

STATE OF NORTH CAROLINA  
UTILITIES COMMISSION  
RALEIGH

DOCKET NO. E-7, SUB 1214

In the Matter of: )  
Application by Duke Energy Carolinas, LLC, ) **DIRECT TESTIMONY OF**  
for Adjustment of Rates and Charges ) **RACHEL S. WILSON ON**  
Applicable to Electric Utility Service in ) **BEHALF OF SIERRA CLUB**  
North Carolina )

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2 **Q Please state your name, business address, and position.**

3 **A** My name is Rachel Wilson and I am a Principal Associate with Synapse Energy  
4 Economics, Incorporated (“Synapse”). My business address is 485 Massachusetts  
5 Avenue, Suite 3, Cambridge, Massachusetts 02139.

6 **Q Please describe Synapse Energy Economics.**

7 **A** Synapse Energy Economics is a research and consulting firm specializing in  
8 electricity industry regulation, planning, and analysis. Synapse’s clients include  
9 state consumer advocates, public utilities commission staff, attorneys general,  
10 environmental organizations, federal government agencies, developers, and  
11 utilities.

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

13 **A** At Synapse, I conduct analysis and write testimony and publications that focus on  
14 a variety of issues relating to electric utilities, including integrated resource  
15 planning, resource adequacy, electric system dispatch, environmental regulations  
16 and compliance strategies, and power plant economics.

17 I also perform modeling analyses of electric power systems. I am proficient in the  
18 use of spreadsheet analysis tools, as well as optimization and electricity dispatch  
19 models to conduct analyses of utility service territories and regional energy  
20 markets. I have direct experience running the Strategist, PROMOD IV,  
21 PROSYM/Market Analytics, PLEXOS, EnCompass, and PCI Gentrader models,  
22 and I have reviewed input and output data for several other industry models.

23 Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an  
24 economic and business consulting firm, where I provided litigation support in the  
25 form of research and quantitative analyses on a variety of issues relating to the  
26 electric industry.

1 I hold a Master of Environmental Management from Yale University and a  
2 Bachelor of Arts in Environment, Economics, and Politics from Claremont  
3 McKenna College in Claremont, California.

4 A copy of my current resume is attached as Exhibit RW-1.

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

6 **A** I am testifying on behalf of Sierra Club.

7 **Q Have you testified previously before the North Carolina Utilities**  
8 **Commission?**

9 **A** Yes. I testified before this Commission in Docket No. EMP-105, Sub 0.

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

11 **A** The purpose of my testimony is to evaluate the economics of the coal-fired units  
12 owned by Duke Energy Carolinas (DEC or the Company) and assess the prudence  
13 of continuing to invest in and operate these units, which include Cliffside Units 5  
14 and 6, Belews Creek Units 1 and 2, Allen Units 1-5, and Marshall Units 1-4.

15 **Q Please identify the documents and filings on which you base your opinions.**

16 **A** My findings rely primarily upon the testimony, exhibits, and discovery responses  
17 of DEC and its witnesses. I also rely to a limited extent on certain industry  
18 publications.

19 In addition to my resume, exhibits to this testimony include:

20 Confidential Exhibit RW-2: [BEGIN CONFIDENTIAL] [REDACTED]

21 [REDACTED] [END CONFIDENTIAL]

22 Confidential Exhibit RW-3: [BEGIN CONFIDENTIAL] [REDACTED]

23 [REDACTED] [END CONFIDENTIAL]

24 Exhibit RW-4: Georgia Public Service Commission. 2019. Docket No. 42310.

25 Order Adopting Stipulation as Amended

1 **II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS**

2 **Q Please summarize your primary conclusions.**

3 **A** My primary findings indicate that all DEC's coal units operated uneconomically  
4 for at least the three years from 2016 through 2018. I estimate that each of the  
5 coal units had negative net value of between [BEGIN CONFIDENTIAL] [REDACTED]  
6 [REDACTED] [END CONFIDENTIAL] from 2016 to 2018. Despite  
7 these net losses, DEC continues to determine unit retirement dates for its coal  
8 fleet based solely on depreciation studies.

9 My analysis shows that each of DEC's coal units will continue to operate  
10 uneconomically in the future. DEC has not provided any economic assessments of  
11 the continued operation of its coal-fired units, even as low gas prices and  
12 declining costs for renewables have disadvantaged many coal units across the  
13 country. Thus, the Company has not demonstrated that continuing to invest in its  
14 coal fired units is a prudent decision and provides value to ratepayers.

15 **Q Please summarize your primary recommendations.**

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

- 17 1. I recommend that the Commission disallow past spending on capital projects  
18 incurred between the 2017 rate case and this rate case, given that the data  
19 show that all of DEC's coal units had negative net value in 2016 and 2017,  
20 and nine of DEC's 13 coal units had net negative value in 2018. Capital  
21 spending during this time period should be disallowed until DEC provides  
22 evidence of an analysis demonstrating the value of the investment done at the  
23 time the investment decision was made.
- 24 2. I recommend that DEC consider operating its units seasonally and only during  
25 months of peak demand to minimize losses to ratepayers.
- 26 3. I recommend that the Commission place a cap on future capital expenditures  
27 intended to prolong the lives of the DEC coal units as generating assets, and  
28 require the utilities to come to the Commission for approval of any

1 expenditure that exceeds that cap before the expenditure can be recovered  
2 from ratepayers.

3 **III. DEC'S COAL UNIT PLANS AND PROPOSALS**

4 **Q Which DEC generating units are the focus of this testimony?**

5 **A** This testimony focuses on the economics of DEC's 13 coal units for which the  
6 utility is seeking cost recovery in this case. These include Cliffside Units 5 and 6,  
7 Belews Creek Units 1 and 2, Allen Units 1-5, and Marshall Units 1-4.

8 **Q What are DEC's plans regarding the future operation of these units?**

9 **A** Exhibit 1 of the Direct Testimony of John J. Spanos suggests a "probable  
10 retirement year" for each of DEC's coal units. According to this document, the  
11 probable retirement years are: 2024 for Allen Units 1-5; 2026 for Cliffside Unit 5;  
12 2034 for Marshall Units 1-4; 2037 for Belews Creek Units 1-2; and 2048 for  
13 Cliffside 6. These retirement dates accelerate the retirements of Allen Units 4 and  
14 5, Cliffside Unit 5, and Belews Creek Units 1 and 2 from those in DEC's 2019  
15 Integrated Resource Plan (IRP).<sup>1</sup>

16 **Q What is the basis for DEC's assumed coal unit retirement dates?**

17 **A** DEC bases its retirement dates on the most recent depreciation study approved by  
18 the Commission.<sup>2</sup> In the 2019 IRP, the retirement dates were based on the  
19 depreciation study approved in the 2017 rate case. Spanos Exhibit 1 is the most  
20 recent depreciation study of which DEC is seeking approval in this docket, and  
21 the retirement dates listed above come from that study. The depreciation in that  
22 study refers generally to the loss of service value that result from "wear and tear,  
23 decay, action of the elements, obsolescence, changes in the art, changes in  
24 demand and the requirements of public authorities."<sup>3</sup> The depreciable life span  
25 estimates for DEC's coal units specifically considered the following: life spans of

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<sup>1</sup> Duke Energy Carolinas. *2019 Integrated Resource Plan*. Page 89.

<sup>2</sup> Duke Energy Carolinas. *2019 Integrated Resource Plan*. Page 89.

<sup>3</sup> Direct Testimony of John J. Spanos. Page 3, lines 9-14.

1 similar generating units, unit age, general operating characteristics, major  
2 refurbishments, and discussions with management personnel regarding the long-  
3 term outlook for the units.<sup>4</sup>

4 **Q Did DEC provide any economic analyses of alternative retirement dates in its**  
5 **2019 IRP or in this rate case?**

6 **A** No. DEC has not provided any economic analyses of alternative retirement dates  
7 for its coal units. DEC was ordered to do such an analysis as part of its 2020 IRP,<sup>5</sup>  
8 however, which is expected in September 2020.

9 **Q What is the implication of this lack of analysis?**

10 **A** The implication of this lack of analysis is that DEC has assumed that it is cost-  
11 effective for ratepayers if the utility operates its coal units based solely on their  
12 depreciable lives rather than performing an economic assessment. DEC has  
13 therefore provided no justification for continuing to invest in its coal units, and  
14 thus no basis for asking its customers to pay for capital expenditures associated  
15 with continued operation.

16 **Q Have recent electricity market trends affected the economics of coal units in**  
17 **the United States?**

18 **A** Recent market trends have had a negative impact on the general economics of  
19 coal units across the country and led to a sizable number of retirements.  
20 According to the U.S. Energy Information Administration (EIA), more than  
21 65,000 MW of coal capacity retired between 2007 and 2018.<sup>6</sup> Coal retirements in  
22 2018 alone totaled 12,900 MW.<sup>7</sup> A range of factors have contributed to these  
23 retirements, including sustained low gas prices and increased competition from

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<sup>4</sup> Spanos Exhibit 1. Page 40.

<sup>5</sup> North Carolina Utilities Commission. August 27, 2019. *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses.*

<sup>6</sup> U.S. EIA. 2018. *Today in energy: U.S. coal consumption in 2018 expected to be the lowest in 39 years.* Available at: <https://www.eia.gov/todayinenergy/detail.php?id=37817>.

<sup>7</sup> U.S. EIA. 2019. *Today in energy: More than 60% of electric generating capacity installed in 2018 was fueled by natural gas.* Available at: <https://www.eia.gov/todayinenergy/detail.php?id=38632>.

1 renewables, which can be expected to persist in the future. Competition from gas  
2 and renewables has led to decreases in capacity factors at the coal units that have  
3 continued to operate.<sup>8</sup>

4 **Q Have other utilities responded to these changes in the electric sector by**  
5 **conducting retirement assessments of their coal units?**

6 **A** Yes. Economic assessments of existing coal units have become an increasingly  
7 common component of utility resource planning. In its 2018 IRP, Northern  
8 Indiana Public Service Company (NIPSCO) examined alternative retirement dates  
9 for its five existing coal units, concluding that customers would save more than \$4  
10 billion by retiring those units in 2023 rather than operating them until 2030.<sup>9</sup>  
11 PacifiCorp's 2019 IRP includes a unit-by-unit retirement analysis of alternative  
12 retirement dates, years before the end of the units' depreciable lives, for each of  
13 its 22 coal units across its six-state service territory.<sup>10</sup> Georgia Power's 2019 IRP  
14 also included a retirement analysis for each of its existing coal units.<sup>11</sup>

15 **Q What are the important characteristics of a rigorous coal unit retirement**  
16 **analysis?**

17 **A** A rigorous analysis would include all costs and benefits associated with near-term  
18 and mid-term retirement dates. The continued operation of each coal unit would  
19 be compared to an optimized replacement resource portfolio, rather than a single  
20 replacement resource, that can provide all of the services that would otherwise be  
21 provided by the retiring unit. The cost of replacement resources should be  
22 informed by recent all-source requests for proposals (RFPs).

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<sup>8</sup> U.S. EIA. 2018. *Today in energy: U.S. coal consumption in 2018 expected to be the lowest in 39 years*. Available at: <https://www.eia.gov/todayinenergy/detail.php?id=37817>.

<sup>9</sup> Northern Indiana Public Service Company LLC. 2018. *Integrated Resource Plan*. Available at: <https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=15>.

<sup>10</sup> Utility Dive. 2019. *PacifiCorp sees 2 GW coal retirement, \$599M savings by 2040 in latest planning scenarios*. Available at: <https://www.utilitydive.com/news/pacifiCorp-sees-2-gw-coal-retirements-599m-savings-by-2040-in-latest-plann/562670/>.

<sup>11</sup> Georgia Power. 2019. *Technical Appendix Volume 2: Unit Retirement Study to 2019 Integrated Resource Plan*. Georgia Public Service Commission Docket No. 42310.



1 **IV. COAL-RELATED COSTS FOR WHICH DEC IS SEEKING RECOVERY**

2 **Q What types of coal unit expenses is DEC seeking to recover through this**  
3 **case?**

4 **A** DEC is seeking to recover three types of expenses associated with its coal-fired  
5 units in this case: operations and maintenance (O&M) expenses, ongoing capital  
6 expenditures, and previously incurred capital expenditures associated with unit  
7 maintenance and environmental projects.

8 **A What is the test year upon which DEC's rate case application is based?**

9 The test period is January 1, 2018 through December 31, 2018.

10 **Q What levels of O&M expense did DEC incur at its coal units in 2018?**

11 **A** The plant-specific O&M expenses incurred by DEC in 2018 are listed in Table 1.  
12 DEC's total 2018 O&M expense at its four coal plants totals \$192.8 million.

13 **Table 1. DEC coal plant O&M expense, 2018**

Cost Description	Allen	Belews Creek	Cliffside	Marshall
500 - Oper, Supv, and Engr Exp	\$ 2,509,861	\$ 3,864,728	\$ 2,808,785	\$ 4,440,801
502 - Steam Exp	\$ 5,259,905	\$ 16,818,140	\$ 15,502,867	\$ 15,631,121
505 - Electric Exp	\$ 1,640,748	\$ 1,401,414	\$ 1,960,610	\$ 2,335,330
506 - Misc Steam Power Exp	\$ 2,806,754	\$ 5,320,866	\$ 4,096,446	\$ 5,236,860
509 - Allowances	\$ 107	\$ 1,819	\$ 581	\$ 1,693
<b>Total Operations</b>	<b>\$ 12,217,375</b>	<b>\$ 27,406,967</b>	<b>\$ 24,369,289</b>	<b>\$ 27,645,805</b>
510 - Maintenance Supv and Engr	\$ 2,128,603	\$ 4,674,208	\$ 2,565,924	\$ 3,839,799
511 - Maintenance of Structures	\$ 2,901,369	\$ 12,067,660	\$ 4,035,090	\$ 5,164,734
512 - Maintenance of Boiler	\$ 3,434,025	\$ 13,785,625	\$ 10,981,066	\$ 12,355,167
513 - Maintenance of Electric Plant	\$ 1,258,030	\$ 7,305,692	\$ 3,411,695	\$ 6,067,265
514 - Maintenance of Misc Steam Plant	\$ 487,487	\$ 2,348,327	\$ 670,184	\$ 1,650,557
<b>Total Maintenance</b>	<b>\$ 10,209,514</b>	<b>\$ 40,181,512</b>	<b>\$ 21,663,959</b>	<b>\$ 29,077,522</b>
<b>Total Operation &amp; Maintenance</b>	<b>\$ 22,426,889</b>	<b>\$ 67,588,479</b>	<b>\$ 46,033,248</b>	<b>\$ 56,723,327</b>

14 *Source: Sierra Club DR 2-1 Attachment 1.xlsx.*

1 **Q What levels of capital expense did DEC incur at its coal units in 2018?**

2 **A** The plant-specific capital expenses incurred by DEC in 2018 are listed in Table 2.  
 3 DEC's total 2018 capital expense at its four coal plants totals \$509.4 million. This  
 4 includes expenditures classified by the Company as associated with ash and  
 5 wastewater compliance under the Coal Combustion Residuals (CCR) rule and the  
 6 Effluent Limitation Guidelines (ELG) as well as capital expenditures associated  
 7 with maintenance and investment.<sup>12</sup>

8 **Table 2. DEC coal plant capital expense, 2018**

Plant	CCR/ELG	Non- Environmental	Total CapEx
<b>Allen</b>	\$70,376,644	\$22,182,553	\$92,559,197
<b>Belews Creek</b>	\$52,831,663	\$91,945,624	\$144,777,287
<b>Cliffside</b>	\$14,646,379	\$100,399,363	\$115,045,743
<b>Marshall</b>	\$83,469,539	\$73,513,019	\$156,982,558
<b>Total</b>	\$221,324,225	\$288,040,559	\$509,364,784

9 *Source: Sierra Club 2-1c DEC Capital – Supplemental.xls.*

10 **Q What levels of capital expense is DEC planning to incur at its coal units in**  
 11 **future projections?**

12 **A** The plant-specific capital expenses planned by DEC for the 10-year period  
 13 between 2019 and 2028 are listed in Confidential Table 3. The combined  
 14 environmental and non-environmental capital expenditures total almost [BEGIN  
 15 CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] in 2019 alone.

<sup>12</sup> Synapse sorted Duke's capital expenditures into the CCR/ELG and non-environmental categories.

1 Confidential Table 3. [REDACTED]

Year	Environmental				Non-Environmental				Total
	Allen	Belews Creek	Cliffside	Marshall	Allen	Belews Creek	Cliffside	Marshall	
2019	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
2020	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
2021	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
2022	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
2023	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
2024	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
2025	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
2026	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
2027	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
2028	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

2 Source: CONFIDENTIAL\_DEC Sierra Club DR 2-13.xlsx, No CO2 Constraints.

3 V. HISTORICAL ECONOMIC STATUS OF DEC COAL UNITS

4 Q Did you assess the recent performance of DEC’s coal units?

5 A Yes. Using data provided by DEC, I evaluated the net value of each of DEC’s  
6 coal units between 2016 and 2018.

7 Q Please summarize your findings regarding the recent economic performance  
8 of DEC’s coal units.

9 A Confidential Table 4 summarizes the results of my analysis. I find that for each of  
10 DEC’s coal units, the costs to maintain and operate the unit exceeded the value  
11 provided by the unit by a total of [BEGIN CONFIDENTIAL] [REDACTED]  
12 [REDACTED] [END CONFIDENTIAL] over the three-year period. [BEGIN  
13 CONFIDENTIAL] [REDACTED]  
14 [REDACTED] [END CONFIDENTIAL]<sup>13</sup>

<sup>13</sup> [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL]

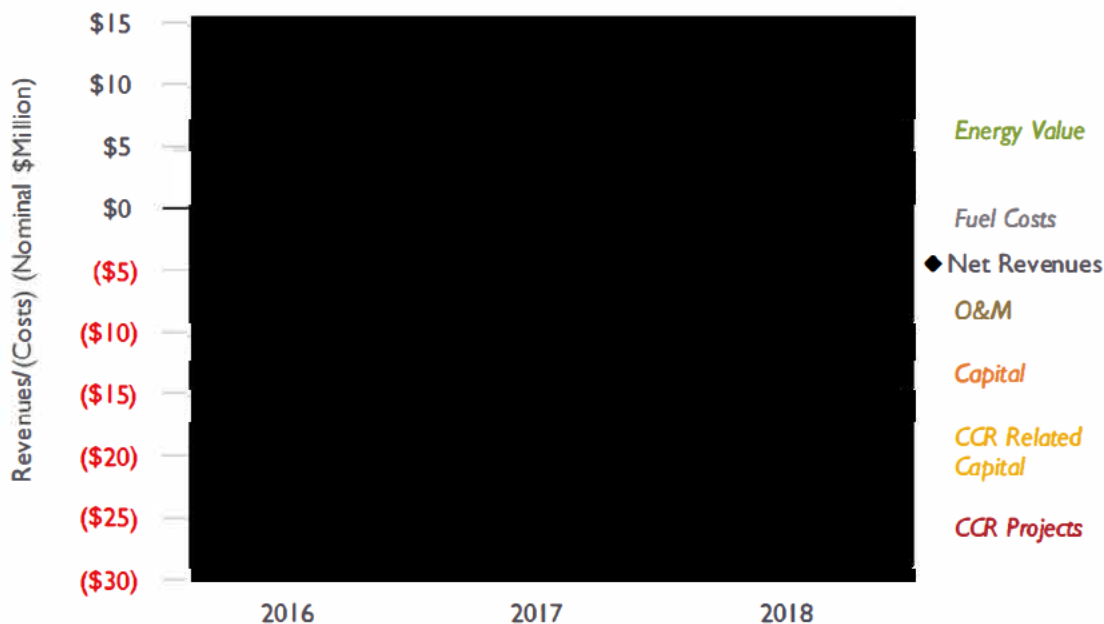
1 **Confidential Table 4.** [REDACTED]

Unit	2016	2017	2018	Total
Allen 1	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 2	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 3	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 4	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 5	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Cliffside 5	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Cliffside 6	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 1	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 2	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 3	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 4	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Belews Creek 1	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Belews Creek 2	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

2 *Sources: DEC discovery responses; Synapse tabulation.*

3 Confidential Figure 1 shows the energy value and cost streams for Allen 1, as  
 4 well as the unit's net revenues between 2016 and 2018. Individual results for the  
 5 other 12 DEC units are shown in Confidential Exhibit RW-2.

1 **Confidential Figure 1.** [REDACTED]

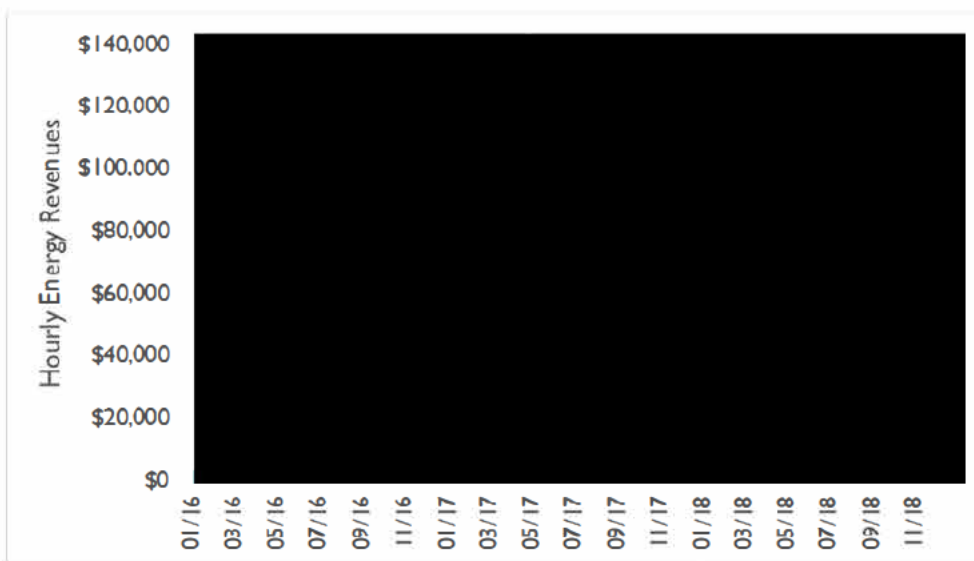


2

3 **Q Why do the units have higher energy values in 2018 despite producing less**  
 4 **energy on average compared to 2016 and 2017?**

5 **A** This is mainly attributed to the cold snap in early 2018, as shown in Confidential  
 6 Figure 2, below. The hourly lambda for the peak times in January 2018 increased  
 7 to [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL].  
 8 Therefore, the units earned a disproportionate amount of value compared to  
 9 previous months due to this cold snap.

1 **Confidential Figure 2.** [REDACTED]



2

3 **Q Describe how you arrived at the values in Confidential Table 4.**

4 **A** The values presented are based on data related to each unit's energy value, fuel  
 5 costs, O&M costs, environmental costs, capital costs, and ash management costs.  
 6 DEC provided historical hourly generation for each of the units.<sup>14</sup> To calculate  
 7 each unit's energy value, each unit's converted hourly net generation was

<sup>14</sup> DEC Response to Sierra Club DR 2-10, attachments "CONFIDENTIAL 2019 DEC NC Sierra Club 2-10 – DEC Coal HourlyProdCost2018-2019.xls" and CONFIDENTIAL 2019 DEC NC SC 2-10e- Coal HourlyProdCost 2016-2017-Supplemental.xls".

Although DEC did not specify if these hourly generation values were gross or net, a comparison to the monthly net generation values that were provided in 2-10D indicate that the hourly values were gross. Despite the fact that we had explicitly requested hourly net generation via discovery, DEC provided monthly net generation values to SC 2-10D. In DEC's response to SC 2-10E, the Company provided hourly production costs and hourly generation in MWh. Because the monthly net generation values provided in 2-10D were always smaller than the hourly generation values aggregated to the monthly level provided in 2-10E, it is valid to assume the hourly values are gross. For example, the net generation for Allen 1 in May 2016 was reported by DEC in 2-10D to be [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] MWh. However, when the hourly MWh values for Allen 1 in May 2016 from 2-10E are summed, the result is zero. Because negative hourly generation values never appear in 2-10E, the values must be gross.

To convert the hourly gross generation to hourly net generation, the hourly gross values were multiplied by a net-to-gross ratio. This ratio was calculated by dividing the provided monthly net generation by the aggregated hourly gross generation for each unit, month, and year.

1 multiplied by the relevant hourly DEC system lambda<sup>15</sup> as provided in  
2 discovery.<sup>16</sup>

3 DEC provided the total fuel cost burned at the plant-level, and these costs were  
4 allocated based on annual generation levels to get unit-level fuel costs.<sup>17</sup>

5 DEC also provided O&M costs at the plant-level. Although it is standard to show  
6 fixed O&M costs separately from non-fuel variable O&M costs, DEC stated in  
7 discovery that “the Company does not identify historical costs as either fixed or  
8 variable.”<sup>18</sup> For this reason, the O&M costs are shown as one category and the  
9 plant-level costs are divided into unit-level costs using annual generation levels.

10 DEC provided plant-level capital costs. For the years 2016 and 2017, these  
11 capital costs were classified by category.<sup>19</sup> These categories included  
12 “Environmental”, “Investment”, and “Maint-Maint”. The capital cost workbook  
13 also had a column to indicate if the cost was related to Coal Combustion Products.  
14 The capital costs provided for 2018 were not labeled by category, nor was there a  
15 column to indicate if the cost was related to Coal Combustion Products.<sup>20</sup> It was  
16 therefore assumed that a capital expenditure was associated with Coal  
17 Combustion Products if it had the text “CCP” or “Bottom Ash Conversion” in the  
18 project description. Because all capital costs were provided at the plant-level, they  
19 were allocated to individual units based on nameplate capacity.

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<sup>15</sup> The term “system lambda” refers to the marginal cost of electricity in a system and, in an electricity market, is the locational marginal price of energy in a given hour.

<sup>16</sup> DEC Response to Sierra Club DR 2-10, attachment “SCDR\_2-10a\_DECSysystemLambda.xls”.

<sup>17</sup> DEC Response to Sierra Club DR 2-9, attachment “CONFIDENTIAL DEC Sierra DR 2-9i\_supplemental.xls”.

<sup>18</sup> DEC Response to Sierra Club DR 2-1.

<sup>19</sup> DEC Response to Sierra Club DR 2-9, attachment “2019 DEC NC SC 2-9 j,k Capex DEC 2016-2017-Supplemental.xls”.

<sup>20</sup> DEC Response to Sierra Club DR 2-1, attachment “2019 DEC NC Sierra Club 2-1 c DEC Capital – Supplemental.xls”.

1 DEC also provided cost estimates for coal ash remediation projects by plant.<sup>21</sup>  
 2 These values were allocated to individual units based on nameplate capacity size.  
 3 Fuel, O&M, capital costs, and coal ash management costs were subtracted from  
 4 each unit’s energy value to arrive at annual net value.

5 **Q Did you evaluate the economics of the plants without the historical capital**  
 6 **expenditures?**

7 **A** Yes. The results of the economic analysis that exclude historical capital  
 8 expenditures are shown in Confidential Table 5. [BEGIN CONFIDENTIAL]  
 9 [REDACTED]  
 10 [REDACTED] [END CONFIDENTIAL]. The remaining units have a [BEGIN  
 11 CONFIDENTIAL] [REDACTED]  
 12 [REDACTED] [END CONFIDENTIAL]. Once again, [BEGIN  
 13 CONFIDENTIAL] [REDACTED]  
 14 [REDACTED] [END CONFIDENTIAL].

15 **Confidential Table 5.** [REDACTED]  
 16 [REDACTED]

Unit	2016	2017	2018	Total
Allen 1	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 2	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 3	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 4	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 5	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Cliffside 5	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Cliffside 6	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 1	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 2	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 3	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 4	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Belews Creek 1	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Belews Creek 2	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

<sup>21</sup> DEC Response to Sierra Club DR 2-18, attachment “DEC SC 2-18.xlsx”.



1

2 **Q What are your recommendations to the Commission with regard to any**  
3 **request for recovery of past spending on capital projects at DEC's coal units?**

4 **A** I recommend that the Commission disallow past spending on capital projects  
5 incurred between the 2017 rate case and this rate case, given that the data show  
6 that all of DEC's units had negative net value in 2016 and 2017, and nine of  
7 DEC's thirteen units had net negative value in 2018. DEC made capital  
8 investments in these coal-fired units either without evaluating the economics of  
9 continuing to operate the units, or despite the fact that the units had negative value  
10 to DEC ratepayers. Capital spending during this time period should be disallowed  
11 until DEC provides evidence of an analysis demonstrating the value of the  
12 investment done at the time the investment decision was made.

13 **Q Do you have any recommendations with respect to the operation of DEC's**  
14 **coal units?**

15 **A** The data indicate that DEC's coal units only have positive net value in years with  
16 extreme weather. DEC should thus consider operating its units seasonally and  
17 only during months of peak demand to minimize losses to ratepayers until their  
18 retirement dates.

19 **VI. FORWARD-LOOKING ECONOMIC STATUS OF DEC COAL UNITS**

20 **Q Did you also evaluate the forward-looking economic performance of DEC's**  
21 **coal units?**

22 **A** Yes. I analyzed the projected energy value of DEC's coal units in each year from  
23 2019 to 2040 using data provided by the Company.

24 **Q Please summarize the results of that forward-looking economic analysis.**

25 **A** Based on DEC's projections, I find that the Company's coal units are likely to  
26 [BEGIN CONFIDENTIAL] [REDACTED] [END  
27 CONFIDENTIAL]. Confidential Table 6 indicates that [BEGIN  
28 CONFIDENTIAL] [REDACTED]

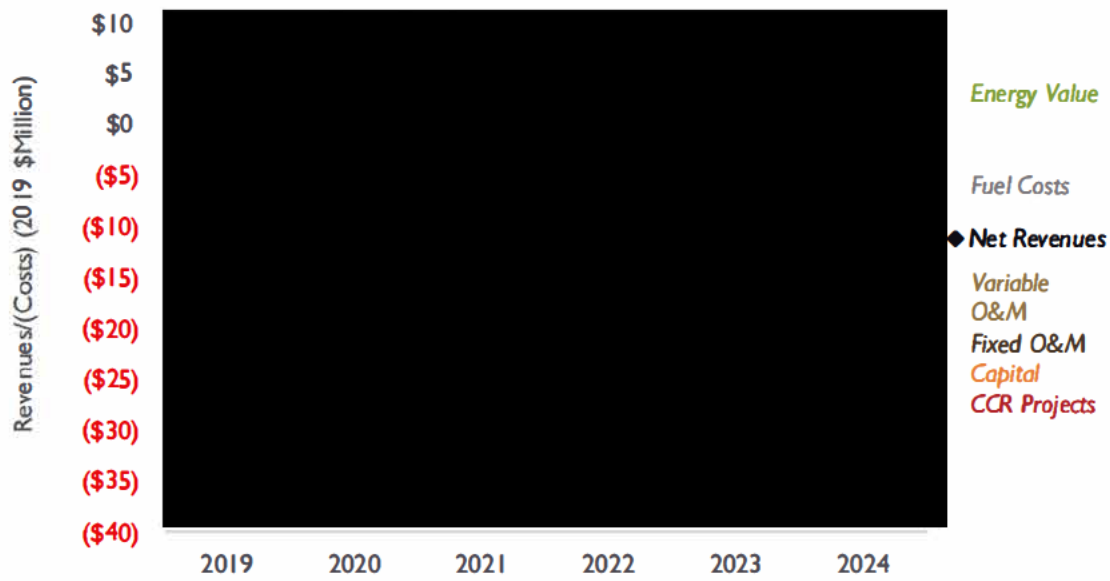
1 [REDACTED] [END  
 2 CONFIDENTIAL]. Values for 2029 to 2040 are not shown, but the [BEGIN  
 3 CONFIDENTIAL] [REDACTED] [END  
 4 CONFIDENTIAL].

5 **Confidential Table 6.** [REDACTED]

Unit	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Allen 1	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 2	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 3	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 4	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Allen 5	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Cliffside 5	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Cliffside 6	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 1	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 2	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 3	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Marshall 4	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Belews Creek 1	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Belews Creek 2	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

6  
 7 Confidential Figure 3 shows the projected energy value and cost streams for Allen  
 8 1, as well as the unit’s net revenues between 2019 and 2024. In 2019, [BEGIN  
 9 CONFIDENTIAL] [REDACTED]  
 10 [REDACTED] [END CONFIDENTIAL] for a unit that it planned to retire at the end of  
 11 2024. Results for the remaining DEC units are shown in Confidential Exhibit  
 12 RW-3.

1 Confidential Figure 3. [REDACTED]



2

3 **Q Describe how you evaluated the forward-looking economic performance of**  
4 **DEC’s coal units.**

5 **A** The net values presented are based on DEC data related to each unit’s projected  
6 energy revenues, fuel costs, O&M costs, and capital costs.

7 DEC declined to provide the forecasted avoided energy costs or projected energy  
8 market prices requested through discovery. In response to discovery follow ups,  
9 the only resource DEC provided was their proposed avoided cost energy rate  
10 schedule from NCUC Docket No. E-100, sub 158.<sup>22</sup> Therefore, the Variable Rate  
11 for Annualized Energy of 3.03 cents per KWh from the attachment was used to  
12 calculate projected energy revenues for each unit. The rate was taken to be in  
13 2018\$ and converted to nominal dollars for the duration of the analysis period.<sup>23</sup>

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<sup>22</sup> DEC Response to Sierra Club DR 2-14, attachment “DEC Sierra 2-14 Avoided Cost Annualized Rates.pdf”.  
<sup>23</sup> DEC Second Supplemental Response to Sierra Club DR 2-14.

1 DEC directly provided unit-specific capacity, capacity factor, fixed O&M, fuel  
2 costs, and capital costs based upon their 2019 IRP studies.<sup>24</sup> DEC also provided  
3 unit-specific capital costs and fixed O&M costs for Allen 4, Allen 5, and Cliffside  
4 5 based upon their 2019 depreciation study with accelerated retirement dates.<sup>25</sup>  
5 The values from the Company's "No CO2 Constraint" IRP analysis were used as  
6 given for all units except for Allen 4, Allen 5, and Cliffside 5. For those three  
7 units, the CapEx and fixed O&M data provided by the IRP study were replaced  
8 with the updated values from the depreciation study because they take into  
9 account the accelerated retirement dates. The generation, variable O&M costs,  
10 and fuel costs were adjusted to be zero in the years following the units'  
11 retirements, as opposed to the values the IRP study had assumed.

12 DEC directly provided forecasted ash management costs through 2040 by plant.<sup>26</sup>  
13 These costs were allocated to each unit using nameplate capacity.

14 Fuel, O&M, capital costs, and forecasted coal ash management costs were  
15 subtracted from energy revenues to arrive at net revenues for each plant and each  
16 year.

17 **Q What are the implications of these uneconomic results for ratepayers?**

18 **A** The continued negative values associated with DEC's coal units means that  
19 ratepayers will continue to pay for the Company's uneconomic operation of its  
20 coal fleet.

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<sup>24</sup> DEC Response to Sierra Club DR 2-13, attachment "CONFIDENTIAL 2019 DEC NC SCDR\_2-13\_a-o\_t\_DEC\_CONFIDENTIAL.xlsx".

<sup>25</sup> DEC Response to Sierra Club DR 2-5, attachment "CONFIDENTIAL 2019 DEC NC\_SierraClub\_DR2-5\_Nov2019DECRetirementAnalysis.xls".

<sup>26</sup> DEC Response to Sierra Club DR 2-18, attachment "DEC SC 2-18.xlsx".

1 **Q Do your findings regarding the recent negative values associated with DEC's**  
2 **coal units indicate that the Company should retire all of its coal units**  
3 **immediately?**

4 **A** No. Retirement of DEC's entire coal fleet at once would likely lead to reliability  
5 issues in DEC's service territory. It is also possible that retirement of a portion of  
6 DEC's coal fleet may improve the economics of the remaining coal units.  
7 However, the recent net losses of DEC's coal units should, at a minimum,  
8 encourage DEC to perform a rigorous economic assessment of alternative  
9 retirement dates for each of its units.

10 **Q Are there additional reasons that DEC should evaluate alternative**  
11 **retirement dates for its coal units?**

12 **A** Yes. On October 29, 2018, Governor Roy Cooper signed Executive Order 80,  
13 which directed the North Carolina Department of Environmental Quality to  
14 develop a Clean Energy Plan. That Plan was released in October 2019, setting a  
15 goal to reduce emissions of carbon dioxide (CO<sub>2</sub>) from the electric sector by 70  
16 percent below 2005 levels by 2030.<sup>27</sup> In a separate docket, Duke Energy Progress  
17 stated that in order to reduce emissions commensurate with North Carolina goals,  
18 as well as its own corporate goals, it would need to accelerate the pace of coal  
19 plant retirements and replace those units with low-emitting resources.<sup>28</sup>  
20 Duke Energy, DEC's parent company, also has its own carbon-reduction goals,  
21 which are to cut CO<sub>2</sub> emissions by 50 percent or more by 2030 and to attain net-  
22 zero emissions by 2050.<sup>29</sup>

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<sup>27</sup> North Carolina Department of Environmental Quality. 2019. *North Carolina Clean Energy Plan*. Available at: [https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC\\_Clean\\_Energy\\_Plan\\_OCT\\_2019\\_.pdf](https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf).

<sup>28</sup> Duke Energy Progress. Response to Friesian Holdings Data Request 2-8. Docket No. EMP-105, Sub 0.

<sup>29</sup> Duke Energy. *Global Climate Change*. Available at: <https://www.duke-energy.com/our-company/environment/global-climate-change>.

1 **Q** What are your recommendations to the Commission with regard to any  
2 request for recovery of future capital investments at DEC's coal units?

3 **A** I recommend that the Commission place a cap on future capital expenditures  
4 intended to prolong the lives of the DEC units as generating assets, and require  
5 the utilities to come to the Commission for approval of any expenditure that  
6 exceeds that cap before the expenditure can be recovered from ratepayers. The  
7 cap could be lower for units with near-term retirement dates as indicated by the  
8 most recent depreciation study, e.g. Allen Units 1-4, with a service life that ends  
9 in 2024. The cap could also be contingent upon the results of DEC's unit  
10 retirement study, to be included with the 2020 IRP.

11 Similar action has been taken in other jurisdictions. The Georgia Public Service  
12 Commission, for example, recently applied a cap to capital spending at the  
13 utility's Bowen plant in the recent 2019 proceeding.<sup>30</sup>

## 14 **VII. PRUDENCE OF DEC INVESTMENTS IN ITS COAL UNITS**

15 **Q** Has DEC demonstrated the prudence of its historical capital investments in  
16 its coal units, for which it is seeking cost recovery?

17 **A** No. In order to demonstrate prudence in the context of utility planning, DEC  
18 would need to show that its decision to commit to a particular power plant  
19 construction project is justified. Planning prudence includes consideration of a  
20 reasonable set of alternatives, the use of appropriate models and methodologies,  
21 and the collection and application of current forecasts and data. Costs that are  
22 found by regulators to have been incurred imprudently should generally be  
23 disallowed from rates. Similarly, assets that are not used and useful should be  
24 removed from rate base. Customers should not be asked to bear the burden  
25 associated with unjustified system planning decisions.

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<sup>30</sup> Georgia Public Service Commission. 2019. Docket No. 42310. Order Adopting Stipulation as Amended. Attached as Exhibit RW-4.

1 **Q What do you mean by “used and useful” in this context?**

2 **A** The “used” part of the “used and useful” standard is relatively straightforward.  
3 Specifically, regulators should determine whether a particular asset is physically  
4 used in providing service to customers. Examples of equipment not “used” in  
5 providing service can include power plants that have been retired from service,  
6 environmental retrofit equipment that is not operated, transmission or distribution  
7 equipment that has been removed from the grid, and previously installed meters  
8 that are uninstalled as part of a meter replacement program.

9 The “useful” portion is more complex, as a particular item can be used in  
10 providing service but not be economically useful. For example, there may have  
11 been a power plant construction project that was planned in a prudent manner but  
12 may operate at costs significantly higher than the economic value of the output for  
13 reasons beyond the utility’s control and ability to reasonably foresee. In such a  
14 circumstance a regulatory commission may find that the plant is prudent and used,  
15 but not economically useful in providing service to customers.

16 **Q Why are these ratemaking concepts important in this docket?**

17 **A** DEC is effectively requesting that the Commission determine that its past and  
18 future capital expenditures represent prudent investments in its coal fleet. I  
19 understand that the Commission applies a presumption of prudence to utility  
20 expenditures in some circumstances. There have been no other dockets before the  
21 Commission to determine whether DEC’s capital expenditures were prudent prior  
22 to the Company actually spending the money, or whether DEC’s coal units are  
23 “used and useful.” Therefore, it is important that the Commission consider the  
24 economics of each of the units when ruling on DEC’s application in this docket.  
25 While the Commission might consider DEC’s coal fleet “used” because it  
26 provides energy to ratepayers, given the fact that the coal units are providing  
27 energy uneconomically, and increasing costs to DEC ratepayers, they are not  
28 currently “useful.”

1 **Q Does DEC provide evidence in this docket of either prudence in its capital**  
2 **spending at its coal units or that they are used and useful?**

3 **A** No. DEC witness Steve Immel testifies only to the used and usefulness of the gas  
4 conversions at Cliffside Unit 5 and 6 and Belews Creek Unit 1, stating that “The  
5 conversion of Cliffside Station and Belews Creek Unit 1 provides customers with  
6 flexibility to utilize the most cost-effective fuel. The compliance efforts and the  
7 conversion of Cliffside Station and Belews Creek Unit 1 are used and useful,  
8 providing customers reliable low-cost generation. The capital investments  
9 position the Company to provide safe, reliable, and efficient operation of these  
10 assets, with high quality performance.”<sup>31</sup>

## 11 **VIII. CONCLUSIONS AND RECOMMENDATIONS**

12 **Q Please summarize your conclusions.**

13 **A** My primary findings indicate that all DEC’s coal units operated uneconomically  
14 for at least the three years between 2016 and 2018. I estimate that each of the coal  
15 units had negative net value of between [BEGIN CONFIDENTIAL] [REDACTED]  
16 and [REDACTED] [END CONFIDENTIAL] from 2016 to 2018. Despite these net  
17 losses, DEC continues to determine unit retirement dates for its coal fleet based  
18 solely on depreciation studies and continues to invest in its uneconomic coal  
19 units.

20 My analysis shows that each of DEC’s coal units will continue to operate  
21 uneconomically in the future. DEC has not provided any economic assessments of  
22 the continued operation of its coal-fired units, even as low gas prices and  
23 declining costs for renewables have disadvantaged many coal units across the  
24 country. Thus, the Company has not demonstrated that continuing to invest in its  
25 coal fired units is a prudent decision and provides value to ratepayers.

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<sup>31</sup> Direct Testimony of Steve Immel. Page 7, lines 4-9.



1 **Q Please summarize your recommendations.**

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

- 3 1. I recommend that the Commission disallow past spending on capital projects  
4 incurred between the 2017 rate case and this rate case, given that the data  
5 show that all of DEC's units had negative net value in 2016 and 2017, and  
6 nine of DEC's thirteen units had net negative value in 2018. Capital spending  
7 during this time period should be disallowed until DEC provides evidence of  
8 an analysis demonstrating the value of the investment done at the time the  
9 investment decision was made.
- 10 2. I recommend that DEC consider operating its units seasonally and only during  
11 months of peak demand to minimize losses to ratepayers.
- 12 3. I recommend that the Commission place a cap on future capital expenditures  
13 intended to prolong the lives of the DEC units as generating assets, and  
14 require the utilities to come to the Commission for approval of any  
15 expenditure that exceeds that cap before the expenditure can be recovered  
16 from ratepayers.

17 **Q Does this conclude your direct testimony?**

18 **A** Yes, it does.



**SIERRA CLUB**  
**WILSON EXHIBIT RW-1**

**RESUME**

Docket No. e-7, Sub 1214

**Rachel Wilson, Principal Associate**

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**PROFESSIONAL EXPERIENCE**

**Synapse Energy Economics Inc.**, Cambridge, MA. *Principal Associate*, April 2019 – present, *Senior Associate*, 2013 – 2019, *Associate*, 2010 – 2013, *Research Associate*, 2008 – 2010.

Provides consulting services and expert analysis on a wide range of issues relating to the electricity and natural gas sectors including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; electric system dispatch; and environmental compliance technologies, strategies, and costs. Uses optimization and electricity dispatch models, including Strategist, PLEXOS, EnCompass, PROMOD, and PROSYM/Market Analytics to conduct analyses of utility service territories and regional energy markets.

**Analysis Group, Inc.**, Boston, MA.

*Associate*, 2007 – 2008, *Senior Analyst Intern*, 2006 – 2007.

Provided litigation support and performed data analysis on various topics in the electric sector, including tradeable emissions permitting, coal production and contractual royalties, and utility financing and rate structures. Contributed to policy research, reports, and presentations relating to domestic and international cap-and-trade systems and linkage of international tradeable permit systems. Managed analysts' work processes and evaluated work products.

**Yale Center for Environmental Law and Policy**, New Haven, CT. *Research Assistant*, 2005 – 2007.

Gathered and managed data for the Environmental Performance Index, presented at the 2006 World Economic Forum. Interpreted statistical output, wrote critical analyses of results, and edited report drafts. Member of the team that produced *Green to Gold*, an award-winning book on corporate environmental management and strategy. Managed data, conducted research, and implemented marketing strategy.

**Marsh Risk and Insurance Services, Inc.**, Los Angeles, CA. *Risk Analyst*, Casualty Department, 2003 – 2005.

Evaluated Fortune 500 clients' risk management programs/requirements and formulated strategic plans and recommendations for customized risk solutions. Supported the placement of \$2 million in insurance premiums in the first year and \$3 million in the second year. Utilized quantitative models to create loss forecasts, cash flow analyses and benchmarking reports. Completed a year-long Graduate Training Program in risk management; ranked #1 in the western region of the US and shared #1 national ranking in a class of 200 young professionals.

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## EDUCATION

**Yale School of Forestry & Environmental Studies**, New Haven, CT

Masters of Environmental Management, concentration in Law, Economics, and Policy with a focus on energy issues and markets, 2007

**Claremont McKenna College**, Claremont, California

Bachelor of Arts in Environment, Economics, Politics (EEP), 2003. *Cum laude* and EEP departmental honors.

**School for International Training**, Quito, Ecuador

Semester abroad studying Comparative Ecology. Microfinance Intern – Viviendas del Hogar de Cristo in Guayaquil, Ecuador, Spring 2002.

## ADDITIONAL SKILLS AND ACCOMPLISHMENTS

- Microsoft Office Suite, Lexis-Nexis, Platts Energy Database, Strategist, PROMOD, PROSYM/Market Analytics, EnCompass, and PLEXOS, some SAS and STATA.
- Competent in oral and written Spanish.
- Hold the Associate in Risk Management (ARM) professional designation.

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## TESTIMONY

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**Georgia Public Service Commission (Docket No. 42310 & 42311):** Direct testimony of Rachel Wilson regarding various components of Georgia Power's 2019 Integrated Resource Plan. On behalf of the Sierra Club. April 25, 2019.

**Washington Utilities and Transportation Commission (Dockets UE-170485 & UG-170486):** Response testimony regarding Avista Corporation's production cost modeling. On behalf of Public Counsel Unit of the Washington Attorney General's Office. October 27, 2017.

**Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449):** Cross-rebuttal testimony evaluating Southwestern Electric Power Company's application for authority to change rates to recover the costs of investments in pollution control equipment. On behalf of Sierra Club and Dr. Lawrence Brough. May 19, 2017.

**Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449):** Direct testimony evaluating Southwestern Electric Power Company's application for authority to change rates to recover the costs of investments in pollution control equipment. On behalf of Sierra Club and Dr. Lawrence Brough. April 25, 2017.

**Virginia State Corporation Commission (Case No. PUE-2015-00075):** Direct testimony evaluating the petition for a Certificate of Public Convenience and Necessity filed by Virginia Electric and Power Company to construct and operate the Greensville County Power Station and to increase electric rates to recover the cost of the project. On behalf of Environmental Respondents. November 5, 2015.

**Missouri Public Service Commission (Case No. ER-2014-0370):** Direct and surrebuttal testimony evaluating the prudence of environmental retrofits at Kansas City Power & Light Company's La Cygne Generating Station. On behalf of Sierra Club. April 2, 2015 and June 5, 2015.

**Oklahoma Corporation Commission (Cause No. PUD 201400229):** Direct testimony evaluating the modeling of Oklahoma Gas & Electric supporting its request for approval and cost recovery of a Clean Air Act compliance plan and Mustang modernization, and presenting results of independent Gentrader modeling analysis. On behalf of Sierra Club. December 16, 2014.

**Michigan Public Service Commission (Case No. U-17087):** Direct testimony before the Commission discussing Strategist modeling relating to the application of Consumers Energy Company for the



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authority to increase its rates for the generation and distribution of electricity. On behalf of the Michigan Environmental Council and Natural Resources Defense Council. February 21, 2013.

**Indiana Utility Regulatory Commission (Cause No. 44217):** Direct testimony before the Commission discussing PROSYM/Market Analytics modeling relating to the application of Duke Energy Indiana for Certificates of Public Convenience and Necessity. On behalf of Citizens Action Coalition, Sierra Club, Save the Valley, and Valley Watch. November 29, 2012.

**Kentucky Public Service Commission (Case No. 2012-00063):** Direct testimony before the Commission discussing upcoming environmental regulations and electric system modeling relating to the application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity and for approval of its 2012 environmental compliance plan. On behalf of Sierra Club. July 23, 2012.

**Kentucky Public Service Commission (Case No. 2011-00401):** Direct testimony before the Commission discussing STRATEGIST modeling relating to the application of Kentucky Power Company for a Certificate of Public Convenience and Necessity, and for approval of its 2011 environmental compliance plan and amended environmental cost recovery surcharge. On behalf of Sierra Club. March 12, 2012.

**Kentucky Public Service Commission (Case No. 2011-00161 and Case No. 2011-00162):** Direct testimony before the Commission discussing STRATEGIST modeling relating to the applications of Kentucky Utilities Company, and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity, and approval of its 2011 compliance plan for recovery by environmental surcharge. On behalf of Sierra Club and Natural Resources Defense Council (NRDC). September 16, 2011.

**Minnesota Public Utilities Commission (OAH Docket No. 8-2500-22094-2 and MPUC Docket No. E-017/M-10-1082):** Rebuttal testimony before the Commission describing STRATEGIST modeling performed in the docket considering Otter Tail Power's application for an Advanced Determination of Prudence for BART retrofits at its Big Stone plant. On behalf of Izaak Walton League of America, Fresh Energy, Sierra Club, and Minnesota Center for Environmental Advocacy. September 7, 2011.

## PRESENTATIONS

Wilson, R. 2017. "Integrated Resource Planning: Past, Present, and Future." Presentation for the Michigan State University Institute of Public Utilities Grid School. March 29, 2017.

Wilson, R. 2015. "Best Practices in Clean Power Plan Planning." NASEO/ACEEE Webinar. June 29, 2015.

Wilson, R. 2009. "The Energy-Water Nexus: Interactions, Challenges, and Policy Solutions." Presentation for the National Drinking Water Symposium. October 13, 2009.

*Resume dated October 2019*



**SIERRA CLUB**  
**WILSON EXHIBIT RW-4**  
**GEORGIA STIPULATION**

Docket No. e-7, Sub 1214

## COMMISSIONERS:

LAUREN "BUBBA" McDONALD, CHAIRMAN  
 TIM G. ECHOLS  
 CHUCK EATON  
 TRICIA PRIDEMORE  
 JASON SHAW



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EXECUTIVE SECRETARY  
G.P.S.C.DEBORAH K. FLANNAGAN  
EXECUTIVE DIRECTORREECE McALISTER  
EXECUTIVE SECRETARYDOCKET# 42310, 42311  
DOCUMENT# 177908, 177909

Georgia Public Service Commission

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- Docket No: 42310** In Re: Georgia Power Company's 2019 Integrated Resource Plan and Application for Certification of Capacity from Plant Scherer Unit 3 and Plant Goat Rock Units 9-12, Application for Decertification of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6 and Plant Riverview Units 1-2.
- Docket No. 42311** In Re: Georgia Power Company's 2019 Application for the Certification, Decertification, and Amended Demand-Side Management Plan.

ORDER ADOPTING STIPULATION AS AMENDED

## APPEARANCES:

On behalf of Georgia Public Service Commission:

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 PRESTON THOMAS, Attorney  
 -and-  
 DANIEL WALSH, Attorney  
 Office of the Attorney General

On behalf of Georgia Power Company:

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 BRANDON MARZO, Attorney  
 STEVE HEWITSON, Attorney

ALAN R. JENKINS, Attorney

**On behalf of Concerned Ratepayers of Georgia:**

STEVEN PRENOVITZ  
BEN STOCKTON

**On behalf of Emory University:**

WILLIAM W. MAYCOCK, Attorney  
R. DANIELLE BURNETTE, Attorney

**On behalf of Georgia Association of  
Manufacturers and Georgia Industrial Group:**

CHARLES B. JONES, III, Attorney

**On behalf of Georgia Distributed Generation  
Group, Inc.:**

DARGAN SCOTT COLE, Attorney

**On behalf of Georgia Interfaith Power & Light  
and Partnership for Southern Equity:**

KURT EBERSBACH, Attorney  
STACEY SHELTON, Attorney  
CHRISTINA ANDREEN, Attorney

**On behalf of Georgia Large Scale Solar  
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WILLIAM BRADLEY CARVER, SR., Attorney

**On behalf of Solar Energy Industries  
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Energy Association, Inc.:**

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STEVEN L. JONES, Attorney

**On behalf of Georgia Watch:**

LIZ COYLE

BERNETA L. HAYNES, Attorney

**On behalf of McFinney, LLC:**

JOE McDONOUGH, Managing Partner

**On behalf of Resource Supply Management:**

JAMES CLARKSON

**On behalf of the Sierra Club:**

ROBERT JACKSON, Attorney  
ZACHARY M. FABISH, Attorney  
KASEY STURM, Attorney

**On behalf of Southern Alliance for Clean  
Energy:**

ROBERT B. BAKER, Attorney

**On behalf of Southern Renewable Energy  
Association:**

BRUCE BURCAT, Attorney

**On behalf of Southface Energy Institute and  
Vote Solar:**

STEPHEN E. O'DAY, Attorney

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**BY THE COMMISSION:**

On January 31, 2019, Georgia Power Company ("Georgia Power" or the "Company") submitted to the Georgia Public Service Commission ("Commission") an Application for Integrated Resource Plan ("IRP" or "Plan") for approval pursuant to O.C.G.A. § 46-3A-1 *et. Seq.* Included in the Company's filing was an Application for Certification Capacity from Plant Scherer Unit 3 and

Plant Goat Rock Units 9-12, Application for Decertification of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6 and Plant Riverview Units 1-2, Docket No. 42310. The Company also simultaneously submitted an Application for the Certification, Decertification, and Amended Demand-Side Management Plan (“DSM Application”) Docket No. 42311.

## JURISDICTION AND AUTHORITY

Georgia Power is a public electric utility serving retail customers within the State of Georgia. Georgia Power is one of the retail operating companies of which the Southern Company system is comprised. This Commission has jurisdiction over Georgia Power’s IRP and DSM Application pursuant to O.C.G.A. § 46-2-20, 46-2-21, 46-2-23 generally, and the IRP Act in particular.

The IRP Act requires the Company to file an Integrated Resource Plan at least every three years.<sup>1</sup> The Company’s obligations with respect to the information that is filed is set forth pursuant to criteria identified in the Commission’s IRP Rules. A “plan” is defined in the Act as an Integrated Resource Plan that contains the utility’s electric demand and energy forecast for at least a 20-year period; program for meeting the requirements shown in its forecast in an economical and reliable manner; the analysis of all capacity resource options, including both demand-side and supply-side options; and the assumptions used and the conclusions reached with respect to the effect of each capacity resource option on the future cost and reliability of electric service. The Plan also must:

- (A) Contain the size and type of facilities which are expected to be owned or operated in whole or in part by such utility and the construction of which is expected to commence during the ensuing ten years or such longer period as the Commission deems necessary and shall identify all existing facilities intended to be removed from service during such period or upon completion of such construction;

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<sup>1</sup> O.C.G.A. § 46-3A-2.

- (B) Contain practical alternatives to the fuel type and method of generation of the proposed electric generating facilities and set forth in detail the reasons for selecting the fuel type and method of generation;
- (C) Contain a statement of the estimated impact of proposed and alternative generating plants on the environment and the means by which potential adverse impacts will be avoided or minimized;
- (D) Indicate, in detail, the projected demand for electric energy for a 20-year period and the basis for determining the projected demand;
- (E) Describe the utility's relationship to other utilities in regional associations, power pools, and networks;
- (F) Identify and describe all major research projects and programs which will continue or commence in the succeeding three years and set forth the reasons for selecting specific areas of research;
- (G) Identify and describe existing and planned programs and policies to discourage inefficient and excessive power use; and
- (H) Provide any other information as may be required by the Commission.<sup>2</sup>

The Commission is required under O.C.G.A. § 46-3A-2 to make determinations as to the adequacy of the IRP and to ensure that the utility's Plan has appropriately addressed numerous matters. There must be a determination that the forecast requirements contained in the Plan are based on substantially accurate data and an adequate method of forecasting.<sup>3</sup> The Commission must also find that the Plan identifies and considers any present and projected reductions in the demand for energy that may result from measures to improve energy efficiency in the industrial, commercial, residential, and energy-producing sectors of the state.<sup>4</sup>

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<sup>2</sup> O.C.G.A. § 46-3A-1(7).

<sup>3</sup> O.C.G.A. § 46-3A-2(b)(1).

<sup>4</sup> O.C.G.A. § 46-3A-2(b)(2).



Further, the Commission must determine whether the Plan adequately demonstrates the economic, environmental, and other benefits to the state and to customers of the utilities, associated with the following possible measures and sources of supply:

- (A) Improvements in energy efficiency;
- (B) Pooling of power;
- (C) Purchases of power from neighboring states;
- (D) Facilities that operate on alternative sources of energy;
- (E) Facilities that operate on the principle of cogeneration or hydro-generation; and
- (F) Other generation facilities and demand-side options.<sup>5</sup>

After hearings have been conducted on a Plan, the Commission may approve the IRP; approve it subject to stated conditions; approve it with modifications; approve it in part and reject it in part; reject the plan as filed; or provide an alternate plan, upon determining that this is in the public interest.<sup>6</sup>

An electric utility is entitled to recover the approved or actual cost, whichever is less, of any certificated demand-side capacity option in rates, along with an additional sum.<sup>7</sup> In determining the additional sum, the Commission “shall consider lost revenues, if any, changed risks, and an equitable sharing of benefits between the utility and its retail customer.”<sup>8</sup>

## BACKGROUND AND STATEMENT OF PROCEEDINGS

On February 2, 2019, the Commission issued its Procedural and Scheduling Order in both Dockets setting forth the dates for filing of testimony and briefs, as well as the dates for the hearings in this matter. These proceedings were declared to be contested cases as the term is defined in O.C.G.A. § 50-13-13 and were also held to encompass complex litigation pursuant to O.C.G.A. §

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<sup>5</sup> O.C.G.A. § 46-3A-2 (b)(3).

<sup>6</sup> GPSC Utility Rule 515-3-4-.01(2).

<sup>7</sup> O.C.G.A. § 46-3A-9

<sup>8</sup> *Id.*

9-11-33(a). The two proceedings were assigned Docket Numbers 42310 and 42311, respectively, and combined for purposes of administrative efficiency and convenience.

Pursuant to O.C.G.A. § 46-3A-5(c), the Commission established the fee for review of the IRP within sixty days of the filing of the applications. On March 16, 2019, the Commission concluded that six hundred eighteen thousand three hundred eighty-five dollars (\$618,385.00) was the appropriate fee for review and analysis of the Company's filing.

On April 8, 2019, in accordance with the Procedural and Scheduling Order, the Commission heard direct testimony of Georgia Power's two panels of witnesses: (1) Jeffery R. Grubb, Narin Smith, Michael A. Bush and Jeffrey B. Weathers; and (2) Mark S. Berry and Aaron D. Mitchell.

The Commission conducted hearings on the direct cases of the Public Interest Advocacy Staff ("PIA Staff") and intervening parties in both Dockets on April 13 – 15, 2019. The PIA Staff sponsored several witnesses and witness panels: a panel consisting of Ralph Smith and Robert Trokey; panel witnesses Philip Hayet, Tom Newsome and Stephen Baron; individual testimony of John Hutts and John Chiles; panel witnesses Jamie Barber, John Kaduk, Richard Spellman and John Athas; and lastly, a panel consisting of Jamie Barber, Nick Cooper and Richard Spellman.

The Intervening parties testified as follows: Commercial Group - Steve Chriss; Concerned Ratepayers of Georgia - Steven C. Prenovitz; Emory University - panel Joan Kowal and Edward T. Borer, Jr.; Georgia Center for Energy Solutions - Peter J. Hubbard; Georgia Distributed Generation Group - panel Dr. Ben Johnson and Ryan Sanders; Georgia Interfaith Power & Light and Partnership for Southern Equity - James Wilson; Georgia Interfaith Power & Light and Partnership for Southern Equity, Southface Energy Institute and Vote Solar - William M. Cox; Georgia Large Scale Solar Association - panel John Sterling, Lynnae Willette, John Vanhoe and Arne Olson; Georgia Solar Energy Industries Association, Inc. - panel William M. Cox and Karl R. Rabago; Georgia Solar Energy Association, Inc. - panel Casey M. Busch, Steve A. Chiarello, George N. Mori and Thatcher R. Young; Georgia Watch - panel of Charles Harak and Lindsey Robbins; Sierra Club - Rachel S. Wilson; Southern Alliance for Clean Energy and

Southern Renewable Energy Assoc. - Mark Detsky; Southern Alliance for Clean Energy - panel Theresa Perry, Brendan J. Kirby and Forest Bradley - Wright and panel John D. Wilson and Bryan A. Jacob; and Southern Renewable Energy Assoc. - Michael Goggin and Joshua D. Rhodes.

On June 6, 2019, Georgia Power and PIA Staff executed and submitted a Stipulation designed to resolve all the issues that were raised in these two dockets. (See Attachment A) Subsequently, on June 11, 2019, The Commercial Group, Georgia Industrial Group (“GIG”) and Georgia Association of Manufacturers (“GAM”) signed the Stipulation; Georgia Watch signed the Stipulation on June 18, 2019; and the Georgia Distributed Generation Group signed the Stipulation thereafter. The Stipulation along with the Company’s rebuttal testimony were addressed by Georgia Power’s witness panel Jeffrey R. Grubb, Narian Smith, Michael A. Bush and Jeffrey B. Weathers on June 11, 2019.

The Stipulation contains 43 provisions. There are twenty-seven provisions pertaining to the Supply Side Plan and sixteen provisions pertaining to the Demand Side Plan as outlined in Attachment A.

On June 24, 2019 briefs and/or proposed orders were filed by parties in the case. Five signing parties filed briefs in support of the Stipulation and nine non-signing parties filed brief and/or proposed orders making the following recommendations.

#### **NON-SIGNING PARTIES’ POSITIONS**

##### **Georgia Interfaith Power & Light and Partnership for Southern Equity – GIPL & PSE (“GIPL”)**

GIPL recommended that the Commission amend the Stipulation to include and require the Company to: (1) model a scenario in which energy efficiency measures are allowed to compete against supply-side measures. Additionally, the DSM Plan must demonstrate optimization of DSM resources, including program budget and details concerning how the Plan balances economic efficiency and rate impacts; (2) develop its 2022 IRP, to allow demand-side

resources to compete with supply-side resources; (3) collaborate with Staff and interested stakeholders, over the next year, to model ways to meet a 1% energy efficiency savings target by 2025; (4) continue offering the Automated Benchmarking Tool and to promote the tool; (5) increase funding of its low-income energy efficiency program to \$400,000 in 2020, and \$500,000 in each of the two subsequent years so that by 2022 the total funding reaches \$4 million; (6) work with Staff and interested stakeholders to conduct a data-driven and collaborative conversation over the next year. The group will submit a report to the Commission by January 31, 2021 to inform 2022 IRP planning; (7) add a total of 3,000 MW of renewable energy, over the next three years, including 250 MW of distributed generation. The DG portion must include at least 100 MW of a standard offer, buy-all/sell-all program, with a fixed price levelized over thirty years set at 5 percent below avoided cost; (8) reevaluate and update as appropriate the avoided cost methodology used in Docket 4822, over the next year, while allowing for participation by interested stakeholders; (9) designate at least 100 MW of utility-scale solar capacity to a municipal subscription program designed for government customers; (10) dedicate 10 MW of its approved storage capacity to be deployed in resilience hubs in underserved and vulnerable rural and urban communities for critical emergency services. The Company and Staff will work together to identify and gather input from interested communities on their needs; (11) eliminate winter declining block rates in the upcoming 2019 rate case and, before the 2022 IRP, investigate scaling up the Company's residential thermostat demand-response program to address winter reliability concerns; (12) approve its coal ash clean-up strategy only for those methods that comply with the federal and state CCR Rules; and (13) continue operating its MATS controls to control emission of mercury and other air toxins irrespective of any state or federal attempts to weaken existing standards for the control of mercury and other air toxins. (GIPL/PSE Brief at pp. 2-4).

### **Georgia Large Scale Solar Association**

Georgia Large Scale Solar Association recommended that the Commission adopt the Stipulation with the following changes: (1) Increase by 1,000 MWs from the stipulated agreement, utility scale solar program. The procurement(s) shall be completed by 2021 with all procurements accepting commercial operations dates of 2023 (1500 to 2500). (2) Hold a break

out session between PSC Staff and interested Intervenors at the conclusion of this IRP to update the Renewable Cost-Benefit Framework ("RCB") and develop a methodology to value solar + storage in an all source procurement prior to the 2022-2023 capacity-based RFP and prior to the onset of the Company's 2022 resource planning. (GLSSA Brief at pp. 1-2).

**Georgia Solar Energy Assoc., Inc. & Georgia Solar Energy Industries Assoc., Inc. (GSEA & GSEIA)**

Georgia Solar recommended that the following directives be included in the Stipulation: (1) Direct the Company to develop and implement a Customer-Sited BA/SA tariff. (2) Revise the program guidelines for customer-sited program following the precedent of the Customer-Sited BA/SA program in REDI. (3) Expand the RNR tariff to include small and medium business customers with solar DG needs between 250 kW to 3 MW. (4) Revise the RCB to properly consider the geographic benefit and cost savings to the Company from deployment of solar generation at or near load. And (5) Modification of PURPA avoided costs and RCB for application to basic QFs. (GSEA & GSEIA Brief at p. 17)

**Resource Supply Management - ("RSM")**

RSM recommended that participation in DSM programs be voluntary for all customers and that customers should be allowed to opt-out of Demand Side Measures along with the associated surcharges on customer bills. (RSM Brief at p. 1).

**Sierra Club**

Sierra Club recommended that the Commission direct Georgia Power to (1) significantly expand its procurement of renewable resources, (2) retire Plant Bowen or lower the caps on expenditures in line with those placed on Hammond and McIntosh in the 2016 IRP and that the Commission state that exceedances of the caps are not recoverable from ratepayers and (3) in future IRP dockets, employ resource dispatch modeling that analyzes all resource types head-to-head. (Sierra Club Brief at p. 1).

**Southern Alliance for Clean Energy, Inc. ("SACE")**

SACE recommended the following: (1) the amount of renewable energy generation be increased to a minimum of 3,000 MW; (2) the amount of distributed generation be expanded to 450 MW and any amount of distributed generation not under development or contract by January 1, 2022, automatically be allocated to either the CRSP or REDI II programs; (3) the Company be ordered to update its analysis of technical feasibility of renewable energy factoring in the flexible operating mode of solar; (4) the DSM Advocacy Program be adopted or double the amount of energy efficiency savings in the DSM plan and make the Manufactured Homes Program a pilot program; (5) the Company be directed to use an All-Source Bidding process in future RFPs that does not exclude any type of generation resource; (6) Plant Wansley be included in the 2022-23 capacity RFP; (7) the seven critical improvements and additional enhancement to the CRSP program recommended by SACE witness Perry be adopted; (8) the Company be directed to reexamine the generation remix cost method, the support capacity, the winter reserve requirements in the RCB Framework and recalculate the reserve margins and capacity worth factor tables prior to issuing any RFPs; (9) the Company's additional sum proposal be redesigned to ensure risk and equitable sharing of benefits are considered; and (10) all parties may intervene and fully participate in any proceedings regarding the RCB Framework, the RFPs for all renewable energy generation and all semi-annual reviews of the Company's coal combustion residual compliance efforts. (SACE Brief at pp. 16-17).

#### **Southern Renewable Energy Association ("SREA")**

SREA recommended that the IRP be rejected for not providing for a sufficiently sized, nor suitably timed, renewable energy request for proposal ("RFP") process. SREA requested that the Commission consider the following findings and recommendations: (1) Determine that the 1,500 MW solicitation for large scale renewables as part of the Customer Renewable Supply Procurement (CRSP) program is too small and fails to incorporate of the benefits of various renewable resources. (2) The Commission modify CRSP to include a competitive solicitation of at least 3,000 MW's of renewable energy. (3) Within CRSP, 1,000 MW's of large-scale renewable energy resources should be dedicated for customer subscription for new and existing customers with a minimum of 3 MW's of aggregated load. (4) The remaining 2,000 MW's (or greater) of large-scale renewable energy resources within CRSP should be provided for the entire

customer base. (5) Before ITC tax incentives begin to phase out, the Company needs to develop a RFP process that produces proposals, evaluates results, and allows the Commission to review and approve proposals in a much more expedient manner. (6) The Company should be required to include fuel hedging as a placeholder in the Renewable Cost Benefit (RCB) Framework. This Framework should also consider the benefits of solar energy, wind power, and energy storage as long-term price hedges for volatile fossil fuel pricing. (7) The Commission should modify the proposed “Capacity Requests for Proposals” (RFPs) to become “All-Source” RFPs. And (8) The Commission should order that intervening parties in this docket will be formally included in discussions regarding the proposed CRSP program, the updated RCB Framework, Capacity RFP’s, and the Battery Energy Storage System RFP. (SREA Brief at pp. 3-4).

### **Southface & Vote Solar**

Southface and Vote Solar contend that there are several deficiencies in the proposed Stipulation and recommended that the Commission:

#### **Supply Side Plan:**

(1) Increase total renewable energy procurement in this IRP to at least 3,000 MW. (2) Expand the 150 MW DG procurement proposed in the Stipulation to 250 MW of capacity, including 150 MW of competitively bid DG and 100 MW of fixed price DG to be set at 5% below avoided cost. (3) Increase the overall utility-scale solar procurement by up to 100 MW and dedicate this capacity to a municipal customer subscription program open to existing government customer load. (4) Open a proceeding under Dockets 4822 and 16573 to examine Georgia Power’s calculation of avoided cost. (5) Proposed continuation of negotiations between the Company and PIA Staff on the RCB Framework include interested Intervenors that were party to the 2019 IRP. (6) Dedicate at least 10 MW of the approved energy storage capacity to projects that both demonstrate and support local resilience. (7) Consider support for implementation of the Emory Micro-Grid project.

#### **Demand Side Plan**

(1) Require higher energy savings performance for Georgia Power’s DSM portfolio now. In addition, requested the Commission direct the 2020-2021 DSM Work Group to thoroughly

explore the option of adopting a DSM performance target for Georgia Power that provides the backdrop for a 2022 DSM program portfolio that will achieve savings equal to one percent of prior year retail sales by 2025. (2) Direct the DSM Work Group to produce a DSM policy framework that clarifies the Commission's perspective on the costs and benefits of DSM resources and outlines positions of agreement among the DSM Work Group participants. (3) Support implementation of a modest industrial DSM pilot program targeting small and medium industrial customers. (4) Support the Stipulation provision aimed at capping the dramatic growth in DSM program non-incentive costs. (5) Support the Stipulation provision to further reduce administrative costs for the Income Qualified Tariff Based proposed pilot program and ensure the Company continues to seek input of interested stakeholders on Pilot program design and implementation specifics. (6) Support continued operation of Automated Benchmarking Tool by Georgia Power for the next three years. And (7) Expand the Stipulation provision regarding final DSM program plans to include a requirement that Georgia Power publish the Final Program Plans in the docket. (Southface & Vote Solar Brief at pp. 25-27).

### **Emory University**

Emory University filed testimony promoting the proposal that Georgia Power and Emory University work together to develop microgrid technologies for use around the state, specifically around Emory's campuses. In the Stipulation, Supply Side Plan provision 27 specifically states that neither the PIA Staff nor the Company recommended the Emory microgrid project. However, if the Commission decided that it is appropriate to move forward with the project, both the PIA Staff and Company recommended that it be done so only on the condition that, if the project costs exceed the benefits to other ratepayers, Emory agrees to pay the difference. Emory University was silent on provision 27 deciding not to file a brief on the matter. However, during witness testimony, they stated that the university would not pursue the microgrid with Georgia Power if the cost burden to other customers outweighed the benefits. (Tr.1789).

### **Other Parties of Record**



Testimony was not filed by the following non-signing parties: McFinney, LLC and Resource Supply Management. Briefs were not filed by the following non-signing parties: Concerned Ratepayers of Georgia, Emory University, Georgia Center for Energy Solutions, and McFinney, LLC.

## FINDINGS OF FACT AND CONCLUSIONS OF LAW

### 1.

To ensure that the competing interests of all parties were properly considered, the Commission carefully considered the Stipulation, Attachment A, entered into by the Stipulating Parties of record including the testimony given and the various exhibits entered by all of the parties. The Commission finds and concludes that the terms of the Stipulation are supported by the evidence in the record and is a fair and reasonable resolution which appropriately strikes the balance of the interest of all Parties while ensuring system reliability and providing energy at a reasonable cost. Therefore, the Commission approves and adopts the Stipulation as amended below.

### 2.

Paragraph 3 of the Stipulation states that:

*The Company shall procure 1,500 MW alternating current ("AC") of new utility scale renewable resources, defined as projects greater than 3 MW AC. 500 MW of these new resources shall be dedicated to all retail customers. The Customer Renewable Supply Procurement Program ("CRSP") is approved and shall be increased such that it will procure energy from 1,000 MW (600 MW of utility scale renewable resources for subscription by existing CRSP eligible customers, and 400 MW for subscription by CRSP eligible customers adding new load). The Utility scale procurement shall take place through two separate Requests For Proposals ("RFP"). The first RFP is expected to be issued in 2020 and will seek 250 MW of renewables with in-service dates of 2022 and 2023 for all retail customers, 300 MW for subscription by existing CRSP eligible customers, and up to 400 MW for subscription by CRSP eligible customers adding new load. The second RFP is expected to be issued in 2021 and will seek 250 MW of renewables with in-service dates of 2023 and 2024 for all retail customers, 300 MW for subscription by existing CRSP eligible customers and 0 to 400 MW for subscription by CRSP eligible customers adding new load (0 MW to 400 MW represents the remainder of any resources not procured for subscription by CRSP eligible customers adding new load in the first RFP). Any capacity for new load that remains unsubscribed at the end of the second RFP would be offered to any existing CRSP eligible customers whose Notice of Intent ("NOI") capacity request had not been fully met. Any remaining amounts*

*procured through the RFPs for CRSP but unsubscribed by CRSP participants will be used to serve all retail customers.*

The Commission finds and concludes it is more reasonable and appropriate to increase the amount of the utility scale renewable procurement to 2000 megawatts alternating current. The amount procured by the Customer Renewable Supply Procurement Program will remain at 1000 megawatts with the additional 500 megawatts going to the retail customers. Each of the two proposed Requests for Proposals ("RFP") will increase by 250 megawatts.

3.

Paragraph 5 of the Stipulation discusses an RFP concerning distributed generation which reads in part:

*The Company shall issue an RFP to procure energy from up to 150 MW AC of distributed generation solar resources ("DG") greater than 1 kW but not more than 3 MW AC.<sup>9</sup>*

The Commission finds that the amount of the distributed generation (DG) procurement shall be increased to 210 megawatt alternating current, which includes 160 megawatts of DG Requests for Proposal and a 50 megawatt customer-sited DG program. The Commission concludes that it is appropriate that projects for the customer-sited program shall be greater than one kilowatt but not more than three megawatts. Procurement shall be done through an application process, and if oversubscribed, a lottery shall be conducted. The Commission has determined that the customer-sited projects shall be paid avoided costs as calculated by the Renewable Cost Benefit Framework.

4.

The Commission recognizes the benefits of biomass as a renewable resource and finds and concludes that increased inclusion should be considered in the future development of the Company's Integrated Resource Plan. Noting that, the Commission directs the Company and Staff to work together on a proposal to procure an additional 50 megawatts of new biomass

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<sup>9</sup> Stipulation - Supply Side Plan, p. 3.

generation to serve Georgia Power's customers. This generation will utilize the competitive solicitation model that allows the Company to recover all of its program costs and grants the Company an additional sum.

The Company and Staff are directed to return to this Commission no later than the end of second quarter 2020 with a proposed biomass procurement strategy for the Commission's consideration and approval.

5.

The Commission finds that it is reasonable and appropriate to further advance the educational feature of integrated resource planning going forward. Therefore, the Commission concludes that the education initiative, Learning Power<sup>10</sup> budget shall be increased to \$4 million annually for 2020 through 2022.

6.

The Commission finds and concludes that the record reflects the necessity and need for further development for energy storage capability. Further, witness's testimony noted that the cost associated with battery technology continues to decline. (Tr. Pp. 2448, 2792) Therefore, the Commission directs Georgia Power to develop a pilot project utilizing used lithium ion batteries for a grid-connected charging system for electric vehicles. The goal for the pilot shall include keeping charging of clean electric vehicles affordable and insulating the grid from spikes in electricity demand. The cost of the pilot shall not exceed \$250,000. Georgia Power shall work with the Staff in designing the project to ensure that the project has a public benefit.

7.

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<sup>10</sup> Stipulation – Demand Side Plan, Paragraph 11, p.10.

The Commission finds that the record in this proceeding established that the Automated Benchmarking Tool (“ABT”) provides current value to customers and that demand for the ABT will continue to grow. The Commission directs Georgia Power to continue making the ABT available in the same manner for the next three years.

8.

With respect to Energy Efficiency, the Commission finds and concludes that the energy saving targets for the Company’s residential and commercial energy efficiency programs be increased by 15 percent and the relative program budgets be increased by 10 percent. The Commission staff and the Company shall meet within 60 days of the Final Order to finalize the revised DSM portfolio and the DSM budgets for 2020 through 2022, which should include a projected 15 percent increase in savings.

9.

The record in this case identifies potential concerns with Georgia Power’s current avoided cost calculation. The Company’s obligation to determine the underlying avoided cost is imposed on the Company by the Public Utility Regulatory Policy Act (PURPA), a federal law. The Company proposed the RCB framework to identify additional cost savings resulting from the deployment of renewable generation resources in the 2016 IRP, and it was adopted by this Commission. PURPA’s calculation of the Company’s underlying avoided costs, and RCB’s calculation of additional cost savings resulting from deployment of renewables, particularly distributed solar generation, seek different objectives and utilize different calculations. But together, PURPA and RCB are the building blocks used by the Company to set compensation rates for distributed solar generation.

The Commission is compelled by the testimony that highlighted the fact that, although the Company makes an annual filing of its avoided cost under PURPA, which are subject to the Commission’s review, the methodology has not been the subject of a full review in twenty-five (25) years. The Commission finds and concludes that these concerns should be addressed shortly after the conclusion of Docket No. 42516, the 2019 Rate Case, through the Commission re-

opening a proceeding in Docket No. 4822 to ensure appropriate valuation of renewable and demand-side resources. PIA Staff is directed to initiate a review of the Company's methodology and computation of avoided cost under PURPA.

**10.**

The Commission finds and concludes that the remaining provisions of the agreement shall have full force and effect as stated in the Stipulation and concludes that all other recommendations and requests from the Non-signing parties are denied.

\*\*\*\*\*

**ORDERING PARAGRAPHS**

**WHEREFORE, IT IS ORDERED,** that the Commission adopts the Stipulation (Attachment A) as amended herein as a fair and reasonable resolution of the issues in Docket Nos. 42310 and 42311.

**ORDERED FURTHER,** that the amount of the utility scale renewable procurement shall increase to 2000 megawatts alternating current. The amount procured by the Customer Renewable Supply Procurement Program shall remain at 1000 megawatts with the additional 500 megawatts going to the retail customers. Each of the two proposed Requests for Proposals ("RFP") shall increase by 250 megawatts.

**ORDERED FURTHER,** that the amount of the distributed generation procurement shall increase to 210 megawatt alternating current, which includes 160 megawatts of DG Requests for Proposal and a 50 megawatt customer-sited DG program. The customer-sited program shall be greater than one kilowatt but not more than three megawatts. Procurement shall be done through

an application process, and if oversubscribed, a lottery shall be conducted. The customer-sited projects shall be paid avoided costs as calculated by the Renewable Cost Benefit Framework.

**ORDERED FURTHER**, that the Company and Commission staff shall work together on a proposal to procure an additional 50 megawatts of new biomass generation to serve Georgia Power's customers. This generation shall utilize the competitive solicitation model that allows the Company to recover all of its program costs and grants the Company an additional sum. The Company and Commission staff shall come back to this Commission by no later than the end of second quarter 2020 with a proposed biomass procurement strategy for the Commission's consideration and approval.

**ORDERED FURTHER**, that the education initiative, Learning Power, budget shall be increased to \$4 million annually for 2020 through 2022.

**ORDERED FURTHER**, that Georgia Power shall develop a pilot project utilizing used lithium ion batteries for a grid-connected charging system for electric vehicles. The goal for the pilot shall include keeping charging of clean electric vehicles affordable and insulating the grid from spikes in electricity demand. The cost of the pilot shall not exceed \$250,000. Georgia Power shall work with the Commission staff in designing the project to ensure that the project has a public benefit.

**ORDERED FURTHER**, that the Company's Automated Benchmarking Tool ("ABT") shall be continued for the next three years.

**ORDERED FURTHER**, that the energy saving targets for the Company's residential and commercial energy efficiency programs shall be increased by 15 percent and the relative program budgets shall be increased by 10 percent. The Commission staff and the Company shall meet within 60 days of the issuance of this Order to finalize the revised DSM portfolio and the DSM budgets for 2020 through 2022, which must include a projected 15 percent increase in savings.

**ORDERED FURTHER**, that shortly after the conclusion of the 2019 Rate Case, Docket No. 42516, the PIA Staff shall initiate a review of the Company's methodology and computation of avoided cost in Docket No. 4822 pursuant to the Public Utility Regulatory Policy Act of 1978 to ensure appropriate valuation of renewable and demand-side resources.

**ORDERED FURTHER**, the Commission finds that remaining provisions of the agreement shall have full force and effect as stated in the Stipulation.

**ORDERED FURTHER**, that with the exception of the above findings of facts and conclusions of law, the Commission denies the remaining recommendations of all non-signing parties.

**ORDERED FURTHER**, all findings, conclusions, and decisions contained within the preceding sections of this Order are hereby adopted as findings of fact, conclusions of law, and decisions of regulatory policy of this Commission.

**ORDERED FURTHER**, that a motion for reconsideration, rehearing, oral argument, or any other motion shall not stay the effective date of this Order, unless otherwise ordered by the Commission.

**ORDERED FURTHER**, that jurisdiction over this matter is expressly retained for the purpose of entering such further Order(s) as this Commission may deem just and proper.

The above by action of the Commission in Administrative Session on the 16 day of July 2019.



Reece McAlister  
Executive Secretary

7-29-19  
Date



Lauren "Bubba" McDonald  
Chairman

7/29/19  
Date



## COMMISSIONERS:

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## Georgia Public Service Commission

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June 6, 2019

Mr. Reece McAlister  
Executive Secretary  
Georgia Public Service Commission  
244 Washington Street, S.W.  
Atlanta, GA 30334

**RE: Docket No. 42310 & Docket No. 42311 / Georgia Power Company's 2019 Integrated Resource Plan and Georgia Power Company's 2019 Demand Side Management**

Dear Mr. McAlister:

Enclosed for filing please find a Stipulation executed on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff and Georgia Power Company.

We have furnished an electronic and/or a copy by mail of this filing to all parties in this docket.

Sincerely,

Preston Thomas  
Attorney

## STATE OF GEORGIA

## BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

## In Re:

Georgia Power Company's )  
 2019 Integrated Resource Plan and )  
 Application for Certification of Capacity ) Docket No. 42310  
 From Plant Scherer Unit 3 and Plant )  
 Goat Rock Units 9-12 and Application )  
 for Decertification of Plant Hammond )  
 Units 1-4, Plant McIntosh Unit 1, Plant )  
 Langdale Units 5-6, Plant Riverview )  
 Units 1-2, and Plant Estatoah Unit 1 )

## In the Matter of:

Georgia Power Company's ) Docket No. 42311  
 Application for the Certification, )  
 Decertification, and Amended )  
 Demand Side Plan )

Stipulation

The Georgia Public Service Commission (the "Commission") Public Interest Advocacy Staff ("PIA Staff"), Georgia Power Company ("Georgia Power" or the "Company") and the undersigned intervenors (collectively the "Stipulating Parties") agree to the following stipulation as a resolution of the above-styled proceedings to consider the Company's 2019 Integrated Resource Plan (the "2019 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan (the "2019 DSM Plan"). The Stipulation is intended to resolve all of the issues in these Dockets. The Stipulating Parties agree as follows:

Supply Side Plan

1. The 2019 IRP is approved as amended by this Stipulation.
2. Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2 shall be decertified and retired as provided for in the 2019 IRP.

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3. The Company shall procure 1,500 MW alternating current ("AC") of new utility scale renewable resources, defined as projects greater than 3 MW AC. 500 MW of these new resources shall be dedicated to all retail customers. The Customer Renewable Supply Procurement Program ("CRSP") is approved and shall be increased such that it will procure energy from 1,000 MW (600 MW of utility scale renewable resources for subscription by existing CRSP eligible customers, and 400 MW for subscription by CRSP eligible customers adding new load). The Utility scale procurement shall take place through two separate Requests For Proposals ("RFP"). The first RFP is expected to be issued in 2020 and will seek 250 MW of renewables with in-service dates of 2022 and 2023 for all retail customers, 300 MW for subscription by existing CRSP eligible customers, and up to 400 MW for subscription by CRSP eligible customers adding new load. The second RFP is expected to be issued in 2021 and will seek 250 MW of renewables with in-service dates of 2023 and 2024 for all retail customers, 300 MW for subscription by existing CRSP eligible customers and 0 to 400 MW for subscription by CRSP eligible customers adding new load (0 MW to 400 MW represents the remainder of any resources not procured for subscription by CRSP eligible customers adding new load in the first RFP). Any capacity for new load that remains unsubscribed at the end of the second RFP would be offered to any existing CRSP eligible customers whose Notice of Intent ("NOI") capacity request had not been fully met. Any remaining amounts procured through the RFPs for CRSP but unsubscribed by CRSP participants will be used to serve all retail customers.

All revenues collected through CRSP program, with the exception of the additional sum as described in Paragraph 7, and all appropriate costs, that are not being recovered elsewhere by the Company, incurred for CRSP procurement shall be included in the fuel clause and recovered through Fuel Cost Recovery mechanism ("FCR"). The CRSP costs and revenues to be included in FCR includes, but are not limited to, the costs to implement and administer the CRSP, the bid fees collected, the NOI Fees collected, and the cost of purchase power agreements ("PPA") executed through the CRSP program including any payments for PPAs made by participants. All revenues collected, and all appropriate costs, not being recovered elsewhere by the Company, incurred for the 500 MW of utility scale procurements for all customers shall be included in the fuel clause and recovered through FCR.

4. Within 60 days of the Final Order the PIA Staff and the Company shall begin to meet to develop the specific guidelines and NOI requirements for the CRSP Program. The proposed guidelines will be submitted to the Commission for

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Docket No. 42311, GPC DSM Application

approval.

5. The Company shall issue an RFP to procure energy from up to 150 MW AC of distributed generation solar resources ("DG") greater than 1kW but not more than 3 MW AC. The projects must be at or below the Company's projected avoided costs. Contract terms will be up to 30 years. DG projects must interconnect to Georgia Power's distribution system. Bid fees will be set to recover the total cost of procurement for the solicitation. All revenues collected, and all appropriate costs not being recovered elsewhere by the Company incurred for DG procurements shall be included in the fuel clause and recovered through FCR.
6. The Renewable Cost Benefit Framework ("RCB") shall be utilized in the evaluation of bids received through the utility scale and DG RFPs. The PIA Staff has raised specific issues regarding the RCB components of Deferred Generation Capacity, Generation Remix, and Support Capacity and recommended that solar plus storage be considered its own technology using the RCB Framework. The Company and PIA Staff will work collaboratively to resolve the concerns raised by PIA Staff in this case. The Company and PIA Staff will meet within four months of issuance of Final Order in this case and make a good faith effort to resolve the issues. If the issues have not been resolved within this time, the Company and PIA Staff will work to resolve the issues before the next IRP. PIA Staff and the Company also understand that resolution of these issues does not limit the positions that either Party can take regarding the RCB in a future proceeding where modifications to the RCB may be considered. Until such time as these issues are resolved, the RCB used in evaluations will be based on the RCB components and methodologies as filed in the IRP using updated B2019 assumptions (or for later solicitations the applicable vintage assumptions) and calculations of deferred capacity value for the RCB will be based on the B2018 CWFT using the summer TRM of 16.25% as shown in Table B.1 of the January 2019 Reserve Margin Study.
7. The Additional Sum for utility scale resources procured pursuant to Paragraph 3 above and the DG resources in Paragraph 5 shall be set at 8.5% of the projected net benefits. This amount shall be levelized and recovered annually for the term of the PPA.
8. The use of seasonal planning by the Company to provide greater visibility into both summer and winter capacity needs is approved. In the event winter system conditions result in the need for transmission system assessments, the Company would incorporate applicable winter assessment results into future filings of

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## Technical Appendix Volume 3.

9. The Company and PIA Staff recognize that the use of a winter target reserve margin ("TRM") is necessary to effectuate seasonal planning as approved by this Stipulation. In the absence of a Commission approved winter TRM, the Company will use the System winter TRM for seasonal planning until such time as a winter TRM is agreed to between Staff and the Company and approved by the Commission. There is no requirement for the Commission to act upon the winter TRM until such time as one is approved. The Company may propose resource additions, if needed, to meet winter TRM, and the Commission can determine at that time what the appropriate winter TRM is and whether such additional capacity is needed. Stipulating Parties further agree that the Company may propose the adoption of a specific winter TRM in a future IRP proceeding or IRP update. The Company and PIA Staff will meet within six months of issuance of Final Order in this case to discuss these issues and will work to address the issues before the next IRP.
10. The Stipulating Parties agree that the Scherer Unit 3 Capacity offer should be rejected by the Commission. The offer by the Company, and the rejection by the Commission fulfills the Company's requirements under Docket No. 26550 to offer this capacity to the retail jurisdiction. The Company may, at its own discretion, offer such capacity in the wholesale market or to the retail jurisdiction in a future capacity solicitation or through other permissible vehicles.
11. The Company shall initiate a 2022-2023 and a 2026-2028 capacity-based RFP. The RFPs will be structured to address the capacity needs being sought and will require a level of capacity firmness and dispatchability that will be developed in conjunction with Commission Staff and the IE during the RFP development process. Specific RFP guidelines including resource eligibility requirements, updated IRP assumptions, and evaluation methodology and criteria will be approved by the Commission in accordance with the Commission's proscribed RFP process and may accommodate bids from renewable resources paired with storage. The Company agrees to include language in such RFPs that permit the Company to reject all bids at its discretion.
12. The parties acknowledge that should the retirement of Plant Bowen Units 1 and 2 be necessary there will be transmission issues that need to be addressed in the 2019 base rate case. However, the parties have not agreed on the best solutions to those issue. The Company will explore both traditional transmission solutions and alternatives to traditional transmission solutions (non-wire solutions) and

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compare the costs of each approach.

13. The Company agrees to limit capital expenditures specific to Plant Bowen Units 1 and 2 through July 31, 2022. The capital expenditures approved in this paragraph are intended to allow for safe and reliable operations of the units. The Company agrees to annual limits on capital expenditures of \$19 Million per year, or \$57 Million for the three-year period ending July 31, 2022. The Company agrees to provide a justification to Staff for expenditures that may be needed to maintain safe and reliable operation of Bowen 1 and 2 that exceed the limits provided for in this Paragraph. Within 60 days of the final order in this case, Staff and the Company will meet to develop reporting requirements.
14. The certification of the upgrade to the Goat Rock Hydro-electric facility Units 9-12 is not approved at this time. The Stipulating Parties agree to modifications to the Company's plans to modernize its hydro-electric fleet so that such efforts focus upon five modernization projects. The projects are Terrora, Tugalo, Bartlett's Ferry, Nacoochee, and Oliver. The Company and PIA Staff agree to work together to determine the appropriate information sharing process to allow the Commission to monitor the Company's modernization efforts.
15. The Company is granted authority in this IRP to develop, own and operate energy storage demonstration projects totaling up to 80 MW. The Company will procure the batteries for its ownership through a competitive RFP process. The company will competitively solicit Engineering Procurement and Construction services and shall include the option of turnkey proposals as well. The Company will be required to file a plan with the Commission before undertaking construction and procurement of each project being proposed. In such filing the Company will provide the objectives of the project, location of the project, transmission evaluation of the project and detailed operating and testing plans. Commission Staff shall have 60 days to review the plans prior to Commission approval.
16. The Company's Environmental Compliance Strategy ("ECS") is approved. This includes specific approval of the Company's plans to address coal combustion residuals ("CCR") at the Company's ash ponds and landfills. Stipulating Parties acknowledge that projected CCR compliance cost have been reviewed in this case, but agree that it is not necessary for the Commission to approve a specific budget for CCR compliance in this IRP proceeding. The Parties agree that the Company will seek recovery of such costs in its 2019 base rate case. The PIA Staff reserves the right to challenge the Company's request in the 2019 base rate case, including, but not limited to, the period over which they

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are recovered and the method by which they are recovered. To ensure the Commission is updated on CCR compliance efforts the Company will provide semi-annual reports to the Commission. The Company and Commission Staff will collaborate upon the schedule and content of such reports. The Company will also file the ECS annually with the Commission no later than March 31<sup>st</sup> of each year.

17. The detailed cost information that supports the measures taken to comply with the existing government imposed environmental mandates necessary for the Company to implement its environmental compliance plan as presented in Technical Appendix Volume 1 of the 2019 IRP, "Environmental Compliance Cost Recovery (ECCR) table" is acknowledged subject to the limits outlined in Paragraph 13 regarding Plant Bowen Units 1 and 2. Recovery of actual environmental compliance plan costs will be determined by the Commission in a rate case.
18. The remaining net book values of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Unit 1-2 shall be reclassified as a regulatory asset and the Company shall continue to provide for amortization expense at the same rate as determined in the Company's 2013 base rate case. Timing of recovery of the remaining balance as of December 31, 2019 will be deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

Any unusable M&S inventory balance remaining at the date of the unit retirement shall be reclassified as a regulatory asset and the timing of recovery deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

19. Any over or under recovered cost of removal balances for each Retirement Unit shall be deferred for consideration until the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the appropriate period in which the costs should be recovered. Parties may argue their respective positions on that issue in the 2019 base rate

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case.

20. In Docket No. 36989 the Commission approved the donation of Kraft land to the Georgia Port Authority including approval of the accounting treatment for the donation proposed by Georgia Power. PIA Staff has raised a desire to propose alternative ratemaking treatment for the income tax benefits related to the Plant Kraft land donation. The Company believes the issue of the appropriate accounting treatment for the Kraft land donation is resolved per the Commission's Order in Docket No. 36989. To the extent PIA Staff disagrees, the Parties agree that any disagreement may be considered in the 2019 base rate case.
21. In the Commission's Final Order in Docket 40161 and 40162 the Commission authorized the Company to spend up to \$99 million between now and the end of the second quarter of 2019 to investigate the option of pursuing new nuclear generation as a potential base load option at a site in Stewart County, Georgia. That Order further found that if the project was terminated, costs incurred toward that effort would be deferred for recovery to a regulatory asset and the timing of that recovery would be addressed in a future base rate case in which the Commission will determine the appropriate period to amortize the recovery of such costs. The Order also held that for ratemaking purposes, the Stewart County property shall continue to be categorized as Plant Held for Future Use. Nothing in this Stipulation is intended to limit the rights of PIA Staff or the Company to pursue their respective positions on cost recovery of Stewart County Site investigation cost.
22. When filing the 2022 IRP or when filing any updates to the IRP prior to the 2022 IRP filing, the Company agrees to provide the Commission Staff working copies of, or access to data used to develop charts, tables, and graphics contained in the filing; models (for example, transmission models, load forecast models, financial models and economic models), and results of relevant analyses performed in the development of that IRP. The models and analyses should be configured to replicate inputs used to derive results incorporated in its base case scenario, and this information shall be provided within 10 days after the IRP or update to the IRP is filed.
23. The Company will compute weather normalized peak demands for the winter and summer seasons of each historical year going forward starting in 2019.
24. The Company will investigate methodologies for allocating long-term annual energy sales for each class to monthly amounts to account for anticipated trends

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Docket No 42310, GPC 2019 IRP  
Docket No. 42311, GPC DSM Application



in seasonal energy sales.

25. The Company agrees to file with the 2022 IRP a forecast scenario of Georgia Power's Peak and Energy forecast using data for the most recent 20 year normal weather.
26. In conjunction with the ongoing level of review and analysis required by this agreement, Georgia Power will agree to pay for any reasonably necessary specialized assistance to the Staff in an amount not to exceed \$500,000 annually. This amount paid by Georgia Power under this paragraph shall be deemed as a necessary cost of providing service and the Company shall be entitled to recover the full amount of any costs charged to the utility.
27. Neither Staff nor the Company has recommended the Emory micro grid project. However, if the Commission decides that it is appropriate to move forward with the project, both the Staff and Company recommend that it be done so only on the condition that, if the project costs exceed the benefits to other ratepayers, Emory agrees to pay the difference.

#### Demand Side Plan

1. The Demand Side Plan is approved as amended by this Stipulation.
2. The Company and Staff shall collaborate to investigate methodologies to model DSM as an additional scenario in its supply side system planning tools as a part of its IRP development and resource optimization process where DSM will be modeled alongside traditional supply-side options. The company will produce a white paper and discuss its findings with the Staff nine months prior to the filing of the 2022 IRP.
3. Georgia Power and PIA Staff agree that calculations of the kWh and kW savings from the Company's certified DSM programs in 2023 be adjusted to actual savings once the Company has completed the impact and process evaluations for each certified DSM program and the Company and Staff reach agreement on evaluation impacts during 2021.
4. The Company and PIA Staff agree that the percentage increases in the current certified program budgets for non-incentive program costs per first-year kWh saved for the 2020 to 2022 period when compared to 2017 and 2018 actual spending on non-incentive costs per first-year kWh saved will be capped at no

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Docket No 42310, GPC 2019 IRP  
Docket No. 42311, GPC DSM Application

more than a 50 percent increase. The 2020 to 2022 budgets for the Company's certified programs will be as presented in Staff Exhibits BSKA-8 and BCS-7. This agreement does not set a precedent for requested budget requests in future IRP cycles and only applies to 2020 through 2022 because implementation costs have the potential to change over time in future IRP cycles.

5. The Demand Side Management Working Group ("DSMWG") will continue in its present form and be involved in the development of future demand side management programs in the same manner as the DSMWG has operated in past IRP cycles.
6. For the Income-Qualified ("Crowd Funding") Program, the Company will maintain the current EASP participant cap of \$3,750 per household, the Company will expand its potential crowd funding donation sources, and for the initial term of the Program the Company will not earn an Additional Sum on the savings realized by donations from individuals, non-profits, grants, companies, and partnerships. After the initial review of the Program, the Company may request an additional sum in the 2022 IRP for the Program.
7. The Company and PIA Staff agree to work together over the next nine-months to investigate the reduction of administrative costs for a potential Income Qualified Tariff Based Financing Pilot for 500 income qualified customers. The Company and Staff will also work together to set a policy for the collection of uncollectibles from a potential Income Qualified Pilot through the Residential DSM Tariff. The Company will file a more complete pilot plan with the Commission by April 1, 2020.
8. The Commercial Custom Program will include a per building cap of \$75,000 in its final program plan.
9. Once a program implementer is selected and program plans are drafted, the program plans for all approved energy efficiency and demand response programs will be provided to Staff for review prior to the implementation of the programs. The Company should provide Staff up to 15 working days for review of the draft Final Program Plans. In order to deliver programs for customers on schedule, the Company will work with Staff to discuss and address potential concerns with final program plans without delaying program implementation schedules.
10. The current Commission policy that requires the Company to provide detailed evaluation plans for each of the approved DSM programs within 90 days of the selection of Program Implementers for each of the certified programs will

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Docket No 42310, GPC 2019 IRP  
Docket No. 42311, GPC DSM Application

continue. However, the Staff will work with the Company to extend the 90 days on an as needed basis as it has in past IRP cycles.

11. The Education Initiative Learning Power budget will continue at \$3 million annually for 2020 through 2022.
12. The Residential and Commercial Energy Efficiency Consumer Awareness annual budgets will continue at \$4.5 million and \$1.1 million, respectively.
13. The Company's pilot budget will be set at \$3million annually and split between the Residential and Commercial classes. The Company will seek Staff's input before the start of any pilot. This pilot budget includes \$400,000 in pilot evaluation costs.
14. The HopeWorks low income weatherization program budget will increase to \$400,000 per year.
15. The Company will earn an Additional Sum for DSM programs according to the mechanism approved in the Commission's August 2, 2016 Final Order in Docket 40161 & 40162.
16. The Company agrees that all references to Non-Participant Spillover ("NPSO") will be removed from its program plans and will not be considered in future calculations of Additional Sum.

Agreed to this 6<sup>th</sup> day of June, 2019.



Preston Thomas

On Behalf of the Georgia Public Service Commission  
Public Interest Advocacy Staff



Brandon F. Marzo

On Behalf of Georgia Power Company

Stipulation  
Docket No 42310, GPC 2019 IRP  
Docket No. 42311, GPC DSM Application

## BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of	)	
	)	Docket No. 42310
Georgia Power Company's	)	
2019 Integrated Resource Plan	)	
	)	
Georgia Power Company's	)	Docket No. 42311
2019 Demand Side Management Plan	)	

CERTIFICATE OF SERVICE

I hereby certify that the foregoing Stipulation in the above-referenced docket was filed with the Commission's Executive Secretary, an electronic copy of same was served upon all parties and persons listed below via electronic mail, or unless otherwise indicated, as follows:

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So certified, this 6th day of May 2019.



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