharing which had been incorporated in prior rate plans.

Step Increase Approach

Q. DOES STAFF RECOMMEND A STEP-APPROACH FOR THE 2021 AND 2022 INCREASED REVENUE REQUIREMENTS?

A. Yes. Staff believes that a step-approach involving interim filings during the 2020-2022 three-year plan period would be far preferable to approving a levelized revenue requirement under the circumstances present in the current Georgia Power rate case. The Commission has employed step increases effectively in the context of three-year plans, including for the Company's recovery additional revenue requirements associated with Plant McDonough Units 4 and 5 in compliance with the Commission's 2010 Rate Case Order in Docket No. 31958.

Q. WHAT ARE THE REASONS FOR RECOMMENDING A STEP INCREASE APPROACH, RATHER THAN A LEVELIZED APPROACH TO THE THREE-YEAR RATE PLAN?

A. First, customers should not be required to pay for 2021 and 2022 revenue requirements starting January 1, 2020, i.e., before the related costs have been incurred, especially during a period when the economy could be entering into a recession. Also, the Company has projected that Plant Vogtle Unit 3 will be in commercial operation by November 2021 and Unit 4 by November 2022. Currently, the Company is collecting

1 from ratepayers portions of the financing cost for those units while they are under
2 construction. The Company continues to incur construction costs and AFUDC. While
3 those dates might be delayed, the Vogtle Unit 3 and 4 rate impacts, once more fully
4 recognized, are anticipated to be substantial.²⁹

5
6 Furthermore, Staff has concerns about some of the large items in the 2021 and 2022
7 revenue requirements. Under a levelized approach, ratepayers would incur the costs
8 related to these items beginning January 1, 2020. These items include recognition of cost
9 increases that are occurring in 2021 and 2022 beyond levels projected for 2020. These
10 concerns, coupled with the uncertainties about the timing of cost incurrence, warrant a
11 cautious approach to determining appropriate revenue requirements for the Company for
12 the 2021 and 2022 plan years.

13
14 **Q. PLEASE EXPLAIN ANY POTENTIAL IMPACT ON ENVIRONMENTAL**
15 **COSTS PROJECTED FOR 2021 AND 2022 FROM ANY CHANGES TO THE**
16 **RULES AND/OR COMPLIANCE DATES.**

17 A. The timing and level of certain environmental costs, such as plant retirements and
18 environmental retrofits that have been addressed in the 2019 IRP, could be affected if any
19 revisions are made to environmental regulations, including the compliance date.

20

²⁹ Plant Vogtle Units 3&4 being placed into commercial operation could increase base rate revenue requirements by approximately \$1 billion per year assuming no additional delays or cost overruns or Commission disallowances. This would be offset by approximately \$200 million per year from termination of the Nuclear Construction Cost Recovery tariff.

1 **Q. ALTHOUGH THE COMPANY HAS INDICATED THAT IT WOULD PREFER A**
2 **LEVELIZED THREE-YEAR RATE PLAN, DID THE COMPANY**
3 **ACKNOWLEDGE THAT A STEP-INCREASE APPROACH COULD BE USED**
4 **FOR THE INCREASED REVENUE REQUIREMENTS FOR 2021 AND 2022?**

5 A. Yes. During the hearings on Georgia Power's direct case, the Company acknowledged
6 that estimates can become less reliable the further out into the future they extend. (Tr.
7 348.) Moreover, while the Company would prefer its proposed levelized approach, it
8 acknowledged that an alternative would be to step-up the increases over the three-year
9 period covered by the projected test years for 2020, 2021 and 2022. (Tr. 345-48).

10
11 **Q. HAS THE COMMISSION PREVIOUSLY DIRECTED THE COMPANY TO FILE**
12 **INTERIM RATES THAT WOULD BECOME EFFECTIVE DURING THE TERM**
13 **OF A THREE-YEAR ACCOUNTING ORDER?**

14 A. Yes. For example, as provided for in the approved stipulation and Commission Order in
15 Docket No. 31958, the Company filed to increase rates effective in 2012 and 2013. On
16 November 1, 2011, the Company filed updated Demand Side Management (DSM)
17 Residential and Commercial tariffs for approval. These tariffs were approved by the
18 Commission, allowing the Company to collect its updated DSM revenue requirement. At
19 the same time, the Company also updated its Nuclear Construction Cost Recovery
20 (NCCR) tariff to collect \$258.6 million for projected 2012 financing costs associated
21 with Plant Vogtle Units 3 and 4. The effective date of those tariff updates was January 1,
22 2012.

Sharing of Gains on Disposition of Land and Utility Property

Q. HAS THE COMPANY MADE A PROPOSAL FOR THE SHARING OF GAINS ON THE DISPOSITION OF LAND?

A. Yes. The Poroach/Adams/Robinson panel presents the Company's proposal for the prospective sharing for gains and losses on the disposition of utility land at pages 49-50 of their Direct Testimony. The Company proposes that any net gains or losses on disposition of utility land, including land held in PHFFU, be shared 20% with customers, with the Company retaining the remaining 80%. The Company states that this sharing would be applied prospectively and that there are no gains or losses from land sales projected in its budgets. The Company proposes that the Commission adopt this proposal prospectively, recognizing that the Commission has the ability to establish retail ratemaking on its own application and the Company indicates that it is sensitive to the concerns Commission Staff has raised related to the disposition of land.

Q. DOES STAFF AGREE THAT SHARING OF THE GAINS AND LOSSES ON THE SALE OF UTILITY LAND, INCLUDING LAND THAT HAS BEEN INCLUDED IN PHFFU, SHOULD BE APPLIED?

A. Yes. Staff supports the sharing of the gains and losses on the sale of utility land, including land that has been included in PHFFU.

Q. DOES STAFF AGREE WITH THE SHARING RATIO PROPOSED BY THE COMPANY?

A. No. Staff recommends that the sharing ratio be based on the number of years in which the PHFFU was included in rate base to the number of years the PHFFU was held, subject to

1 a maximum sharing of 80% for customers and that the remaining 20% be retained by the
2 Company. The Company's customers have been paying the Company for a rate base
3 return on the cost of the land in the PHFFU account, and for related costs such as
4 property taxes. Given the historical responsibility for payment by customers of such
5 costs (i.e., the historical responsibility of customers to pay for the financing costs and
6 holding costs over lengthy periods during which land had not been used in the provision
7 of public utility services), the sharing ratio should be higher for customers than the
8 Company has proposed. Staff believes that a sharing ratio based on the proportional
9 number of years a land parcel was included in rate base to the total number of years
10 which that parcel was held, subject to a maximum customer sharing ratio of 80% on gains
11 of sale or utility land strikes a better balance and is more reasonable than the Company's
12 proposal.

13
14 **Application of Earnings Above Top End of Band**

15 **Q. PLEASE ADDRESS THE STAFF'S RECOMMENDATION CONCERNING**
16 **EARNINGS SHARING WITHIN THE AUTHORIZED EARNINGS BAND.**

17 A. As part of the alternative rate plan, Staff recommends that an earnings sharing
18 mechanism should continue to apply, but with certain modifications/improvements from
19 how it has been applied under the Stipulation in Georgia Power's last rate case. While
20 Georgia Power's earnings band in the past has been a 200 basis point range in its last
21 three rate cases, Staff recommends narrowing of the earnings band. For purposes of this
22 plan Staff recommends a band of 9.2% to 10.5% which would allow the Company to

1 retain all revenues up to 1.3% above Staff's recommend authorized ROE rather than up to
2 1.0% under previous settlements.

3
4 **Q. HOW DOES STAFF RECOMMEND THAT EARNINGS ABOVE THE TOP END**
5 **OF THE BAND BE APPLIED?**

6 A. As noted above, Staff proposes an ROE band of 9.2% to 10.5% above which is 130 basis
7 points above the 9.2% ROE recommended by Staff witness Gorman. Staff recommends
8 that all revenues above the top end of the band be used 100% to accelerate recovery by
9 the Company of regulatory assets, such as remaining book value for retired coal plants.

10
11 **Q. WHAT IS THE REASON FOR APPLYING EARNINGS ABOVE THE TOP-END**
12 **OF THE BAND FOR THE RECOVERY OF REGULATORY ASSETS, RATHER**
13 **THAN FOR SHARING BETWEEN CUSTOMERS AND GEORGIA POWER**
14 **COMPANY?**

15 A. Referring to Exhibit__(RS/RT-2), Schedule B, pages 1 through 4, lines 34, 35, 38 and 39,
16 there are regulatory assets/cost deferrals for Environmental CWIP (\$21.2 million retail
17 jurisdictional rate base amount for the test year), retired units remaining net book value
18 (\$588.5 million), and unusable inventory regulatory assets (\$37 million). Some portion of
19 these deferrals could potentially be recognized on an accelerated basis up to the amount
20 of the revenue requirement excess associated with the excess earnings. Many of these
21 regulatory assets are no longer in use or useful. Accelerated amortization though
22 application of excess revenues above the earning band would strike a more appropriate
23 balance between ratepayer and Company investor interest. In some of the Company's

prior rate cases, the Commission has approved settlements which require revenues above the earnings band to be applied against Company costs. This would benefit the Company by accelerating the recovery of deferred costs. It would benefit customers by helping to pay down a portion of the deferred costs, so the overall level of such costs rolling into the Company's next rate case, which is likely to be a Vogtle Units 3 and 4 in-service driven rate case, would be less than otherwise if over-earnings in 2020 and 2021 are applied to accelerate the recovery of some of the Company's deferred cost balances.

In this manner, earnings above the top of the sharing band to help mitigate the impact on ratepayers of the cost deferrals and regulatory assets that the Company has been accumulating.

XV. SUMMARY OF STAFF RECOMMENATIONS

Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATIONS.

A. Staff shows a revenue excess for the test year ending July 31, 2020 and for calendar year 2020. Staff recommends no traditional base rate change for January 1, 2020. Staff recommends that the Company file compliance filings on October 1, 2020 for a January 1, 2021 step increase and on October 1, 2021 for a January 1, 2022 step increase.

Staff has made the following recommendations:

1. Accept the adjustments identified by the Company in its errata filing.
2. Accept the adjustments described in our testimony for the test year and each plan year for calculating the revenue requirement excess or deficiency (or excess) for traditional base rates (as shown in Exhibit __RS/RT-2), for the ECCR (as shown in Exhibit __RS/RT-3), for DSM (as shown in Exhibit __RS/RT-4), for Municipal Franchise Fees (as shown in Exhibit __RS/RT-5), and for CCR ARO Compliance (as shown in Exhibit __RS/RT-6).
3. The traditional revenue requirement for Georgia Power in this rate case should be determined based on the use of the Commission-ordered test year ending July 31, 2020.
4. The appropriate traditional test year average retail rate base is \$20.063 billion which is \$33.9 million lower than the Company's proposed traditional test year average retail rate base of \$20.097 billion.

- 1 5. The appropriate traditional test year retail operating income is \$1.477 billion,
2 which is \$28.028 million higher than the Company's proposed test year traditional
3 test year retail operating income of \$1.449 billion.
- 4 6. The appropriate traditional test year overall rate of return for Georgia Power in
5 this case that Staff used 6.69% and includes a fair return on equity of 9.2% the
6 capital structure as recommended by Staff witness Michael Gorman. As noted, the
7 cost of long-term debt used was slightly higher than Mr. Gorman's
8 recommendation, due to timing.
- 9 7. The appropriate income expansion factor to be used for ratemaking purposes in
10 this case is 74.616%.
- 11 8. That rates be set using the traditional test year ratemaking components.
- 12 9. That the Company's proposed 2020-2022 levelization revenue requirement
13 adjustment of \$353.2 million to derive a levelized revenue deficiency amount of
14 \$209.2 million per year for 2020-2022 (not including CCR ARO Compliance) not
15 be adopted. Rather, Staff recommends that a step-increase approach be used if a
16 three-year rate plan is adopted.
- 17 10. That current rates be maintained through 2020, and to defer the amount of the
18 excess revenues to reduce the rate increases for 2021 and 2022.
- 19 11. That the revenue excess in 2020 be used for accelerated recognition of deferred
20 costs in 2020 up to the amount of the revenue excess.
- 21 12. Continuation of the existing DSM tariff rider, reflecting Staff's carrying cost rates
22 and Staff's recommended cost of capital.

1 13. Continuation of the existing DSM tariff rider, reflecting Staff's carrying cost rates
2 and Staff's

3 14. That the contingency amounts included in the ECCR revenue requirement be
4 removed.

5 15. Prior to requesting ECCR cost recovery each year, the Company should refine the
6 estimate as much as possible.

7 16. That the Commission not pre-approve a level of ECCR cost recovery for years
8 2021 and 2022 in the current rate case, but rather that the Company making an
9 annual compliance filing to update the ECCR spending and estimates each year
10 on October 1 of the preceding year for ECCR rates to become effective the
11 following January 1.

12 17. That the Commission not pre-approve a level of CCR ARO cost recovery for
13 years 2021 and 2022 in the current rate case, but rather that the Company making
14 an annual compliance filing to update the CCR ARO spending and estimates each
15 year on October 1 of the preceding year for CCR ARO rates to become effective
16 the following January 1.

17 18. That the contingency amounts included in the CCR ARO revenue requirement be
18 removed.

19 19. That the Company receive a carrying cost allowance based on the cost of long-
20 term debt with no ROE component, rather than a full rate base return (including
21 an equity return and income tax gross-up) on the CCR ARO amounts while they
22 are being recovered.

1 20. Prior to requesting CCR ARO cost recovery each year, the Company should
2 refine the estimate as much as possible.

3 For the rate plan, Staff also recommends:

- 4 • an earnings band of 9.2% to 10.5%, i.e., extending 130 basis points above Staff's
5 recommended ROE of 9.2%.
- 6 • application of earnings above the 10.5% top end of Staff's recommended earnings
7 band to the recovery of Company deferred costs and regulatory assets.
- 8 • limiting PHFFU land inclusion in rate base to a maximum of 15 years.
- 9 • sharing of gains or losses on the sale of land that had been included in rate base as
10 PHFFU based on the number of years included in rate base to the total period held
11 by the Company, subject to a cap of 80% customer sharing.

12

13 **Q. DOES THIS COMPLETE YOUR TESTIMONY?**

14 **A. Yes.**