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Mr. Walter L. Thomas, Jr.
Secretary
Alabama Public Service Commission
RSA Union Building
100 North Union Street, Suite 950
Montgomery, Alabama 36130

Re: Alabama Public Service Commission Docket No. 32953
Errata to the Testimony and Exhibits of Alabama Power Company Witnesses

Dear Mr. Thomas:

Alabama Power submits the following errata to the direct and rebuttal testimonies of its witnesses in the above-captioned proceeding, filed September 6, 2019 and January 27, 2020, respectively. As explained below, these errata reflect corrections, information previously marked confidential that Alabama Power has unredacted and supplements to Alabama Power's exhibits. Testimony and exhibits not included in today's filing remain unchanged.

Corrections

1. Direct Testimony of John B. Kelley:
   a. P. 12, lines 3-4 (table) – replaced 600 MW of CTs in 2027 with 300 MW of CTs and 300 MW of CCs
   b. Exhibit JBK-1, pp. 21-22, Figure III-B-1 – corrected the graph
   c. Exhibit JBK-1, p. 23, section labeled "Weather Uncertainty" – replaced "more than forty years" with "more than thirty years"
   d. Exhibit JBK-1, p. 32, Figure III-F-1 – replaced 600 MW of CTs in 2027 with 300 MW of CTs and 300 MW CCs

2. Direct Testimony of Jeffrey B. Weathers:
   a. Exhibit JBW-1, p. 5, Table I.1 – changed TVA Summer Reserve Margin Modeled (%); changed Duke Energy Carolina Summer Reserve Margin Modeled (%); changed PowerSouth Summer Reserve Margin Modeled (%)

b. Exhibit JBW-1, p. 6, Table I.2 – changed PowerSouth Winter Reserve Margin Modeled (%)

Unredacted Information

1. Direct Testimony of John B. Kelley – unredacted all but two items (both on p. 22)
2. Exhibit JBK-1 – unredacted several items
3. Rebuttal Testimony of John B. Kelley – unredacted all testimony
4. Rebuttal Testimony of Maria J. Burke – unredacted all testimony and Rebuttal Exhibits MJB-1, MJB-2 and MJB-4

Supplemental Exhibits

1. Exhibit JBK-9 – supplemented with Central Alabama Purchase and Sale Agreement signature page (executed in counterparts)
2. Rebuttal Exhibit JBK-2 – paper copy of the Southern Company System Intercompany Interchange Contract

If you have any questions, please do not hesitate to contact me.

Sincerely,

Abby Fox

Abby Fox

cc: (w/enclosures)
Hon. John A. Garner
Service List

BEFORE THE
ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	**)**	**PETITION**
	)	
Petitioner	**)**	
	)	**Docket No. ________**

DIRECT TESTIMONY OF JOHN B. KELLEY
ON BEHALF OF ALABAMA POWER COMPANY

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John B. Kelley and my business address is 600 North 18th Street, Birmingham, Alabama.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Alabama Power Company ("Alabama Power" or "Company") as Director of Forecasting and Resource Planning.

Q. DESCRIBE THE PRINCIPAL BUSINESS ACTIVITY OF ALABAMA POWER.

A. Alabama Power is a public utility company, organized and existing under the laws of the State of Alabama. Alabama Power operates an integrated electric utility system across a large portion of the State. To this end, the Company's primary business activities are the generation, transmission and distribution of electricity to the public.

Q. BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Illinois in 1983 with a Bachelor of Science in Electrical Engineering degree. In 1987, I received a Master of Business Administration degree from the University of Alabama at Birmingham. I began my career with Southern Company in 1983 as an engineer in the transmission planning department of Southern Company

Services, Inc. ("SCS"). My responsibilities increased in the generation planning and integrated resource planning departments, including a two-year consulting project for the former Southern Electric International. In 1990, I began working for Alabama Power in the marketing department, where I maintained supervisory responsibilities over project analysis. I later served as the Manager of Marketing Services within the Alabama Power retail marketing organization, with responsibilities that included the development of retail market plans, economic evaluations, and mass marketing programs. I was named Director of Forecasting and Resource Planning in 2008.

Q. WHAT ARE YOUR JOB DUTIES AND RESPONSIBILITIES?

A. As Director of Forecasting and Resource Planning, I am responsible for the Company's Integrated Resource Plan ("IRP"), which includes the identification of timely and cost-effective expansions of Alabama Power's resources, such as generation additions, long-term power purchases, demand-side options, and renewable energy and environmentally-specialized generating resources. In addition, I have responsibility for the development of Alabama Power's demand, energy, customer and revenue forecasts.

Q. ARE YOU FAMILIAR WITH THE COMPANY'S PLANS FOR THE RESOURCE ADDITIONS DESCRIBED IN THE PETITION FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY?

A. Yes.

Q. HAVE YOU READ THE PETITION FILED BY THE COMPANY IN THIS PROCEEDING?

A. Yes.

Q. ARE THE STATEMENTS CONTAINED IN THE PETITION TRUE AND CORRECT TO THE BEST OF YOUR KNOWLEDGE, INFORMATION AND BELIEF?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is basically three-fold, and is organized accordingly. First, I will discuss the IRP process used by the Company to determine the need for new capacity resources in order to continue to provide reliable service to customers. I will then overview how Alabama Power identified potential resource opportunities for evaluation, including the Request for Proposals ("RFP") process that was used to determine the availability of reliable and cost-effective capacity alternatives from the wholesale market. Finally, I will summarize the proposed resource additions that the Company has selected for certification as providing reliable service at the lowest practicable total cost (capacity and energy) over the long run. I also will discuss the Company's request for authorization to pursue 200 megawatts ("MW") of demand-side management and distributed energy resource programs.

Q. ARE OTHER WITNESSES ALSO TESTIFYING IN SUPPORT OF THE COMPANY'S PETITION?

A. Yes. In addition to my testimony, the Company is offering the testimony of Jeffrey B. Weathers, Michael A. Bush, M. Brandon Looney and Christine M. Baker.

Q, BRIEFLY DESCRIBE THE TOPICS ADDRESSED BY THOSE OTHER WITNESSES.

A. Mr. Weathers will discuss the latest reserve margin study, which confirms the significant shift in reliability risk from the summer season to the winter season and the associated use of seasonal planning by the Company. Mr. Weathers also discusses the adoption of a winter target reserve margin in addition to the summer target reserve margin.

Mr. Bush describes the development of the Company's turnkey option at the Plant Barry site, which will be accomplished through an agreement between the Company and Mitsubishi Hitachi Power Systems Americas, Inc. and Black & Veatch Construction, Inc. for the associated engineering, procurement and construction.

Mr. Looney overviews the processes used to evaluate the various options available to meet the Company's reliability needs and determine which ones would comprise the most cost-effective portfolio of resource additions.

Finally, Ms. Baker will address how various rate mechanisms and accounting authorizations will apply to the components of the proposed resource portfolio.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE COMPANY AND THE OTHER OPERATING COMPANIES OF THE SOUTHERN ELECTRIC SYSTEM WITH REGARD TO GENERATION PLANNING AND SYSTEM OPERATION?

A. The Company and the other operating companies of the Southern electric system operate their systems on a coordinated basis in order to achieve economies of scale and other available efficiencies. The Intercompany Interchange Contract ("IIC"), which is a rate schedule filed with and approved by the Federal Energy Regulatory Commission, governs the treatment of and accounting for: (i) temporary surpluses and deficits of capacity among the companies; and (ii) energy exchanges and corresponding settlements associated with the economic dispatch of the system power pool. Operating in this manner under the IIC lowers total production cost and enhances system reliability, which benefits all of the operating companies. In addition, the long-term load forecasts of the individual operating companies are combined into a single integrated forecast, which enables them to benefit from system diversity through reserve margins that are lower than would be required were each to operate on a stand-alone basis.

For the affiliated retail operating companies, the resource additions necessary to provide reliable and economic service are determined through a comprehensive and coordinated resource planning process. Using long-term planning reserve margin guidelines, the process determines the amount of capacity, and indicates the type of resource additions, required to provide reliable, efficient and economical service. It should be emphasized that, although engaging in coordinated planning and operation, each retail operating company retains the right and bears the responsibility to determine the resource additions appropriate for its service territory and to operate its system so as to satisfy the needs of its customers in a reliable and efficient manner. The expectation that each operating company will have resources to reliably serve its own customers, which I understand to be an integral part of Alabama Power's status as a public utility under Alabama law, is likewise a fundamental premise embodied the IIC.

I. IRP Process and Indicated Resource Need

Q. WHAT IS THE PURPOSE OF THE IRP PROCESS AND HOW IT IS USED BY THE COMPANY?

A. The IRP process is an analytical tool designed to identify the timing, amount, and types of resources necessary to serve the long-term expected energy and demand requirements of Alabama Power's customers. It involves choosing from a broad range of resource options to produce an indicative benchmark plan of resource additions that is reasonably expected to meet anticipated load obligations (including an appropriate reserve margin) at the lowest practicable cost over the long run. These results help guide the Company as it undertakes to develop and implement a supply-side and demand-side resource strategy that will enable it to continue to provide service that is reliable and cost effective for customers.

Q. CAN THE IRP PROCESS BE REDUCED TO WRITING?

A. Integrated resource planning is not a document, but rather a comprehensive, data-intensive process. The Company does, however, develop a summary report that provides considerable detail regarding the objectives of the IRP process, the major steps, tools, and inputs it employs, and other considerations that together produce the indicative benchmark plan of future resource additions. A copy of the public version of the 2019 IRP Summary Report is appended to my testimony as Exhibit JBK-1.

Q. WAS THIS EXHIBIT PREPARED UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. The Forecasting and Resource Planning organization that I oversee is responsible for implementing the Company's IRP process, including the preparation of this 2019 IRP Summary Report.

Q. BRIEFLY OVERVIEW THE COMPANY'S IRP PROCESS.

A. As described more fully in the 2019 IRP Summary Report, the IRP is an iterative process that evaluates existing and potential resource options to identify the best combination of needed additions, in terms of reliability and expected total cost for serving customers. Using updated marginal cost projections to capture significant changes related to fuel, technology, regulatory compliance and other such factors, the Company evaluates its existing supply-side options to determine what, if any, resource additions or modifications are economically viable. Similarly, the Company uses the same marginal cost approach to evaluate demand-side management ("DSM") programs to determine those that appear cost-effective and thus eligible for inclusion in a new benchmark plan. These results, along with comparable analyses applied to new candidate technologies, are integrated to produce an optimum combination of demand-side and supply-side resources that comprise the benchmark plan. This benchmark plan shows additions that, together with the Company's existing portfolio of resources, will meet the projected demand and energy needs of the Company's customers in a reliable and cost-effective manner.

Q. HOW IS THE AMOUNT AND TIMING OF THE RESOURCE NEED DETERMINED?

A. The determination of the amount and timing of the needed resources starts with an update to the Company's forecast of future energy and peak demand requirements for the next 20 years. Based on this updated load forecast, the Company identifies a schedule of resources required to serve that load reliably, which necessarily includes an appropriate reserve margin.

Q. WHAT IS THE PURPOSE OF A RESERVE MARGIN?

A. Electric utility customers expect and depend on a high level of service reliability. Accordingly, a retail electric utility like Alabama Power must have an economically balanced margin of generating capacity above its anticipated peak load, i.e., a reserve margin. This enables the Company to maintain sustained reliability for its customers, notwithstanding unpredictable events such as equipment failures or extreme weather.

Q. HOW WERE THE RESERVE MARGINS USED IN THE COMPANY'S 2019 IRP DETERMINED?

A. The reserve margins used by the Company are based on the 2018 Reserve Margin Study that analyzed the reliability challenges on the system and then identified risk-adjusted reserve margins that would minimize the combined costs of maintaining reserve capacity, system production costs, and customer costs associated with service interruptions. The 2018 Reserve Margin Study is addressed in the testimony of Mr. Weathers, including a discussion of the underlying methodology and the increased reliability risk in the winter. Winter-related reliability issues are also addressed in the 2019 IRP Summary Report.

The confirmation in the 2018 Reserve Margin Study of a significant increase in winter reliability risks (as identified in the preceding 2015 Reserve Margin Study) led the Company (along with the other operating companies) to begin using seasonal planning in the IRP process. This means that, while in the past the Company has historically relied upon a target reserve margin only for the summer season, it is now using independent evaluations of resource adequacy in both the summer and the winter peak periods to ensure that system reliability is fully addressed year round. This results in the establishment of separate target reserve margins for each of those seasons.

Q. HAS THE COMPANY SEEN CHANGES IN THE LOADS OF ITS CUSTOMERS THAT FURTHER VALIDATE THE ADOPTION OF SEASONAL PLANNING?

A. Yes. Alabama Power has traditionally been considered summer peaking, meaning its annual peak demand has occurred during the summer months. However, in recent years, Alabama Power's winter peak demand has exceeded the summer peak demand. The 2014 actual winter peak was 12,610 MW, which exceeded the prior all-time peak of 12,496 MW that occurred in the summer of 2007. Moreover, on a weather-normalized basis, the Company's winter peak has exceeded its summer peak since 2010, and the Company's most recent load forecast continues to project a winter peak demand that is higher than the summer peak demand.

Q. DO THE RESERVE MARGINS THAT UNDERLIE THE 2019 IRP REFLECT THESE SEASONAL REALITIES?

A. Yes. The Company is maintaining the current 16.25 percent long-term system target reserve margin for the summer peak planning season. To address the winter reliability concerns, the Company is adding a long-term winter target reserve margin of 26 percent for the system, to be used in planning for the winter peak season.

Q. DOES THIS MEAN THAT THE COMPANY MUST HAVE RESERVE MARGINS AT BOTH OF THOSE LEVELS TO MAINTAIN RELIABIITY IN THE RESPECTIVE SEASONS?

A. No. As previously explained, Alabama Power and the other operating companies of the Southern electric system operate on a coordinated basis in order to achieve economies of scale and other available efficiencies. One of the recognized advantages of operating in this manner is the benefit of system diversity, enabling the individual companies to maintain lower "diversified" reserve margins while collectively achieving the higher target reserve margin for the system. Thus, for purposes of long-term planning, Alabama Power's diversified summer target reserve margin is 14.89 percent and its diversified winter target reserve margin is 25.25 percent.

Q. HAS THE ALABAMA PUBLIC SERVICE COMMISSION ("COMMISSION") HAD OCCASION TO REVIEW AND ADDRESS THE IRP PROCESS USED BY THE COMPANY?

A. Yes. The Company has used integrated resource planning for many years and the resulting IRPs have prompted a number of petitions for certification of new resources to satisfy a reliability-based need for additional capacity. On several of those occasions, the Commission has specifically endorsed that process.

Q. DID THE COMPANY FOLLOW THAT SAME PROCESS TO DETERMINE THE RESOURCE NEEDS REFLECTED IN THE CURRENT PETITION?

A. Yes. As one would expect, inputs to the IRP (such as marginal cost projections, load forecasts, target reserve margins, and candidate technologies) are revised and updated over time, but from a conceptual and methodological standpoint, the Company continues to apply the same fundamental IRP process previously endorsed by the Commission. To keep the Commission apprised of the ongoing status of the IRP process, the Company provides to Commission staff its periodic IRP results (typically performed at three-year intervals) and meets with staff to review and discuss the results, including changes in the underlying drivers.

Q. WHAT ARE THE CAPACITY NEEDS INDICATED BY THE IRP FOR THE RESPECTIVE SEASONS?

A. Over the next ten years, the 2019 IRP shows the Company is within its diversified target for the summer season. In the winter, however, the Company's ("APC") reserve margins are below the applicable target, revealing significant capacity needs over that period (shown in red).

Capacity Need (MW) - Winter		
Year	APC Reserve Margin (%)	APC Need (MW)
2020	11.1%	1,650
2021	10.1%	1,788
2022	11.3%	1,702
2023	5.2%	2,447
2024	7.0%	2,229
2025	6.9%	2,243
2026	10.8%	1,652
2027	9.1%	1,844
2028	5.5%	2,270

These results demonstrate that, over this entire timeframe, Alabama Power has a reliability-driven need for additional resources in the winter.

Q. WHAT CAUSES THE INDICATED AMOUNT OF NEED TO SOMETIMES MOVE DOWN FROM ONE YEAR TO THE NEXT?

A. Typically, the amount of need will move up gradually in response to normal load growth. In some years, however, there can be a larger shift, either in the Company's projected load (due, for example, to a new or expiring contract) or in its available resources (due, for example, to a unit addition, expiration of a power purchase agreement, or unit unavailability assumptions).

Q. DO THE SYSTEM RESERVE MARGINS, WHICH REFLECT ALABAMA POWER'S OBLIGATIONS AND RESOURCES ALONG WITH THOSE OF THE OTHER RETAIL OPERATING COMPANIES, INDICATE SUCH A CAPACITY SHORTFALL IN THE WINTER OVER THIS SAME PERIOD?

A. No. When viewed on a coordinated system basis, the reserve margins and indicated capacity additions needed to satisfy the long-term winter planning reserve margin over the 2020-2028 timeframe are as follows.[1]

2019 IRP Winter Benchmark Base Case with Generic Additions						
Year	APC CT's	APC CC's	APC RM	APC NEEDS (MW)	ROC RM	ROC NEEDS (MW)
2020	-	-	11.1%	1,650	24.9%	167
2021	-	-	10.1%	1,788	24.5%	287
2022	-	-	11.3%	1,702	27.9%	(562)
2023	300	-	7.7%	2,147	26.4%	(124)
2024	-	-	9.4%	1,929	27.2%	(366)
2025	-	900	16.7%	1,043	26.1%	(36)
2026	-	-	21.3%	452	26.1%	(21)
2027	300	300	24.9%	44	27.0%	(285)
2028	300	270	26.1%	(100)	26.9%	(250)

Q. WHY DOES ALABAMA POWER HAVE LARGE WINTER CAPACITY NEEDS OVER THIS TIMEFRAME, WHEREAS THE COLLECTIVE SOUTHERN SYSTEM DOES NOT?

A. These capacity needs arise for Alabama Power because its load peaks in the winter season. In contrast, the largest of the retail operating companies, Georgia Power, continues to experience its peak load in the summer. The fact that Georgia Power does so, coupled with its size relative to the other companies, is the reason the winter need shown for the collective system is considerably less, as Georgia Power currently has capacity on its system that can be used to help support the winter requirements of Alabama Power's customers.

[1] For purposes of this table, "CT" means combustion turbine, "CC" means combined cycle, "ROC" means retail operating companies, and "RM" means reserve margin.

Q. GIVEN THE COORDINATED OPERATIONS OF THE SOUTHERN SYSTEM, WHY DOESN'T ALABAMA POWER RELY ON CAPACITY OF THE OTHER OPERATING COMPANIES FOR WINTER RELIABILITY?

A. As noted earlier, each retail operating company is responsible for determining the resource additions appropriate for its own service territory that will enable it to meet the needs of its customers in a reliable and cost-effective manner. Interactions with the affiliated companies through mechanisms such as coordinated planning and operation can and do provide benefits and cost savings (including the ability to take advantage of temporary surplus capacity on the system), but they do not alter this fundamental duty and responsibility. Moreover, much of the capacity that gives rise to the higher reserve levels at the other retail affiliates comprises older fossil steam resources. It is no surprise that such resources across the country are under significant cost pressure that threatens their continued operation, for reasons including the ongoing cost of environmental compliance, forecasted low gas prices, and modest load growth. To that end, Georgia Power recently proposed the retirement of Plant Hammond Units 1-4 and Plant McIntosh Unit 1 (totaling approximately 980 MW), and specifically noted economic challenges associated with the continued operation of Plant Bowen Units 1-2 (totaling approximately 1500 MW). Under the Order Adopting Stipulation As Amended issued by the Georgia Public Service Commission dated July 29, 2019, the Hammond and McIntosh units were officially retired and capital spending limits were established for Bowen Units 1-2 for the next three years. The 2019 IRP seasonal needs presented above already exclude the former, but assume the continued operation of Bowen Units 1-2.

I would emphasize that Alabama Power is not suggesting, and does not know, what Georgia Power's ultimate plans may be for the Bowen units. My point is that these are Georgia Power resources and as the owner it controls decisions impacting their future operation (subject, of course, to requisite regulatory approvals under state law). The same would be true for Mississippi Power Company and the resources that it owns. Alternatively, these companies could seek to make wholesale sales predicated on their owned capacity. In either case, the effect would be a reduction in the level of available capacity reserves on the system. Accordingly, Alabama Power cannot and should not count on the sustained availability of capacity owned by its retail affiliates for use in serving the requirements of Alabama customers, particularly given the Company's reliability obligations as a regulated public utility under Alabama law.

Q. GIVEN THE RESULTS OF ALABAMA POWER'S IRP PROCESS AND OTHER RELEVANT CONSIDERATIONS, HOW MUCH CAPACITY DOES THE COMPANY NEED TO SECURE FOR LONG-TERM RELIABILITY PURPOSES?

A. The IRP results shown for Alabama Power and for the system, coupled with other factors impacting reliable long-term supply, demonstrate a need for the Company to add approximately 2400 MW of additional resources by the 2023-2024 timeframe. This advancement of the resource additions otherwise indicated by the coordinated system plan across the 2023-2028 timeframe will mitigate the described risks and satisfy the Company's statutory duty to make reasonable enlargements of its system to meet the demand of those customers for whom it holds a duty to serve. The portfolio of resource additions proposed for certification, as described in more detail in the last part of my testimony, represent a reliable and cost-effective means of satisfying that need.

II. Identification of Potential Resource Opportunities

Q. HOW DID ALABAMA POWER GO ABOUT IDENTIFYING RESOURCE OPTIONS AND OPPORTUNITIES THAT MIGHT PROVE TO BE COST-EFFECTIVE MEANS OF MEETING ITS RELIABITY NEED?

A. The Company's overarching goal in this undertaking was to consider any resource opportunities that could be appropriate to meet this capacity need, and to then subject those potential options to a rigorous and consistent evaluation. The array of options included the turnkey delivery of a new facility, numerous capacity offerings from the wholesale market, and certain other proposals that evolved from a prior solicitation of renewable energy projects.

Q. DESCRIBE THE DEVELOPMENT OF THE TURNKEY PROJECT.

A. Building and owning needed capacity resources is a traditional option that is almost always available to a public utility. In this instance, that option took the form of a turnkey combined cycle project at Plant Barry, which is described more fully in Mr. Bush's testimony.

Q. HOW DID ALABAMA POWER OBTAIN LONG-TERM CAPACITY OFFERINGS FROM THE WHOLESALE MARKETS?

A. In order to determine the terms and conditions of available opportunities in the wholesale market, the Company publicized and issued a capacity Request for Proposals ("Capacity RFP"). A copy of that RFP is appended to my testimony as Exhibit JBK-2.

Q. WAS THE CAPACITY RFP CONDUCTED UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. HAS ALABAMA POWER RECENTLY CONDUCTED ANOTHER SOLICITATION THAT FOLLOWED A SIMILAR STRUCTURE?

A. Yes. In accordance with the requirements of the Commission's order in Docket No. 32383, a Renewable RFP was conducted by Forecasting and Resource Planning in 2018 to help identify potentially viable renewable resources that might be candidates for certification pursuant to that order.

Q. BRIEFLY DESCRIBE THE CAPACITY RFP.

A. On September 21, 2018, the Company issued the Capacity RFP, soliciting proposals for capacity resources either in the form of a power purchase agreement ("PPA") or an agreement for the acquisition of new-build or existing facilities. The Company expressed a willingness to consider any type of resource that would provide reliable, dispatchable, cost-effective capacity and energy to meet the needs of its customers. Commencement of service would be in the 2019-2023 timeframe, with the amount depending upon the cost competitiveness of the respective offers as well as other options available to the Company. Notice of the RFP was publicized through BusinessWire, a press release distribution service that reaches online, print, broadcast and radio media outlets, reporters and wire services. In addition, a dedicated website was established for the Capacity RFP.

Q. WHAT WAS THE LEVEL OF RESPONSE FROM WHOLESALE MARKET PARTICIPANTS?

A. Interested bidders submitted 19 proposals that totaled approximately 5,000 MW of capacity (excluding the effect of multiple offerings from the same resource). The electronic bids were opened on November 13, 2018, in the presence of an independent accounting firm and a member of the Commission staff, with an electronic copy of each proposal being retained for future reference by the accounting firm.

Q. WHAT WERE THE MAJOR STEPS IN THE CAPACITY RFP PROCESS AFTER THE PROPOSALS WERE RECEIVED?

A. In general terms, the process consisted of the following steps. For the most part, these are set forth in chronological order, but some overlap may necessarily have occurred.

- Assessment of bids to confirm material compliance with the terms of the Capacity RFP
- Preliminary evaluation on the basis of production costs and other factors
- Initial due diligence related to proposals to acquire existing facilities
- A more detailed evaluation to derive a “Competitive Tier” of proposals
- Initial meetings with each Competitive Tier bidder, encouraging proposal and pricing updates
- Receipt of updated bid proposals, with electronic copies transmitted to the independent accounting firm for retention
- Detailed due diligence related to proposals to acquire existing facilities
- Further analysis of the updated bid proposals, including preliminary transmission costs and impacts, to determine an initial “Shortlist”
- One-on-one negotiations for projects on the Shortlist, with encouragements for proposal and pricing updates
- Further analysis to reflect updated information (e.g., bidder proposal refinements, due diligence information, transmission impacts), along with associated contract negotiations

Q. WERE THESE PROPOSALS EVALUATED IN A COMPARABLE MANNER?

A. Yes. The economic evaluations used throughout this process assessed the costs and benefits associated with the various competing proposals in a comprehensive and nondiscriminatory manner. To that end, the Reliability and Resource Procurement group at SCS headed up by Mr. Looney conducted the economic evaluations for the proposals originating from bids in the Capacity RFP as well as the turnkey proposal. The evaluation of proposals for solar photovoltaic facilities paired with battery energy storage systems ("Solar/BESS") was performed by Forecasting and Resource Planning consistent with the Company's prior evaluations of solar and other renewable resources.

Q. WHY DID YOU RETAIN EVALUATION RESPONSIBILITY FOR THE SOLAR/BESS PROJECTS?

A: Given that these proposals originated from the Renewable RFP, Forecasting and Resource Planning had already begun to analyze them and therefore retained evaluation responsibility for the Solar/BESS projects to facilitate ongoing negotiations and to achieve an outcome that best satisfied Alabama Power's indicated needs.

Q: HOW WERE THE SOLAR/BESS PROJECTS EVALUATED?

A: Forecasting and Resource Planning utilized an approach comparable to that employed by Mr. Looney's group and considered the same cost components and resource benefits.

Q. EXPLAIN HOW THE SOLAR/BESS PROJECTS EVOLVED.

A. I mentioned previously that the Company conducted a Renewable RFP in 2018 in an effort to identify potentially viable renewable resources that might be candidates for certification pursuant to the Commission's order in Docket No. 32382. As discussions were ongoing in connection with some of those renewable projects, the Company received proposals for stand-alone battery storage in response to the Capacity RFP. Although the stand-alone battery storage projects were not economically viable options, the Company concluded that a pairing of such storage projects with renewable (solar) projects emanating from the

Renewable RFP might together comprise cost-effective capacity resources. That idea led to the submission of various Solar/BESS proposals that, as discussed below, proved to be economically attractive when modeled along with existing system resources.

III. Portfolio of Resources Proposed for Certification

Q. DESCRIBE THE PORTFOLIO OF RESOURCES THAT WERE SELECTED FOR CERTIFICATION BY THE COMPANY, ON THE BASIS OF COST-EFFECTIVENESS AND RELIABILTY, TO MEET THE CAPACITY NEED IDENTIFIED THROUGH THE 2019 IRP PROCESS.

A. As reflected in the Petition for a Certificate of Convenience and Necessity, the resource portfolio proposed by the Company to meet the identified capacity need is as follows:

- Five (5) Solar/BESS project PPAs, with a cumulative winter capacity equivalence of 340 MW (68 MW each)
- Barry Unit 8 Combined Cycle Project, with an ultimate winter capacity rating of 743 MW
- Hog Bayou PPA, with a winter capacity rating of 238 MW
- Acquisition of Central Alabama Generating Station, with a winter capacity rating of 915 MW

These supply resources will add an additional 2236 MW to the Company's winter capacity. While largely resolving the pressing reliability need in the winter season, this total falls short of the indicated need for approximately 2400 MW by the 2023-2024 timeframe. The Company plans to address that difference through the pursuit of approximately 200 MW of new demand-side management programs and distributed energy resources that will be reflected in the next iteration of the IRP.

Q. HOW DID THE COMPANY DETERMINE THE SUPPLY-SIDE RESOURCES SHOWN ABOVE TO BE THE MOST RELIABLE AND COST-EFFECTIVE PORTFOLIO OPTIONS?

A. As discussed more fully in Mr. Looney's testimony, the detailed economic evaluation of the expected costs and benefits associated with the various proposals yielded a rank order indicative of their relative economic merit. In addition, and as he explains, a portfolio analysis was necessary to capture the potential for transmission interaction (and hence cost impacts) among the multiple proposals required to satisfy the need. I also directed Mr. Looney to examine the proposals under scenarios representing alternative fuel cost and carbon cost futures. The results of the alternative scenarios produced the portfolio reflected in the Company's petition. Appropriate regard was also given to the total amount of capacity proposed in the portfolio, as compared to the amount of need identified in the 2019 IRP.

Q. DESCRIBE EACH OF THE SUPPLY-SIDE RESOURCES IN THE PROPOSED PORTFOLIO.

A. The capacity associated with Solar/BESS projects is reflected in five PPAs with special purpose entities owned by three different developers: three projects with NextEra (Dallas County Solar, LLC, Dothan Solar, LLC and Talladega Solar, LLC), one project with Origis (AL Solar C, LLC), and one project with Southern Current (Anniston Solar, LLC). The PPAs are all structured the same, providing for a nominal 80 MW solar facility plus a nominal 80 MW BESS. Each BESS must be able to discharge 80 MW for two hours (for a total amount of stored energy of 160 MWh) so as to meet critical system peak demands. Although the BESS component of the contracts provides capacity to the Company, payments to the sellers are all energy-based. Alabama Power has the right to direct the charging and discharging of the BESS during an eight-month period each year, including both the winter and summer peak seasons. The seller is subject to liquidated damages under certain specified circumstances, including failure to meet contractual guarantees relating to actual production from the solar facility and the capacity of the BESS. These PPAs are appended to my testimony as Exhibit JBK-3, Exhibit JBK-4, Exhibit JBK-5, Exhibit JBK-6 and Exhibit JBK-7.

Barry Unit 8 is a combined cycle facility with initial capacity ratings of 726 MW (with a scheduled uprate to 743 MW) in the winter and 653 MW (with a scheduled uprate to 685 MW) in the summer. It is being constructed pursuant to a turnkey contract with Mitsubishi Hitachi Power Systems Americas, Inc. and Black & Veatch Construction, Inc., both of whom are responsible for the engineering, equipment procurement and construction activities specified in the contract. The Company (through its agent, SCS) will maintain oversight to ensure contract compliance and is also responsible for certain site-related and interconnection work. A full description of the Barry Unit 8 project is set forth in Mr. Bush's testimony, which includes relevant portions of the turnkey contract as an exhibit.

The proposed PPA between Alabama Power and Mobile Energy, LLC (an affiliate of the LS Power Development, LLC) ("Mobile"), appended to my testimony as Exhibit JBK-8, provides the Company rights to the entire capability of the Hog Bayou Energy Center located in Mobile County, Alabama, for a total term of approximately nineteen (19) years. The Hog Bayou Energy Center is a combined cycle, natural-gas fired facility with a summer rating of 222 MW and a winter rating of 238 MW. In order to address certain near-term reliability needs, the PPA calls for an early start period beginning in 2020 through November 2023, followed by a fifteen (15) year term beginning in December 2023. Along with monthly capacity payments, Alabama Power is responsible for an energy payment that includes a charge for each unit start, plus a charge for variable O&M expenses and a fuel adjustment based on a guaranteed heat rate. (The PPA also includes a minimum availability rate.) As this is a "tolling" PPA, the Company is handling the fuel-related arrangements (commodity and transportation). Extended periods of unavailability below a specified level constitutes an event of default by Mobile, in which case Alabama Power would be entitled to termination payments.

The final supply-side component of the portfolio is the acquisition of the Central Alabama Generating Station ("Central Alabama") located near Billingsley, Alabama. Central Alabama is a combined cycle facility constructed in 2003, with a winter capacity rating of 915 MW and a summer capacity rating of 890 MW. The facility is owned by Tenaska Alabama II Partners, L.P., a Delaware limited partnership in which a Tenaska subsidiary is the managing general partner and majority owner. Until May 2023, Central Alabama is subject to a PPA with [redacted] under which it is entitled to the capacity of the facility and the associated energy. Upon the closing of a Purchase and Sale Agreement ("PSA"), Alabama Power will become the owner of Central Alabama. At that point, the facility is expected to have a remaining useful life of approximately 23 years. The terms and provisions of the above-described PPA with [redacted] will remain in place until it expires, with Alabama Power entitled to receive the associated revenues. The Company will thereafter have the same rights and responsibilities associated with Central Alabama as with any other generating facility owned by the Company. The PSA is subject to a number of conditions, specifically including receipt of requisite regulatory approvals. The PSA, in its agreed upon form and with relevant ancillary transaction documents, is appended to my testimony as Exhibit JBK-9. The PSA is not yet signed by the parties, but execution is forthcoming. At an appropriate time, the Company will supplement this exhibit to reflect finalization.

Q. DESCRIBE THE DEMAND-SIDE MANAGEMENT AND DISTRIBUTED ENERGY RESOURCE PROGRAMS THAT THE COMPANY SEEKS TO PURSUE.

A. As set forth in the petition, the Company is requesting authorization to pursue an increase of 200 MW in demand-side management and distributed energy resource programs. At this time, the Company does not know the mix of programs it will seek to implement; however, examples of potential demand-side management programs include:

- A smart thermostat program, coupled with the deployment of high efficiency heat pumps;
- An "Orchestrated Energy" program, by which the Company would incent the shifting of load from higher cost periods to lower cost periods; and
- Expansion of existing standby generation, non-firm, load shifting and critical peak pricing programs.

Q. WHAT DISTRIBUTED ENERGY RESOURCE PROGRAMS IS THE COMPANY CONTEMPLATING?

A. Here too, the Company's program evaluation remains ongoing. The Company envisions, however, the potential for deployments both at a utility scale level as well as smaller scale facilities (e.g., less than 1 MW), all at customer locations.

Q. DOESN'T THE COMPANY HAVE AN EXISTING CERTIFICATE FOR SUCH PROJECTS?

A. The Commission did authorize a blanket certificate for renewable generation and environmentally specialized resources in 2015 in Docket No. 32382. By its terms, that certificate expires in 2021, which is during the triennial cycle of the Company's integrated resource plan. The Company may separately elect to pursue renewal of that certificate, but in connection with the current need-based petition, the Company seeks to obtain appropriate authorization now so that it can proceed forward with program development.

Q. HOW DOES THE COMPANY PROPOSE TO IMPLEMENT ITS DEMAND-SIDE MANAGEMENT AND DISTRIBUTED ENERGY RESOURCE PROGRAMS?

A. Similar to the projects under the renewable generation certificate, the Company would submit the demand-side management and distributed energy resource programs for Commission approval on a project-by-project basis. For each project, Alabama Power's evaluative criteria would be that the project results in positive benefit for all customers over the term of the project relative to the applicable benchmark plan, taking into account the costs and revenue impacts of the project and the expected value corresponding to the avoided capacity addition, along with other positive benefits that may accrue through load growth, load retention or other relevant considerations associated with the particular project.

Q. DO YOU HAVE ANY CONCLUDING REMARKS RELATED TO THE COMPANY'S PETITION AND ASSOCIATED TESTIMONY?

A. As demonstrated in my testimony and that of the other witnesses, the Company's petition is fully supported in all respects. There is the clear showing of a need for additional capacity resources that will enable Alabama Power to continue to fulfill its duty to provide reliable service to its customers. The testimony further shows that the Company has selected a portfolio that constitutes a reasonable and cost-effective means of satisfying that need.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Direct Testimony of John B. Kelley

Updated Exhibit JBK-1

PUBLIC VERSION

Alabama Power

2019
Integrated Resource Plan Summary Report
Confidential Version

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FIGURES

APPENDICES

EXECUTIVE SUMMARY

The 2019 Integrated Resource Plan ("2019 IRP")[1] for Alabama Power Company ("Alabama Power" or "Company") is a comprehensive process that serves as the foundation for certain decisions affecting the Company's future portfolio of supply-side and demand-side resources.[2] The IRP process does not produce binding determinations concerning new specific resources that the Company will procure in the future. Rather, it is a management tool that, using the best information currently available, facilitates the Company's ability to make future resource decisions that result in reliable and cost-effective electric service to customers, while accounting for risks and uncertainties inherent in planning for resources sufficient to meet expected customer demand. The dynamic nature of the Company's IRP process thus produces a comprehensive plan of indicative resource additions that serves as the basis on which the Company can develop and manage its portfolio of supply-side and demand-side management ("DSM") resources to provide reliable electric service to its customers.

The IRP is developed on a formal basis every three years and is reviewed with the staff of the Alabama Public Service Commission ("APSC"). This review keeps the APSC informed as to the timing of needed resource additions, while also helping to ensure that the process yields results that are consistent with the Company's ultimate goals of minimizing rates and providing the desired level of service reliability. These goals are important because they allow the Company to be competitive with other energy providers and promote economic development within the State of Alabama.

Alabama Power remains committed to maintaining a diverse supply-side generating portfolio, along with cost-effective DSM resources that benefit all customers. Resource diversity on the supply side, which includes nuclear, natural gas, coal, oil, hydroelectric, wind, solar, and biomass resources, provides significant benefit to customers, as it enables the Company to adapt to changes impacting its energy supply obligations. In that regard, the Company's generating fleet is transitioning due to a number of factors, including the cost of natural gas and the cost impacts of various environmental regulations

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[1] As noted, the IRP is a comprehensive, data-intensive process that ultimately yields an indicated list of future resource additions designed to meet appropriate reliability requirements in a cost-effective manner. This Summary Report only serves to overview that process and summarize its results; however, for ease of reference this document is sometimes referred to as the "2019 IRP".

[2] Appendix 1 is a detailed list of all supply-side resources owned and controlled by Alabama Power. Appendix 2 summarizes the Company's activities related to existing and potential Demand Side Management ("DSM") programs.

by the U.S. Environmental Protection Agency ("EPA"). A recent example of an environmentally-driven change is the retirement of Gorgas Units 8-10 due to the compliance requirements of EPA's coal combustion residuals rule (Disposal of Coal Combustion Residuals from Electric Utilities, or "CCR Rule"). Ongoing uncertainties also persist in connection with EPA's Effluent Limitation Guidelines rule addressing wastewater limits for steam electric power plants, as well as initiatives at the federal level to regulate or tax carbon dioxide ("CO2") emissions. The cost and operating implications for the Company's supply resources related to these and other considerations remain factors in the Company's planning scenarios related to the 2019 IRP.

As reflected in the 2019 IRP, Alabama Power's planning process now separately considers the winter and the summer seasons, thereby ensuring sufficient reserve capacity during different times of the year, as compared to a focus solely on summer reliability. Historically, the Company's capacity planning decisions have been driven by summer peak loads and a corresponding summer-focused Target Reserve Margin. These planning techniques have proven to be successful in supporting reliability, while cost-effectively meeting the needs of customers. However, operational experience over the last several years, and in particular a winter peak demand for the Alabama Power system, demonstrates a significant transition in reliability risk from the summer-only season to predominantly the winter season. As a result, Alabama Power is modifying its summer-based capacity planning approach to specifically address reliability on a seasonal basis. Seasonal planning provides greater visibility into capacity needs in both summer and winter, rather than limiting reliability decisions to a single season.

In support of the transition to seasonal planning, the 2019 IRP reflects the results of the most recent Reserve Margin Study for the Southern Company System ("System"). The Reserve Margin Study provides a detailed reliability analysis that yields Target Reserve Margins for the System. Based upon the Reserve Margin Study, the Company is utilizing seasonal Target Reserve Margins for all future planning purposes. For long-term planning starting in 2022 and beyond, the Company's plan maintains a System Target Reserve Margin of 16.25 percent for summer periods ("Summer Target Reserve Margin"). For winter periods, the Company is adopting a long-term planning Target Reserve Margin for the System of 26 percent ("Winter Target Reserve Margin"). Consistent with past practice, the Company also evaluated the short term (2019-2021) Target Reserve Margin and for planning purposes is adopting a 15.75 percent target for summer and a 25.5 percent target for winter. Due to the benefits of load diversity, coordinated planning and operations, and the ability to share resources, the Southern Company retail operating companies can together achieve these System targets by each utilizing diversified reserve margins that are lower than the Target Reserve Margins for the System. Thus, the diversified Summer Target Reserve Margins for Alabama Power are 14.89 percent over the long-term and 14.39 percent over the short-term. Likewise, Alabama Power's diversified Winter Target Reserve Margins are 25.25 percent over the long-term and 24.75 percent over the short-term. These diversified values are subject to change in response to changes in System load diversity. Figure ES-1 compares the previous planning reserve margin targets to those predicated on the updated Reserve Margin Study.

FIGURE ES-1: Summer and Winter Target Planning Reserve Margin Comparison

	Previous Reserve Margin Study	**Updated Reserve Margin Study**
System Long-Term Target Planning Reserve Margin (Summer)	16.25%	16.25%
System Short-Term Target Planning Reserve Margin (Summer)	14.75%	15.75%
Diversified Long-Term Target Planning Reserve Margin (Summer)	14.74%	14.89%
Diversified Short-Term Target Planning Reserve Margin (Summer)	13.26%	14.39%
System Long-Term Target Planning Reserve Margin (Winter)	-	26.00%
System Short-Term Target Planning Reserve Margin (Winter)	-	25.50%
Diversified Long-Term Target Planning Reserve Margin (Winter)	-	25.25%
Diversified Short-Term Target Planning Reserve Margin (Winter)	-	24.75%

Based on these Target Reserve Margins, and taking into account the Company's load forecast and other considerations reflected in the 2019 IRP, Alabama Power projects a resource deficit as of the upcoming winter period (2019-2020). Interim steps can be taken at the Southern Pool[3] level to address this anticipated deficit; however, subsequent winters demonstrate deficits as well. Accordingly, longer-term resources need to be procured to address the Company's deficit in winter 2024 and

[3] The Southern Pool is governed by the terms of the Southern Company System Intercompany Interchange Contract, which is a rate schedule on file with the Federal Energy Regulatory Commission ("FERC"). Well-recognized benefits of pooling include lower production costs for the participants (as opposed to stand-alone operation), lower reserve margins due to load diversity, and the ability to take advantage of economies of scale by sharing temporary surplus and deficit capacity.

beyond. To meet this need, the Company will continue to employ the principles discussed earlier to identify an economic set of resource options that are projected to provide the most benefit to customers at the lowest practicable cost. Upon identification of these resources, the Company will seek authorization from the APSC for procurement or development rights, as applicable.

I. INTRODUCTION AND OVERVIEW

Alabama Power is an investor-owned electric utility, organized and existing under the laws of the State of Alabama, and is a subsidiary of the Southern Company. In addition to Alabama Power, the Southern Company is the parent of Georgia Power Company, Mississippi Power Company, and Southern Power Company (collectively, the "Operating Companies"), as well as certain service and special-purpose subsidiaries. Alabama Power is primarily engaged in generating, transmitting and distributing electricity to the public in a large section of Alabama. The Company's retail rates and services are regulated by the APSC under the provisions of Title 37 of the Code of Alabama.

The Company has approximately 1.48 million customers, of which approximately 86 percent (1.27 million) are residential; 13.5 percent (200,000) are commercial; and 0.5 percent (6,900) are industrial and other. Alabama Power has approximately 1.57 million transmission and distribution poles, and approximately 85,000 miles of wire. The Company strives to maintain cost-effective and reliable service to its customers. For the years 2017-2018, the Company had a service reliability of 99.98 percent. As noted earlier, Alabama Power has a diverse mix of supply-side (both owned and contracted) and demand-side resources, including hydroelectric, natural gas, nuclear, coal, oil, renewable projects,[4] combined heat and power, and DSM programs.

As of April 2019, Alabama Power's supply-side capacity resources had a winter generating capability of approximately 12,600 MW and a summer generating capability of approximately 12,500 MW. These resources, along with active DSM programs having a capacity value of approximately 1,200 MW, represent a diverse mix of capacity totaling nearly 14,000 MW, as demonstrated in the following chart. A more detailed breakdown of the Company's generating and demand side resources is presented in Appendices 1 and 2.

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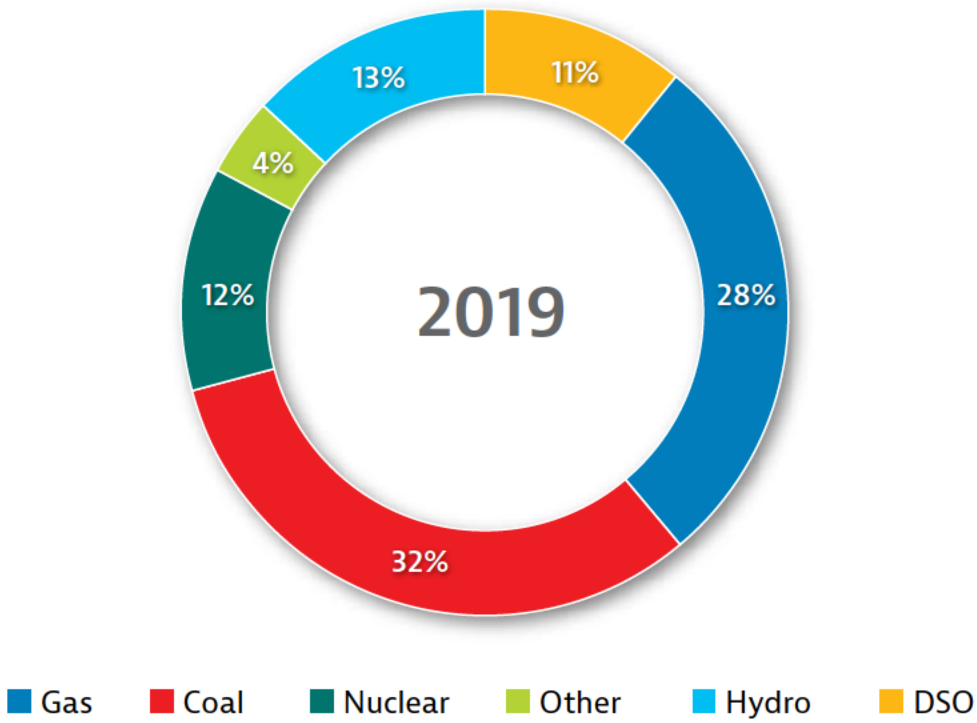
[4] As applicable to all references of renewable projects in this 2019 IRP, the Company has rights to the environmental attributes, including the renewable energy certificates ("RECs"), associated with the energy from these projects. Alabama Power can choose to retire some, or all, of these environmental attributes on behalf of its retail electric customers, or it can sell the environmental attributes, either bundled with energy or separately, to third parties. Included in Appendix 1 is a listing of the Company's contracted or owned renewable projects. Appendix 3 provides an overview of the Company's efforts directed to the procurement of renewable resources.

Figure I-1: Alabama Power Capacity Mix



This document summarizes the results of Alabama Power's 2019 IRP and describes the process used in its development. As noted at the outset, the IRP serves as the foundation for certain decisions affecting the Company's portfolio of generating resources, facilitating the Company's ability to provide reliable and cost-effective electric service to its customers. At the most basic level, the IRP yields an indicative annual schedule of integrated supply-side and demand-side resource additions to accomplish the aforementioned objectives, consistent with the Company's duties and obligations to the public as a regulated public utility. The Company's IRP is performed through a coordinated process utilized across the Southern Company retail operating companies, with the assistance of their agent, Southern Company Services, Inc. ("SCS"). The process used by Alabama Power to develop the IRP comports with the provisions of the Public Utility Regulatory Policies Act of 1978, as amended, which contemplates the use of appropriate integrated resource planning by electric utilities.

Together with the other Operating Companies, Alabama Power participates in the Southern Pool, which provides for coordinated system operations and centralized unit commitment and joint dispatch of the Operating Companies' respective generating units.[5] In order to take advantage of economies of scale, the retail Operating Companies engage in the coordinated planning of their respective resource additions; however, each such operating company retains final decision-making authority with regard to any resource additions that it may require, consistent with its respective duty of service as provided by law.

The System is represented on the Southeastern Electric Reliability Council ("SERC"), which serves to coordinate operations and other measures to maintain a high level of reliability for the electric system in the Southeastern United States. Likewise, Alabama Power and the other retail Operating Companies, along with other transmission owners in the region, are sponsors of the Southeastern Regional Transmission Planning process, which provides an open, coordinated, and transparent transmission planning process for much of the Southeast in accordance with the requirements of FERC.

In order to anticipate future energy and demand requirements of the customers it serves, Alabama Power develops a load forecast that comprises a 20-year projection of the expected growth in customer requirements. Using the best information reasonably available, the Company then develops an IRP that reflects the indicated optimal mix of supply-side and demand-side resources to meet this projected customer peak demand in a reliable and cost-effective manner. Alabama Power has traditionally been considered summer peaking, meaning its annual peak demand falls during the summer months; however, its customer demands have been growing in the winter months. Indeed, in recent years, Alabama Power's weather-normalized winter peak demand has exceeded its summer peak demand, and its most recent load forecast projects a predominant winter peak demand. The Company's load forecast is discussed further in Section III.B.

[5] *On January 1, 2019, Gulf Power Company was sold to NextEra Resources and is no longer a subsidiary of the Southern Company. During a transition period, Gulf Power will continue to participate in the Southern Pool, but is no longer a part of coordinated planning by the remaining retail operating companies.*

II. ENVIRONMENTAL STATUTES AND REGULATIONS[6]

II.A. General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations that impact air, water, and land resources. Applicable statutes include: the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning and Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and state regulations. Compliance with these and other environmental requirements involves significant capital and operating costs. Through 2018, the Company had invested approximately $5.4 billion in environmental capital retrofit projects to comply with these requirements. The Company currently expects that capital expenditures to comply with environmental statutes and regulations will total approximately $635 million from 2019 through 2023. These estimates do not include any potential compliance costs associated with pending regulation of CO2 emissions from fossil fuel-fired electric generating units. The Company also anticipates costs associated with closure in place and groundwater monitoring of ash ponds in accordance with the CCR Rule, which are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation ("ARO") liabilities.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and the outcome of any associated legal challenges; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. To date, the Company's compliance strategy in response to federal environmental requirements has resulted in a reduction of more than 2,100 MW of coal-fired capacity, due either to fuel switching, the retirement of units, or the placing of units on inactive reserve. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units.

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[6] The information in this section is drawn from the combined annual report on Form 10-K of The Southern Company and the Operating Companies for the year ended December 31, 2018, as filed with the Securities and Exchange Commission. Any material difference between the information contained therein and this section is unintended and the annual report should be referenced as the controlling discussion.

Compliance with any new federal or state legislation or regulations relating to air, water, and land resources or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be known with certainty until the applicable legislation or regulation is finalized, legal challenges are resolved, and any necessary rules are implemented at the state level. In any case, such governmental mandates could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Many of the Company's commercial and industrial customers may also be affected by such future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

II.B. Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Additional controls to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements may become necessary in the future, depending on further actions taken by the EPA.

In 2012, the EPA finalized the Mercury and Air Toxics Standards ("MATS") rule, which imposed stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units ("EGUs"). The compliance deadline set by the final MATS rule was April 16, 2015, with provisions for extensions to April 16, 2016. The implementation strategy for the MATS rule included emission controls, retirements, and fuel conversions to achieve compliance by the deadlines applicable to each Company unit. In June 2015, the Supreme Court issued a decision finding that, in developing the MATS rule, the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant ("HAP") emissions from EGUs. In December 2015, the D.C. Circuit remanded the MATS rule to the EPA without vacatur to respond to the Supreme Court's decision. The EPA's supplemental finding in response to the Supreme Court's decision, which was finalized in April 2016, did not have any impact on the MATS rule compliance requirements or deadlines.

On December 26, 2018, the EPA proposed to revise the Supplemental Cost Finding for MATS. The EPA proposes to correct what it identifies as flaws in the 2016 cost/benefit analysis it used to regulate HAPs from coal- and oil-fired EGUs. The EPA has now determined that the direct benefits from regulating HAPs from EGUs are grossly outweighed by the costs and consequently, it is not "appropriate and necessary" to regulate EGU HAP emissions. However, the EPA is not proposing to rescind MATS, and it reasons that MATS will remain in place based on its interpretation of 2008 D.C. Circuit Court decisions. In a companion action, the EPA is also proposing that remaining risks associated with EGU HAP emissions are acceptable and therefore, more stringent standards under MATS are not warranted.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard ("NAAQS"). In 2015, the EPA adopted a revised eight-hour ozone NAAQS and in 2017 published its final area designations for Alabama. All areas within the Company's service territory have achieved attainment of the 2015 ozone standard.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS, and the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA completed final designations for the 2012 annual standard for Alabama in March 2015, and no new nonattainment areas were designated within the Company's service territory.

Final revisions to the NAAQS for sulfur dioxide ("SO2"), which established a new one-hour standard, became effective in 2010. In January 2017, the Company submitted modeling showing attainment of the SO2 standard in the vicinity of its coal-fired generating plants. Based on this modeling analysis, the EPA did not designate any area in Alabama as nonattainment for this standard. On May 25, 2018, in its review of the SO2 ambient air quality standard, the EPA proposed to retain the existing level of the standard.

In February 2014, the EPA proposed to delete from the Alabama State Implementation Plan ("SIP") the Alabama opacity rule that the EPA approved in 2008. This action by the EPA, which provides operational flexibility to affected units, was in response to a 2013 ruling by the U.S. Court of Appeals for the Eleventh Circuit that vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA's latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act.

In 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR") to address impacts in downwind states of SO2 and nitrogen oxide ("NOX") emissions from fossil fuel-fired electric generating plants. CSAPR established emissions trading programs and allowance budgets for certain states and allocates emissions allowances for sources in those states, including Alabama. In 2016, the EPA published a final CSAPR Update rule, establishing more stringent ozone season NOX emissions budgets for several states, including Alabama. On December 6, 2018, the EPA finalized the "CSAPR Close-Out" rule regarding interstate transport requirements for the 2008 ozone standard. The EPA determined that the 20 states affected by the CSAPR Update rule (including Alabama) have fully met their interstate transport obligations and that emissions from these states do not contribute significantly to any downwind state's ability to meet the 2008 ozone standard. The Company is complying with CSAPR and operating its units within the emissions allowances allocated to the Company under all CSAPR allowance programs.

The EPA finalized regional haze regulations in 2005 and 2017. These regulations require states, tribal governments, and various federal agencies to develop and implement plans to reduce pollutants that impair visibility and demonstrate reasonable progress toward the goal of restoring natural visibility conditions in certain areas, including national parks and wilderness areas. In December 2018, the EPA proposed to approve the State of Alabama's progress report for the first regional haze planning period. Alabama must also submit to the EPA by July 31, 2021 a revised SIP, demonstrating continued reasonable progress towards achieving visibility improvement goals. These plans could require reductions in certain pollutants, such as particulate matter, SO2, and NOX, which could result in increased compliance costs. Regional haze regulations also involve the application of Best Available Retrofit Technology ("BART") to sources including certain Company generating units. What constitutes BART has been the subject of litigation and is still an unresolved issue for some units operated by the Company and thus the ultimate impact from BART requirements is currently unknown.

In 2012, the EPA published proposed revisions to the New Source Performance Standard ("NSPS") for

Stationary Combustion Turbines ("CTs"). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units) during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In June 2015, the EPA published a final rule requiring certain states (including Alabama) to revise or remove the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction ("SSM") by no later than November 2016. In ensuing litigation, the EPA filed a motion with the D.C. Circuit to hold the matter in abeyance while the agency conducts a review. The court granted EPA's motion and the agency is reconsidering its SSM policies and guidance.

II.C. Water Quality

In November 2015, the EPA published the final effluent limitations guidelines rule that imposes stringent technology-based requirements for certain wastestreams from steam electric power plants ("2015 ELG Rule"). The 2015 ELG Rule requires major changes to wastewater treatment systems at coal-fired plants, with stringent restrictions affecting the disposition of fly ash transport water ("FATW"), bottom ash transport water ("BATW"), and flue gas desulfurization ("FGD" or "scrubber") wastewater. The new effluent limits will be implemented in National Pollutant Discharge Elimination System ("NPDES") permits issued by the Alabama Department of Environmental Management ("ADEM"), with applicability based on relevant information provided by the facility (as early as November 1, 2018, but not later than December 31, 2023). However, uncertainty surrounds certain portions of the 2015 ELG Rule, as the EPA is scheduled to issue a new rulemaking by spring of 2020 that could revise the limitations and/or applicability dates for BATW and FGD wastewater. The impact of any changes to the 2015 ELG Rule will depend on the content of the new rule and the outcome of any legal challenges.

Another part of the Clean Water Act ("CWA") applicable to Alabama Power is Section 316(b), which requires that "the location, design, construction and capacity of cooling water intake structures reflect the best technology available ["BTA"] for minimizing adverse environmental impact." After a series of rulemakings and court cases extending all the way to the U.S. Supreme Court, a final rule was published in the Federal Register in August 2014, establishing impingement mortality and entrainment requirements for existing power generating facilities and manufacturing and industrial facilities that are designed to withdraw more than two million gallons of water per day from waters of the United States and use at least 25 percent of that water exclusively for cooling purposes ("316(b) Rule"). The new rule became effective in October 2014. Compliance is required "as soon as practicable" according to the schedule of requirements set by the permitting authority. NPDES permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. With the recent issuance of the Greene County NPDES permit renewal, ADEM has required any remaining Section 316(b) studies to be submitted in the next 5-year permit cycle. Alabama Power has begun conducting these studies and currently anticipates that changes to Cooling Water Intake Structures ("CWIS") may include fish-friendly CWIS screens with fish return systems and the addition of minor monitoring equipment at certain plants. However, the ultimate impact of the 316(b) Rule will depend on the outcome of these plant-specific studies and any additional protective measures required by ADEM to be incorporated into each plant's NPDES permit renewal in the next permit cycle, based on site-specific factors.

In June 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of Waters of the United States ("WOTUS") for all CWA programs. The final rule significantly expanded the scope of federal jurisdiction under the CWA and could have a material adverse impact on economic development projects, which could affect growth in customer demand. In addition, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines. Moreover, in 2019, the EPA and the Army Corps of Engineers are anticipated to publish a final rule to replace the WOTUS definition established in 2015. The impact of any changes to the 2015 WOTUS rule will depend on the content of this final rule and the outcome of any challenges.

II.D. Coal Combustion Residuals

In 2015, the EPA finalized the CCR Rule, which established non-hazardous solid waste regulations for the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments (ash ponds) at active generating power plants. Among other things, the CCR Rule requires CCR units to be evaluated against a set of performance criteria. The State of Alabama has also finalized its own regulations regarding the handling of CCR. In April 2019, Alabama Power initiated closure of its unlined CCR impoundments and ash ponds.

II.E. Climate Issues

On July 8, 2019, the EPA published the final version of the Affordable Clean Energy ("ACE") Rule, which is to replace a regulation enacted in 2015 (the "Clean Power Plan" or "CPP") that would limit CO2 emissions from existing fossil fuel-fired EGUs. The CPP has been stayed by the U.S. Supreme Court since February 2016. The ACE Rule would require states to develop unit-specific CO2 emission rate standards based on heat-rate efficiency improvements for existing coal-fired steam units. Under the final rule, combustion turbines, including natural gas combined cycles units, are not affected sources. Alabama Power owns seven coal-fired steam units to which the ACE Rule is applicable. The ultimate impact of this rule on Alabama Power is currently unknown and will depend on subsequent state plan developments and requirements, along with any associated legal challenges.

On December 20, 2018, the EPA published a proposed review of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units final rule ("2015 NSPS Rule"). The EPA's final 2015 NSPS rule set standards of performance for new, modified, and reconstructed electric utility generating units, which includes stationary combustion turbines and fossil-fired steam boilers. This proposal reduces the stringency of the 2015 NSPS Rule by not basing the new and reconstructed fossil-fired steam boiler and integrated gasification combined cycle ("IGCC") standards on partial carbon capture and sequestration. The impact of any changes to this rule will depend on the content of the final rule and the outcome of any legal challenges.

Separate and apart from these regulations, the prospect remains for federal legislation imposing a tax on carbon emissions or establishing a national cap and trade carbon emission allowance system. As with other environmental requirements, any legislative or regulatory action directed to CO2 emissions could result in significant additional capital expenditures or compliance costs for the Company, and thus affect future unit retirement and replacement decisions.

III. INTEGRATED RESOURCE PLAN

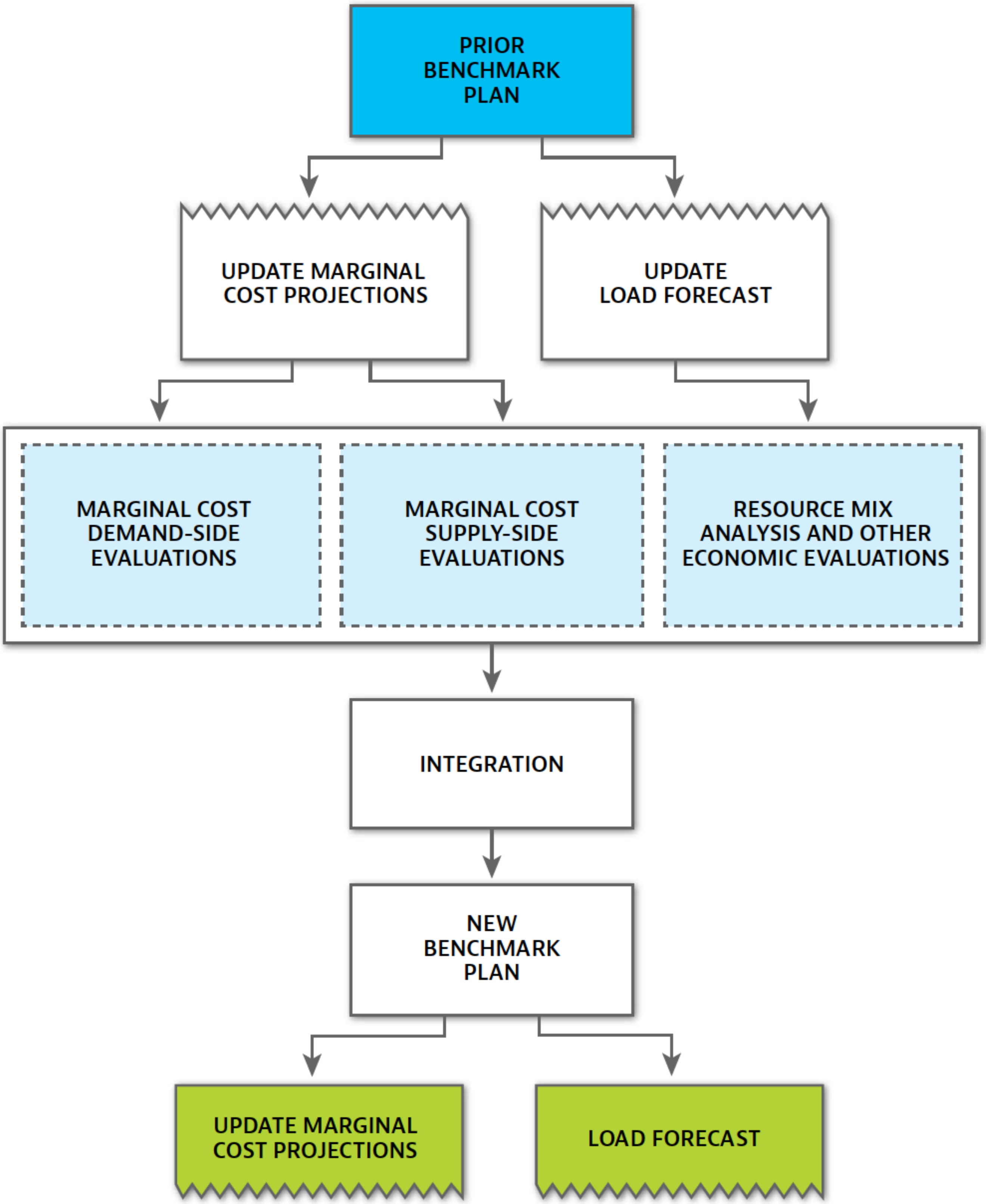
III.A. Process Overview

The integrated resource planning process is designed to identify the timing, amount, and types of resources necessary to serve the long-term energy and demand requirements of Alabama Power's customers. Aided by the IRP, the Company is able to develop and implement a resource strategy that is reasonably expected to provide for cost-effective and reliable service.

The 2019 IRP, which has a 20-year planning horizon, indicates the optimal mix of resources necessary to meet customers' future load requirements. Using the best information available at the time of its development, the IRP provides the basis for estimating potential capital expenditures that may be required for future generating capacity additions. In the IRP, both supply-side and demand-side options are evaluated and integrated on a consistent basis using marginal cost analysis. This approach ensures that both options are identified for potential selection and deployment when such options represent a viable economic choice.

As shown in Figure III-A-1, integrated resource planning is an iterative process that evaluates existing and potential resource options in an effort to identify the best combination, in terms of reliability and expected total cost for serving customers.

FIGURE III-A-1: Alabama Power IRP Process



The principal components in the process are as follows:

Update Marginal Cost Projections Based on Latest IRP

Marginal cost projections are derived using the previous IRP. These projections are then updated to recognize any significant changes in costs such as fuel, technology, and regulatory compliance.

Load Forecast

A forecast of future energy and peak demand requirements for the next 20 years is developed. This forecast incorporates an estimate of future economic conditions and trends in customer energy usage.

Marginal Cost Demand-Side Evaluations

DSM programs (also referred to as demand-side options, or "DSOs") are evaluated on a marginal cost basis. This procedure is used to identify cost-effective DSM programs for inclusion in the IRP.

Marginal Cost Supply-Side Evaluations

Marginal cost evaluations are performed to determine if modifications to existing supply-side resources or power purchases from other suppliers are economically viable.

Resource Mix Analysis and Benchmark Evaluations

This part of the IRP process involves the development of an optimal resource mix. The resource mix is a flexible, iterative analysis that allows for integration of the appropriate combination of resources that will serve the projected load at the lowest expected total cost (both fixed and variable), while maintaining the target reliability guideline. This step includes sensitivity analyses to establish boundaries within which the conclusions of a benchmark plan remain valid.

The resource mix analysis incorporates the impacts of existing and projected DSM programs, revised load information, and updated cost information (including fuel, capital, operation and maintenance). It also incorporates the most recent information on the characteristics of existing resources, both supply-side and demand-side, as well as changes such as expected in-service dates of resource additions, the expiration of PPA resources, and assumptions regarding future resource availability.[7] The flexibility of the IRP process allows insertion of marginal cost results from the supply-side or demand-side options in any sequence. The result is a benchmark plan that identifies the most cost-effective combination of options, which in turn informs the Company's decision-making as it seeks to acquire or develop resources to address future needs.

In planning future resource additions, consideration is given to uncertainties associated with unforeseen unit outages, abnormal weather, and load forecast deviations. In order to minimize the effects of these uncertainties, criteria are established that qualify and quantify an appropriate level of capacity reserves in both the summer and winter seasons. These reserves are planned to be available to account for the potential inability to meet load requirements due to generation shortfalls resulting from uncertainties inherent in the resource planning process. The minimum long-term target reserve margin guideline, which is periodically reviewed and re-evaluated, is based on risk-adjusted economic analyses, operating experience and system operation input, and seeks to minimize the combined cost of new generating capacity, production costs, and customer-related costs associated with outages while also ensuring the Company meets minimum reliability criteria thresholds.

Consistent with the updated Reserve Margin Study (discussed in greater detail in Section III.D), the 2019 IRP utilizes a minimum long-term Summer Target Reserve Margin of 16.25 percent for summer periods and 26 percent for the minimum long-term Winter Target Reserve Margin. By virtue of load diversity across the Southern System, the Summer Target Reserve Margin can be met if each Operating Company maintains a long-term summer reserve margin of at least 14.89 percent. Similarly, the Winter Target Reserve Margin can be met if each Operating Company maintains a long-term winter reserve margin of at least 25.25 percent. In other words, Alabama Power can maintain a long-term winter reserve margin of 25.25 percent but realize a level of reliability equivalent to 26 percent, thereby avoiding the cost of building or purchasing additional resources associated with the 0.75 percent differential. These capacity savings represent one of the many recognized benefits of operating as part of the Southern Pool.

[7] *These assumptions are for study purposes only and do not reflect management decisions regarding the actual useful lives of such resources.*

Integration

Demand-side and supply-side options identified as cost-effective choices for resource additions, but not previously reflected in the prior IRP's benchmark plan, are incorporated in the IRP during the integration phase. This phase consists of determining the Company's best alternative for meeting the resource needs identified in the benchmark plan, coordinating resource additions with those of the other retail Operating Companies, and performing a financial assessment of the plan.
The process described above is not necessarily set forth in chronological order, as many evaluations are performed concurrently. Marginal cost evaluations can be performed or updated at several points in the process.

III.B. Load Forecast

The Company annually produces a short-term and long-term energy and peak demand forecast for territorial customers of Alabama Power, including projections of customer growth, peak demand (MW), and monthly energy consumption (kWh). The 2019 IRP reflects a 20-year load forecast for the years 2019 through 2038.

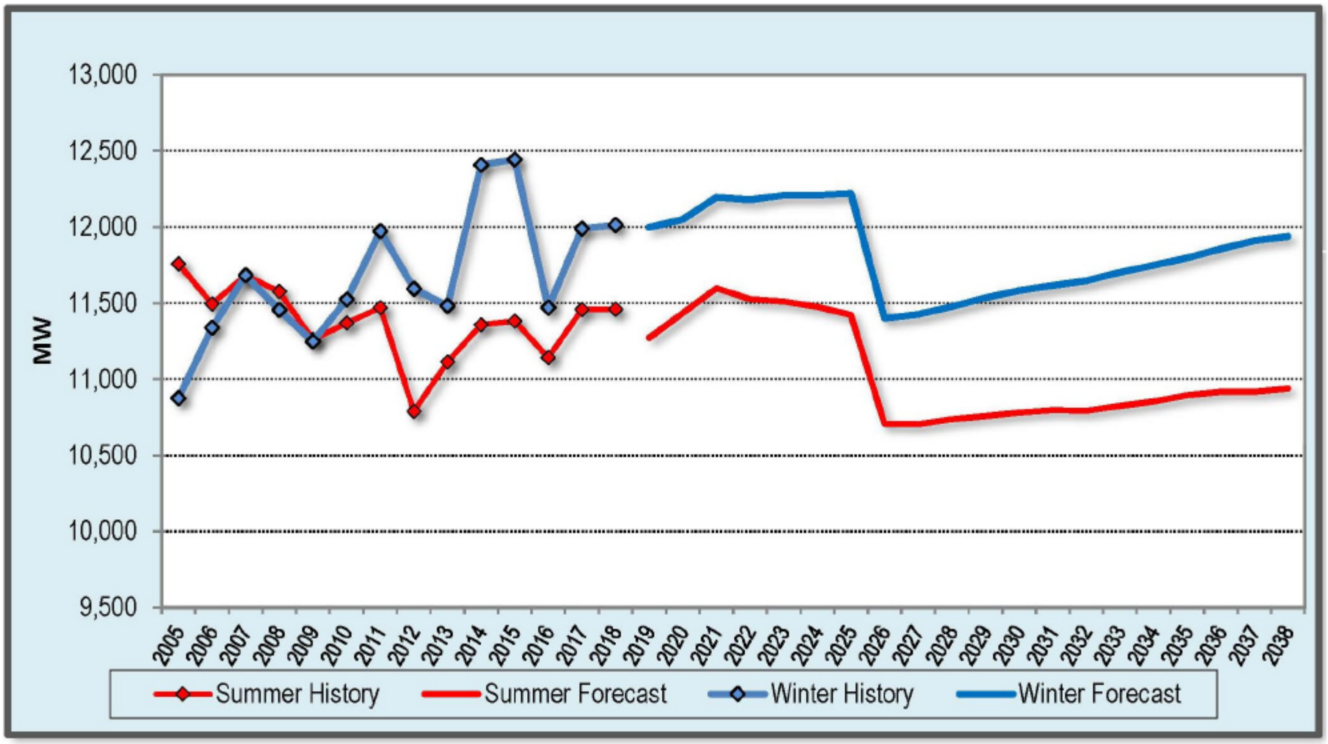
Underlying this load forecast are economic data and forecasts supplied by IHS Markit. This information includes available employment and demographic data as well as other economic indicators for the state, all of which support the development of econometric models used to forecast the number of customers, which is a major input to the load forecasting process. The other major input, per customer electricity consumption, is less correlated with economic growth and more related to trends in increased efficiency and other factors that are resulting in a decline in usage.

Alabama Power has traditionally been considered summer peaking, meaning its annual peak demand has occurred during the summer months. However, in recent years, Alabama Power's winter peak demand has exceeded the summer peak demand. The 2014 actual winter peak was 12,610 MW (prior to the utilization of interruptible and demand management options), which exceeded the prior all-time peak of 12,496 MW that occurred in the summer of 2007. Indeed, weather normalization studies indicate that the weather adjusted winter peak has exceeded the weather adjusted summer peak since 2010. The Company's most recent load forecast projects a winter peak demand that is between

5 and 7.5 percent higher than the summer peak demand.

Figure III-B-1 represents the Company's weather normalized historical summer and winter peak demands since 2005, and clearly shows that weather adjusted winter peaks began to exceed summer peaks as early as 2010. The graph also illustrates the Company's forecasted winter and summer peak demands from 2019 through 2038. In 2022 and 2026, there is a projected loss of wholesale load due to the expiration of certain existing contracts. For the summer, there is an expected average annual demand growth rate of approximately 0.5 percent from 2019 through 2023 and approximately -0.3 percent from 2023 through 2038. For the winter peak demand, there is an expected average annual growth rate of 0.4 percent from 2019 to 2023 and approximately -0.2 percent from 2023 through 2038. These projected rates are lower than those shown in the 2016 IRP, and reflect the effects of a slower economic growth in the near term and, over the long term, the referenced loss of wholesale contracts and greater penetration of appliance and lighting efficiencies.

FIGURE III-B-1: Alabama Power Weather Normalized Historical Peak Demand with Forecast



	Winter Peak		Summer Peak	
Year	Demand (MW)	Growth	Demand (MW)	Growth
2019	11,998		11,272	
2020	12,051	0.44%	11,436	1.45%
2021	12,197	1.21%	11,598	1.42%
2022	12,179	-0.15%	11,525	-0.63%
2023	12,209	0.25%	11,510	-0.13%
2024	12,210	0.01%	11,474	-0.31%
2025	12,221	0.09%	11,423	-0.44%
2026	11,401	-6.71%	10,707	-6.27%
2027	11,427	0.23%	10,704	-0.03%
2028	11,478	0.45%	10,735	0.29%
2029	11,535	0.50%	10,758	0.21%
2030	11,582	0.41%	10,780	0.20%
2031	11,617	0.30%	10,798	0.17%

2032	11,647	0.26%	10,793	-0.05%
2033	11,702	0.47%	10,824	0.29%
2034	11,749	0.40%	10,853	0.27%
2035	11,798	0.42%	10,895	0.39%
2036	11,857	0.50%	10,916	0.19%
2037	11,910	0.45%	10,918	0.02%
2038	11,938	0.24%	10,940	0.20%

These forecast results are heavily dependent on the level of expected economic activity and continued employment growth in the State of Alabama. Another influencing factor is continued exports of products produced in Alabama (primarily transportation equipment), which is an important consideration as Alabama remains a heavy manufacturing state.

III.C. Fuel Forecast

Both short-term (current year plus two) and long-term (year four and beyond) fuel and allowance price forecasts are developed for use not only in the Company's planning activities, but also in its business case analyses and other applicable decisions. Short-term forecasts are updated monthly as part of the Company's fuel budgeting process and marginal pricing dispatch procedures. The long-term forecasts are developed each year for use in the Company's planning activities. Charles River Associates ("CRA"), the Company's scenario modeling consultant, produces the long-term fuel price forecasts for natural gas and coal.

The development of the long-term forecasts is a highly collaborative effort between CRA, SCS, and the retail Operating Companies. CRA's MRN-NEEM national, multi-sector, energy-economy model, with support from other CRA models, is used to generate integrated results for natural gas and coal prices, in five-year increments, for the period 2023 through 2058. The integrated modeling approach makes it possible to develop forecasts for natural gas and coal prices that are internally consistent with one another and with other variables and feedbacks involving economic growth, electricity consumption, and output across many sectors and regions. The integrated approach takes a set of assumptions about market fundamentals and then solves for the prices that make the quantity supplied equal to the quantity demanded in all markets. In addition, the integrated approach simulates interactions among different markets and thereby reveals how such things as environmental regulations and natural gas supply outlooks shape the disposition of economic output across sectors, as well as the competition between coal and natural gas as a generation fuel.

III.D. Reserve Margin

Electric utility customers expect and depend on a high level of service reliability. Accordingly, a retail electric utility should have an economically balanced margin of generating capacity above its anticipated peak load—the reserve margin. This enables the utility to maintain sustained reliability for its customers, notwithstanding unexpected events such as equipment failures or extreme weather. Reserve planning must be done on both a short-term and long-term basis, as the processes to procure additional capacity can take several years. A reserve margin study facilitates the identification of an appropriate amount of reserve capacity that should be targeted for any point in the future.

As for the System specifically, the maintenance of sufficient reserve capacity allows the Operating Companies to serve customer demand reliably, even with the prevalence of unpredictable conditions that can affect customer demand.

- **Weather Uncertainty:** The System's "weather-normal" load forecasts are based on average weather conditions over more than thirty years. If the weather is hotter than normal during warm seasons or colder than normal during cold seasons, the load will be higher. The System's peak demand can be as much as 6.6 percent higher in a hot summer year and 22 percent higher in a cold winter year than in an average year.

- **Economic Growth Uncertainty:** It is difficult to project exactly how many new customers will request electric service or how much power existing customers will use from season to season. Based on historical projections and actual economic growth, peak demand may grow [redacted]

- **Unit Performance:** While the Operating Companies maintain low forced outage rates for their respective units, there have been occasions in the last ten years when [redacted]

[redacted] of the capacity of the System has been in a forced outage state concurrently.

- **Market Availability Risk:** The ability to obtain resources on short notice from the market when needed to address a System resource adequacy issue is uncertain. In general, having access to resources in neighboring regions enhances a region's reliability due to load and resource diversity. However, the amount, cost, and deliverability of those resources are subject to the external region's resource-adequacy situation or transmission constraints at any given time. While a region can expect some level of support from its neighbors, each region must carry adequate reserves and manage its own reliability risks. This necessarily results in an element of uncertainty regarding the availability of such external support when it is needed.

While each of these four factors creates a need for capacity reserves on its own, a confluence of all these risk factors poses considerable risk. Very high capacity reserves would be required to meet customers' load demands plus operating reserve requirements to address the simultaneous occurrence of all such events. However, the maintenance of such high levels of capacity reserves, in an effort to eliminate all reliability risk, would come at significant expense.

A more appropriate approach to establish a reasonable reserve margin is to minimize the combined costs of maintaining reserve capacity, system production costs, and customer costs associated with service interruptions, and then adjust for the value at risk. This approach results in the Economic Optimum Reserve Margin ("EORM"), properly adjusted for risk. However, that risk-adjusted EORM must also meet a minimum reliability criteria threshold. Common practice in the industry regarding this threshold is to plan for a Loss of Load Expectation ("LOLE") of no greater than 0.1 days per year, which is more commonly referred to in the industry as a one event in ten years criterion ("1:10 LOLE").

As discussed earlier, the Company has historically relied upon a Target Reserve Margin only for the summer season. However, the 2015 Reserve Margin Study results shown in the 2016 IRP identified a significant increase in winter reliability risks due to several factors that had not previously been incorporated in the reserve margin determination. These included: (1) the narrowing of the difference between summer and winter weather-normal peak loads; (2) higher volatility of winter peak demands relative to summer peak demands; (3) increased occurrence of unit outages due to cold weather; (4)

greater penetration of solar resources; and (5) increased risk of fuel delivery disruption due to winter conditions. Along with these, the 2018 Reserve Margin Study identified a sixth factor—decreased supply alternatives from the wholesale power markets.

To address winter reliability issues, the Target Reserve Margin used in the 2016 IRP increased from 15 percent to 16.25 percent. Upon further consideration of the winter-related reliability risks, the Company will now use an independent evaluation of resource adequacy in both the summer and winter peak periods to ensure that System reliability is fully addressed. This results in the establishment of both a Summer Target Reserve Margin and a Winter Target Reserve Margin.

Defining Target Reserve Margins

The traditional formulation of the Summer Target Reserve Margin is stated in terms of weather-normal summer peak demands and summer capacity ratings according to the following formula:

$$STRM = \frac{TSC\text{-}SPL}{SPL} \times 100\%$$

Where:

STRM = Summer Target Reserve Margin;

TSC = Total Summer Capacity; and

SPL = Summer Peak Load.

The Winter Target Reserve Margin is similarly derived, but uses weather-normal winter peak demands and winter capacity ratings per the following formula:

$$WTRM = \frac{TWC - WPL}{WPL} \times 100\%$$

Where:

WTRM = Winter Target Reserve Margin;

TWC = Total Winter Capacity; and

WPL = Winter Peak Load.

Target Reserve Margins

After analyzing the load forecast and weather uncertainties, the cost of expected unserved energy, and the projected generation reliability of the System, the Company is maintaining the current 16.25 percent long-term Target Reserve Margin for the System as the Summer Target Reserve Margin to be applied to the summer peak planning season. To address the winter reliability concerns, the Company is adding a long-term Winter Target Reserve Margin of 26 percent for the System to be applied to the winter peak planning season. As explained in the 2018 Reserve Margin Study, the 26 percent long-term Winter Target Reserve Margin is consistent with the results of the 2015 Reserve Margin Study.

For the short-term, the Company is increasing the Summer Target Reserve Margin from 14.75 to 15.75 percent, with a commensurate short-term Winter Target Reserve Margin of 25.5 percent. The smaller gap between the long-term and short-term periods (regardless of season) is a direct consequence of changing load characteristics and energy efficiency programs that have reduced the overall peak demand response to economic uncertainty.

As noted earlier, one of the benefits of operating as part of the Southern Pool is that each Operating Company can carry fewer reserves than the System target. Thus, the diversified Summer Target Reserve Margin that applies to Alabama Power is 14.89 percent over the long-term and 14.39 percent over the short-term. Similarly, the Company's diversified Winter Target Reserve Margin is 25.25 percent over the long-term and 24.75 percent over the short-term. Changes in the load of each Operating Company relative to the loads of the others can impact this diversification effect.

Figure III-D-1 depicts the projected winter and summer reserve margins for Alabama Power through 2038, absent any resource additions. As the figure shows, the Company's winter reserve margin is projected to be below both its diversified long-term Winter Target Reserve Margin (25.25 percent) and its diversified short-term Winter Target Reserve Margin (24.75 percent) for all years of the planning timeframe. The figure also shows the Company to be periodically below its Summer Target Reserve Margin. Figure III-D-2 provides the corresponding capacity amounts that would address Alabama Power's reliability deficits for the winter periods. Resolving the shortfalls in the winter periods with resources available year-round will also resolve the shortfalls occurring during corresponding summer periods shown on Figure III-D-3.

FIGURE III-D-1: Alabama Power Projected Seasonal Reserve Margins

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Winter	11.1%	10.1%	11.3%	5.2%	7.0%	6.9%	10.8%	9.1%	5.5%	5.0%
Summer	21.5%	20.5%	21.2%	15.8%	15.9%	16.4%	19.3%	14.5%	14.1%	13.9%
	2030	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	
Winter	4.5%	4.2%	4.0%	3.0%	2.1%	1.7%	-3.0%	-13.0%	-20.7%	
Summer	13.7%	13.5%	13.5%	12.8%	12.1%	11.6%	7.6%	-10.5%	-10.7%	

FIGURE III-D-2: Alabama Power Projected Winter Capacity Needs

Capacity Need (MW) - Winter		
Year	APC Reserve Margin (%)	APC Need (MW)
2020	11.1%	1,650
2021	10.1%	1,788
2022	11.3%	1,702
2023	5.2%	2,447
2024	7.0%	2,229
2025	6.9%	2,243
2026	10.8%	1,652
2027	9.1%	1,844
2028	5.5%	2,270
2029	5.0%	2,340
2030	4.5%	2,399
2031	4.2%	2,442
2032	4.0%	2,479
2033	3.0%	2,601
2034	2.1%	2,716
2035	1.7%	2,777
2036	-3.0%	3,344
2037	-13.0%	4,556
2038	-20.7%	5,489

FIGURE III-D-3: Alabama Power Projected Summer Capacity Needs

Capacity Need (MW) - Summer		
Year	APC Reserve Margin (%)	APC Need (MW)
2020	21.5%	(817)
2021	20.5%	(709)
2022	21.2%	(725)
2023	15.8%	(110)
2024	15.9%	(121)
2025	16.4%	(172)
2026	19.3%	(473)
2027	14.5%	45
2028	14.1%	81
2029	13.9%	107
2030	13.7%	132
2031	13.5%	152
2032	13.5%	147
2033	12.8%	222
2034	12.1%	306
2035	11.6%	354
2036	7.6%	791
2037	-10.5%	2,774
2038	-10.7%	2,799

While the Southern Pool affords the participants the ability to rely on temporary surplus capacity on the System, each Operating Company is expected to have adequate resources, including an appropriate level of reserves, to reliably serve its own load obligations. Moreover, much of the available "surplus" in the Southern Pool is made up of fossil steam resources that are under significant cost pressures due to continued additional environmental compliance costs, coupled with forecasted low gas prices and modest load growth. The retail Operating Companies that own these units may decide at any point to retire some of the capacity on which Alabama Power might otherwise attempt to rely. Alternatively, those companies could make wholesale sales predicated on some or all of that capacity. In either case, the effect would be a reduction in the level of available capacity reserves on the System. Accordingly, Alabama Power must address its reserve deficiency, and intends to do so through appropriate action before the APSC.

III.E. Emerging Resiliency Needs

The Company remains committed to maintaining a robust and resilient electric system that is capable of reliably delivering electric energy, even in the face of unexpected events such as natural and man-initiated disruptions. The Company has a history of managing and planning for reliability risk through its reserve margin process, transmission planning analysis, and similar reliability studies, while also demonstrating substantial commitment to infrastructure protection initiatives. As the Company's generating fleet continues to transition away from resources with on-site fuel storage, there is increased fuel transportation risk associated with providing reliable electric service to customers. Additionally, the threat of low probability, high-impact events (such as physical- and cyber-attacks on electricity infrastructure) continues to grow.

At the bulk power system level, the Company routinely evaluates various contingencies as part of its transmission planning process and proposes projects to mitigate the risks associated with these contingencies. This level of planning meets or exceeds current North American Electric Reliability Corporation (NERC) standards. However, as the Company's generation resource mix continues to transition, continued transmission planning considerations must be given to these changing conditions to ensure future reliability and resilience of the bulk power system. The considerations could lead to the inclusion of other planning alternatives, such as a more expansive use of inactive reserve or the addition of fuel storage. Any actions, however, will be preceded by additional assessments of contingencies that may affect the IRP, such as the simultaneous failure of multiple elements of the electricity supply chain (e.g., transmission substations, gas pipelines, communication infrastructure, and generating stations). In many cases, this level of assessment is beyond current NERC planning standards. The Company remains committed to the reliable service of its customers, however, and will adapt as circumstances warrant.

III.F. Development of Indicative Resource Additions

In developing the benchmark plan, the Company begins with its existing resource portfolio, including its active DSM programs, along with its forecast of future customer needs.[8] For purposes of identifying future resource additions, the Company evaluates established and emerging resource

[8] *An active DSM program is one that is dispatchable or controllable by the Company. In contrast, a passive DSM is an alternative adopted by customers that becomes embedded in their electric energy use patterns and requirements. The effects of passive DSM additions are captured in the load forecast in the form of peak load reduction megawatts.*

options. The objective is to assess their cost, status of development, safety, operational reliability, flexibility, economic viability, fuel availability, construction lead times, and other factors.

The following is an overview of the screening process used to assess candidate technologies to determine those suitable for further screening for potential inclusion as indicative resource options in the expansion planning process.

- **Preliminary Screening:** The preliminary screening process identifies numerous technologies for strategic assessment. This strategic and qualitative assessment considers the maturity of the technology, construction lead times, operating characteristics, and financial requirements, along with cost uncertainties, environmental costs, safety of construction and operation, and resource availability. Many technologies from the initial list do not pass the preliminary screening due to their limited applicability to the territory (e.g., ocean thermal generation) or their early stage of development (e.g., magneto hydrodynamics).

- **Secondary Screening:** Technology options that pass the preliminary screening are then retained for a secondary screening. Generic candidate options are identified using qualitative factors such as scalability, repeatability, site requirements, and fuel availability. If a technology has potentially desirable characteristics, but only under unique circumstances (or not readily scalable and repeatable), then it will not pass the secondary screening and become a generic candidate or receive a Levelized Cost of Energy ("LCOE") analysis. Technologies that have desirable characteristics under unique application settings, such as specific customer requirements or geographic requirements, are retained separately to be evaluated for future projects should the right set of circumstances arise.

  The identified generic candidates will undergo additional screening using a LCOE analysis. A LCOE analysis is a common industry method of using screening-level costs to provide an indication of the economic viability of one generating technology option when compared to others. LCOE models include both capital and operating costs relative to the energy produced. The results can then be used to perform a relative comparison of generating units with different operational profiles.

• **Expansion Planning Process:** Candidate technology options retained after the secondary screening become options for the expansion planning process. These options are further screened using a busbar analysis to identify economic options over a range of capacity factors.[9] Options selected at this stage are not, however, determinative of the resource or resources that will ultimately be procured. Rather they serve to indicate the type(s) of resource(s) (and the time needed for deployment) that may be required to meet an identified capacity need.

For the 2019 IRP, the above process yielded the following benchmark plan for Alabama Power. As reflected in Figure III-F-1, the plan calls for the addition of combined cycle and CT technologies totaling approximately 2,400 MW through 2028.

[9] *Intermittent resources, such as solar and wind, were not included as selectable technologies for the expansion planning model, but instead are evaluated pursuant to a separate analysis.*

FIGURE III-F-1: Alabama Power Winter Benchmark Plan

2019 IRP Winter Benchmark Base Case with Generic Additions						
Year	APC CT's	APC CC's	APC RM	APC NEEDS (MW)	ROC RM	ROC NEEDS (MW)
2020	-	-	11.1%	1,650	[redacted]	[redacted]
2021	-	-	10.1%	1,788	[redacted]	[redacted]
2022	-	-	11.3%	1,702	[redacted]	[redacted]
2023	300	-	7.7%	2,147	[redacted]	[redacted]
2024	-	-	9.4%	1,929	[redacted]	[redacted]
2025	-	900	16.7%	1,043	[redacted]	[redacted]
2026	-	-	21.3%	452	[redacted]	[redacted]
2027	300	300	24.9%	44	[redacted]	[redacted]
2028	300	270	26.1%	(100)	[redacted]	[redacted]
2029	30	-	25.8%	(60)	[redacted]	[redacted]
2030	30	-	25.5%	(31)	[redacted]	[redacted]
2031	30	-	25.4%	(18)	[redacted]	[redacted]
2032	120	-	26.1%	(101)	[redacted]	[redacted]
2033	30	-	25.3%	(9)	[redacted]	[redacted]
2034	180	-	25.9%	(74)	[redacted]	[redacted]
2035	-	60	25.9%	(73)	[redacted]	[redacted]
2036	-	600	26.1%	(106)	[redacted]	[redacted]
2037	-	1,170	25.8%	(64)	[redacted]	[redacted]
2038	-	960	26.0%	(91)	[redacted]	[redacted]

The benchmark plan resulting from the 2019 IRP reflects the fact that the Company's electric demand (with necessary reserves) is materially higher than the Company's winter capacity resources, starting with the winter of 2020.[10] Resource additions needed to address the resulting capacity shortfall are delayed until 2023 (300 MW), and then staggered across the following five years (900 MW in 2025; 1,170 MW in 2027-2028).[11] The delay is predicated on the assumption that, notwithstanding its winter capacity shortfall, Alabama Power can rely on the capacity reserves of the other Retail Operating Companies ("ROC") by virtue of its participation in the Southern Pool.

[10] *The benchmark plan reflects a capacity deficit on the System in 2020 and 2021, which is largely driven by Alabama Power's winter need, but there is no corresponding resource addition shown for Alabama Power in these years. This is because the IRP is a planning process that directs resource additions no earlier than three years into the future, which reflects the realities of the lead-times (e.g., commercial development and procurement; regulatory authorization) inherent in the addition of resources to the System.*

[11] *The benchmark plan indicates a winter-driven need for Alabama Power to add approximately 400 MW over the period 2029-2034.*

Alabama Power believes that reliance on Pool length, with supplement capacity from the wholesale market on an as-needed basis, is a viable approach to address short-term reliability. Beyond that short-term window, though, Alabama Power cannot confidently rely on capacity reserves in the Southern Pool to address its reliability needs. As discussed earlier, there are two reasons for this conclusion. First, the Southern Pool affords the participants the ability to rely on temporary surplus capacity on the System, but each Operating Company is expected to have adequate resources, including an appropriate level of reserves, to reliably serve its own load obligations. Consistent with this expectation, it is incumbent on Alabama Power to address significant and persistent shortfalls in its required level of capacity reserves needed to provide adequate reliability for its own customers. A second reason relates to the ongoing assurance of the available surplus in the Southern Pool. As stated earlier, much of that surplus capacity comprises fossil steam resources that are under challenging cost pressures for reasons including the ongoing cost of environmental compliance, forecasted low gas prices, and modest load growth. The retail Operating Companies that own these units may decide at any point to retire some of the capacity on which Alabama Power might otherwise attempt to rely. Alternatively, those companies are free to make wholesale sales predicated on some or all of that capacity. In either case, the effect would be a reduction in the level of available capacity reserves on the System.

Accordingly, Alabama Power has concluded that a modest acceleration of the resource additions indicated across the 2023 through 2028 time-frame will mitigate the described risks and better facilitate its statutory duty to make reasonable enlargements of its system to meet the demand of those customers for whom it holds a duty of service. Specifically, the Company intends to deploy additional resources by the winter of 2024 to address its Target Reserve Margin shortfalls for both the winter and summer seasons in a cost-effective manner. This plan already incorporates the effects of additional active and passive DSM resources across the planning horizon. The Company presently is working to identify the exact resources to respond to this need, including cost-effective demand-side opportunities. When the most appropriate resources are identified, the Company will file a petition for a certificate of convenience and necessity with the APSC requesting authorization to proceed with the resource additions.

IV. CONCLUSION

The 2019 IRP process has identified certain short- and long-term capacity needs for Alabama Power. In particular, the Company's Winter Target Reserve Margin is well below its diversified winter target planning reserve margin guideline in the planning timeframe, signaling a significant need to add reserve capacity to address its winter reliability concerns. Consistent with its obligation to provide reliable service to its customers, the Company intends to pursue the necessary and appropriate measures to satisfy those needs. By doing so, Alabama Power will be in a position to continue meeting the demands of its customers in a reliable manner over the 20-year planning horizon, consistent with its statutory duty of service to its customers.

APPENDIX 1

Alabama Power Company Existing Supply-Side Resources

FIGURE A1-1: Alabama Power Company Existing Supply-Side Resources
(as of April 30, 2019)

Alabama Power Company Owned & Contracted Resource Summary						
	Plants	Units	Nameplate/ Contract Capacity (MW)	IRP Summer Capacity (MW)	IRP Winter Capacity (MW)	
Fossil	9	31	7,837	7,934	8,097	
Nuclear	1	2	1,720	1,751	1,751	
Hydro	14	41	1,668	1,695	1,656	
Solar	2	2	18	3	1	
Ownership Total	*26*	*76*	*11,243*	*11,383*	*11,505*	
Contracted Total	*N/A*	*N/A*	*1,546*	*1,127*	*1,124*	
Total Owned & Contracted			*12,788*	*12,510*	*12,629*	

Fossil Steam Plants						
Plant	Units	Nameplate Capacity (MW)	IRP Summer Capacity (MW)	IRP Winter Capacity (MW)	In-Service Year	Notes
Barry	1	125	80	80	1954	Barry 1 restored to active service in 2019
	2	125	80	80	1954	Barry 2 restored to active service in 2019
	4	350	362	362	1969	
	5	700	757	757	1971	
Gadsden	1	60	64	17	1949	
	2				1949	Gadsden 2 unavailable after Spring 2019
Gaston	1	125	127	127	1960	Ratings reflect 50% Alabama Power operating capacity; 100% owned by Southern Electric Generating Company (SEGCO)
	2	125	128	128	1960	Ratings reflect 50% Alabama Power operating capacity; 100% owned by Southern Electric Generating Company (SEGCO)
	3	125	127	127	1961	Ratings reflect 50% Alabama Power operating capacity; 100% owned by Southern Electric Generating Company (SEGCO)
	4	125	128	128	1962	Ratings reflect 50% Alabama Power operating capacity; 100% owned by Southern Electric Generating Company (SEGCO)
	5	880	832	832	1974	
Gorgas	8				1956	Gorgas 8 retired April 15, 2019
	9				1958	Gorgas 9 retired April 15, 2019
	10				1972	Gorgas 10 retired April 15, 2019
Greene County	1	150	159	159	1965	Ratings reflect Alabama Power 60% ownership
	2	150	160	160	1966	Ratings reflect Alabama Power 60% ownership
Miller	1	606	633	633	1978	Ratings reflect Alabama Power 91.8% ownership
	2	606	634	634	1985	Ratings reflect Alabama Power 91.8% ownership
	3	660	687	687	1989	
	4	660	699	699	1991	
Total	*16*	*5,572*	*5,657*	*5,611*		

Nuclear Steam Plants						
Plant	Units	Nameplate Capacity (MW)	IRP Summer Capacity (MW)	IRP Winter Capacity (MW)	In-Service Year	Notes
Farley	1	860	874	874	1975	
	2	860	877	877	1979	
Total	2	1,720	1,751	1,751		

Alabama Power Company Supply-Side Resource Summary - cont.

Gas-Fired Plants (Combustion Turbines)						
Plant	Units	Nameplate Capacity (MW)	IRP Summer Capacity (MW)	IRP Winter Capacity (MW)	In-Service Year	Notes
Greene County	2	80	84	100	1996	
	3	80	82	98	1996	
	4	80	81	97	1995	
	5	80	82	98	1995	
	6	80	81	97	1995	
	7	80	80	96	1995	
	8	80	83	99	1996	
	9	80	82	98	1996	
	10	80	85	101	1996	
Total	*9*	*720*	*740*	*884*		

Gas-Fired Plants (Combined Cycles)						
Plant	Units	Nameplate Capacity (MW)	IRP Summer Capacity (MW)	IRP Winter Capacity (MW)	In-Service Year	Notes
Barry	6	535	550	567	2000	
	7	535	557	572	2001	
Washington County	1	123	100	107	1999	Co-generation plant
Lowndes County	1	105	92	102	1999	Co-generation plant located at SABIC Innovative Plastics (formerly GE Plastics)
Theodore	1	236	231	245	2001	Co-generation plant
Total	*5*	*1,535*	*1,530*	*1,593*		

Oil-Fired Plants (Combustion Turbines)						
Plant	Unit	Nameplate Capacity (MW)	IRP Summer Capacity (MW)	IRP Winter Capacity (MW)	In-Service Year	Notes
Gaston	A	10	8	10	1970	Ratings reflect 50% Alabama Power operating capacity; 100% owned by Southern Electric Generating Company (SEGCO)
Total	*1*	*10*	*8*	*10*		

Solar Powered Facilities						
Plant	Unit	Nameplate Capacity (MW)	IRP Summer Capacity (MW)	IRP Winter Capacity (MW)	In-Service Year	Notes
Fort Rucker		10.6	1.9	1	2017	
Anniston Army Depot		7.4	1.4	0	2017	
Total	*2*	*18*	*3*	*1*		

Contracted Capacity						
Plant		Nameplate Capacity (MW)	IRP Summer Capacity (MW)	IRP Winter Capacity (MW)	In-Service Year	Notes
Calhoun Power PPA		700	632	708	2003	
Westervelt PPA		8	6	6	2012	
Chisholm View PPA		202	41	53	2013	
Buffalo Dunes PPA		202	50	57	2014	
LaFayette PPA		72	17	3	2017	
Other		362	381	298		Represents net capacity that the Company has rights to through various contracts
Total		*1,546*	*1,127*	*1,124*		

Alabama Power Company Supply-Side Resource Summary - cont.

Hydro Electric Plants						
Plant	Units	Nameplate Capacity (MW)	IRP Summer Capacity (MW)	IRP Winter Capacity (MW)	In-Service Year	Notes
Weiss	1	29.25	27	24	1962	Upper Coosa Group
	2	29.25	27	24	1961	Upper Coosa Group
	3	29.25	27	24	1961	Upper Coosa Group
Henry	1	24.3	24	23	1966	Upper Coosa Group
	2	24.3	24	23	1966	Upper Coosa Group
	3	24.3	24	23	1966	Upper Coosa Group
Logan Martin	1	45	43	40	1964	Upper Coosa Group
	2	45	43	40	1964	Upper Coosa Group
	3	45	43	40	1964	Upper Coosa Group
Lay	1	29.5	30	30	1968	Lower Coosa Group
	2	29.5	30	30	1968	Lower Coosa Group
	3	29.5	30	30	1967	Lower Coosa Group
	4	29.5	30	30	1967	Lower Coosa Group
	5	29.5	30	30	1967	Lower Coosa Group
	6	29.5	30	30	1967	Lower Coosa Group
Mitchell	4	20	19	19	1949	Lower Coosa Group
	5	50	48	49	1985	Lower Coosa Group
	6	50	48	49	1985	Lower Coosa Group
	7	50	48	49	1985	Lower Coosa Group
Jordan	1	25	32	33	1928	Lower Coosa Group
	2	25	32	33	1928	Lower Coosa Group
	3	25	32	33	1928	Lower Coosa Group
	4	25	32	33	1928	Lower Coosa Group
Bouldin	1	75	75	75	1967	Lower Coosa Group
	2	75	75	75	1967	Lower Coosa Group
	3	75	75	75	1967	Lower Coosa Group
Martin	1	46	46	44	1926	Tallapoosa Group
	2	41	41	39	1926	Tallapoosa Group
	3	40	40	38	1926	Tallapoosa Group
	4	55	55	52	1952	Tallapoosa Group
Thurlow	1	34.02	34	33	1930	Tallapoosa Group
	2	34.02	34	33	1930	Tallapoosa Group
	3	12.96	13	12	1930	Tallapoosa Group
Yates	1	23.5	22	23	1928	Tallapoosa Group
	2	23.5	22	23	1928	Tallapoosa Group
Harris	1	66	67	62	1983	Tallapoosa Group
	2	66	67	62	1983	Tallapoosa Group
Smith	1	78.75	89	88	1961	Warrior Group
	2	78.75	89	88	1962	Warrior Group
Bankhead	1	53.985	53	53	1963	Warrior Group
Holt	1	46.944	48	48	1968	Warrior Group
Total	*41*	*1,668*	*1,695*	*1,656*		

APPENDIX 2

Alabama Power Company
Demand-Side Management Programs

Alabama Power is committed to both economic growth and environmental stewardship within the state. In concert with customer needs and desires, Alabama Power works to ensure that it continues to have the reliable and cost-effective energy needed to promote the interests of the region. In doing so, Alabama Power continues to be an industry leader in cost-effective DSM programs. The Company implements DSM measures and programs that are designed to reduce customers' energy bills, improve their competitiveness, assist with system load shape management (thereby reducing costs and the need for future capital investment), and help customers use energy as efficiently as possible. All customer segments (industrial, commercial, and residential) are potential participants in these programs.

Changes in technology and other influencing factors can, along with education, provide opportunities for the Company to work more with customers to help them manage and control their energy use, making it more efficient and economical. In managing its DSM programs, Alabama Power must be mindful of the effect they can have on electricity prices. Accordingly, the Company pursues those programs that are expected to benefit all of its customers, thereby avoiding the situation where some customers are effectively being caused to subsidize the benefits realized by others.

The economic health of all customers is not only important to Alabama Power, but also to the state and its future economic vitality. Therefore, future DSM programs can be expected to continue to balance these considerations in a cost-effective manner – encouraging customers' wise and efficient use of energy, while maintaining an economically vibrant and productive region.

Alabama Power currently has customers participating in more than 15 DSM programs in the residential, commercial, and industrial sectors, as well as programs managed through the Company's Distribution Operations. The 2019 IRP includes approximately 1,511 MW of existing contracted active demand-side programs that have allowed the deferral of 1,219 MW of supply-side resource capacity in the winter. The difference between the nominal values shown for the demand-side programs and the associated supply-side resource capacity deferrals is due to the lower availability of capacity equivalence under DSM program, as compared to a supply-side resource. As noted earlier, DSM programs that are subject to the direct control of the Company (e.g., non-residential interruptible load) are called "active DSM." The DSM programs dependent on customer behavior or energy usage patterns (e.g., equipment SEER efficiency increases, insulation/infiltration upgrades) are called "passive DSM." The passive DSM programs serve to reduce expected peak load and consequently are embedded in the Company's load forecast. Existing passive DSM programs are estimated to have resulted in a winter peak load reduction of 363 MW. Therefore, the total amount of existing DSM programs reflected in the 2019 IRP is 1,511 MW plus 363 MW, for a total of 1,874 MW.

Active DSM Programs

The capacity values associated with the Company's active DSM programs, as reflected in the 2019 IRP, are shown in Figure A2-1 Winter and Figure A2-1 Summer, followed by a description of those programs.

FIGURE A2-1 Winter

INTEGRATED RESOURCE PLAN - 2019

Projections of Active Demand-Side Options (DSOs) 2019-2038

Active DSOs

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Contract Amounts	(1,511)	(1,511)	(1,683)	(1,853)	(1,853)	(1,853)	(1,853)	(1,844)	(1,844)	(1,845)
Resource Deferral Amounts	(1,218)	(1,219)	(1,355)	(1,490)	(1,490)	(1,490)	(1,490)	(1,482)	(1,482)	(1,483)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Contract Amounts	(1,846)	(1,846)	(1,847)	(1,847)	(1,848)	(1,848)	(1,849)	(1,849)	(1,850)	(1,850)
Resource Deferral Amounts	(1,483)	(1,484)	(1,484)	(1,484)	(1,485)	(1,485)	(1,486)	(1,487)	(1,487)	(1,487)

Active DSOs - Contract Amounts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Rate Real Time Pricing (RTP)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
150 & 200 Hour Interruptible	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)
600 Hour Interruptible	(542)	(542)	(712)	(882)	(882)	(882)	(882)	(882)	(882)	(882)
Non-Indust. Direct Load Control	0	0	0	0	0	0	0	0	0	0
Customer Standby Generation	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
Distribution Regulation Option Program (DROP)	(134)	(135)	(137)	(136)	(137)	(137)	(137)	(128)	(128)	(129)
Total Active DSO - Contract Amount	(1,511)	(1,511)	(1,683)	(1,853)	(1,853)	(1,853)	(1,853)	(1,844)	(1,844)	(1,845)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Rate Real Time Pricing (RTP)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
150 & 200 Hour Interruptible	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)
600 Hour Interruptible	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)
Non-Indust. Direct Load Control	0	0	0	0	0	0	0	0	0	0
Customer Standby Generation	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
Distribution Regulation Option Program (DROP)	(129)	(130)	(130)	(130)	(131)	(132)	(132)	(133)	(133)	(134)
Total Active DSO - Contract Amount	(1,846)	(1,846)	(1,847)	(1,847)	(1,848)	(1,848)	(1,849)	(1,849)	(1,850)	(1,850)

Active DSOs - Resource Deferral Amounts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Rate Real Time Pricing (RTP)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
150 & 200 Hour Interruptible	(649)	(649)	(649)	(649)	(649)	(649)	(649)	(649)	(649)	(649)
600 Hour Interruptible	(430)	(430)	(565)	(699)	(699)	(699)	(699)	(699)	(699)	(699)
Non-Indust. Direct Load Control	0	0	0	0	0	0	0	0	0	0
Customer Standby Generation	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Distribution Regulation Option Program (DROP)	(125)	(126)	(128)	(127)	(128)	(128)	(128)	(119)	(119)	(120)
Total Active DSO - Resource Deferral Amount	(1,218)	(1,219)	(1,355)	(1,490)	(1,490)	(1,490)	(1,490)	(1,482)	(1,482)	(1,483)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Rate Real Time Pricing (RTP)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
150 & 200 Hour Interruptible	(649)	(649)	(649)	(649)	(649)	(649)	(649)	(649)	(649)	(649)
600 Hour Interruptible	(699)	(699)	(699)	(699)	(699)	(699)	(699)	(699)	(699)	(699)
Non-Indust. Direct Load Control	0	0	0	0	0	0	0	0	0	0
Customer Standby Generation	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Distribution Regulation Option Program (DROP)	(121)	(121)	(121)	(122)	(122)	(123)	(123)	(124)	(125)	(125)
Total Active DSO - Resource Deferral Amount	(1,483)	(1,484)	(1,484)	(1,484)	(1,485)	(1,485)	(1,486)	(1,487)	(1,487)	(1,487)

Active Demand-Side Options are those activated, i.e., dispatchable or controllable, by the Company at the time of need.
Active DSOs are explicitly indicated in the Integrated Resource Plan (IRP) as a resource. Active DSOs reflected here are inputs for the 2019 IRP.

FIGURE A2-1 Summer

INTEGRATED RESOURCE PLAN - 2019

Projections of Active Demand-Side Options (DSOs) 2019-2038

Active DSOs

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Contract Amounts	(1,510)	(1,682)	(1,853)	(1,853)	(1,852)	(1,852)	(1,844)	(1,836)	(1,836)	(1,837)
Resource Deferral Amounts	(1,446)	(1,609)	(1,771)	(1,770)	(1,770)	(1,770)	(1,762)	(1,753)	(1,753)	(1,754)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Contract Amounts	(1,837)	(1,837)	(1,837)	(1,837)	(1,838)	(1,838)	(1,838)	(1,839)	(1,839)	(1,839)
Resource Deferral Amounts	(1,754)	(1,754)	(1,755)	(1,754)	(1,755)	(1,755)	(1,756)	(1,756)	(1,756)	(1,756)

Active DSOs - Contract Amounts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Rate Real Time Pricing (RTP)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
150 & 200 Hour Interruptible	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)
600 Hour Interruptible	(542)	(542)	(712)	(882)	(882)	(882)	(882)	(882)	(882)	(882)
Non-Indust. Direct Load Control	(8)	(7)	(7)	(7)	(7)	(7)	0	0	0	0
Customer Standby Generation	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
Distribution Regulation Option Program (DROP)	(126)	(128)	(130)	(129)	(129)	(129)	(128)	(120)	(120)	(120)
Total Active DSO - Contract Amount	(1,510)	(1,682)	(1,853)	(1,853)	(1,852)	(1,852)	(1,844)	(1,836)	(1,836)	(1,837)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Rate Real Time Pricing (RTP)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
150 & 200 Hour Interruptible	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)	(819)
600 Hour Interruptible	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)	(882)
Non-Indust. Direct Load Control	0	0	0	0	0	0	0	0	0	0
Customer Standby Generation	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
Distribution Regulation Option Program (DROP)	(120)	(121)	(121)	(121)	(121)	(122)	(122)	(122)	(122)	(123)
Total Active DSO - Contract Amount	(1,837)	(1,837)	(1,837)	(1,837)	(1,838)	(1,838)	(1,838)	(1,839)	(1,839)	(1,839)

Active DSOs - Resource Deferral Amounts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Rate Real Time Pricing (RTP)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
150 & 200 Hour Interruptible	(776)	(776)	(776)	(776)	(776)	(776)	(776)	(776)	(776)	(776)
600 Hour Interruptible	(513)	(675)	(836)	(836)	(836)	(836)	(836)	(836)	(836)	(836)
Non-Indust. Direct Load Control	(8)	(8)	(7)	(7)	(7)	(7)	0	0	0	0
\Customer Standby Generation	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
Distribution Regulation Option Program (DROP)	(133)	(135)	(137)	(136)	(136)	(135)	(135)	(126)	(126)	(126)
Total Active DSO - Resource Deferral Amount	(1,446)	(1,609)	(1,771)	(1,770)	(1,770)	(1,770)	(1,762)	(1,753)	(1,753)	(1,754)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Rate Real Time Pricing (RTP)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
150 & 200 Hour Interruptible	(776)	(776)	(776)	(776)	(776)	(776)	(776)	(776)	(776)	(776)
600 Hour Interruptible	(836)	(836)	(836)	(836)	(836)	(836)	(836)	(836)	(836)	(836)
Non-Indust. Direct Load Control	0	0	0	0	0	0	0	0	0	0
Customer Standby Generation	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
Distribution Regulation Option Program (DROP)	(127)	(127)	(127)	(127)	(127)	(128)	(128)	(129)	(129)	(129)
Total Active DSO - Resource Deferral Amount	(1,754)	(1,754)	(1,755)	(1,754)	(1,755)	(1,755)	(1,756)	(1,756)	(1,756)	(1,756)

Active Demand-Side Options are those activated, i.e., dispatchable or controllable, by the Company at the time of need.
Active DSOs are explicitly indicated in the Integrated Resource Plan (IRP) as a resource. Active DSOs reflected here are inputs for the 2019 IRP.

DESCRIPTION OF ACTIVE DSM PROGRAMS

Residential Demand Response Programs:

1. Centsable Switch – A cycling program whereby a customer's HVAC is cycled 67 percent during the months of June through September up to 5 hours per day, subject to a maximum of 150 hours per year.

2. SmartPower Critical Peak Pricing Program – Participating customers receive service under a time-of-use rate with a critical peak price ("CPP") component, and are incented to manage their load during critical peak periods through the issuance of price signals from the Company.

Commercial and Industrial Demand Response Programs:

1. Industrial Interruptible Program – This program, which is currently one of the largest of its kind in the nation, allows Alabama Power to call for the interruption of load with 15 to 30 minutes' notice. The Company's right to interrupt is subject to contractual limitations (e.g., no more than 200 to 600 hours per year and no longer than 8 hours per call).

2. Real Time Pricing – Industrial pricing option based on marginal costs plus applicable adders to recover fixed costs.

3. Standby Generator Program – Under this program, customers enter into a contract with Alabama Power to switch to their standby generators with no notice for use in non-emergency circumstances. The Company is limited to calling these contracts for not more than 200 hours a year (not including maintenance and testing), with no call exceeding 8 hours.

4. Supplemental Reserves – Less than 15-minute interruptible load that can be called as needed to support system operations.

Transmission and Distribution Energy Efficiency Programs:

1. Distribution Regulation Optimization Program ("DROP") – A conservation voltage control option that lowers the voltage on distribution feeders to lower the demand and reduce Volt Ampere Reactive ("VAR") requirements on the system. The target activation periods under this program are the summer and winter peaks.

Active DSM Pilot Programs – The Company is currently conducting the following pilot programs with small test groups within the residential class to assess the potential for active DSM in the winter.

1. Power Pause – The Power Pause pilot officially started on June 1, 2019. The premise behind the pilot is the development of a residential interruptible program that can be utilized not only for summer months, but also for winter and shoulder months. The current program is limited to employees taking service from the Company and only applies to customers with a 200-amp service. Beginning in 2020, a 400-amp meter should be available and will allow the Company to extend the pilot to additional participants. The pilot allows the Company, using remote connect/disconnect ("RCDC") meters, to interrupt electric service to participants subject to the following parameters:

- Months Available – January to December
- Total Annual Interruptible Hours – 40 Hours
- Maximum number of Hours per Event – 4 Hours
- Maximum events in a day – 2 Events
- Available Time Periods – Monday – Friday (24 Hours per Day)
- Excluded Time Periods – Holidays and Weekends.

2. Residential Water Heater Pilot – The Residential Water Heater pilot is expected to start later this year (2019). The goal of the pilot is to study electric water heating usage patterns of the Company's customers and then accommodate those patterns in a way that reduces overall electrical demand without adversely impacting the availability of hot water for those customers. Based on the participant's hot water usage pattern, the participant will be placed in a specified group. The Company will then manage the water heater demand of the various groups using switches that control the electric elements and temperature, providing an opportunity for peak load shaving throughout the year.

Passive DSM Programs

The projected load reductions associated with the Company's passive DSM programs, as embedded in the load forecasts underlying the 2019 IRP, are shown in Figure A2–2 Winter and Figure A2–2 Summer, followed by a description of those programs.

FIGURE A2-2 Winter

INTEGRATED RESOURCE PLAN - 2019

Projections of Passive Demand-Side Options (DSOs) 2019-2038

Gross Peak Load

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PEAK (MW) Winter	12,356	12,414	12,565	12,552	12,587	12,594	12,610	11,796	11,827	11,883

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
PEAK (MW) Winter	11,944	11,996	12,037	12,072	12,133	12,186	12,241	12,306	12,366	12,400

Passive DSO Impacts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Residential Energy Efficiency Programs	(150)	(150)	(150)	(150)	(151)	(151)	(151)	(151)	(151)	(151)
Commercial Energy Efficiency Programs	(43)	(45)	(47)	(49)	(51)	(53)	(55)	(57)	(58)	(60)
Industrial Energy Efficiency Programs	(165)	(168)	(171)	(174)	(177)	(180)	(183)	(187)	(190)	(193)
Peak (MW) Winter	(358)	(363)	(368)	(373)	(378)	(384)	(389)	(395)	(400)	(405)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Residential Energy Efficiency Programs	(151)	(151)	(151)	(151)	(151)	(151)	(151)	(151)	(152)	(152)
Commercial Energy Efficiency Programs	(61)	(62)	(64)	(66)	(67)	(69)	(71)	(73)	(75)	(77)
Industrial Energy Efficiency Programs	(197)	(201)	(204)	(208)	(212)	(216)	(220)	(225)	(229)	(233)
Peak (MW) Winter	(409)	(414)	(420)	(425)	(431)	(437)	(443)	(449)	(456)	(462)

Net Peak Load

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PEAK (MW) Winter	11,998	12,051	12,197	12,179	12,209	12,210	12,221	11,401	11,427	11,478

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
PEAK (MW) Winter	11,535	11,582	11,617	11,647	11,702	11,749	11,798	11,857	11,910	11,938

Passive DSOs are those alternatives adopted by customers that become inherent in their electric energy use pattern and requirements. Passive DSOs are embedded in the Company's load forecast and enumerated in the Integrated Resource Plan.

FIGURE A2-2 Summer

INTEGRATED RESOURCE PLAN - 2019

Projections of Passive Demand-Side Options (DSOs) 2019-2038

Gross Peak Load

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PEAK (MW) Summer	11,635	11,804	11,971	11,903	11,894	11,863	11,818	11,107	11,109	11,144
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
PEAK (MW) Summer	11,172	11,200	11,223	11,224	11,261	11,296	11,344	11,372	11,380	11,409

Passive DSO Impacts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Residential Energy Efficiency Programs	(150)	(150)	(150)	(151)	(151)	(151)	(151)	(151)	(151)	(151)
Commercial Energy Efficiency Programs	(45)	(47)	(49)	(51)	(53)	(55)	(57)	(58)	(60)	(61)
Industrial Energy Efficiency Programs	(168)	(171)	(174)	(177)	(180)	(183)	(187)	(190)	(193)	(197)
Peak (MW) Summer	(363)	(368)	(373)	(378)	(384)	(389)	(395)	(400)	(405)	(409)
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Residential Energy Efficiency Programs	(151)	(151)	(151)	(151)	(151)	(151)	(151)	(152)	(152)	(152)
Commercial Energy Efficiency Programs	(62)	(64)	(66)	(67)	(69)	(71)	(73)	(75)	(77)	(79)
Industrial Energy Efficiency Programs	(201)	(204)	(208)	(212)	(216)	(220)	(225)	(229)	(233)	(238)
Peak (MW) Summer	(414)	(420)	(425)	(431)	(437)	(443)	(449)	(456)	(462)	(469)

Net Peak Load

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PEAK (MW) Summer	11,272	11,436	11,598	11,525	11,510	11,474	11,423	10,707	10,704	10,735
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
PEAK (MW) Summer	10,758	10,780	10,798	10,793	10,824	10,853	10,895	10,916	10,918	10,940

Passive DSOs are those alternatives adopted by customers that become inherent in their electric energy use pattern and requirements. Passive DSOs are embedded in the Company's load forecast and enumerated in the Integrated Resource Plan.

Residential Energy Efficiency Programs:

1. Smart Neighborhood Builder Program – This program promotes the installation of heat pumps and electric water heaters in new homes that are constructed to meet a Home Energy Rating System ("HERS") Index of 65 or below. A typical home built to the 2006 International Energy Conservation Code ("IECC") would be given a HERS rating of 100. Each point of reduction in the HERS index represents a one percent increase in energy efficiency. Therefore, a Smart Neighborhood home is at least 35% more efficient than a typical home built to the 2006 IECC. Additionally, Smart Neighborhood homes feature smart home devices, such as smart thermostats and smart light switches, which allow homeowners to monitor and control their energy usage from their mobile device.

2. Heat Pump Water Heater Program – This program promotes the installation of heat pump water heaters which uses energy efficient heat pump technology to transfer heat from the surrounding environment to the water.

3. Tankless Water Heater Program – This program promotes the installation of electric tankless water heaters in new construction. Electric tankless water heaters heat water when it is needed instead of holding the water in a tank.

4. Residential Time Advantage Rates – Time Advantage Rates provide pricing signals by time period to incent customers to shift their usage to lower cost periods.

5. Residential Plug-in Electric Vehicle Rate Rider – The rider offers a daily 1.7155 cent/kWh discount on the customer's whole house electric usage between the hours of 9pm and 5am to incent the customer to charge their electric vehicle(s) during off-peak hours.

Residential Customer Value Programs:

1. In-Home Energy Check-Up – This program provides for in-home energy audits performed by Alabama Power Energy Sales and Efficiency personnel.

2. Online Energy Check-Up – This program makes an on-line energy audit available to all residential customers.

Commercial Energy Efficiency Programs:

1. Energy Star Cooking – This program promotes Energy Star cooking equipment in the commercial market.

2. Heat Pump Water Heater Program –This program promotes heat pump water heaters in the commercial market.

3. Business Time Advantage Rates – Time Advantage Rates provide pricing signals by time period to incent customers to shift their usage to lower cost periods.

Commercial and Industrial Customer Value Programs:

1. In-Business Energy Check-Up (Commercial) – This program makes available an in-business energy audit performed by Alabama Power Energy Sales and Efficiency personnel.

2. Smart Energy Use Program (Industrial) – This program provides customers with an evaluation of their manner (equipment type or technology application) and practices of energy consumption.

Transmission and Distribution Energy Efficiency Programs:

1. Distribution Energy Efficiency Program ("DEEP") – DEEP operates continuously using capacitors to reduce voltage drop on distribution feeders. The lower voltage upstream of distribution feeders lowers the demand and reduces VAR requirements on the system.

Alabama Power's overarching goal as an electric supplier is to maintain high reliability at cost-effective rates, while providing exceptional customer service. With respect to energy efficiency, the Company supports reasonable building codes and appliance standards that result in customers becoming more efficient in their use of electricity. Alabama Power also works with its customers to help them learn ways to better manage their energy usage and thereby become more efficient users. As part of these efforts, the Company's energy efficiency programs are reasonably expected to benefit all customers, enabling them to realize lower rates than would have been the case had other alternatives been pursued (either supply side or demand side).

APPENDIX 3

Alabama Power Company
Procurement of
Renewable Resources

Consistent with the 2013 and 2016 IRPs, the Company continues to explore adding to its generation mix renewable resources that are projected to bring benefits to customers. This strategy is evidenced by the Company's procurement and development of over 500 MW of renewable energy since 2011. Under these projects, the Company has rights to the environmental attributes, including the renewable energy certificates ("RECs"), associated with the energy. Alabama Power can retire some, or all, of these environmental attributes on behalf of its retail electric customers or it can sell the environmental attributes, either bundled with energy or separately, to third parties.

The Company's renewable resource strategy also reflects action taken by the APSC. On September 16, 2015, the Commission issued to the Company a certificate of convenience and necessity in Docket No. 32382 authorizing the development or procurement of up to 500 MW of capacity and energy from renewable energy and environmentally-specialized generating resources. Projects presented to the Commission for approval pursuant to the certificate must satisfy certain eligibility criteria. First, the project must involve a renewable energy resource (such as those identified in Alabama Code § 40-18-1(30)) or an environmentally specialized generating resource (such as combined heat and power) and be no larger than 80 MW (measured in alternating current ("AC") terms). Second, the project must meet certain economic benefits criteria, namely, that it is expected to result in a positive economic benefit for all of Alabama Power's customers. The APSC will consider projects up to 160 MW of the certificated amount annually; any proposal in excess of that annual threshold requires prior authorization. In addition, any unexercised authority under the certificate expires after six years.

Consistent with the certificate authority in Docket No. 32382, the APSC subsequently approved two projects on December 14, 2015. Specifically, on December 14, 2015, the APSC authorized Alabama Power to construct and own two solar facilities at army installations served by the Company, which were placed into commercial operation in 2017. Fort Rucker was placed into service on April 1, 2017 at 10.6 MW and Anniston Army Depot ("ANAD") was placed into service on July 14, 2017 at 7.4 MW. Additionally, on June 9, 2016, the APSC approved a power purchase agreement ("PPA") for the output of a solar facility near the town of LaFayette in Chambers County, which went into commercial operation on December 15, 2017 at 72 MW. These solar projects are reflected in this 2019 IRP. Alabama Power is receiving all energy and associated RECs generated by these projects, which it uses to serve its customers with solar energy and also sells portions to third parties for the benefit of customers.

Also, pursuant to the certificate authority in Docket No. 32382, the Company will continue to consider and evaluate other projects that would satisfy the criteria set forth in the Commission's certificate order through biannual Renewable Requests for Proposals ("RFPs"). Qualifying proposals submitted through these RFPs will afford Alabama Power an opportunity to review market offerings and determine whether there are economic and viable energy projects suitable for pursuit consistent with the requirements of the order.

The Company will continue to consider and evaluate projects that resulted from the 2016 or 2018 RFPs and unsolicited bids for projects that would satisfy the criteria set forth in the Commission's certificate order. Additional renewable resources will be added to its plan as they are identified, either through the exercise of the authority under that certificate or through another vehicle.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BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	**)**	**PETITION**
	)	
Petitioner	**)**	
	)	**Docket No. 32953**

REBUTTAL TESTIMONY OF JOHN B. KELLEY
ON BEHALF OF ALABAMA POWER COMPANY

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is John B. Kelley. I am the Director of Forecasting and Resource Planning for Alabama Power Company ("Alabama Power" or "Company"). My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q. HAVE YOU PREVIOUSLY PRESENTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. In my Direct Testimony, I described the process used to develop the Integrated Resource Plan ("IRP"), whereby Alabama Power determines the need for new capacity resources required for the continued provision of reliable service to our customers. To the extent the IRP shows a reliability need, it also produces a Benchmark Plan of indicative resources, against which the Company can evaluate alternatives that might prove to be more cost effective. My testimony outlined the various ways in which Alabama Power identified resource opportunities for evaluation, including Request for Proposal ("RFP") processes. Finally, I summarized the resource additions that the Company has proposed for certification and explained why, as part of this portfolio, the Company is seeking authorization to pursue 200 megawatts ("MW") of demand-side management ("DSM") and distributed energy resource ("DER") programs.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to intervenors in this proceeding whose sponsored witnesses offer opinions challenging the Company's proposal and the support provided by my Direct Testimony.

Q. ARE YOU RESPONDING TO ALL THE CLAIMS AND ARGUMENTS RAISED BY INTERVENORS?

A. No. Intervenors, particularly Sierra Club and Energy Alabama/Gasp, do not seem interested in a merits-based decision predicated on pertinent considerations. It is clear these intervenors simply do not want electricity supplied by natural gas-fired generation, period. Sierra Club witness Mr. Stetson, a Beyond Coal Senior Campaign Representative, readily admits this, stating that Sierra Club and its members "oppose fossil-fired generation."[1] Mr. Stetson does not acknowledge, however, how Sierra Club's "Beyond Coal" campaign has evolved over the years, with iterations including the "Beyond Natural Gas" campaign[2] and more recently the "Beyond Dirty Fuels" campaign.[3] This latest version seems to target hydraulic fracturing ("fracking") of oil and gas and attempts to halt development and construction of new natural gas pipelines. Indeed, when Sierra Club first

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[1] Stetson Testimony, page 5, lines 14-18.

[2] Sierra Club, *Beyond Natural Gas*, https://content.sierraclub.org/campaigns/beyond-natural-gas.

[3] Sierra Club, *Beyond Dirty Fuels*, https://www.sierraclub.org/dirty-fuels.

began promoting its Beyond Natural Gas campaign, its leadership made clear that its goal would be "preventing new gas plants from being built whenever we can."[4]

Given this absolutist posturing, it should not be surprising that the testimony sponsored by Sierra Club and Energy Alabama/Gasp is riddled with erroneous assumptions and results-oriented arguments. Similar defects permeate the testimony of AIEC's witness Mr. Pollock. My Rebuttal Testimony does not attempt to refute each and every such assumption and argument, but instead focuses on those areas of intervenor testimony that have the potential to confuse the record or otherwise misconstrue the basis for and legitimacy of Alabama Power's proposed resource portfolio.

Q. PLEASE SUMMARIZE THESE AREAS.

A. Generally speaking, intervenors focus on the following: (i) Alabama Power's IRP process, including its underlying elements; (ii) the cost-effectiveness of the proposed resource portfolio, including the manner in which it was selected; (iii) the Company's DSM programs, including the test for assessing cost-effective programs; and (iv) the long-term viability of the proposed resource portfolio. As the Company's testimony in this proceeding demonstrates, Alabama Power's IRP is a proven, effective tool that enables the Company to plan responsibly, manage resource adequacy and identify cost-effective solutions to meet its system needs. Moreover, the resource portfolio that has been identified comprises a diverse mix of supply- and demand-side options, and represents the least-cost means of reliably addressing Alabama Power's capacity deficit on both a short-term and long-term basis. It is my understanding that two showings must be made for the

[4] Amy Harder, *War Over Natural Gas About to Escalate: Sierra Club launches 'Beyond Gas' campaign*, NATIONAL JOURNAL (May 3, 2012).

issuance of a certificate of convenience and necessity in this proceeding: the petitioner must demonstrate a capacity need, and must also establish that the resource(s) proposed to meet that need are cost-effective and reliable. Alabama Power has satisfied these requirements.

ALABAMA POWER'S CAPACITY NEED

Q. WHAT IS THE CAPACITY NEED IDENTIFIED IN THE COMPANY'S 2019 IRP AND WHY DOES IT NECESSITATE IMMEDIATE ACTION?

A. The 2019 IRP identified a winter capacity shortfall of 1,650 MW in 2020, which by 2024 grows to 2,229 MW. Accordingly, it is both prudent and necessary to secure additional capacity to reestablish an adequate level of Company reserves.

Q. ENERGY ALABAMA/GASP WITNESS MR. RÁBAGO ACCUSES ALABAMA POWER OF BUILDING RATE BASE FOR THE PURPOSE OF GROWING SHAREHOLDER EARNINGS AT THE EXPENSE OF CUSTOMERS. IS THIS A VALID CRITICISM?

A. Absolutely not. The IRP process leads to the selection of resource options at the lowest practicable cost over the long-term. The proposed portfolio identified through the IRP process consists of six power purchase agreements, one power plant to be built, one acquisition of an existing power plant and an assortment of new DSM/DER measures. Clearly, this does not represent an effort to build rate base at the expense of customers. Rather, it represents the lowest cost solution to address an identified reliability need.

Q. MR. RÁBAGO ALSO CLAIMS THAT ALABAMA POWER HAS BEEN AWARE

OF WINTER RELIABILITY ISSUES FOR SOME TIME AND HAS FAILED TO ACT RESPONSIBLY. IS THAT TRUE?

A. No. The need to add capacity only became actionable (through pursuit of this certificate) when the Company adopted seasonal planning in the 2019 IRP, quantifying the level of capacity deficit relative to a winter target reserve margin. Mr. Rábago reveals his lack of knowledge of the Company's operational response to winter reliability concerns when he dramatically declares that we have neglected to act in the face of a "clear and present danger."[5] Contrary to his assertion, the Company has been taking steps to address winter-related reliability issues for some time, but in a measured fashion that likewise belies his accusation that we are bent on expanding rate base.

Q. WHEN DID THE COMPANY BEGIN CONSIDERING RELIABILITY CHALLENGES PRESENTED BY WINTER CONDITIONS?

A. Around 2011, ERCOT imposed rolling winter blackouts as a result of extreme weather conditions, prompting NERC to promulgate guidelines for winter readiness. In 2012, the Company added January and February to the reliability goals of the generating fleet and incorporated freeze protection strategies into plant maintenance. With time, these strategies expanded to include Southern system "winter readiness" exercises to ensure that plant personnel and system operators are cognizant of the operational risks associated with extreme winter conditions and available responsive procedures. Alabama Power also works with the other members of the Pool to limit generator maintenance during January and other potentially reliability-sensitive times.

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[5] *See* Rábago Testimony page 12, lines 7-8.

Q. WAS ATTENTION TO WINTER RELIABILITY LIMITED TO THESE INITIATIVES?

A. No. After the Polar Vortex event of 2014, the system examined the factors influencing winter reliability concerns as part of the 2015 Reserve Margin Study. As a result of that study, the Company concluded that an increase to its summer target reserve margin (from 15.0 percent to 16.25 percent) could be another means to help address winter reliability. As Mr. Weathers' testimony reflects, that step ultimately proved to be an interim measure, later replaced by seasonal planning and a defined winter target reserve margin.

Q. HAS THE COMPANY TAKEN STEPS TO IMPROVE ITS CAPACITY POSITION APART FROM THIS PETITION FOR NEW RESOURCE ADDITIONS?

A. Yes. In 2019, Barry Units 1 and 2 were returned to active service, and unit up-rates have been initiated at Barry Units 6 and 7 in conjunction with routine milestone maintenance activities. The Company also is taking steps to increase its demand-side option ("DSO") portfolio.

Q. VARIOUS INTERVENOR WITNESSES ARGUE THAT THE COMPANY'S 26 PERCENT WINTER TARGET RESERVE MARGIN IS TOO HIGH. DO YOU AGREE?

A. No. This issue is addressed in detail in the Rebuttal Testimonies of Mr. Weathers and Mr. Carden. Suffice it to say that intervenors seem to believe that because other investor-owned utilities have not adopted a 26 percent reserve margin—or more precisely, the Company's diversified winter target of 25.25 percent—then Alabama Power must be wrong. This simplistic conclusion fails to appreciate the nuanced factors at play in the development of reserve margins, including the fact that such margins depend on system-specific considerations such as load shape characteristics, generation mix and weather, all of which can vary from state to state and region to region. Customer mix (e.g., the amount of residential customers versus industrial customers) influences reserve margin levels as well. Put simply, there is not a "one-size-fits-all" reserve margin percentage. That said, I would note that both TVA and PowerSouth Energy Cooperative–both of which serve load in Alabama and experience similar weather to what is seen in Alabama Power's footprint–plan for a 25 percent winter reserve margin.

Q. MR. POLLOCK STATES THAT VARIOUS INVESTOR-OWNED UTILITIES IN FLORIDA HAVE A LOWER (20 PERCENT) RESERVE MARGIN THAN ALABAMA POWER. DOES THIS COMPARISON HAVE ANY MERIT?

A. No. In addition to generation mix, customer mix, and other system-specific factors affecting reserve margin, winter weather in Florida is quite different than that experienced here in Alabama. On the rare occasion that Central or South Florida experiences cold weather, the magnitude and duration are not nearly as severe or impactful to system electric load as is the case in Alabama. Conversely, and for reasons including more extreme summer temperatures, the referenced Florida utilities maintain a higher summer reserve margin than does Alabama Power.

Q. DO YOU BELIEVE THAT THE COMPANY'S DIVERSIFIED LONG-TERM TARGET PLANNING RESERVE MARGIN OF 25.25 PERCENT IN THE WINTER AND 14.89 PERCENT IN THE SUMMER ARE REASONABLE?

A. Yes. These target reserve margins are not only reasonable, but also necessary to provide Alabama Power customers with a reliable system. These margins were determined through an exhaustive and well-documented study specific to our system's loads, resources and weather conditions.[6] Planning to these system-specific targets is far superior to "borrowing" the reserve margins of neighboring utilities and hoping that doing so works for Alabama Power and its customers.

Q. TO WHAT EXTENT CAN THE COMPANY RELY ON THE SOUTHERN COMPANY POOL TO MITIGATE ITS CAPACITY DEFICIT?

A. Consistent with operations under the Southern Company System Intercompany Interchange Contract ("IIC" or "Pool"), Alabama Power is permitted to rely on surplus capacity of the other retail operating companies in order to address a temporary capacity deficit. Such a course, however, cannot be the long-term solution to our winter reliability need. Under the IIC, all operating companies are contractually obligated to bring sufficient resources to reliably serve their respective load obligations.

Q. WHAT IS THE IIC?

A. As discussed in my Direct Testimony, the IIC is a contract on file with the Federal Energy Regulatory Commission ("FERC") that sets forth the duties and obligations of the members to accomplish the operational objectives of that arrangement.[7]

Q. EXPLAIN HOW SOUTHERN SYSTEM OPERATIONS ARE CONDUCTED UNDER THE IIC.

A. Under the IIC, Alabama Power and other members of the Pool combine their supply- and demand-side resources and service obligations. The Pool then commits and dispatches members' resources in order to serve their collective obligations in a reliable and economic

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[6] *See* Ex. JBW-1.

[7] *See* Southern Company System Intercompany Interchange Contract, Rate Schedule No. 138, FERC Docket No. ER18-1947 (effective Jan. 1, 2019).

manner. Serving the collective load in this fashion enhances service reliability, while minimizing total production cost for the system to the benefit of all members.[8]

Participation in the Pool provides some obvious benefits for Alabama Power's customers:

- *Lower fuel costs*: joint unit commitment and centralized dispatch result in lower fuel costs because the process takes advantage of the diverse and real-time market conditions of a variety of resources.
- *Improved real-time reliability:* coordinating plant maintenance outages and leveraging other members' resource availability mitigates real-time unit outage impacts and improves reliability.
- *Diversified target reserve margins*: coordinated planning and operation enables operating companies to maintain lower reserve levels reflective of the timing and magnitude of the companies' coincident and non-coincident peak demands.
- *Planning reliability*: coordinating with other members of the Pool affords Alabama Power the ability to take advantage of surplus capacity in the Pool to address a temporary capacity deficit.

Q. WHY CAN'T ALABAMA POWER RELY ON SOUTHERN POOL LENGTH TO RESOLVE ITS CAPACITY NEEDS?

A. The IIC explicitly directs that "each operating company is expected to have adequate resources to reliably serve its own obligations."[9] In fact, this requirement is emphasized

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[8] The IIC provides for an after-the-fact accounting of system dispatch so that each operating company's lowest cost resources are retained by that company for the benefit of its customers.

[9] *See* IIC Section 7.1.

as a "fundamental premise" of the IIC.[10] Thus, while operating companies can look to one another for potential support to address a temporary capacity deficit,[11] the Pool cannot serve as a long-term source of reliable supply. To the extent witnesses such as Sierra Club's Ms. Wilson and AIEC's Mr. Pollock claim otherwise, they would have the Company breach the terms of the IIC. Moreover, Alabama Power cannot presume an ongoing surplus of Pool capacity. Members of the Pool have no obligation to preserve capacity for the benefit of other Pool members. They can sell their additional capacity in the wholesale market, and they can also make decisions regarding their resources that impact the level of surplus capacity in the Pool. Thus, even if Alabama Power could ignore its legal obligations in a FERC tariff and look to other Pool participants as a means to address its capacity deficit, the Company cannot plan on those participants' resources being available for an extended period.

Q. IS THERE ANY REASON TO THINK THAT OTHER POOL MEMBERS MAY BE PLANNING TO RETIRE SOME OF THEIR SURPLUS CAPACITY?

A. Yes. As ordered by the Mississippi Public Service Commission, Mississippi Power recently filed a Reserve Margin Plan that indicated the most economic option to address Mississippi Power's excess capacity would be to consider the early retirement of Watson Units 4 and 5 and Greene County Units 1 and 2 (subject to the completion of proposed

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[10] Other provisions of the IIC echo this requirement. *See, e.g.*, IIC Section 1.6 ("[A]ll of the Operating Companies will continue to share in all of the benefits and burdens of this IIC, including complying with operating, dispatch and reserve requirements….").

[11] *See* IIC Section 7.1 ("[T]he Operating Companies recognize that in any given year one or more of them may have a temporary surplus or deficit of capacity as a result of coordinated planning or by virtue of load uncertainty, unit availability, and other such circumstances.").

transmission and system reliability improvements and joint owner approval).[12] Combined, these resources represent more than 1,250 MW of capacity currently in the Pool. Additionally, as I mentioned in my Direct Testimony, Georgia Power has committed to limit its capital spending on Bowen Units 1 and 2, suggesting that this approximately 1,450 MW of capacity potentially could be decommissioned in the next Georgia Power IRP cycle.

Q. IF GEORGIA POWER WERE TO PURSUE SUCH A COURSE, WHY COULDN'T ALABAMA POWER SIMPLY LOOK TO REPLACEMENT CAPACITY SECURED BY GEORGIA POWER, AS IMPLIED BY MR. POLLOCK?

A. If Georgia Power determined to decommission Bowen Units 1 and 2, then Georgia Power would, through the development of its own IRP, determine any resulting capacity need to serve its own customers. Georgia Power would not add capacity simply for the benefit of Alabama Power customers, as Mr. Pollock seems to suggest.[13]

Q. ARE THERE ANY OTHER PROBLEMS WITH MR. POLLOCK'S AND MS. WILSON'S CLAIMS THAT ALABAMA POWER SHOULD SIMPLY LEAN ON THE POOL?

A. Yes. The Alabama Legislature has long required utilities, including Alabama Power, to render adequate service to the public and make such reasonable improvements, extensions and enlargements of its plants, facilities and equipment as may be necessary to meet the growth and demand of the territory which it is under the duty to serve.[14] Thus, embracing

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[12] *See* Mississippi Power Company's Reserve Margin Plan Filing, MPSC Docket No. 2018-AD-145 (Aug. 6, 2018).

[13] *See* Pollock Testimony, page 14, line 19 through page 15, line 3.

[14] *See* Ala. Code § 37-1-49.

these witnesses' arguments would result in Alabama Power planning and operating its system in an irresponsible, imprudent and illegal manner.

Q. GIVEN THAT THE 2019 IRP IS SHOWING A CAPACITY NEED OF APPROXIMATELY 2,200 MW IN 2024, WHY IS ALABAMA POWER SEEKING AUTHORIZATION FOR A PORTFOLIO OF APPROXIMATELY 2,400 MW?

A. As reflected in my Direct Testimony, the IRP demonstrated a need of approximately 2,200 MW of additional capacity in order to reliably serve its customers in the winter of 2024. The additional 200 MW requested in the petition reflects a need that arises contemporaneously with Barry Unit 8 coming into service, pursuant to applicable operating procedures.

Q. PLEASE EXPLAIN.

A. An analysis of the transmission system with Barry Unit 8 online and operating showed the need to invest $69 million in transmission upgrades in order to accommodate simultaneous full output from both Plant Barry (including Barry Unit 8) and Greene County Units 1 and 2. Alternatively, output at Greene County Units 1 and 2 could be limited to 200 MW, with the remaining capability treated as non-firm capacity. The Company chose this alternative (increasing the need from 2,200 MW to 2,400 MW) because the cost of replacing the Greene County capacity was less than the cost of the additional transmission investment, and hence more beneficial for customers.

Q: DOES THIS MEAN THAT GREENE COUNTY UNITS 1 AND 2 WOUILD BE DERATED?

A: No. As stated, the capacity at these units above 200 MW will be considered "non-firm capacity." To the extent system conditions allow for operation of the units above 200 MW, Greene County Units 1 and 2 can be operated above that level. For reliability planning purposes, however, the capacity of these units cannot exceed 200 MW.

Q. WAS THE COST ASSOCIATED WITH THE DESCRIBED TREATMENT OF THE GREENE COUNTY UNITS INCLUDED IN THE ECONOMIC EVALUATION OF THE BARRY UNIT 8 PROPOSAL?

A. Yes. This cost was included in the Barry Unit 8 evaluation, which nonetheless showed that resource to be among the most cost-effective in the portfolio.

Q: SEVERAL WITNESSES STATE THAT ONLY A PORTION OF THE PORTFOLIO SHOULD BE APPROVED NOW, LEAVING THE COMPANY TO SEEK NEW OPTIONS AT A LATER DATE. IS DELAY A VIABLE OPTION?

A: No. A wait and see approach is inconsistent with the Company's responsibility to provide reliable service to customers, which necessarily requires an adequate reserve margin. Moreover, abandoning the resources in the portfolio will deprive the Company's customers of the cost-effective options that have been secured, leaving them exposed both to reliability risk as well as the potential for increased costs associated with a later procurement of replacement capacity. In my opinion, the favorable pricing reflected in this portfolio is unlikely to be replicated any time soon.

Q: DOES THE PROJECTED DECLINE IN ALABAMA POWER'S WINTER PEAK LOAD BETWEEN 2019 AND 2031 OFFER A BASIS TO FOREGO SOME OF THE PORTFOLIO?

A: No. While it is true that Alabama Power's projected winter peak load is forecasted to be lower in 2031 than 2019, this must be placed in the proper context. Alabama Power's retail winter peak load is projected to continue to increase from 2019, and the status of certain wholesale contracts remains unclear. The Benchmark Plan conservatively assumes that when existing wholesale contracts reach their maturation dates, the corresponding load-serving obligations cease. Therefore, the Company removed these loads from the forecast.

Q: IS THIS WHAT ALABAMA POWER EXPECTS TO HAPPEN?

A: No, but it is a possible outcome. Alabama Power has long been a provider of wholesale service for other retail suppliers in the state and cannot dismiss the possibility that it might continue to supply these customers after the contracts terminate. Thus, Alabama Power's total projected winter peak load may not decline to the extent shown, if at all. Even if it did decline, that outcome would present alternatives for Alabama Power and its customers.

Q: WHAT MIGHT TRANSPIRE IF ALABAMA POWER ENTERED INTO A PERIOD WHERE IT HELD CAPACITY ABOVE ITS TARGET RESERVE MARGIN?

A: Alabama Power would have several options if it entered a period during which it held capacity reserves above the target margin. Alabama Power might take no action if reserve levels were projected to decline in response to load growth. Alternatively, that circumstance would be an important consideration in the evaluation of the future operation of units approaching the end of their depreciable lives. Alabama Power also could explore the feasibility of short-term wholesale sales. Regardless, it is not unusual for a utility like Alabama Power, with significant retail service obligations, to find itself with reserve levels temporarily above a long-term target. In my experience, such a situation affords the Company's planning function with broader alternatives to optimize the resource fleet as a whole.

RESOURCE IDENTIFICATION AND THE RFP PROCESS

Q. SEVERAL INTERVENORS CLAIM THAT THE COMPANY'S ANALYSES DID NOT FAIRLY CONSIDER RENEWABLES. ARE THESE CLAIMS ACCURATE?

A. No. One repeated claim is that the IRP somehow preordained or biased outcomes by excluding renewables from the development of the Benchmark Plan. The Benchmark Plan provides only guidance to the Company as to what types of capacity resources (e.g., peaking versus intermediate or baseload) are needed to meet future resource obligations in the least-cost manner. The Benchmark Plan does not dictate which technologies will ultimately be selected as part of a final resource portfolio, so its exclusion of renewables is of no consequence. As with any resource procurement effort, the goal of the Company is to find resource options of any type that are superior to the Benchmark Plan, providing comparable reliability at a lower cost. This objective, and the fallacy of their own accusation of unfair treatment of renewables, should be obvious to intervenors, given that the Company's proposed portfolio includes renewable options.

Q. SIERRA CLUB WITNESS MR. DETSKY IS CRITICAL OF ALABAMA POWER'S RFP PROCESSES. WHAT IS YOUR RESPONSE?

A. The process the Company used to arrive at its proposed resource portfolio was fair and comprehensive. The Capacity RFP solicited capacity from wholesale market participants on a broad basis, with the key requirements being that the proposals encompassed dispatchable capacity that was connected to or deliverable at the border of the Southern electric system.[15] The Company also worked with original equipment manufacturers to

[15] Proposed acquisitions also were required to be sited in the state of Alabama.

explore the feasibility and cost-effectiveness of potential turnkey combined cycle power plants, as discussed by Mr. Bush. The Company also relied on its biennial Renewable RFP process.[16] In addition, Alabama Power explored potential DSOs and DER projects that might prove cost effective. The combined results of these initiatives were evaluated against the Benchmark Plan and across a wide range of scenarios covering varying price paths for natural gas and carbon dioxide. As a result of this evaluation, Alabama Power selected the resource portfolio proposed in this certification filing, which provides the lowest cost mix of resources to meet Alabama Power's stated reliability needs.

Q. WHY DID THE COMPANY DECIDE TO USE MULTIPLE RFPS, RATHER THAN A SINGLE ONE?

A. Recall that the RFP for renewable resources stemmed from an existing docket and covered only resource proposals that satisfied certain parameters. Thus, a broader solicitation in the form of the Capacity RFP was necessary to canvass the market for other resource options. In addition, the turnkey inquiry was a first-of-its kind approach for Alabama Power, as Mr. Bush discussed in his Direct Testimony.

Q. WERE RENEWABLE ENERGY RESOURCES EXCLUDED FROM THE CAPACITY RFP?

A. No. The Capacity RFP specifically solicited renewable projects, subject to dispatchability requirements. The Capacity RFP also allowed the market to submit solar proposals when paired with energy storage or another type of generator providing capacity value. Thus,

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[16] Order Granting Approval of Petition of Alabama Power Company, Ala. Pub. Serv. Comm'n Docket No. 32382 (Sept. 16, 2015).

the market had multiple opportunities to propose renewable offerings for the Company to evaluate.

Q. MR. DETSKY CLAIMS THAT RESTRICTIONS IN THE RENEWABLE RFP IMPACTED MARKET RESPONSE. DO YOU AGREE WITH HIS OPINION?[17]

A. No. Most of Mr. Detsky's claims are answered by the previous observation—the Capacity RFP (which served as a complement to the Renewable RFP) was open to renewable resource proposals. He acts as if the Renewable RFP was the only means for renewable input, which as explained above is clearly not the case. With respect to his criticism concerning an equity cost applicable to PPAs, Mr. Detsky is simply wrong when he alleges that this adversely affected renewable projects. Specifically, he testifies that "the Company added substantial [equity] cost to every PPA in its evaluation process."[18] As noted by Ms. Baker and Mr. Looney, however, no such equity cost was included in the evaluation of any of the PPAs for renewable projects.

Q. THE ECONOMIC ANALYSIS PRESENTED IN MR. LOONEY'S DIRECT TESTIMONY INDICATES THAT THE SOLAR BESS PROJECTS HAVE THE BEST OVERALL ECONOMICS OF ALL THE PROPOSED RESOURCES. WHY DID THE COMPANY ONLY SELECT FIVE OF THEM TO INCLUDE IN ITS PROPOSED RESOURCE PORTFOLIO?

A. The Company is pursuing all of the Solar BESS projects that proved to be economically viable. The Company evaluated approximately 1,000 MW of Solar BESS projects;

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[17] In response to a discovery question regarding his claim that the restrictions "anecdotally" caused independent power producers not to bid, Mr. Detsky clarified that the statement was based on his experience and that an errata would be filed by Sierra Club substituting "anecdotally" with "in my opinion."

[18] *See* Detsky Testimony, page 23, lines 7-17.

however, only 400 MW exhibited better economics than the other projects in the proposed portfolio. That said, these combined projects represent one of the largest announced Solar BESS deployments in the United States to date.

Q. WHY WERE THE OTHER SOLAR BESS PROJECTS EXCLUDED FROM THE PROPOSED PORTFOLIO?

A. Most of the Solar BESS projects were not pursued due to associated transmission system costs. In addition, the Company took into account the proximity of any project to an existing customer whose industrial operations would be sensitive to adverse impacts on power quality that might be caused by a Solar BESS project. Finally, as Mr. Looney explains in his Rebuttal Testimony, there is a practical limit to the amount of two-hour BESS capacity that can be added to the system before the capacity value begins to degrade.

Q. MR. DETSKY SUGGESTS THAT ALABAMA POWER SHOULD START OVER AND CONDUCT AN "ALL SOURCE RFP". WHAT IS YOUR REACTION TO THIS RECOMMENDATION?

A. As a practical matter, Alabama Power already has performed an "all source RFP." The Company surveyed the market for conventional generation, power purchase agreements, acquisitions, new builds, batteries, dispatchable renewables and distributed energy resources. All viable proposals were then considered as part of a single evaluation. I would also note that the "all source RFP" of Public Service Company of Colorado touted by Mr.

Detsky appears to be a collective reference to four individual RFPs, making it seem quite similar to the overlapping solicitations conducted by Alabama Power.[19]

Q. IF THE PROPOSED PORTFOLIO IS APPROVED, WHAT WILL THE COMPANY'S CAPACITY MIX BE IN 2024?

A. The Company's proposed portfolio, if approved, would further diversify the Company's resource mix. As of 2024, Alabama Power's capacity would comprise approximately 30 percent coal and 30 percent natural gas; nuclear capacity would constitute slightly more than 10 percent; and the remaining 30 percent would come from the Company's DSOs, hydroelectric generation and other sources of renewable power.[20] In my experience, this mix represents a well-balanced and diversified portfolio of capacity supply.

Q. THE COMPANY'S PROPOSED PORTFOLIO HAS MORE THAN 1,800 MW OF GAS-FIRED GENERATION. WOULD THIS ADDITIONAL GENERATION MAKE THE COMPANY TOO RELIANT ON NATURAL GAS, AS ASSERTED BY INTERVENORS?

A. No. As explained in Mr. Weathers' Rebuttal Testimony, the natural gas generation in the proposed portfolio does not create reliability concerns or otherwise exacerbate the gas-related risk addressed in the Reserve Margin Study. I would also note that the proposed

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[19] Xcel Energy, *Colorado's 2017 All-Source Solicitation*, https://www.xcelenergy.com/company/rates_and_regulations/resource_plans/psco_2017_all_source_solicitation, attached as Reb. Ex. JBK-1.

[20] To the extent Alabama Power generates or receives the renewable energy credits ("RECs") associated with these projects, Alabama Power retains the option to use those RECs to serve its customers with renewable energy or sell the RECS, either bundled with energy or separately, to third parties for the benefit of customers.

portfolio is expected to produce significant fuel savings, as identified in the analysis conducted by Mr. Looney's organization.[21]

Q. PLEASE ELABORATE ON THE FUEL SAVINGS THE PROPOSED PORTFOLIO IS EXPECTED TO DELIVER.

A: In the case of proposed Barry Unit 8, the heat rate is one of the best in the industry. With addition of the rights to Hog Bayou and Central Alabama, both of which are efficient and flexible combined cycle facilities, Alabama Power will be able to gain for our customers the benefit of historically low natural gas costs that are forecast to remain low for years to come. The advent of fracking coupled with horizontal drilling has turned the United States into the world's leading producer of natural gas, and this increase in supply has driven costs down to some of the lowest sustained prices on record. When these highly efficient machines are fueled with low-cost natural gas, customers benefit from significant fuel cost savings. Adding the projected energy benefits from the Solar BESS projects also adds to the fuel cost savings of the portfolio.

Q. SIERRA CLUB WITNESS MS. WILSON EXPRESSES CONCERN THAT GAS IS UNRELIABLE IN THE WINTER. IS THIS A LEGITIMATE CONCERN FOR THE PORTFOLIO?

A. No. To address the potential supply and demand imbalances that can occur with natural gas in the winter, Alabama Power contracts for firm transportation ("FT") of natural gas. This provides greater reliability than interruptible or "as-available" natural gas supply.

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[21] *See* Ex. MBL-1.

Under Southern's fuel policy, which is consistent with the IIC requirement that each operating company bring adequate resources to reliably serve its own obligations, Alabama Power may not rely on a natural gas resource as firm capacity unless there is a FT contract in place or the resource possesses sufficient on-site back-up fuel.

DEMAND-SIDE OPTIONS AND DISTRIBUTED ENERGY RESOURCES

Q. HAVE YOU REVIEWED INTERVENORS' TESTIMONY REGARDING THE COMPANY'S DSO PROGRAMS?

A. Yes, I have read the testimony of Sierra Club witness Ms. Wilson, and Energy Alabama/Gasp witnesses Messrs. Howat and Rábago, all of which are critical of the Company's development and implementation of DSO programs.

Q. ARE THEIR CRITICISMS VALID?

A. No.

Q. PLEASE EXPLAIN.

A. Alabama Power has a robust and cost-effective portfolio of DSO programs. When measured in MW, Alabama Power already has one of the largest demand-response programs of any utility in the country. As these programs grow over the next few years, Alabama Power will likely have the largest demand response program in the country.

Q: WHAT WOULD BE THE COMPANY'S RESOURCE NEED IN THE ABSENCE OF THESE DSO PROGRAMS?

A: Alabama Power's active demand response programs currently offset approximately 1,200 MW of supply-side resources.[22] By 2024, this number is expected to grow to nearly 1,500 MW. Coupled with the cumulative load reduction achieved from the passive DSO programs, and accounting for the proposed 200 MW of new DSM and DER programs reflected in the portfolio, Alabama Power's DSO programs will be eliminating the need for approximately 2,000 MW of supply-side capacity. By way of comparison, that amount is larger than the collective capacity of Barry Unit 8, the Central Alabama acquisition and the Hog Bayou PPA. In the absence of the Company's industry-leading DSO programs, Alabama Power would have a need for well over 4,000 MW of new capacity to meet the reliability needs of our customers, instead of the proposed portfolio of 2,400 MW.

Q: IN ADDITION TO DEMAND RESPONSE, DOES ALABAMA POWER OFFER PROGRAMS TO ENCOURAGE ENERGY EFFICIENCY?

A: Yes. The Company offers a variety of programs that promote energy-savings through such means as high efficiency water heating equipment, smart thermostats and customer energy audits (both on-site and on-line). The Company also runs a Smart Neighborhood Builder Program that encourages builders to incorporate energy efficiency upgrades during the construction phase, thereby enhancing the expected energy profile of the home.

Q. INTERVENORS MAKE MUCH OF THE FACT THAT ALABAMA POWER RECEIVES LOW SCORES IN THE ANNUAL "UTILITY SCORECARD" PUBLISHED BY THE AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT

[22] *See* Ex. JBK-1, Appendix 2, page 3.

ECONOMY ("ACEEE"). CAN YOU PROVIDE SOME INSIGHT REGARDING THESE SCORES?

A. In our view, ACEEE—which is an advocacy group—employs unfair and biased scoring methodologies that do not provide a meaningful measure of effective DSO and energy efficiency programs. For example, in the year evaluated in the most recent scorecard, Alabama Power operated twenty energy efficiency programs. Nonetheless, the Company's "score" is drastically low because ACEEE has chosen to assign more "point value" to the amount of money utilities spend on energy efficiency programs, as opposed to the results of those programs. ACEEE even touts that spending is a "critical indicator of a utility's commitment to energy efficiency; higher levels of spending indicate significant investment in administration and evaluation of programs."[23] This philosophy seems to penalize those utilities that are more effective in achieving energy reductions in a more cost-effective manner. A high score can be achieved simply by spending a lot of money on the programs, regardless of their outcome.

Similarly, the Company has programs that are not captured in the ACEEE Scorecard. For instance, we have nearly 500 MW of Commission-authorized combined heat and power ("CHP") projects operating as part of our resource fleet today. These projects have been in place for many years, and yet ACEEE gives Alabama Power no credit for the development of these resources.

Q. ARE STATES THAT ARE HIGHLY RANKED BY ACEEE ABLE TO PROVIDE LOWER COST ELECTRICITY TO CUSTOMERS THAN ALABAMA POWER?

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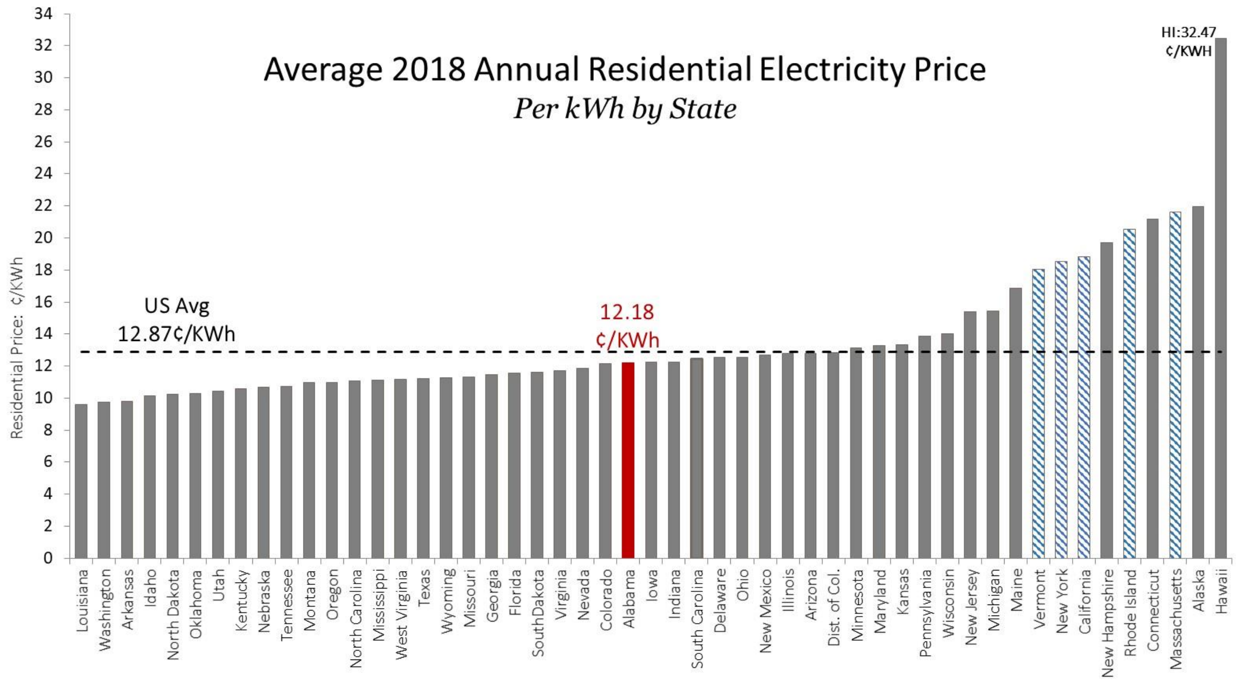
[23] Am. Council for an Energy-Efficient Econ., *2017 Utility Energy Efficiency Scorecard*, page 18, *available at* https://aceee.org/research-report/u1707 ("*Utility Scorecard*").

A. No—just the opposite. The graph below ranks the cost per kilowatt hour for residential electricity from the 2018 EIA-861 report. Alabama is represented by the red bar at 12.18¢ per kilowatt hour, below the national average of 12.87¢ per kilowatt hour, and well below Massachusetts, California, Rhode Island, Vermont and New York, which are the top five finishers in ACEEE's state scorecard.[24]

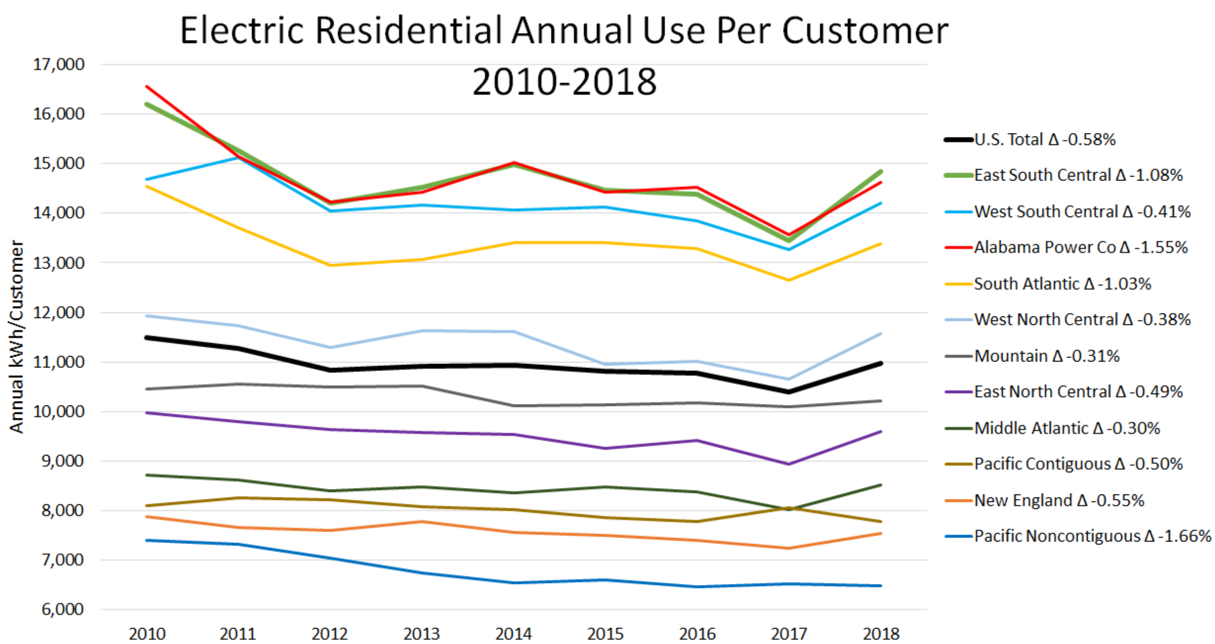


Q. IS AN INCREASED INVESTMENT OF CUSTOMER DOLLARS NECESSARY TO REALIZE ENERGY EFFICIENCY IMPROVEMENTS?

A. No. As reflected in the graph below, almost all areas of the country have experienced a decline in electricity use per residential customer over the 2010-2018 time frame. Notably, the reductions depicted for Alabama Power are among the highest in the country, but such

[24] *See generally* Am. Council for an Energy-Efficient Econ., *2019 State Energy Efficiency Scorecard*, *available at* https://aceee.org/research-report/u1908.

reductions were accomplished without the spending levels that SELC witness Mr. Howat seems to consider appropriate. Drivers of these reductions are likely numerous, including not only standards promulgated by the federal government, but also Alabama Power's educational customer service messages encouraging energy efficiency.



If data for Alabama Power were included for the year 2019, the Company's trendline would be even lower, with a compound annual average growth rate of -1.66 percent in residential use per customer. I can only provide these 2019 results for Alabama Power because comparable data for all Census regions is not expected to be available until October 2020.

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS ABOUT INTERVENORS' CRITICISMS OF ALABAMA POWER'S DSO INITIATIVES?

A. It appears disingenuous to claim that Alabama Power is not doing enough demand-side management, given that it is offsetting more megawatts than almost every utility in the country. There is virtually no mention of Alabama Power's demand response accomplishments by intervenors. Digging deeper, it appears that the criticisms are rooted in their preference for passive DSOs ("energy efficiency"), rather than demand response.

Q. WHAT DO INTERVENORS ADVOCATE IN THIS AREA?

A. Intervenors seem to want Alabama Power to spend millions of dollars—perhaps even hundreds of millions of dollars—in an attempt to reduce annual electricity sales, in the hope of avoiding new generating capacity by also avoiding the peak demand. In other words, intervenors seem to believe that if the Company spends enough, it will cause a reduction in energy consumption, which in turn will reduce peak demand and consequently the need for additional supply-side resources.

Q. DO YOU HAVE ANY ISSUES WITH THIS APPROACH?

A. If the economics demonstrated that spending money to reduce sales rather than to add generation to serve load made sense for our customers, then Alabama Power would do so. The Company's existing and planned energy efficiency programs reflect this view. The larger issue, however, on which intervenors and I disagree, is the manner by which to properly evaluate the costs and benefits of potential programs.

Q. HOW SHOULD THE COSTS AND BENEFITS OF SUCH PROGRAMS BE EVALUATED?

A. The Ratepayer Impact Measure ("RIM") test is the proper means for gauging cost-effectiveness.

Q. WHY DOES THE COMPANY USE THE RIM TEST?

A. The RIM test is the most appropriate measure for a demand-side management program because programs that "pass" the RIM test produce net benefits to *all customers* over the useful life of the program. This is consistent with the fact that all customers bear the costs of the program. A program failing to pass RIM places upward pressure on rates, harming non-participants (and potentially participants as well). In this respect, I find it curious that Mr. Howat, whose testimony focuses on impacts to low-income customers, would support any test other than RIM. In fact, Mr. Howat goes so far as to suggest that the Company should analyze investing in energy efficiency programs in an amount equivalent to 2.7 percent of the Company's revenues. Such investment would equate to approximately $150 million per year, which would produce an increase in residential electricity prices. Moreover, this course would have no possibility of meeting the reliability needs of Alabama Power's customers. According to the 2017 ACEEE report referenced by Mr. Howat,[25] the top five scoring utilities in terms of energy efficiency impacts achieved an average peak load reduction of approximately 148 MW. Load reductions of such magnitude fall woefully short of Alabama Power's forecasted reliability need of approximately 2,400 MW. Equally revealing from the 2017 ACEEE report is the cost of peak load reductions achieved by the top five spending utilities, which in 2015 realized an average peak load reduction of 100 MW at an average cost of $1,980 per kW. By requiring an appropriate assessment of costs and benefits, the RIM test ensures that such outcomes would be to the benefit of all customers.

Q. DO INTERVENORS SUPPORT THE USE OF THE RIM TEST?

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[26] *See Utility Scorecard*.

A. No, and this is our main area of disagreement on demand-side issues. Intervenors advocate discontinuing use of the RIM test and instead employing approaches such as the Total Resource Cost ("TRC").

Q. WHAT IS THE DIFFERENCE BETWEEN THE RIM TEST AND THE TRC TEST?

A. The central difference is subsidization. The RIM test places limits on cross-subsidization between customers, while the TRC test imposes no such limits. For this reason, RIM is sometimes referred to as the "No Losers" test. Unlike the TRC, if a program passes RIM, all customers benefit, and average prices will not increase for those customers who choose not to participate in the particular DSM program. A program passing TRC but failing RIM indicates that it will place upward pressure on all rates, with the greater impact on the bills of non-participants.

Q. WHAT ARE THE BENEFITS OF A DSO PROGRAM TO NON-PARTICIPANTS?

A. The benefits to non-participants are the costs that are not incurred as a result of the program over the relevant time period. This could include the present value of, among other things, avoided generation capacity costs, fuel costs, transmission and other power delivery costs, unit commitment costs, certain O&M costs and environmental compliance costs. Sometimes these are described collectively as "avoided costs."

Q. WHAT ABOUT OTHER COSTS THAT MIGHT BE AVOIDED, SUCH AS THE CARBON COSTS THAT MS. WILSON DISCUSSES?

A. The benefits and costs properly evaluated through the RIM test are those that are borne by Alabama Power customers, as reflected in their electric bills. It would not be proper to include speculative costs, such as a "social cost" of carbon, in these analyses, as doing so would inherently bias the results in favor of whatever unmade policy decision was attempting to be advanced through the inclusion of the supposed cost.

Q. HOW DOES THE RIM TEST TAKE INTO ACCOUNT A REVENUE REDUCTION EXPECTED TO RESULT FROM A DSO PROGRAM?

A. The RIM test includes any such revenue loss as a cost. In contrast, the TRC ignores the effect of lost revenue.

Q. WHY IS IT APPROPRIATE TO INCLUDE LOST REVENUE AS A COST?

A. Alabama Power's rates are cost-based. Thus, even when a demand-side program results in less energy use by participating customers, the utility's fixed costs largely remain unchanged and must still be recovered from customers. Hence the upward pressure on rates corresponding to the lost revenues is appropriately included in the RIM test as a cost.

Q. HOW DOES A DEMAND-SIDE PROGRAM PASS THE RIM TEST?

A. The RIM test incorporates both the NPV of costs and the NPV of benefits of a program over its useful life from the perspective of existing ratepayers. In order for a program to pass the RIM test, the NPV of the benefits must exceed the NPV of the costs. When this occurs, the program will put downward pressure on rates and is thus good for all ratepayers. The costs calculated in a RIM test include lost revenues and program cost. Benefits include avoided fuel, generation, transmission, and distribution cost as a result of doing the program.

Q. IS MR. DETSKY'S ASSERTION THAT ALABAMA POWER FAILS TO APPLY THE RIM TEST TO SUPPLY-SIDE OPTIONS CORRECT?

A. No. Alabama Power applies the RIM test to the evaluation of supply-side resources required for reliability purposes. It seems Mr. Detsky fails to understand that "downward pressure on rates" does not necessarily mean "rate reduction." A rate reduction is a possible outcome, but downward pressure on rates can also mean that the costs of the resulting portfolio are lower than those associated with alternatives under consideration.

Mr. Howat makes a similar observation when he states that the Company's entire portfolio should be rejected because it will result in an increase in residential customer bills. This runs contrary to other aspects of his testimony. If, as Mr. Howat states, "home energy security" includes "uninterrupted access to necessary service", adopting Mr. Howat's recommendation and rejecting Alabama Power's petition will jeopardize the home energy security of all customers, including low income customers. Without the required resources to meet customer demand, all customers are at risk of having electricity service interruptions during peak periods, which typically occur during very cold and very hot periods when electricity demand is high.

Q. MS. WILSON ASSERTS THAT THE LEVELIZED COST OF SAVED ENERGY IS 2.5¢ PER KILOWATT HOUR AND SHOULD BE CONSIDERED THE "FIRST FUEL." DO YOU AGREE?

A. No. The Lawrence Berkeley report on which Ms. Wilson relies for this statement appears to be using non-RIM analyses to create this value, and does not include the cost of lost revenues.[26] Were all costs properly considered, the levelized cost of saved electricity would be significantly higher.

Q. IS THE PROPOSED 200 MW OF DSM AND DER REFLECTED IN THE PORTFOLIO ACHIEVABLE?

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[26] *See* Ex. RW-3.

A. I believe it is achievable over the timeframe of the 2019 IRP.

Q. WHAT FORM DO YOU EXPECT THOSE PROGRAMS TO TAKE?

A. At this time, I am not entirely sure. As discussed above, Alabama Power is exploring the expansion of some of its existing DSO programs, which have been quite successful. Moreover, the Company is piloting new DSO and DER programs to gain additional insight into their feasibility. As I explain in my Direct Testimony, however, all of these programs will have to satisfy appropriate metrics, in particular the RIM test.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Rebuttal Testimony for John B. Kelley

Reb. Ex. JBK-2

RATE SCHEDULE NO. 138

SOUTHERN COMPANY SYSTEM
INTERCOMPANY INTERCHANGE CONTRACT

BETWEEN

ALABAMA POWER COMPANY,
GEORGIA OWER COMPANY,
GULF POWER COMPANY,
MISSISSIPPI POWER COMPANY,
SOUTHERN POWER COMPANY,
AND
SOUTHERN COMPANY SERVICES, INC.

Dated May 1, 2007

SOUTHERN COMPANY SYSTEM INTERCOMPANY INTERCHANGE CONTRACT

ARTICLE I - RECITALS

Section 1.1: This contract is made and entered into this 1st day of May, 2007, by and between Alabama Power Company, a corporation organized and existing under the laws of the State of Alabama with its principal office in Birmingham, Alabama; Georgia Power Company, a corporation organized and existing under the laws of the State of Georgia with its principal office in Atlanta, Georgia; Gulf Power Company, a corporation organized and existing under the laws of the State of Florida with its principal office in Pensacola, Florida; Mississippi Power Company, a corporation organized and existing under the laws of the State of Mississippi with its principal office in Gulfport, Mississippi; and Southern Power Company, a corporation organized and existing under the laws of the State of Delaware with its principal office in Birmingham, Alabama, all such companies being hereinafter collectively referred to as the "OPERATING COMPANIES"; and Southern Company Services, Inc., a subsidiary service company ("AGENT" or "SCS").

W I T N E S S E T H:

Section 1.2: WHEREAS, the common stock of the OPERATING COMPANIES is owned by The Southern Company, a public utility holding company; and

Section 1.3: WHEREAS, the OPERATING COMPANIES can be operated as an integrated electric utility system; and

Section 1.4: WHEREAS, the OPERATING COMPANIES have so operated their respective electric generating facilities and conducted their system operations (generally referred to as the "Pool") pursuant to and in accordance with the provisions of an interchange contract among themselves, the most recent of which being The Southern Company System Intercompany Interchange Contract dated February 17, 2000, as modified effective July 1, 2006 to reflect an intra-corporate reorganization ("the 2000 Contract"); and

Section 1.5: WHEREAS, the OPERATING COMPANIES desire to replace the 2000 Contract with an amended and restated contract; and

Section 1.6: WHEREAS, all of the OPERATING COMPANIES will continue to share in all of the benefits and burdens of this IIC, including complying with operating, dispatch and reserve requirements, participating in opportunity sales transactions, and bearing responsibility for their portion of purchases.

Section 1.7: NOW, THEREFORE, in consideration of the foregoing and the mutual covenants and agreements hereinafter stated, the OPERATING COMPANIES agree and contract as follows:

ARTICLE II - TERM OF CONTRACT

Section 2.1: This contract will be referred to as the Southern Company System Intercompany Interchange Contract ("IIC"). The IIC shall become effective as provided in Section 2.2 hereof, and shall continue in effect from year to year thereafter subject to termination as provided hereinafter. When this IIC has become effective, it shall supersede and replace the 2000 Contract, and references to a section of such superseded intercompany interchange contract in other agreements of the OPERATING COMPANIES shall be taken to mean reference to the section of substantially like import in this IIC.

Section 2.2: This IIC was submitted as part of a filing in compliance with the orders of Federal Energy Regulatory Commission ("Commission" or "FERC") in Southern Company Services, Inc., Docket Nos. EL05-102, et al., 117 FERC ¶ 61,021 (2006) and Southern Company Services, Inc., Docket Nos. EL05-102, et al., 119 FERC ¶ 61,065 (2007). Pursuant to the Commission's acceptance of such compliance filing, this IIC is effective as of May 1, 2007.

Section 2.3: This IIC may be terminated at any time by mutual agreement of the OPERATING COMPANIES or may be terminated at any time by any OPERATING COMPANY by its giving to each of the other OPERATING COMPANIES and the AGENT written notice of its election to so terminate its participation in this IIC at least five (5) years prior to the date of termination. This IIC shall continue in full force and effect as to each OPERATING COMPANY until terminated as hereinabove provided.

ARTICLE III - PRINCIPAL OBJECTIVES OF INTERCOMPANY INTERCHANGE CONTRACT

Section 3.1: The purpose of this IIC is to provide the contractual basis for the continued operation of the electric facilities of the OPERATING COMPANIES in such a manner as to achieve the maximum possible economies consistent with the highest practicable reliability of service, with the reasonable utilization of natural resources and effect on the environment, and to provide a basis for equitably sharing among the OPERATING COMPANIES the costs associated with the operation of facilities that are used for the mutual benefit of all the OPERATING COMPANIES.

Section 3.2: It is recognized that reliability of service and economy of operation require that the energy supply to the system be controlled by means of centralized economic dispatch and that this will require adequate communication facilities and the provision of economic dispatch computer facilities and automatic controls of generation.

Section 3.3: It is recognized that the IIC provides for the retention of lowest cost energy resources by each OPERATING COMPANY for its own customers. Energy in excess of that necessary to meet each OPERATING COMPANY's requirements is delivered to the Pool as Interchange Energy and may include: (i) energy generated from plants other than conventional hydro or nuclear; and (ii) purchased energy.

Section 3.4: It is recognized that, under this IIC, each OPERATING COMPANY will share in the benefits and pay its share of the costs of coordinated operations as agreed upon in accordance with the terms hereof. All costs and revenues associated with wholesale transactions under this IIC will be shared among all OPERATING COMPANIES on a comparable basis through the application of the governing procedures and methodologies to all such OPERATING COMPANIES.

Section 3.5: It is recognized by the OPERATING COMPANIES that coordinated electric operation contemplates minimum cost of power supply upon the interconnected system, consistent with service requirements and other operating limitations. Benefits of integrated operation accruing to the respective OPERATING COMPANIES are predicated upon cooperative efforts toward this objective and are so reflected in all IIC determinations.

Section 3.6: This IIC is applicable only to the transactions described herein, as specifically set forth in ARTICLE VII – INTERCHANGE CAPACITY TRANSACTIONS BETWEEN THE OPERATING COMPANIES, ARTICLE VIII – INTERCHANGE ENERGY TRANSACTIONS BETWEEN THE OPERATING COMPANIES, and ARTICLE IX – PROVISION FOR OTHER INTERCHANGE TRANSACTIONS. Otherwise, sales between the OPERATING COMPANIES (including, but not limited to, sales from Southern Power Company to the other OPERATING COMPANIES or sales from the other OPERATING COMPANIES to Southern Power Company) require an appropriate filing under Section 205 of the Federal Power Act and acceptance thereof by the Commission.

ARTICLE IV - ESTABLISHMENT OF OPERATING COMMITTEE AND DESIGNATION OF AGENT

Section 4.1 – Establishment of Operating Committee: A designated representative from each of the OPERATING COMPANIES, together with a designated representative of the AGENT who shall act as chairman, shall form and constitute an Operating Committee to meet as needed to determine the methods of operation hereunder.

Section 4.2 – Duties of Operating Committee: The Operating Committee's areas of responsibility include such matters as developing the concepts, terms and conditions of this IIC; providing guidance and direction to the AGENT regarding economic power system operations and the costs associated therewith; reviewing and recommending generation expansion plans for approval by the respective OPERATING COMPANIES pursuant to Section 4.3; and addressing other power system matters that relate to the overall coordinated operation of the Southern electric system. Each OPERATING COMPANY representative has one vote and all decisions must be unanimous.

Section 4.3 – Review and Recommendation of Generation Expansion Plans: The Southern Power Company representative on the Operating Committee will not participate in reviewing and recommending generation expansion plans of the other OPERATING COMPANIES or the system, nor will the Southern Power Company representative have access to materials developed in conjunction with the formulation of such generation expansion plans. Notwithstanding Section 4.2 above, the Southern Power Company representative shall not be eligible to vote with respect to these expansion plans. Moreover, Southern Power Company will not receive market information from the other OPERATING COMPANIES through its participation in the Operating Committee.

Section 4.4 – Transmission Information: The Operating Committee does not have any duties or responsibilities with respect to transmission-related activities (including transmission reliability) and, consistent with the Standards of Conduct, will not receive non-public transmission information. The IIC (including Operating Committee membership) is not to serve as a means whereby non-public transmission information is shared in a manner contrary to the Commission's Standards of Conduct. Further, Southern Power Company is to be treated as an Energy Affiliate under the Commission's Standards of Conduct and therefore cannot receive any non-public transmission information.

Section 4.5 – Operating Committee Discretion: Certain provisions of the Manual afford a degree of latitude to the Operating Committee with regard to decisions that it is authorized to make thereunder. When such discretion is exercised, the AGENT will summarize the decision in an informational filing to be submitted to the Commission within ten (10) business days.

Section 4.6 – Designation of AGENT: SCS, as a party to this IIC, is designated as AGENT of the OPERATING COMPANIES for purposes of this IIC. In addition, SCS may serve as AGENT and represent the OPERATING COMPANIES, or any of them, in all things to be done in the execution of and operation under existing contracts with nonaffiliated utilities or entities (hereinafter referred to as "OTHERS"), or contracts supplemental thereto.

Section 4.7 – Duties of AGENT: The AGENT is responsible for all administrative and coordination functions in order to effectuate the terms and conditions of this IIC. From time to time, the OPERATING COMPANIES, or any of them, may also have contracts with OTHERS that provide for the purchase and/or sale of capacity and/or energy by the OPERATING COMPANIES. The AGENT will make the payments associated with purchases under these contracts and under any other contracts or arrangements under which it acts as agent for the OPERATING COMPANIES. Each OPERATING COMPANY will reimburse the AGENT for its portion of such total payments in accordance with the arrangement in effect with respect to the particular contract. Similarly, the AGENT will collect the payments due for sales under these contracts (and under any other contracts or arrangements under which it acts as agent) and will distribute such payments among the OPERATING COMPANIES in accordance with the arrangement in effect with respect to the particular contract.

Section 4.8 – Term of Agency: The provisions of this IIC providing for authority for the AGENT to act on behalf of the OPERATING COMPANIES, or any of them, shall be deemed to refer, insofar as applicable, to all contracts under which the AGENT acts as agent for the

OPERATING COMPANIES and, notwithstanding anything to the contrary in ARTICLE II hereof, this IIC shall continue in effect insofar as it pertains to other contracts under which the AGENT acts as agent for the OPERATING COMPANIES during the life of any such contracts. The OPERATING COMPANIES may, however, designate a new agent to act hereunder by giving thirty (30) days written notice thereof to the AGENT, whereupon such new agent shall be the AGENT hereunder.

ARTICLE V - OPERATION AND MAINTENANCE OF ELECTRIC GENERATING FACILITIES

Section 5.1: The OPERATING COMPANIES agree to maintain their respective electric generating facilities in good operating condition and to operate such facilities in coordination with those of the other OPERATING COMPANIES as an integrated electric system in accordance with determinations made from time to time by the Operating Committee in order that an adequate power supply shall be available to meet the requirements of the customers of the respective parties hereto at the lowest cost consistent with a high degree of service reliability.

Section 5.2: With respect to its participation in this IIC, Southern Power Company may have access to information regarding the operation of its own plants or other generation resources (such as those acquired by contract) that it has committed to the Pool (“Pool resources”), but it may not otherwise have access to information regarding the operation of Pool resources of the other OPERATING COMPANIES.

ARTICLE VI - INCORPORATION OF THE ALLOCATION METHODOLOGY AND PERIODIC RATE COMPUTATION MANUAL

Section 6.1 – Incorporation of Manual: The mechanics and methods for determining the charges for reserve sharing capacity and for energy purchased and sold between the OPERATING COMPANIES, the monthly capability requirement determinations, and the monthly billings and payments between the OPERATING COMPANIES are described in detail in the Allocation Methodology and Periodic Rate Computation Manual ("Manual") attached hereto and incorporated herein by reference. The Manual also supplies more detailed explanation of provisions of this IIC and is necessary to effectuate its intent.

Section 6.2 – Purpose of Manual: The Manual contains a description of the methodology and procedure used to calculate the charges provided for in this IIC. The OPERATING COMPANIES recognize that the costs underlying these charges will change during the term of this IIC for reasons such as changes in loads, investment and expenses, as well as the addition of electric generating resources. Thus, in order for the OPERATING COMPANIES to share equitably in the costs associated with this IIC, it will be necessary to revise or update, on a periodic basis, the cost, expense, load and investment figures utilized in the derivation of the charges hereunder. The Manual will serve as a formula rate allowing for periodic revision of the charges to reflect changes in the underlying cost components.

Section 6.3 – Revision of Charges and Regulatory Filings: The Manual provides that charges derived by application of the formula rate will be shown on Informational Schedules. Since the charges under this IIC will be computed in accordance with the formula rate method and procedures established in the Manual, these submissions will not be initial rates or changes in rates that would require a filing and suspension under the Federal Power Act and the applicable

Rules and Regulations of the Commission. On or before November 1 of each year, the Informational Schedules will be submitted to the Commission for informational purposes to show the application of the formula rate and the resulting charges. Work papers will also be included showing a detailed application of the formula rate contained in the Manual.

Section 6.4 – Revision of Manual: If the Operating Committee determines that revisions to the formula rate are appropriate or necessary, it will direct the AGENT to file the revised Manual with the Commission in order to obtain timely approval or acceptance thereof.

ARTICLE VII - INTERCHANGE CAPACITY TRANSACTIONS BETWEEN THE OPERATING COMPANIES

Section 7.1 – Provision for Sharing of Temporary Surpluses or Deficits of Capacity Between Operating Companies: It is a fundamental premise of this IIC that each OPERATING COMPANY is expected to have adequate resources to reliably serve its own obligations. Nevertheless, the OPERATING COMPANIES recognize that in any given year one or more of them may have a temporary surplus or deficit of capacity as a result of coordinated planning or by virtue of load uncertainty, unit availability, and other such circumstances. It is among the purposes of this IIC to share among the OPERATING COMPANIES the benefits and burdens of their coordinated system operations, including the cost associated with such capacity ("Reserve Sharing"). Reserve Sharing among the OPERATING COMPANIES is accomplished pursuant to transactions (referred to as "purchases" and "sales") effectuated on a monthly basis in accordance with ARTICLES IV and V of the Manual.

Section 7.2 – Charge for Monthly Reserve Sharing Among the OPERATING COMPANIES: The OPERATING COMPANIES recognize that capacity reserves in the Pool are predominantly made up of peaking plant or equivalent purchased resources. Accordingly, the monthly charge for Reserve Sharing among the OPERATING COMPANIES will be based on the most recently acquired peaking plant resource that is available for year-round operation and scheduling. Each OPERATING COMPANY's monthly charge for reserve capacity sold to the Pool is developed in accordance with the formula rate set out in ARTICLE V of the Manual. The monthly capacity charge for each OPERATING COMPANY, as developed in accordance with such formula rate, will be shown on Informational Schedules. Each selling OPERATING COMPANY will sell at its charge shown on such Informational Schedules and the buying OPERATING COMPANIES will purchase at the weighted average charge of the sellers.

ARTICLE VIII - INTERCHANGE ENERGY TRANSACTIONS BETWEEN THE OPERATING COMPANIES

Section 8.1 – Provision for Interchange Energy: Coordinated system operation, utilizing principles of centralized integrated system economic dispatch, results in energy transfers among the OPERATING COMPANIES. Such energy transfers are accounted for on an hourly basis and are referred to as "Interchange Energy." The methodology for determining the amount of Interchange Energy supplied to or purchased from the Pool is set out in ARTICLE II of the Manual. Interchange Energy is composed of the following two categories: (i) Associated Interchange Energy (energy purchased or sold to serve an OPERATING COMPANY's obligations other than those related to opportunity sales); and (ii) Opportunity Interchange Energy (energy purchased or sold to meet an OPERATING COMPANY's responsibility for opportunity sales).

Section 8.2 – Charge for Interchange Energy: The charge for Interchange Energy sales by an OPERATING COMPANY during any hour will be based on the variable costs of the generating resources that are considered as having supplied the Interchange Energy. The methodology for determining the charges for Associated and Opportunity Interchange Energy sales to the Pool during any hour is set out in ARTICLE III of the Manual.

ARTICLE IX - PROVISION FOR OTHER INTERCHANGE TRANSACTIONS

Section 9.1 – Assignable Energy: Assignable Energy is defined as energy derived from internal sources or from OTHERS at a cost that renders it unusable from an economic dispatch perspective. Assignable Energy is assigned to one or more of the OPERATING COMPANIES consistent with the purpose for which it is acquired. Such assignment will be accomplished by first identifying the beneficiary (or beneficiaries) of the Assignable Energy and then determining the appropriate share for each such OPERATING COMPANY. For example, these shares might be based on a Peak Period Load Ratio ("PPLR") in proportion to the PPLRs of other beneficiaries or weighted participation in a bilateral sale. Once assigned, Assignable Energy will not be delivered to the Pool unless it becomes economically usable on the integrated system.

Section 9.2 – Hydroelectric Operation During Periods of Minimum Steam Operations: During certain periods of the year when unusually good flow conditions prevail, certain steam generating units may be taken out of service to increase the utilization of hydro energy. The OPERATING COMPANY having such hydro generation may elect to take a fossil fired generating unit out of service. In the alternative, if another OPERATING COMPANY takes a fossil fired generating unit out of service for the purpose of utilizing such hydro energy, the energy rate between the two OPERATING COMPANIES for that transaction will be the average of the operation and maintenance cost of such hydro energy and the variable cost of the fossil fired generating unit.

Section 9.3 – Tie-Line Frequency Regulation by Hydro Capacity: Tie-line load control and frequency regulation by hydro involves additional costs because of increased expenditures associated with such regulation. The charge for these transactions is computed in accordance with the formula rate contained in ARTICLE VI of the Manual.

Section 9.4 – Pool Transactions with OTHERS: Capacity and energy transactions with OTHERS that are entered into on behalf of the Pool will be governed by the following principles:

Section 9.4.1 – Pool Purchases of Capacity and Energy: The AGENT may periodically purchase capacity and energy from OTHERS for the benefit of the integrated system. Such Pool purchases will initially be allocated at cost to all OPERATING COMPANIES in proportion to their PPLRs, as provided for in ARTICLE X of this IIC. Purchases so allocated may be sold as Interchange Energy when they are economically usable on the integrated system. Adjustments may thereafter be made in order to reconcile any inequitable effects of this process among the OPERATING COMPANIES, with the intent being that none of the individual OPERATING COMPANIES should be adversely impacted by a purchase that benefits the system as a whole. These impacts will be determined through a system simulation that calculates each OPERATING COMPANY's cost of generation that is avoided by the purchase. This avoided cost will be compared on an hourly basis to the cost of the purchase. To the extent the avoided cost exceeds the purchase cost, the effect is "positive" (i.e., cost savings) for that hour. These hourly results will be summed to determine the effect on each OPERATING COMPANY for the day. In situations where individual OPERATING COMPANIES are adversely impacted by a purchase that benefits the system as a whole, such adverse impacts will be offset through a proportional reduction in the positive net benefits realized by the other OPERATING COMPANIES. In the event the net result for the day is negative, that result is shared among the OPERATING COMPANIES on a PPLR basis.

Section 9.4.2 – Pool Sales of Capacity and Energy: The AGENT may from time to time arrange for the sale to OTHERS of capacity and energy available to the Pool at rates provided for in contracts or at rates mutually agreed upon. The capacity and/or energy obligation for the sale, as well as the associated cost, is allocated to each OPERATING COMPANY on a PPLR basis. Payments by OTHERS are also distributed to the respective OPERATING COMPANIES on the basis of PPLRs.

The Pool has the exclusive right to use generation resources committed to the Pool ("Pool resources") to engage in opportunity transactions with OTHERS that would begin and end during the period from the current hour through Friday (midnight) of the following week. Neither Southern Power Company nor any of the other OPERATING COMPANIES can use Pool resources for its own benefit in those wholesale opportunity markets. To the extent Southern Power Company engages in other transactions solely for its own benefit, it must do so using personnel (staff) separate from the personnel (staff) that conducts similar activities on behalf of the other OPERATING COMPANIES.

ARTICLE X – UTILIZATION OF PEAK-PERIOD LOAD RATIOS

Section 10.1 – Certain Allocations and Payments to be Based on Peak-Period Load Ratios: The AGENT is responsible for the annual development of Peak-Period Load Ratios ("PPLRs") for each of the OPERATING COMPANIES. These PPLRs will be utilized for allocation of certain costs, payments, receipts and other obligations, as provided for in this IIC or the Manual. The procedure and methodology for developing the PPLRs are set out in ARTICLE I of the Manual and the resulting PPLR values are shown on an Informational Schedule.

ARTICLE XI - TRANSMISSION SERVICE

Section 11.1 – Applicability of Network Integration Transmission Service: Network Integration Transmission Service ("Network Service") provides for the integration, economic dispatch and regulation of current and planned Network Resources to serve Network Load. Since the OPERATING COMPANIES integrate, economically dispatch and regulate their generating resources to serve their bundled and grandfathered native load ("Native Load") pursuant to this IIC, the associated use of the transmission system is in the nature of Network Service. Except for provisions related to rates and charges, the transmission service provided to these Native Load customers is comparable to Network Service under the Open Access Transmission Tariff ("OATT"). Since the OPERATING COMPANIES' Native Load is specifically included in the determination of the load used to derive the charge for Network Service under the OATT, the OPERATING COMPANIES are bearing a cost responsibility for transactions hereunder comparable to that assigned to other Network Customers.

Section 11.2 – Transmission Service for Other Transactions: All transmission service provided to any or all of the OPERATING COMPANIES (other than service to their Native Load, as described in Section 11.1) is subject to the OATT in all respects, including adherence to the same rates, terms and conditions applicable to other market participants. Any such transmission service will be obtained pursuant to the OATT and/or from other transmission providers.

Southern Power Company specifically commits to take all of its transmission service under the OATT of Southern Companies or from other transmission providers.

ARTICLE XII - BILLING AND PAYMENT

Section 12.1 – Recording and Billing of Energy Transactions: Each OPERATING COMPANY will transmit to the AGENT such data and other information for each hour of the year as is necessary to develop accounting and monthly billing for the various energy transactions specified under this IIC. The AGENT is responsible for assembling all of the data and information and for preparing intercompany energy billing for each month in accordance with the provisions of this IIC. The bills shall contain such details as required to permit review and verification by the OPERATING COMPANIES.

Section 12.2 – Month-End Adjustment of Daily Energy Determinations: It is recognized that the sum of the daily totals of receipts and deliveries (which are based on instantaneous integrated meters) will not exactly equal corresponding amounts determined at month-end (which are based on accumulating meters). Such differences in energy receipts and deliveries are billed or credited to each OPERATING COMPANY at the average cost of Associated Interchange Energy to the Pool for the month.

Section 12.3 – Billing for Reserve Sharing Transactions: The AGENT is responsible for preparing a monthly bill to the OPERATING COMPANIES for all capacity transactions related to Reserve Sharing, as contemplated by this IIC. The bill shall contain such details as required to permit review and verification by the OPERATING COMPANIES.

Section 12.4 – Billing and Payment Date: The AGENT renders all bills provided for in this IIC not later than the 10th day of the billing month. All payments by the OPERATING COMPANIES are made by the 20th day of the billing month.

Section 12.5 – Billing Corrections: If the AGENT discovers missing or erroneous data of a material nature pertaining to prior billings, a correction adjustment applicable to those billings will be based on the period affected by such missing or erroneous data, but not to exceed forty-five (45) days from the date of such discovery ("correction period"). If the correction period is forty-five days, then the period actually used for the calculation will extend to the beginning of the billing month in which the forty-five day period falls. Interest does not accrue on any such adjustment. The resulting billing correction will be applied as soon as practicable to the regular monthly bill.

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IN WITNESS WHEREOF, the parties hereto have caused this instrument to be signed by their duly authorized representatives on the Operating Committee, which signatures may be set forth on separate counterpart pages.

ALABAMA POWER COMPANY

By: ______________________________

Its ________________________

MISSISSIPPI POWER COMPANY

By: ____________________________________

Its ______________________________

GEORGIA POWER COMPANY

By: ______________________________

Its ________________________

SOUTHERN POWER COMPANY

By: ____________________________________

Its ______________________________

GULF POWER COMPANY

By: ____________________________________

Its ______________________________

SOUTHERN COMPANY SERVICES, INC.

By: ____________________________________

Its ______________________________

ALLOCATION METHODOLOGY AND PERIODIC RATE COMPUTATION PROCEDURE MANUAL

Section 0.0 – Description and Purpose of Manual: This Manual is provided for in the Southern Company System Intercompany Interchange Contract ("IIC") entered into the 1st day of May, 2007, and contains a formula description of the methodology and procedure used to calculate the charges under the IIC. The Manual is divided into six (6) basic articles as follows:

ARTICLE I	-	Methodology for Determination of Peak-Period Load Ratios
ARTICLE II	-	Methodology for Determination of Amount of Interchange Energy Sold To and Purchased From the Pool
ARTICLE III	-	Rates for Interchange Energy
ARTICLE IV	-	Methodology for Determination of Monthly Amount of Reserve Sharing Capacity To Be Sold To or Purchased From the Pool
ARTICLE V	-	Rate for Monthly Reserve Sharing Capacity for Each Operating Company
ARTICLE VI	-	Rate for Tie-Line Load Control and Frequency Regulation by Hydro Facilities

ARTICLE I

METHODOLOGY FOR DETERMINATION OF PEAK-PERIOD LOAD RATIOS

Section 1.1 – Provision for Peak-Period Load Ratios: This article of the Manual establishes and provides for the annual derivation of Peak-Period Load Ratios ("PPLRs") that are utilized in energy and capacity transactions and in other allocations as provided for in the IIC. These ratios are shown on Informational Schedule No. 1.

Section 1.2 – Methodology for Determining Peak-Period Load Ratios: The Contract Year in the IIC is defined as January 1st through December 31st. The peak period is defined as the fourteen (14) hours between 7:00 a.m. and 9:00 p.m. (Prevailing Central Time) of each weekday, excluding holidays.

The Peak-Period Load Ratios for the Contract Year are based upon the prior year's actual peak period energy in the months of June, July, and August for each OPERATING COMPANY. The system peak period energy is equal to the sum of all the OPERATING COMPANIES' peak period energy, excluding: (i) opportunity transactions with OTHERS that would begin and end during the period from the current hour through Friday (midnight) of the following week; and (ii) any energy sales transactions that are settled on a financial basis.

The Peak-Period Load Ratios are determined by dividing each OPERATING COMPANY's summation of the June, July, and August actual weekday peak-period energy by the total system June, July, and August actual weekday peak-period energy.

ARTICLE II

METHODOLOGY FOR DETERMINATION OF AMOUNT OF INTERCHANGE ENERGY SOLD TO AND PURCHASED FROM THE POOL

Section 2.1 – Methodology for Determination of Amounts of Interchange Energy: Interchange Energy is composed of the following two categories: (i) Associated Interchange Energy (energy purchased or sold to serve an OPERATING COMPANY's obligations other than those related to opportunity sales); and (ii) Opportunity Interchange Energy (energy purchased or sold to meet an OPERATING COMPANY's responsibility for opportunity sales).

Section 2.1.1 – Determination of Associated Interchange Energy: The amount of Associated Interchange Energy purchased or sold is computed hourly on the basis of the following:

1. Net receipts and deliveries, which is the total of energy delivered by each OPERATING COMPANY to all other OPERATING COMPANIES and to OTHERS, less the total of energy received by each OPERATING COMPANY from all other OPERATING COMPANIES and from OTHERS;

2. Adjustments for schedules of the OPERATING COMPANIES and OTHERS, for energy movements received from or delivered to sources within or outside the territory of the OPERATING COMPANIES and settled for under arrangements made for such energy movements;

3. Adjustments for Opportunity Interchange Energy, as determined pursuant to Section 2.1.2 below; and

4. Adjustments to account for: (i) the effects of remote generation to which an OPERATING COMPANY is entitled and remote load for which an OPERATING COMPANY is responsible; and (ii) hydro energy losses due to tie-line frequency regulation.

Section 2.1.2 – Determination of Opportunity Interchange Energy: The amount of Opportunity Interchange Energy purchased or sold is computed hourly for each opportunity sale in order to account for the difference between an OPERATING COMPANY's responsibility for an opportunity sale and the amount of energy actually generated by that OPERATING COMPANY in connection with such sale.

ARTICLE III
RATES FOR INTERCHANGE ENERGY

Section 3.1 – Procedure for Economic Dispatch: Centralized economic dispatch is accomplished by dispatching system generating resources and purchases to meet the obligations of the OPERATING COMPANIES and to supply energy for sales to OTHERS. System generating resources are dispatched based on marginal replacement fuel cost, variable operation and maintenance expenses, in-plant fuel handling costs, emission allowance replacement costs, compensation for transmission losses, and other such energy related costs that would otherwise not have been incurred. A purchase is recognized in economic dispatch on the basis of its energy cost. The above-referenced cost components are collectively referred to as the "variable dispatch cost."

Section 3.2 – Associated Interchange Energy Rate: The Associated Interchange Energy Rate, as determined for each hour, is based on the variable dispatch cost of the incremental resource(s) that serve the collective obligations of the OPERATING COMPANIES. For each hour, an OPERATING COMPANY supplying Associated Interchange Energy to the Pool will receive a payment determined by multiplying the applicable Associated Interchange Energy Rate by the quantity of kilowatt-hours sold to the Pool. For each hour, an OPERATING COMPANY purchasing Associated Interchange Energy from the Pool will be charged an amount determined by multiplying the Associated Interchange Energy Rate by the quantity of kilowatt-hours purchased from the Pool.

Section 3.3 – Opportunity Interchange Energy Rate: The Opportunity Interchange Energy Rate, as determined for each hour, is based on the variable dispatch cost of the resources that supplied such energy in connection with a given opportunity sale. This rate will be applied to each OPERATING COMPANY's energy obligation for that transaction to derive the payment due from such OPERATING COMPANY. The resulting payments will then be used to reimburse the cost of the OPERATING COMPANIES that supplied the Opportunity Interchange Energy.

Section 3.3.1 – Opportunity Interchange Energy Rates Related to Certain Contracts and Other Obligations of the Operating Companies: The OPERATING COMPANIES are currently obligated to supply various types of energy under certain contracts with Florida Power & Light Company, Jacksonville Electric Authority, Florida Power Corporation, and South Mississippi Electric Power Association. For purposes of these contracts, the variable dispatch cost of resources supplying the energy shall be the same as described in Section 3.1 of the Manual, except that blended replacement fuel cost will be used instead of marginal replacement fuel cost.

Section 3.4 – Variable Operation and Maintenance Expenses For Fossil Fired Units: The variable Operation and Maintenance expenses for fossil fired units for the Contract Year are derived by summing the following budgeted/forecasted components for each unit: (i) all operating material, non-labor, and on-site contract labor charged to FERC Accounts 502 and 505 (Fossil Steam); and (ii) all maintenance material, non-labor, and contract labor charged to FERC Accounts 512 and 513 (Fossil Steam), and 553 (Combustion Turbine). These budgeted expense estimates may be levelized over the major maintenance cycle of a particular unit or set of units. The estimated expenses are divided by the estimated net energy output of each unit to convert the values to dollars per megawatt-hour. The variable Operation and Maintenance expense for each fossil fired unit is shown on Informational Schedule No. 2 for the Contract Year.

Section 3.4.1 – In-Plant Fuel Handling Costs for Fossil Fired Units: In-Plant fuel handling costs for each fossil fired unit for the Contract Year are based on the budgeted/forecasted expenditures for in-plant fuel handling expenses charged to FERC Account 501. These budgeted expense estimates may be levelized over the major maintenance cycle of a particular unit or set of units. The estimated expenses are divided by the estimated net energy output of each unit to convert the values to dollars per megawatt-hour. The in-plant fuel handling cost for each fossil fired unit is shown on Informational Schedule No. 2 for the Contract Year.

Section 3.5 – Blended Replacement Fuel Cost: Blended replacement fuel costs are determined monthly by the AGENT and are defined as the weighted average cost, escalated for the current dispatch period, of fuel receipts for the previous month (both long-term contract and spot market receipts) and the projected fuel receipts for the current month.

Section 3.6 – Marginal Replacement Fuel Cost: Marginal replacement fuel costs for coal are determined at least monthly by the AGENT and reflect the current market price for additional coal needed at a generating facility at the time of such need. For natural gas or oil-fired units, the marginal replacement fuel costs are updated each business day based upon next day market prices.

Section 3.7 – Emission Allowance Replacement Costs: The replacement costs of emission allowances are determined at least monthly by the AGENT and reflect the current market value of such allowances.

Section 3.8 – Revisions in Methodologies: The procedures described in Sections 3.6 and 3.7 will be periodically reviewed by the AGENT and may be revised upon the approval of the Operating Committee.

ARTICLE IV

METHODOLOGY FOR DETERMINATION OF MONTHLY AMOUNT OF RESERVE SHARING CAPACITY TO BE SOLD TO OR PURCHASED FROM THE POOL

Section 4.1 – Formula for Determination of Monthly Reserve Sharing Capacity Sales/Purchases: The monthly capacity sale to or purchase from the Pool for each OPERATING COMPANY for reserve sharing purposes is determined from the following formula:

CS or CP = RS - R

Where:

CS or CP = Capacity sales to the Pool (CS) or capacity purchases from the Pool (CP) by an OPERATING COMPANY for reserve sharing purposes. A negative value indicates a sale to the Pool and a positive value indicates a purchase from the Pool.

RS = Reserve responsibility for each OPERATING COMPANY (See Section 4.1.1).

R = Reserve capacity for each OPERATING COMPANY (See Section 4.1.2).

Section 4.1.1 – Reserve Responsibility (RS): The responsibility for the reserve capacity on the integrated electric system is allocated among the OPERATING COMPANIES on the basis of peak hour load ratios for each month.

RS = L/L' x R

Where:

RS = Reserve responsibility for each OPERATING COMPANY.

L	=	Monthly peak hour load responsibility of each OPERATING COMPANY (See Section 4.3).
L'	=	Monthly peak hour load of the integrated electric system (See Section 4.3).
R	=	Sum of the reserve capacity for all of the OPERATING COMPANIES.

Section 4.1.2 – Reserve Capacity (R): The reserve capacity for each of the respective OPERATING COMPANIES is determined monthly by the following formula:

R = C - CR

Where:

C	=	Total capacity available to the OPERATING COMPANY (See Section 4.2).
CR	=	Total capacity required to meet reliably the OPERATING COMPANY's load responsibility.

The capacity required to meet the OPERATING COMPANY's load responsibility is determined by the following formula:

CR = LC + LCR

Where:

LC	=	Portion of the total capacity required to meet reliably the OPERATING COMPANY's load responsibility that is available for load service ("available portion").
LCR	=	Portion of the capacity required to meet reliably the OPERATING COMPANY's load responsibility that is unavailable for load service for any reason (including forced outage, partial outage or maintenance outage) during the ten (10) highest system peak hours during each month averaged over the most recent three-year period ("unavailable portion"). These unavailable portions of capacity are determined by identifying unavailability specific to each individual OPERATING COMPANY by each generation type. Individual OPERATING COMPANY unavailability factors for each type of

generating capacity will be applied to their respective owned resources in determining their unavailable capacity associated with load service.

The available portion of the total capacity is determined from the following formula:

LC = RPS + DSO + Cha + Cna + Coa

Where:

RPS = Reserved contract purchases from and sales to OTHERS.

DSO = Demand side option equivalent capacity.

Cha = Total conventional hydro capacity less the unavailable portion of conventional hydro capacity.

Cna = Total nuclear capacity less the unavailable portion of nuclear capacity.

Coa = Total available pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity required to meet the remaining portion of the OPERATING COMPANY's load responsibility, calculated as: L - RPS - DSO - Cha - Cna.

The unavailable portion of the total capacity is determined from the following formula:

LCR = Chu + Cnu + (Coa/(1 - (Cou/Cot)) - Coa)

Where:

Chu = Unavailable portion of conventional hydro capacity.

Cnu = Unavailable portion of nuclear capacity.

Cou = Total unavailable pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity.

Cot = Total pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity.

Section 4.2 – Determination of Capacity Available to Each OPERATING COMPANY (C): The capacity available to each OPERATING COMPANY is determined monthly as the sum of available owned, leased, purchased or otherwise available generating units, reserved contract purchases from and sales to OTHERS, and seasonal or other power exchanges, all as established by the Operating Committee as part of the coordinated planning process. The capacity available is determined from the following formula:

$$C = Cc + Cn + Cog + Ccc + Cp + Cct + Ch + Cpsh + DSO + RPS + PRC$$

Where:

Cc	=	Coal capacity.
Cn	=	Nuclear capacity.
Cog	=	Oil and gas steam capacity.
Ccc	=	Combined cycle capacity
Cp	=	Peak Load capacity.
Cct	=	Combustion turbine capacity.
Ch	=	Conventional hydro capacity.
Cpsh	=	Pumped storage hydro capacity.
DSO	=	Demand side option equivalent capacity.
RPS	=	Reserved contract purchases from and sales to OTHERS.
PRC	=	Purchased resource capacity.

The components of the above formula shall be computed as detailed below. The capability demonstrated in accordance with such procedures shall be used in establishing the following year's capacity values. Where seasonal references are made, the seasons shall be defined as follows: Summer (June through September); Fall (October through November); Winter (December through February); and Spring (March through May).

Section 4.2.1 – Certified Rating: The production officer at each OPERATING COMPANY will certify the full load capability of each coal electric generating unit (excluding units from which Unit Power Sales and other similar bulk power sales are made), oil and gas steam electric generating unit, combined cycle unit, and combustion turbine unit. Southern Nuclear Operating Company will certify the capability of each nuclear steam electric generating unit. These certified ratings ("Full Load" ratings) shall represent the full load capability expected to be available continuously on a daily basis, under normal operating conditions, with all units at a given plant operating concurrently. Where appropriate, certified ratings shall be adjusted to reflect cogeneration and seasonal impacts. The production officer at each OPERATING COMPANY will also certify the peak load capability of generating units demonstrating such capability ("Peak Load" capability). The Peak Load capability shall represent the additional amount of generation obtained for a limited period of time by operating all units at a given plant concurrently and under conditions such as, but not limited to, overpressure, valves wide open and top feedwater heaters out of service. These unit ratings will be included in the informational filing submitted in accordance with ARTICLE VI of the IIC.

Section 4.2.2 – Coal (Cc)and Nuclear (Cn) Capacity: The Full Load rating of each coal and nuclear steam electric generating unit shall be based on the unit's capability during hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings.

Section 4.2.3 – Oil and Gas Steam Capacity (Cog): The Full Load rating of each oil and gas steam electric generating unit shall be based on the unit's demonstrated capability during hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings.

Section 4.2.4 – Combined Cycle Capacity (Ccc): The Full Load rating of combined cycle generating units shall be based on the unit's demonstrated capability during hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings. During the other months, an adjustment will be made to the Full Load rating to reflect the unit's capability at expected ambient temperatures for such non-summer period.

Section 4.2.5 – Combustion Turbine Capacity (Cct): The Full Load rating of combustion turbine units is based on the demonstrated output of such unit and the manufacturer's base design curve rating. Combustion turbine units shall demonstrate daily sustained capability during the months of June through August, adjusted for any temporary identifiable deratings. During the fall, winter and spring, adjustments will be made to the Full Load rating to reflect the unit's capability at expected seasonal ambient temperatures.

Section 4.2.6 – Peak Load Capacity (Cp): The Peak Load capacity of demonstrating generating units shall be the additional amount of generation obtained by operating all units at a given plant concurrently and under conditions such as, but not limited to, overpressure, valves wide open and top feedwater heaters out of service. The Peak Load capacity shall be based on such unit's demonstrated capability during hours when the unit demonstrates peak load capability during the months of June through August, adjusted for temporary identifiable deratings.

Section 4.2.7 – Conventional (Ch) and Pumped Storage (Cpsh) Hydro Capacity: For purposes of the IIC, hydro capability is the average simulated generation during eight (8) consecutive hours occurring on five (5) consecutive weekdays using the average water inflows from historical data. The simulation process utilizes maximum (full) gate setting and best (most efficient) gate setting to determine the capability of the hydro facilities. The capability for the months June-August is the summer maximum gate simulated rating. For the months December-May, the capability is the winter maximum gate simulated rating. The capability of the months September-November is the summer best gate simulated rating. To the extent that an OPERATING COMPANY can demonstrate that a hydro facility can actually achieve the maximum gate rating during the fall months, the capability of such hydro facility will be the maximum gate rating.

<u>Section 4.2.8 – Active Demand Side Options – Equivalent Capacity (DSO)</u>: The equivalent capacity of each active demand side option for each month of the calendar year is determined from the following formula:

DSO = [(Cv x ICE) / (1 -(%TL/100))] x A

Where:

DSO = Demand side option equivalent capacity.

Cv = Contracted value.

ICE = Incremental capacity equivalent factor.

%TL = Six (6) percent incremental transmission losses.

A = Availability Factor.

The Incremental Capacity Equivalent Factor is a measure of the effect of a demand side option on generating system reliability. The Availability Factor is a measure of the probability of an active demand side option being available at the time it is needed.

Section 4.2.9 – Reserved Contract Purchases and Sales (RPS): Reserved contract purchases and sales for any month include all contracted capacity purchases from and sales to OTHERS for which there are underlying reserves.

Section 4.2.10 – Purchased Resource Capacity (PRC): Purchased resource capacity includes all purchased capacity for which an underlying generating resource is identified and may represent any type of capacity (e.g., combined cycle).

Section 4.3 – Determination of Peak Hour Load Responsibility of Each OPERATING COMPANY (L): The monthly peak hour load responsibility of each OPERATING COMPANY is determined by the following formula:

L = L' x La/100

Where:

L' = Monthly ten (10) highest hour average load of the integrated electric system.

La = Monthly average percent contribution of each OPERATING COMPANY's ten (10) highest hour average loads to the sum of those loads for all OPERATING COMPANIES for the most recent three-year period.

Section 4.4 – Recognition of Resource Additions or Deletions: For additions or deletions of capacity resources for the coming year, an adjustment will be made in the capability resources of the appropriate OPERATING COMPANY based upon the actual date of the addition or deletion (e.g., commercial operation, retirement, purchase, or sale); provided, however, that the adjustment will not be made in a month earlier than that originally established by the Operating Committee pursuant to the coordinated planning process. If the actual date is on or before the 15th day of the month, the capacity adjustment begins in that month. If the actual date is beyond the 15th day of the month, the capacity adjustment begins in the following month.

Section 4.5 – Capacity Outside of the Coordinated Planning Process: If an OPERATING COMPANY has capacity that was not established by the Operating Committee as part of the coordinated planning process, such capacity will not be included as capacity available to the OPERATING COMPANY (pursuant to Section 4.2 of this Manual) for reserve sharing purposes ("unrecognized capacity"). Notwithstanding the foregoing, if an OPERATING COMPANY's monthly capacity/load ratio, as determined by comparing its available capacity (pursuant to Section 4.2 of this Manual) with its load responsibility (pursuant to Section 4.3 of this Manual), is less than the comparable ratio for the aggregate system (excluding the load responsibility and available capacity of the subject OPERATING COMPANY), then unrecognized capacity (up to an amount that will make these ratios comparable) will be designated as capacity available to that OPERATING COMPANY for that month.

ARTICLE V

RATE FOR MONTHLY RESERVE SHARING CAPACITY FOR EACH OPERATING COMPANY

Section 5.1 – Provision for Monthly Capacity Rate for Reserve Sharing: This article of the Manual establishes the formula rate for deriving the monthly reserve sharing capacity charge for each OPERATING COMPANY based on its most recently installed peaking facilities (or equivalent purchased resources) available for year-round operation or scheduling. OPERATING COMPANIES that have not installed or purchased such facilities or resources within the last five (5) years will utilize the weighted average rate of all the OPERATING COMPANIES that have installed or purchased such facilities or resources. In the event none of the OPERATING COMPANIES have installed or purchased such facilities or resources within the last five (5) years, the rate of the last facility or resource installed or purchased by any of them will be utilized for all OPERATING COMPANIES. The monthly reserve sharing capacity charges are utilized in the determination of payments to the Pool by the OPERATING COMPANIES purchasing capacity during the month and receipts from the Pool by the OPERATING COMPANIES selling capacity during the month. Each OPERATING COMPANY that sells reserve sharing capacity to the Pool will receive a payment based on the product of the amount of net capacity sales (CS) times that OPERATING COMPANY's monthly capacity rate. Each deficit OPERATING COMPANY will make payments to the Pool based on the product of the amount of net reserve sharing capacity purchased (CP) times the weighted average cost of such capacity sold to the Pool during the month. The monthly reserve sharing capacity rate of each OPERATING COMPANY for each month of the Contract Year is shown on Informational Schedule No. 3. Such rates will be revised in accordance with this Manual and the IIC in subsequent contract years.

Section 5.2 – Derivation of Monthly Capacity Costs of Each OPERATING COMPANY: The derivation of the monthly capacity costs of each OPERATING COMPANY, as used for purposes of the reserve sharing capacity rate, is based on one of the following: (i) the capacity cost of the most recently added peaking facility; (ii) the capacity cost of the most recent equivalent purchased resource; or (iii) the weighted system average of the capacity costs of the most recently added peaking facilities or equivalent purchased resources.

The monthly reserve sharing capacity rate of each OPERATING COMPANY for an installed peaking facility under subpart (i) will be determined by the following formula:

R1 = (I x LFCC/100/C1) x MCWF

Where:

R1 = Monthly charges for peaking

facility ($/kW-Month).

I	=	Gross investment in peaking facility ($).
LFCC	=	16.3%, levelized fixed capacity charge.
C1	=	Peaking facility's rated production capability (kW), as determined by Section 4.2 of this Manual.
MCWF	=	Monthly Capacity Worth Factor for the applicable month.

The AGENT may periodically re-evaluate the monthly capacity worth factors based upon evaluations of system reliability. The governing MCWFs will be included in the Informational Schedules submitted in accordance with ARTICLE VI of the IIC.

For purposes of subpart (ii), the monthly reserve sharing capacity rate of each OPERATING COMPANY for an equivalent purchased resource will be the annual capacity rate ($/kW-Year) paid for such resource, multiplied by the applicable MCWF.

For purposes of subpart (iii), the monthly reserve sharing capacity rate will be the weighted system average of the costs of the most recently added peaking facilities (as determined for purposes of subpart (i)) or equivalent purchased resources (as determined for purposes of subpart (ii)), multiplied by the applicable MCWF.

<u>Section 5.3 – Monthly Reserve Sharing Capacity Rate To Be Adjusted For Production Resource Change</u>: If a peaking facility or an equivalent purchased resource of an OPERATING COMPANY is placed in commercial operation or available for scheduling by the 15th day of the month established by the Operating Committee as part of the coordinated planning process, the budgeted investment cost or annual capacity rate will be used in the determination of the monthly reserve sharing capacity rate for such OPERATING COMPANY for that and

subsequent months of the calendar year. If the facility or resource is not placed in commercial operation or available for scheduling by the 15th day of such month, the cost basis established under Section 5.2, as used to derive the monthly reserve sharing capacity rate for the previous month, will remain in effect until the month in which the facility or resource is in commercial operation or available for scheduling on or before the 15th day.

ARTICLE VI

RATE FOR TIE-LINE LOAD CONTROL AND FREQUENCY REGULATION BY HYDRO FACILITIES

Section 6.1 – Provision for Hydro Regulation Energy Losses: Because of energy losses from hydro regulation, the OPERATING COMPANIES supplying this service are deprived of hydro energy. To distribute equitably this loss of energy among the OPERATING COMPANIES in accordance with size of loads regulated and to compensate the OPERATING COMPANIES for regulating services rendered, adjustments in billing determinations are necessary. Hydro energy losses actually incurred by regulating OPERATING COMPANIES during each day are replaced by the Pool at zero cost, and the AGENT allocates such energy losses to all OPERATING COMPANIES in accordance with Peak-Period Load Ratios. Energy lost during high-flow periods is replaced during the period in which such losses occur, and energy lost from poorer efficiencies during normal and low-flow periods is replaced during the 14-hour peak period since hydro energy so lost could have been retained in storage and generated during this period.

Section 6.2 – Provision for Increases in Cost Due to Hydro Regulation: Payments are made to hydro regulating OPERATING COMPANIES for each hour of such regulation for the increase in operating and maintenance expenditures for governor mechanisms and water turbine parts, and these expenses are allocated to all OPERATING COMPANIES in accordance with Peak-

Period Load Ratios. Such payments are calculated using actual expenses incurred through the last calendar year available, adjusted to current-year dollars, for the cost of labor, engineering and supervision, and materials and supplies in the following FERC Accounts: 544-10, Generator and Exciters; 544-20, Hydraulic Turbines and Settings; 544-40, Governors and Control Apparatus; and 544-50, Powerhouse Remote Control Equipment. The basis for hourly payments is the difference in the average hourly costs for regulating plants and non-regulating plants, expressed in the following formula:

Hourly Charge	=	[MCW - (MCWO/HWO) x MCWH]/HOR
Where:		
MCW	=	Summation of costs for regulating plants.
MCWO	=	Summation of costs for non-regulating plants.
HWO	=	Summation of hours for non-regulating plants.
MCWH	=	Summation of hours for regulating plants.
HOR	=	Summation of hours in the regulating mode for regulating plants.

The regulating OPERATING COMPANIES shall supply the AGENT an hourly statement of energy losses incurred in providing hydro regulating services. Such statement should include sufficient detail to permit review and verification by the AGENT.

Section 6.3 – Regulation by Pumped Storage Hydro Projects: It is understood that pumped storage hydro projects owned by the OPERATING COMPANIES may also be used for regulation of the integrated electric system. In such event, the hourly charge for such regulation will be the same charge derived under the formula contained in Section 6.2 hereof.

Section 6.4 – Provision for Increases in Cost Due to Hydro Scheduling: Because the use of hydro resources for tie-line load control and frequency regulation does not allow the hydro energy to be scheduled in the most cost effective manner, less economic gains are achieved than would have been if the hydro energy had been used to displace only the highest cost other energy sources. The difference in actual displacement costs represents the value of the lost economic opportunity by the owning OPERATING COMPANY by such use of hydro energy, or the costs of providing higher cost energy. The AGENT shall allocate such costs to all the OPERATING COMPANIES in accordance with Peak-Period Load Ratios.

[END OF MANUAL]

APPENDIX A to the SOUTHERN COMPANY SYSTEM INTERCOMPANY INTERCHANGE CONTRACT

This Appendix A ("Appendix A") to the Southern Company System Intercompany Interchange Contract ("IIC") is made and entered into as of January 1, 2019, by and between ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, GULF POWER COMPANY, MISSISSIPPI POWER COMPANY, SOUTHERN POWER COMPANY and SOUTHERN COMPANY SERVICES, INC., being an amendment to provide for GULF POWER COMPANY's orderly withdrawal from the IIC.

Article I – Recitals

Section 1.1: WHEREAS, ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, GULF POWER COMPANY, MISSISSIPPI POWER COMPANY and SOUTHERN POWER COMPANY have for many years operated as an integrated electric utility system and have conducted their respective electric generating facilities and system operations (generally referred to as the "Pool") pursuant to and in accordance with the provisions of this IIC, as most recently amended effective May 1, 2007; and

Section 1.2: WHEREAS, 700 Universe, LLC, a wholly owned subsidiary of NextEra Energy, Inc., will acquire from The Southern Company all of the common stock of GULF POWER COMPANY ("Transaction"); and

Section 1.3: WHEREAS, as a result of the Transaction, GULF POWER COMPANY will no longer be a subsidiary of The Southern Company or an affiliate of ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, MISSISSIPPI POWER COMPANY and SOUTHERN POWER COMPANY (hereinafter the "SOUTHERN OPERATING COMPANIES") after the closing of the Transaction; and

Section 1.4: WHEREAS, by separate agreement, this Agreement will be filed with the Federal Energy Regulatory Commission pursuant to Federal Power Act section 205 with a request for an effective date that is the date of the closing of the Transaction ("Effective Date"); and

Section 1.5: WHEREAS, concurrently with the closing of the Transaction, GULF POWER COMPANY will submit a notice to terminate its participation under this IIC in accordance with Section 2.3 of the IIC ("Termination Notice") and desires to withdraw from the IIC in an orderly manner; and

Section 1.6: WHEREAS, the SOUTHERN OPERATING COMPANIES wish to continue to operate under this IIC and provide for an orderly transition period whereby GULF POWER COMPANY terminates its participation under this IIC without disrupting the provision of reliable and cost-effective service to their customers or to customers in GULF POWER COMPANY's service area, as it currently exists; and

Section 1.7: WHEREAS, GULF POWER COMPANY likewise wishes to provide for an orderly transition period whereby it terminates its participation under this IIC without disrupting the provision of reliable and cost-effective service to customers in its existing service area or to the customers of the SOUTHERN OPERATING COMPANIES; and

Section 1.8: WHEREAS, the principal objectives of the IIC are set forth in Article III of the IIC ; and

Section 1.9: WHEREAS, GULF POWER COMPANY desires to continue its participation in the IIC, subject to the terms and conditions set forth herein and therein, until GULF POWER COMPANY's participation ends in accordance with this Appendix A ("Transition Period"); and

Section 1.10: WHEREAS, consistent with the foregoing, the SOUTHERN OPERATING COMPANIES, SOUTHERN COMPANY SERVICES, INC. (as the "AGENT"), and GULF POWER COMPANY (each referred to individually as a "Party" and collectively as the "Parties") agree to the following provisions that, as part of the IIC, shall govern the ongoing respective rights and responsibilities as between (i) GULF POWER COMPANY and (ii) the SOUTHERN OPERATING COMPANIES and the AGENT, under the IIC during the Transition Period.

Article II – Effective Date, Term and Assignment

Section 2.1: This Appendix A and the associated Transition Period shall become effective concurrent with the closing of the Transaction. If for any reason the Transaction does not close, then this Appendix A shall be void and of no legal effect *ab initio*.

Section 2.2: Absent early termination or limited extension as provided herein, the Transition Period shall end at 11:59 pm (prevailing Central time) on the five-year anniversary of the Termination Notice ("Scheduled Termination Date"). After the Transition Period, GULF POWER COMPANY's participation in this IIC will cease and this Appendix A shall no longer be of any force or effect. During the Transition Period, GULF POWER COMPANY shall have no further rights under Section 2.3 of the IIC.

> Section 2.2.1: The Transition Period is subject to early termination in advance of the Scheduled Termination Date pursuant to Section 2.3 or Section 4.4.3 of this Appendix A.
>
> Section 2.2.2: The Transition Period is subject to extension for a period of no more than two (2) additional years beyond the Scheduled Termination Date if GULF POWER COMPANY determines in its discretion it has not been able to establish its own balancing area, acquire the requisite balancing and related services, or establish electric generation and transmission facilities that enable GULF POWER COMPANY to provide the retail and wholesale customers in its current service area with electric services that are substantially comparable in terms of cost and reliability to those being provided to such

customers through its participation in this IIC. In that event, GULF POWER COMPANY shall provide written notice to the AGENT no later than one hundred eighty (180) days prior to the Scheduled Termination Date. Any such notice shall specify the basis for the extension and the duration of the needed extension of the Transition Period, not to exceed two (2) additional years following the Scheduled Termination Date.

Section 2.3: GULF POWER COMPANY shall have the unilateral right to accelerate the Transition Period and terminate its participation under this IIC, subject to at least one hundred eighty (180) days' written notice.

Section 2.4: GULF POWER COMPANY may not assign its rights, interests or obligations under the IIC or this Appendix A, nor shall such rights, interests or obligations be extended to include obligations or resources of GULF POWER COMPANY resulting from a merger or acquisition involving another load-serving entity.

Article III – Modified Rights and Obligations of the Parties under the IIC

Section 3.1: Except as provided herein, the IIC shall remain in effect for the SOUTHERN OPERATING COMPANIES and GULF POWER COMPANY for the Transition Period, during which, and in accordance with this Appendix A, GULF POWER COMPANY shall be deemed an OPERATING COMPANY so as to effectuate the provisions of the IIC and the orderly termination of GULF POWER COMPANY's participation under this IIC. Except as expressly addressed in this Appendix A, the rights of the SOUTHERN OPERATING COMPANIES or GULF POWER COMPANY as OPERATING COMPANIES under the IIC are not limited or affected.

Section 3.2: For purposes of GULF POWER COMPANY's continued participation in the IIC during the Transition Period, the SOUTHERN OPERATING COMPANIES and the AGENT agree and commit not to treat GULF POWER COMPANY in a manner that is discriminatory (i.e., continue to apply the IIC on a comparable basis to all OPERATING COMPANIES).

Section 3.3: GULF POWER COMPANY shall no longer have a representative on the Operating Committee, but shall designate at least one official GULF POWER COMPANY contact who the AGENT shall inform of any proposed changes to the IIC or the policies, practices or procedures used in its implementation that may have a significant effect on GULF POWER COMPANY and of any other proposed actions of the Operating Committee in accordance with the Operating Committee's duties under the IIC. GULF POWER COMPANY will be given reasonable prior notice of such proposed changes or actions so that it will have an opportunity to ask questions, seek additional information, and provide feedback in advance of any Operating Committee decision or the filing of any such change. The AGENT shall cooperate in good faith to answer any such questions, provide requested additional information and facilitate GULF POWER COMPANY's feedback. Any dispute regarding a proposed action of the Operating Committee (except for a proposed change to the IIC addressed in Section 4.2 of this Appendix A) shall be resolved through the dispute resolution process set forth in Section 4.1 of this Appendix A.

Section 3.4: GULF POWER COMPANY may make reasonable inquiries with the AGENT concerning any aspect of GULF POWER COMPANY's IIC monthly bill to ensure that the billing to GULF POWER COMPANY is accurate and determined in a manner that conforms to the IIC and the policies, practices and procedures used in its implementation, as applied on a comparable basis to all OPERATING COMPANIES. Any dispute in this regard shall be subject to Section 12.5 of the IIC and resolved through the dispute resolution process set forth in Section 4.1 of this Appendix A.

Section 3.5: Audit Rights related to IIC Billings

Section 3.5.1: GULF POWER COMPANY shall have the right to conduct or cause to be conducted, at its own expense, a reasonable audit of the data, records and other pertinent information specifically related to the correctness of IIC billings during the Transition Period. GULF POWER COMPANY’s audit rights are further subject to the following conditions:

(i) Audits may be conducted from time to time, but no more frequently than once in any rolling twelve (12) month period.

(ii) AGENT will be provided at least ten (10) business days’ advance notice of any such audit, which notice shall specify the time period of the audit and describe with reasonable specificity the records, information and data to be reviewed.

(iii) No audit shall be conducted during the first week of any month.

(iv) The audit will be conducted during normal business hours and in such a manner as to minimize disruptions to the AGENT and to the SOUTHERN OPERATING COMPANIES.

(v) The time period covered by the audit may not exceed the twenty-four (24) months immediately preceding the notice and may not include any period already subject to an audit hereunder.

(vi) GULF POWER COMPANY will observe the confidentiality obligations set forth in Section 3.6 to the extent the audit encompasses any information subject to those restrictions.

Section 3.5.2: If an audit reveals, and GULF POWER COMPANY provides the relevant audit report showing, calculation errors that resulted in overcharges or underpayments to GULF POWER COMPANY: (i) GULF POWER COMPANY shall notify the AGENT; (ii) the Parties will negotiate in good faith to reach an agreement with respect to the matter; and (iii) for agreed errors, there will be a correction in accordance with Section 12.5 of the IIC (or the AGENT shall promptly cause GULF POWER COMPANY to be paid the amount of the overcharge or underpayment if there is no invoice on which to include the credit). Appropriate corrections or payments by GULF POWER COMPANY also will be made in the event the audit reveals calculation errors that resulted in undercharges or overpayments to GULF POWER COMPANY in its IIC billing.

Section 3.5.3: Any disputes arising from an audit under this Section 3.5 shall be resolved through the dispute resolution process set forth in Section 4.1 of this Appendix A and Section 12.5 of the IIC. If the arbitration upholds the results of the audit and identifies material errors resulting in overcharges or underpayments, the AGENT shall bear the reasonable costs of the audit. For purposes of this provision, a material error is one in which the effect of the erroneous charge or payment on GULF POWER COMPANY is more than ten (10) percent of the monthly average of the sum of the gross IIC billings to GULF POWER COMPANY, as measured over the ten (10) months preceding discovery.

Section 3.6: Consistent with a fundamental premise of the IIC that each OPERATING COMPANY is expected to have adequate resources to reliably serve its own obligations, GULF POWER COMPANY, through its official contact, shall provide the AGENT, not less than annually, sufficient information (e.g., generation expansion plan) to demonstrate GULF POWER COMPANY's compliance with such expectation for the duration of the Transition Period.

Section 3.7: During the Transition Period, the Parties shall abide by the following information restrictions:

Section 3.7.1: GULF POWER COMPANY may have access to information regarding the operation of its own plants or other generation resources (such as those acquired by contract) that it has committed to the Pool, but it may not have access to confidential or proprietary information of the SOUTHERN OPERATING COMPANIES, including information regarding the operation of Pool resources of the SOUTHERN OPERATING COMPANIES, except as expressly provided in Section 3.7.2.

Section 3.7.2: For confidential or proprietary information of the SOUTHERN OPERATING COMPANIES that is already in GULF POWER COMPANY's possession or for which access is unintended or unavoidable (e.g., Energy Management System ("EMS") information), GULF POWER COMPANY will not, directly or indirectly, share (and will take steps to prevent any sharing of) such information with anyone including, but not limited to, wholesale marketing function employees of GULF POWER COMPANY, any of its affiliates, and SOUTHERN POWER COMPANY.

Section 3.7.3: Information provided to the AGENT in accordance with Section 3.6 of this Appendix A: (i) may be shared with SCS personnel responsible for reviewing and aggregating the individual generation expansion plans of all Pool participants in order to present the aggregate generation expansion plan to the Operating Committee for its review and recommendation pursuant to IIC Section 3.6; (ii) may not be shared more broadly with other employees of the SOUTHERN OPERATING COMPANIES without the prior consent of GULF POWER COMPANY; and (iii) may not be shared with any wholesale marketing function employees of either SCS or the SOUTHERN OPERATING COMPANIES. In accordance with Section 5.2 of the IIC, SOUTHERN POWER COMPANY will continue to have no access to information regarding the operation of Pool resources of the other OPERATING COMPANIES, including GULF POWER COMPANY.

Section 3.8: During the Transition Period, SCS (or any replacement AGENT designated by the SOUTHERN OPERATING COMPANIES) shall continue to serve as AGENT for GULF POWER COMPANY for purposes of its participation in this IIC.

Section 3.9: For permissible longer-term wholesale transactions (i.e., outside of the period defined in Section 9.4.2 of the IIC), GULF POWER COMPANY must use its own personnel (staff) separate from the personnel (staff) that conducts similar activities on behalf of the SOUTHERN OPERATING COMPANIES.

Section 3.10: In lieu of IIC Article XI, the transmission service necessary to effectuate GULF POWER COMPANY's continued participation in this IIC during the Transition Period shall be provided in accordance with Commission-approved transmission arrangements for ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, and MISSISSIPPI POWER COMPANY and for GULF POWER COMPANY, as described in the Transmission Service Coordination Agreement.

Article IV – Enforcement and Remedies

Section 4.1: GULF POWER COMPANY's exclusive rights and remedies associated with its continued participation in the IIC involve: (i) challenges to Operating Committee decisions or actions or proposed actions (as described in Section 3.3, specifically excluding decisions to file an amendment to the IIC, as addressed in Section 4.2) on grounds that the challenged action is inconsistent with the principle objectives of the IIC as set forth in Article III thereof; (ii) claims that the AGENT is not applying the IIC (including underlying policies, practices or procedures used in its implementation) on a comparable basis to all OPERATING COMPANIES (as described in Sections 3.2 and 3.4); (iii) claims that the AGENT is not properly billing under the IIC; and (iv) claims that the SOUTHERN OPERATING COMPANIES are in material breach of their obligations under the IIC. With respect to any such matters, the following dispute resolution procedures shall govern:

Section 4.1.1: GULF POWER COMPANY must first discuss any questions, concerns or objections ("Issue") with the AGENT. In connection with such discussions, the AGENT must be afforded a reasonable amount of time to understand and investigate the Issue, including any needed data collection. Unless otherwise agreed, this initial step with the AGENT shall not extend beyond thirty (30) days to address the Issue.

Section 4.1.2: If the Issue is not addressed by the AGENT to GULF POWER COMPANY's satisfaction within thirty (30) days, then GULF POWER COMPANY shall provide written notice to the AGENT describing the Issue and why the AGENT's response has been deemed unsatisfactory by GULF POWER COMPANY. Within ten (10) days after the delivery of the notice, a senior official of the SOUTHERN OPERATING COMPANIES and of GULF POWER COMPANY, each with authority to negotiate and resolve the Issue, shall meet, either in person or by telephonic conference, in an effort to resolve the Issue through mutual agreement. A representative of the AGENT may participate in this meeting. If the Issue has not been resolved within ten (10) days after the meeting of senior officials, then GULF POWER COMPANY may invoke arbitration in accordance with Section 4.1.3.

Section 4.1.3: In the event resolution is not obtained pursuant to Section 4.1.2, the Parties agree that the dispute shall be resolved through binding arbitration. The Parties will cooperate in the arbitration process (including scheduling) so that the Issue will be resolved as quickly as practicable, with due regard for its nature and complexity. Except as provided herein or otherwise agreed by the Parties, the arbitration shall be administered by the American Arbitration Association in accordance with its Commercial Arbitration Rules.

(i) The arbitration panel shall comprise three (3) members, with each Party selecting one member and the two members so named selecting the third member.

(ii) All members must have at least fifteen (15) years of experience in the areas of electric energy and power system operations.

(iii) All members must be neutral, act impartially, and be free from any conflict of interest (financial or otherwise, with no prior or present business or personal relationship with the Parties).

(iv) After selection, the members shall have no ex-parte communications with either Party.

(v) The arbitration and all related information shall be private and confidential, with no disclosure except as required by law or by agreement of the Parties.

(vi) The arbitration shall be held in Orlando, Florida.

(vii) The Party invoking arbitration bears the burden of proof.

(viii) Each Party shall bear its own internal costs (e.g., employees, attorneys and consultants), but the losing Party shall also be responsible for costs otherwise associated with the arbitration process.

Section 4.2: In the event GULF POWER COMPANY, having been informed of a proposed change to the IIC in accordance with Section 3.3, remains opposed to such proposed change, its opposition shall not be the subject of dispute resolution under Section 4.1 and shall not prohibit the AGENT from filing for FERC acceptance of the proposed change. However, in response to that filing, GULF POWER COMPANY may raise its objections with FERC and shall not be prejudiced by the fact that SCS is otherwise its AGENT for purposes of the IIC. Conversely, the AGENT and the SOUTHERN OPERATING COMPANIES shall not be limited in their ability to support the proposed revision as just and reasonable.

Section 4.3: The Parties expressly acknowledge and agree that GULF POWER COMPANY's sole and exclusive remedy for any Issue raised under Section 4.1 is pursuant to the provisions set forth therein. Notwithstanding the foregoing, and without any prejudice to or waiver thereof, in the event GULF POWER COMPANY attempts to bring a proceeding before the FERC regarding any provision of the IIC (including this Appendix A), or any issues related to application or implementation, and such proceeding is not otherwise dismissed, the standard of review to be applied in any such proceeding shall be the most stringent standard permissible under applicable law, as set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp*., 350 U.S. 332 (1956); *Federal Power Commission v. Sierra Pacific Power Co*., 350 U.S. 348 (1956), as clarified in *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County, Washington*, 554 U.S. 527 (2008), and refined in *NRG Power Marketing v. Maine Public Utilities Commission*, 130 S. Ct. 693, 700 (2010).

Section 4.4: In the event the AGENT, on behalf of the SOUTHERN OPERATING COMPANIES, believes there has been a material breach by GULF POWER COMPANY to comply with its obligations under the IIC or this Appendix A, the following procedures shall apply:

> Section 4.4.1: The AGENT shall notify GULF POWER COMPANY of any concerns regarding potential alleged breaches. GULF POWER COMPANY shall be afforded a reasonable amount of time to understand and investigate the concern and, unless otherwise agreed, shall have up to thirty (30) days to address any such concerns.
>
> Section 4.4.2: If such concerns are not addressed by GULF POWER COMPANY to the AGENT's satisfaction, the AGENT shall so notify GULF POWER COMPANY in writing, describing the alleged breach and why GULF POWER COMPANY'S response has been deemed unsatisfactory by the AGENT. Within ten (10) days after the delivery of the notice, a senior official of the AGENT and of GULF POWER COMPANY, each with authority to negotiate and resolve the concern, shall meet, either in person or by telephonic conference, in an effort to resolve the concern through mutual agreement. If the concern has not been resolved within ten (10) days after the meeting of senior officials, then the AGENT may invoke arbitration in accordance with Section 4.4.3.

Section 4.4.3: In the event the AGENT invokes arbitration, the procedures set forth in Section 4.1.3 shall apply. In the event the arbitration concludes that GULF POWER COMPANY is in material breach, then GULF POWER COMPANY shall have thirty (30) days to cure such failure, which cure must be to the AGENT's reasonable satisfaction. In the event GULF POWER COMPANY elects not to cure, or fails to cure, the AGENT may give one hundred and eighty (180) days' written notice to terminate the Transition Period and GULF POWER COMPANY shall thereafter have no further participation under this IIC.

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IN WITNESS WHEREOF, the Parties hereto have caused this instrument to be signed by their duly authorized representatives, which signatures may be set forth on separate counterpart pages.

GULF POWER COMPANY

By: Michael Smith

Its Gen. Mgr. - Gulf

ALABAMA POWER COMPANY

By:

Its SVP/SPO - WEST

GEORGIA POWER COMPANY

By:

Its SVP & SPO - East

MISSISSIPPI POWER COMPANY

By:

Its SVP/SPO - WEST

SOUTHERN POWER COMPANY

By:

Its SVP/SPO

SOUTHERN COMPANY SERVICES, INC.

By:

Its VP Commercial Operations

[END OF APPENDIX A]

Direct Testimony of Jeffrey B. Weathers

Updated Exhibit JBW-1

PUBLIC VERSION

An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System

January 2019

Southern Company

EXECUTIVE SUMMARY

Electric utility customers expect and depend on high levels of service reliability. As such, a prudent utility must have an economically balanced level of generating capacity that both exceeds the peak load and that also meets a minimum reliability threshold. To have this reserve capacity available when it is needed, a utility must plan beyond the upcoming season because the processes to procure capacity, such as building a new unit or procuring a power purchase agreement ("PPA"), can take several years to complete. The purpose of this Economic and Reliability Study of the Target Reserve Margin ("Reserve Margin Study") for the Southern Company System ("System") is to determine the amount of reserve capacity – or the Target Reserve Margin ("TRM") – that should be maintained on the System. The Reserve Margin Study includes the companies that participate in the Intercompany Interchange Contract ("IIC"). Specifically, the Reserve Margin Study includes Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and the portion of Southern Power Company included in the IIC (collectively, the "Operating Companies"). Although the TRM will be used to establish the long-term expansion plan, the 2018 Reserve Margin Study should not be understood to determine one constant reliability index in perpetuity, but rather should be re-evaluated on a periodic basis as the System evolves over time. The results of long-term, constant reliability constraints can be impacted by projected changes in load shapes, unit costs, unit availability, and other factors. The objective is to determine how these constraints affect the next capacity decision, with subsequent re-evaluations modifying downstream decisions, as appropriate.

Traditionally, the TRM has been stated in terms of summer peak demands and summer capacity ratings according to the following formula:

$$TRM = \frac{TSC - SPL}{SPL} x\ 100\%$$

Where:
TRM = Target Reserve Margin;
TSC = Total Summer Capacity; and
SPL = Summer Peak Load.

This traditional representation is essentially a Summer TRM and has been the only reserve margin considered because the System (in aggregate) has always been and remains summer peaking on a weather-normal basis. However, reserve margins can just as easily be stated in alternate terms. Because of increased reliability risk and different capacity resources during the winter season (see Appendix A), this report introduces and recommends the use of a Winter TRM in addition to the traditional Summer TRM. The Winter TRM is stated and represented by the following formula:

$$Winter\ TRM = \frac{TWC - WPL}{WPL} x\ 100\%$$

Where:
TRM = Target Reserve Margin;
TWC = Total Winter Capacity; and
WPL = Winter Peak Load.

Because winter peak loads are different than summer peak loads (lower for a summer peaking utility) and because winter generating capacity can have different operational characteristics than summer generating capacity, the Winter TRM can be higher than the Summer TRM. For example, the final, approved TRM from the 2015 Reserve Margin Study, which was essentially a Summer TRM, represented an increase in TRM from 15% to 16.25% due primarily to winter reliability issues. If planners had generated a Winter TRM from that study, the resulting reserve margin would have been 26%. ***However, such 26% Winter TRM would have represented both the same cost and the same level of reliability as its 16.25% Summer TRM equivalent*** – despite the appearances of being a "higher" reserve margin.

Reserve Margins are necessary because of uncertainties in operational conditions. The four primary uncertainties causing this need are:

1) **Weather**: The System's "weather-normal" load forecasts are based on average weather conditions over the past 30+ years. If the weather is hotter than normal during warm seasons or colder than normal during cold seasons, the load will be higher. The System's peak demand can be as much as 6.6% higher in a hot summer year and 22.0% higher in a cold winter year

than in an average year.[1] Drought conditions and temperature-related impacts on unit outputs can also significantly affect the System's load and capacity balance.

2) **Economic Growth**: It is difficult to project exactly how many new customers a utility will have or how much power existing customers will use from season to season. Based on historical projections and actual economic growth, peak demand may grow by [redacted] more than expected over a four to five-year period.[2]

3) **Unit Performance**: While the Operating Companies have a tremendous track record in keeping very low forced outage rates for the System, there have been occasions in the last ten years when more than 10% of the capacity of the system has been in a forced outage state concurrently.[3]

4) **Market Availability Risk**: The ability to obtain resources from the market when needed to address a short-term System resource adequacy issue is uncertain. In general, having access to resources in neighboring regions enhances a region's reliability due to load and resource diversity. However, the amount, cost, and deliverability of those resources are subject to the external region's resource-adequacy situation or transmission constraints at any given time. While a region can expect some level of support from its neighbors, each region must carry adequate reserves and manage its own reliability risks. Therefore, there is significant uncertainty regarding the availability of such external support when it is most needed.

While each of these four factors creates a need for capacity reserves on its own, confluence of all these risk factors poses considerable risk. Very high capacity reserves would be required to meet customers' load demands plus operating reserve requirements for all occurrences of such events. However, maintaining such high levels of capacity reserves comes at significant expense and may only eliminate very low probability events. A more appropriate approach to setting the TRM is to minimize the combined expected costs of maintaining reserve capacity, System costs, and customer costs associated with service interruptions, and adjust for the value at risk. A proper evaluation of these costs will result in the Economic Optimum Reserve Margin ("EORM"), properly adjusted for risk. However, that risk-adjusted EORM must also meet minimum reliability criteria thresholds. Common practice in the industry regarding this minimum reliability criteria threshold is to plan for a Loss of Load

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[1] See Figure A.4 in Appendix A.
[2] See Table I.3 in Section I.
[3] See Figure I.6 in Section I.

Expectation ("LOLE") of no greater than 0.1 days per year - or more commonly referred to in the industry as a one event in ten years criterion ("1:10 LOLE").

To understand and quantify the overlap of the four contributing factors to the need for reserve margins, a system dispatch model, Strategic Energy and Risk Valuation Model ("SERVM"), is utilized. SERVM evaluates the ability of the System's capacity resources to meet load obligations every hour in a year for thousands of combinations of weather, load forecast error, and unit performance scenarios. The model quantifies, in dollar cost, two components of reliability-related costs. These components are:

1. Production Costs, including the cost of generation as well as the cost of purchases, and
2. Reliability Costs, including the cost of customer outages (*i.e.,* expected unserved energy ("EUE") cost), emergency purchases, the cost of not meeting operating reserve requirements, and non-firm outage costs (i.e., the cost of calling demand response resources).

The Production Costs and Reliability Costs, determined by the SERVM model, are then compared to the Incremental Capacity Cost of new generation reserves. The analysis is performed on a range of planning reserve margins from 10% - 20%. With lower reserve margin levels, the import costs and Reliability Costs are high and vary widely, but the Incremental Capacity Cost and its associated generation cost are low. At higher reserve margin levels, the import costs and Reliability Costs are low, but the Incremental Capacity Cost and its associated generation cost are high. The objective of this study is to find the reserve margin where the sum of these costs is minimized (i.e. the minimum cost point), which is referred to as the EORM. The "U-curve" in Figure 1 shows the sum of Production Costs, Reliability Costs, and Incremental Capacity Costs across the range of reserve margin levels studied and demonstrates that the EORM occurs at a summer reserve margin of 15.25%. The figure represents the weighted average costs over all the load, weather, and outage draws simulated and is stated in terms of the traditional, summer-oriented reserve margin.[4]

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[4] That is, stated in terms of summer capacity ratings and summer weather-normal peak demand.

REDACTED

Figure 1. Traditional EORM U-Curve

However, Appendix A discusses in detail the winter reliability risks facing the System. To address those risks, the same analysis was performed from the perspective of a winter-oriented reserve margin.[5] The "U-Curve" in Figure 2 below shows the results of this analysis and demonstrates that the Winter EORM is 22.5%. Although the winter EORM appears to be much higher than the summer EORM, this difference is merely a function of how they were stated (*i.e.*, stated in summer terms vs. stated in winter terms as described above). The EORMs represent essentially the same level of cost and reliability and are therefore essentially equivalent.

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Figure 2. Winter EORM U-Curve

Finally, since winter is the driving factor behind the traditional results, thus leading to a need for a Winter TRM, an analysis was performed to determine what a Summer TRM would be assuming several of the key winter drivers were removed. Not all the winter-oriented drivers can be easily removed from the analysis, but Figure 3 below shows a summer-focused U-Curve with incremental cold weather outages and fuel constraints removed. The results of this analysis show that the EORM for the Summer TRM when these key winter drivers are removed is 14%.

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Figure 3. Summer EORM U-Curve

These three U-Curves and their associated analyses serve as the basis for determining a recommendation for the Winter and Summer TRM. Since, as described in Appendix A, winter is the constraining season for reliability on the System, the Winter TRM was considered first.

While the minimum cost of the winter U-Curve falls at 22.5%, the components that were evaluated to develop the U-Curve all have substantially different risk characteristics. The fixed costs of procuring capacity under a long-term PPA or building a new unit are relatively independent of the uncertainties that affect reliability. On the other hand, Production Costs and Reliability Costs can both vary significantly depending on weather, load forecast error, and unit performance.

The trade-off between static Incremental Capacity Costs and highly volatile Production Costs and Reliability Costs is difficult to measure. The expected value of Production Costs and Reliability Costs is the weighted average of all modeled simulations. For many mild weather or slow load growth scenarios, these Production and Reliability costs will be lower than the expected outcome. However, for more extreme cases, these Production and Reliability costs will be higher than the expected outcome, but lower in probability of occurrence. The significantly higher costs from these cases represent risk that should be considered when recommending a TRM because some of that risk may be mitigated at low incremental cost. The approach taken to mitigate the risk of potential high cost outcomes involves using a risk metric called Value at Risk ("VaR"). VaR is defined as the difference in cost at the expected value and at some specified confidence interval (e.g., the 80th percentile of risk). The VaR analysis looks at the incremental increase in expected cost to move from one reserve margin to the next reserve margin and compares that with the incremental decrease in VaR. The point at which the incremental increase in total system cost[6] equals the incremental decrease in VaR represents the EORM at that confidence interval (as opposed to the EORM at the weighted average). This analysis was performed at various confidence intervals ranging from the 80th confidence interval up to the 95th confidence interval using 0.25% reserve margin increments. As an example of the results of this analysis, the 80th confidence interval resulted in an EORM of 26.0%,[7] which represented an increase in expected case system costs from the 22.5% TRM of [redacted], but would reduce VaR (i.e., exposure to higher than expected future outcomes) on the System by [redacted].

This can be demonstrated graphically by developing the U-Curve at the 80th confidence interval instead of the expected cost. Figure 5 below shows that if you draw the U-Curve at the 80th confidence interval, the EORM is 26.0% instead of 22.5%. Therefore, a reserve margin a few percentage points higher than the expected case EORM benefits customers by eliminating many of the more expensive scenarios (thereby reducing the customers' exposure to cost risk) without significantly increasing expected costs. This outcome represents the risk-adjusted EORM at that confidence interval.

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[6] Production Cost plus Reliability Cost plus Incremental Capacity Cost.

[7] Moving from 25.75% to 26.0% resulted in an incremental increase in weighted average costs roughly equal to the incremental decrease in VaR, while moving from 26.0% to 26.25% resulted in an increase in weighted costs that was greater than the decrease in VaR.

REDACTED

Figure 5. 80% Confidence Interval U-Curve (Winter)

Additionally, the Reserve Margin Study contains reliability metrics such as LOLE. Common practice in the industry is to ensure that the TRM for planning purposes remains above an LOLE threshold of 0.1 days per year (or often referred to as a one in ten – 1:10 – year expectation of loss of load). LOLE has always been considered as part of the reserve margin studies; but in previous studies, the 1:10 LOLE threshold was below the EORM. In the 2018 Reserve Margin Study, the 1:10 LOLE threshold occurs above the EORM in both the summer and winter studies. It is not, however, greater than the VaR80 result. Therefore, in the 2018 Reserve Margin Study, the 1:10 LOLE threshold must be given greater consideration in the determination of the TRM than in previous studies. Figure 6 below shows the relationship between LOLE and reserve margin for the winter-focused study. The figure shows that the curve crosses the 1:10 LOLE threshold (i.e., an LOLE of 0.1 days per year) at [redacted] reserve margin. It is important that the TRM be above this 1:10 LOLE threshold to ensure an adequate level of reliability on the System. Otherwise, customers may be exposed to potential outages due to generation shortfalls more frequently than in other regions of the country. Results are similar in the traditional study.

REDACTED

Figure 6. LOLE as a Function of Winter Reserve Margin

The 2018 Reserve Margin Study recommends a long-term Winter TRM of 26% based on the following:

1. The TRM should be greater than the 25.25% 1:10 LOLE threshold to ensure an adequate level of reliability on the System;
2. A reserve margin of 26% represents the risk-adjusted EORM at the 80th confidence interval (the 80th percentile of risk – i.e., VaR80);
3. Compared to the 22.5% expected case EORM, a 26% risk-adjusted EORM reduces VaR at the 80th confidence interval by [redacted] while only increasing expected cost by [redacted];
4. Compared to the 25.25% 1:10 LOLE threshold, a 26% risk-adjusted EORM reduces VaR at the 80th confidence interval by [redacted] while only increasing expected cost by [redacted]; and

5. A 26% Winter TRM is consistent with results from the 2015 Reserve Margin Study,[8] confirming the results of that study.

For the long-term Summer TRM, in addition to consideration of the VaR results, consideration must also be given to the combined summer and winter LOLE. While the Summer-oriented U-Curve indicated an EORM of 14%, the VaR85 calculation resulted in a reserve margin of 16.75%. Therefore, a Summer TRM of up to 16.75% could be justified based on this case. However, LOLE must also be considered. If resources added to the System are available in both the winter and the summer, the LOLE will be in accordance to the curve in Figure 6. However, if the System's winter requirements are met with resources that are not available in summer, then a disconnect between the summer LOLE and the winter LOLE occurs. Therefore, when the combined LOLE for both summer and winter are considered, there is a floor for the Summer TRM that must be maintained to ensure that that the total combined summer and winter LOLE does not fall below the 1:10 LOLE threshold ("Summer TRM Floor"). Figure 7 below shows the 1:10 LOLE threshold Summer TRM Floor for various Winter TRM values.

[8] In the 2015 Reserve Margin Study, "An Economic Study of the System Planning Reserve Margin for the Southern Company System" (January 2016), the winter equivalent of the approved 16.25% TRM would have been 26%.

REDACTED

Figure 7. Summer Target Reserve Margin Floor

[redacted]. Therefore, it is recommended that the current, approved 16.25% TRM (which is already stated in summer terms) remain in place as the Summer TRM.

For short-term planning (inside three years), a sensitivity has been performed which recognizes that there is typically less economic uncertainty in the nearer term (1-3 years out) than in the longer term (4 years out or greater). This sensitivity shows a difference in long-term reserve margin and short-term reserve margin of 0.5% is appropriate.

These recommendations are designed to provide guidance for resource planning decisions but should not be considered absolute targets. As explained throughout this report, various factors may justify decisions that result in reserve margins above or below the targets mentioned above such as the large size of capacity additions, the availability and price of market capacity, or economic changes.

RECOMMENDATIONS:

1. Implement Seasonal Planning with a Summer TRM and Winter TRM
2. Maintain current approved TRM of 16.25% as the Summer TRM
3. Implement a Winter TRM of 26%
4. Apply a short-term reserve margin with a 0.5% differential from the long-term reserve margins

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I. ASSUMPTIONS

The following sections of this report provide detailed discussions related to the input assumptions associated with the 2018 Reserve Margin Study.

A. Reliability Simulation Model

SERVM was used to calculate Production Costs and Reliability Costs for determining the EORM. These calculations were performed across a broad range of uncertainty risks in load forecast error, weather, unit availability, and performance of non-dispatchable, renewable resources.

Operating events are selected from actual operating history to determine generating unit availability. For each hour in every simulation, each unit will either be operating, on reserve shutdown, partially failed, completely failed, or on scheduled maintenance. The total capacity online and available for purchase is calculated and compared to the load to determine the associated EUE. Performing the random unit status draws for 100 iterations for every hour in the dataset results in average or expected case EUE.

SERVM perfectly matches load and generation, which is impossible to do in the real world. In actual practice, load would be curtailed in large blocks and would be off longer than necessary. If this reality could be incorporated into the model, the expected EUE would likely increase and the EORM would increase. As such, the results of the 2018 Reserve Margin Study should be considered conservative.

B. Study Year

[redacted] The representative year selected for this study was 2025.

C. Weather Years

The impact of weather on load was reflected by simulating the System using the 54 historical annual weather patterns from 1962 through 2015. These 54 patterns were then used to develop annual load shapes that would approximate what the load shape would be in the study year (2025) if the weather pattern matched that of one of the historical years. Two annual load shapes were developed for each of the 54 weather patterns. One assumed the first day of the year occurred on a Tuesday; the other assumed the first day of the year occurred on a Saturday. This was done to vary what day of the week extreme weather conditions were assumed to occur, since extreme weather can theoretically fall either on the weekend or on a peak day. These 108 datasets or "weather years" were given equal probability of occurrence.

The weather year load shapes were developed by using a neural net model to establish the relationship between the weather and load. The neural net was calibrated using weather and load data for the years 2010 through 2015 so that more recent customer usage patterns are reflected. The calibrated neural net was then used to construct the 108 weather year load shapes using the 54 historical weather patterns and two start days. The resulting loads are integrated hourly load shapes.

The temperature data used to develop these load shapes reflect the system weighted average temperature of several locations around the System's footprint. Figure I.1 and Figure I.2 show the historical low winter and high summer temperatures experienced for the 54 weather years modeled.

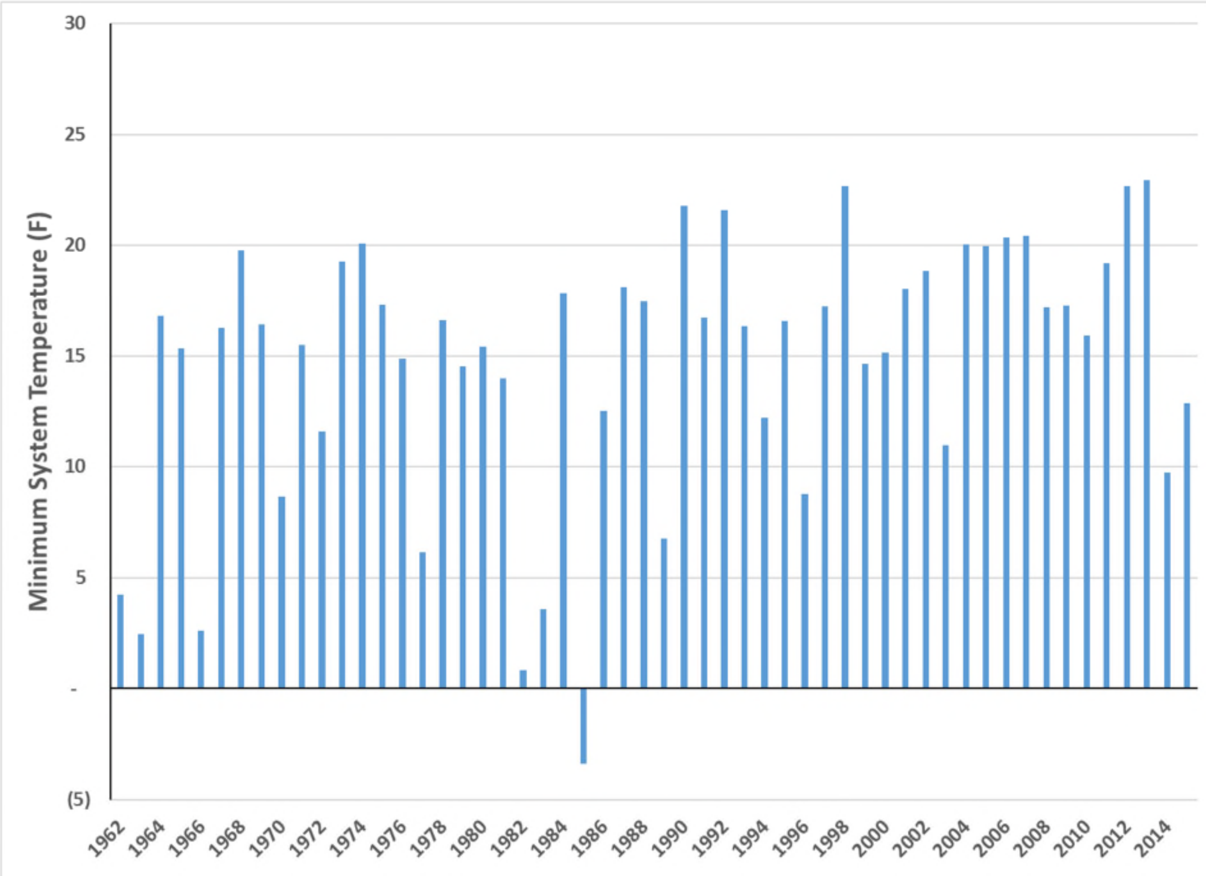

Figure I.1. Historical Low Winter Temperatures

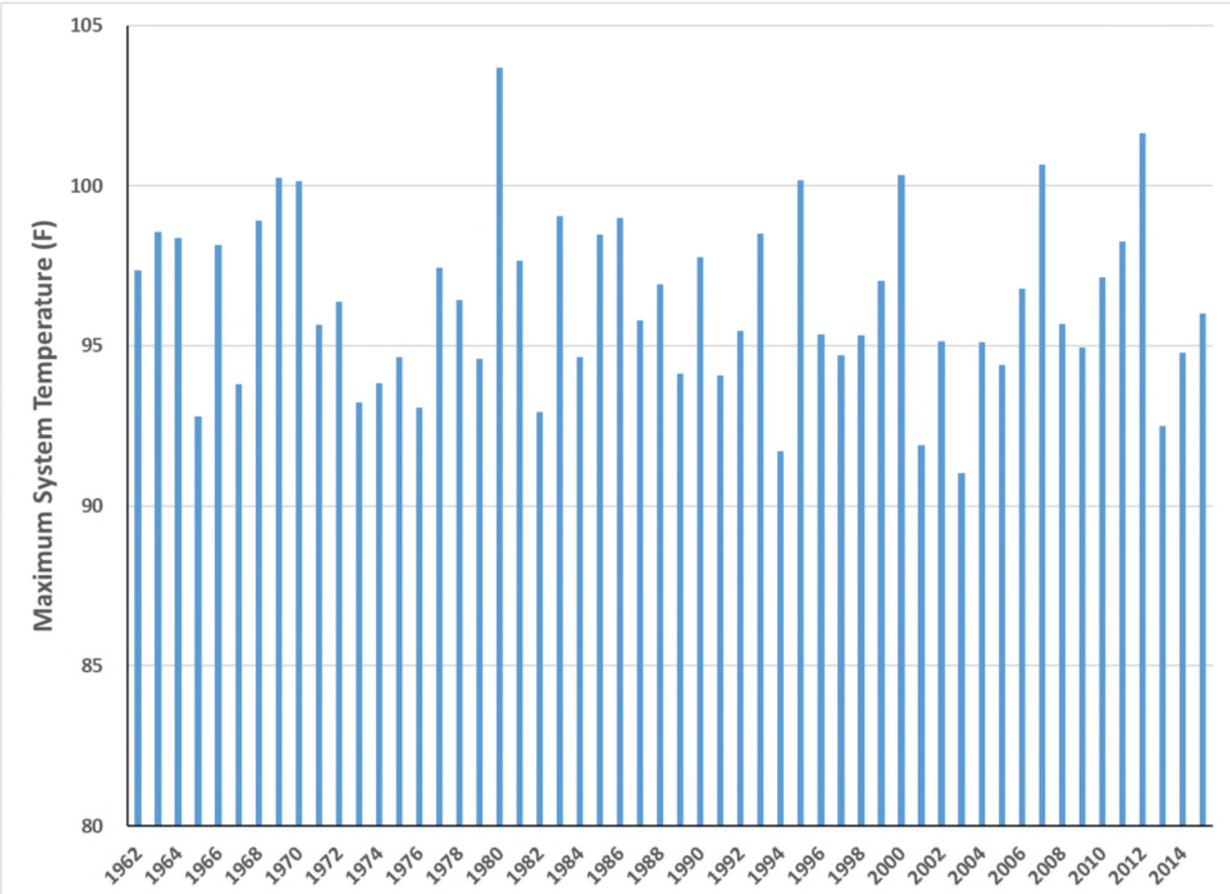

Figure I.2 Historical High Summer Temperatures

D. Market Modeling

The SERVM model allows the System to account for expected support from neighboring regions based on historical load diversity and unit performance diversity. Each weather year modeled uses the actual historical temperature and related load diversity for each region. The System is expected to be able to buy power from neighboring regions that do not typically peak in the same hour as the System if those neighboring regions have economic capacity available to purchase.

Resource adequacy planning requires modelers to build assumptions about the level of support available from neighboring regions. The actual operation of each unit for every neighboring region is modeled in the same way that resources are modeled within the System. Hydro, CTs, base load thermal resources, renewables, and demand response resource ("DRRs") are discretely modeled so that an accurate hourly market price forecast is produced. The CTs that have been modeled as marginal units to the System for purposes of developing the U-Curves are used to avoid purchasing from neighbors at high costs when they are either dispatching high cost resources or in scarcity situations.

The neighboring regions used in the simulation are summarized in Table I.1 (for Summer) and Table I.2 (for Winter) below. The reserve margins modeled in some regions were increased above their published targets to ensure those regions have a reasonable level of reliability (approximately equivalent to the 1:10 LOLE threshold). This is necessary since the regional model used in this analysis does not model a neighboring region's other interconnected regions (*i.e.*, the 2nd tier from the System) to account for the reliability benefit a neighboring region may obtain via purchases from its own neighboring regions. Without the adjustment, the reliability of these regions would be understated and would inappropriately underestimate the System's access to external markets.

Table I.1. Simulation Regions Summary for Summer

Region Name	Summer Reserve Margin Modeled (%)	Peak Load (MW)	Available Transfer Capability into Southern Company Systems (MW)	CBM[9] into Southern Company Systems (MW)
TVA	[redacted]	29425	796	300
Duke Energy Carolina	[redacted]	20433	180	350
SCEG	[redacted]	5736	148	0
Santee Cooper	[redacted]	4288	360	50
FPL	[redacted]	26145	20	100
Duke Energy FL	[redacted]	8796	18	50
JEA	[redacted]	2579	6	100
Power South	[redacted]	2139	300	-
OPC	[redacted]	5962	Unlimited	-
MEAG	[redacted]	2476	Unlimited	-
TAL	[redacted]	632	3	-
MISO	[redacted]	29014	1694	100

[9] Capacity Benefit Margin ("CBM") is a firm import reservation on the transmission system for use during emergencies.

Table I.2. Simulation Regions Summary for Winter

Region Name	Winter Reserve Margin Modeled (%)	Peak Load (MW)	Available Transfer Capability into Southern Company Systems(MW)	CBM into Southern Company Systems (MW)
TVA	[redacted]	30762	809	300
Duke Energy Carolina	[redacted]	21032	230	350
SCEG	[redacted]	5851	169	0
Santee Cooper	[redacted]	4743	416	50
FPL	[redacted]	23293	134	100
Duke Energy FL	[redacted]	10122	123	50
JEA	[redacted]	2782	44	100
Power South	[redacted]	2581	300	-
OPC	[redacted]	5717	Unlimited	-
MEAG	[redacted]	2240	Unlimited	-
TAL	[redacted]	634	18	-
MISO	[redacted]	25577	1688	100

The topology used for the simulations is in Figure I.3.

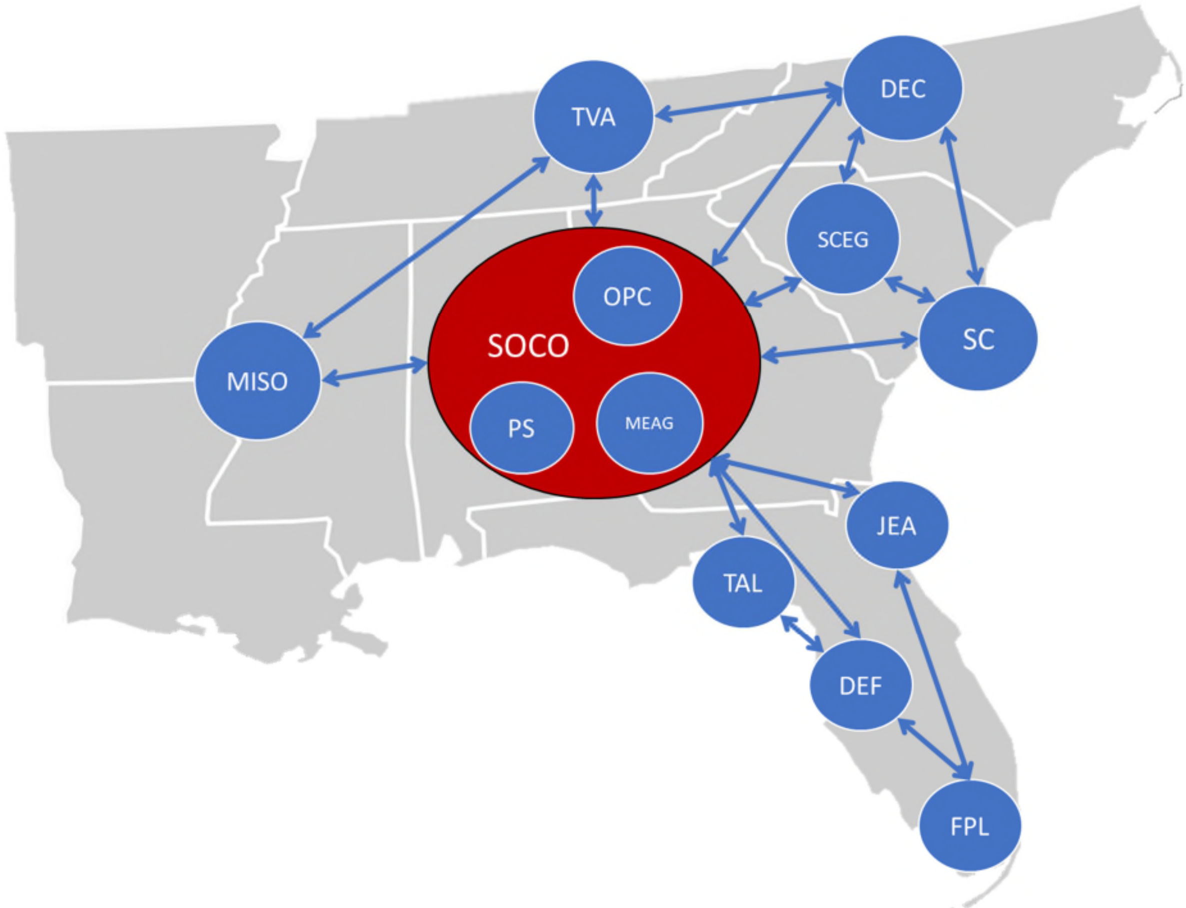

Figure I.3. Simulation Topology

It should be noted that the entirety of the MISO interconnection was not modeled. Rather, only those entities directly interconnected to Southern (Entergy and Cooperative Energy) were modeled. These entities were, however, jointly dispatched as a single entity to reflect operation within the MISO footprint.

Sales and purchase transactions are simulated between regions when the market price in one region is higher than an adjoining region and there is sufficient transfer capability. During extreme scenarios when loads are high, and many units are in a forced outage state, prices can rise substantially higher than the cost of a CT.

Scarcity pricing is the price markets experience when they are short on available capacity and is driven by several complex factors. While the scarcity pricing assumptions used in the Reserve Margin Study have been calibrated to historical scarcity market prices, those relationships may not always hold. During scarcity situations, the System will be subject to the market and, because of the importance of service reliability, is expected to make purchases even at prices well above [redacted] if they are reliably available.

A scarcity pricing curve, developed in conjunction with external consultant "ASTRAPE", used eight years (2010-2017) of historical market purchases to estimate the market purchase cost in scarcity scenarios and is shown in Figure I.4 below. Scarcity prices could rise as high as [redacted] if a region experiences a system emergency and shedding firm load is imminent. Scarcity prices are incremental (in addition to) generation costs.

REDACTED

Figure I.4. Scarcity Pricing Curve

During emergency conditions, the System procures as much energy from the marketplace as possible and utilizes other peaking resources such as interruptible customers, voltage control, and emergency hydro. If the System is still short the necessary capacity to meet load plus operating reserves, CBM is utilized to obtain any additional energy that may be available. The System has CBM reservations on ties with TVA, Duke Energy Carolinas, Entergy, South Carolina Public Service Authority, Florida Power and Light, Duke Energy Florida, and JEA totaling 1,150 MW. This CBM capability was modeled and utilized as needed in the analysis.

Despite the load diversity associated with the regional modeling discussed above, the actual availability of purchases from other entities is not always as available as the SERVM model might indicate. Southern Company's Fleet Operations and Trading ("FOT") organization has advised that under extremely high summer load conditions, the availability of purchases in the marketplace is unlikely to exceed [redacted]. Likewise, under extremely high winter load conditions, the availability of purchases in the marketplace is unlikely to exceed [redacted]. These limitations exist for two reasons. First, during such extreme conditions, other market participants may also be experiencing conditions that approach the limits of their own system. Therefore, even though the model may show some available diversity between the regions, those entities may be unwilling to sell that capacity due to the risks and uncertainty on their own systems. Second, during such extreme conditions, there is often a high likelihood of transmission curtailments and so some capacity that may be available may not be deliverable to the system – even if there is transmission interface capability available. These limitations cannot be precisely modeled within SERVM, but a combination of both limits on sales price and hurdle rates between regions has been implemented as a means of addressing these issues.

Merchant capacity has been present in the southeastern United States for over 15 years, but the sporadic nature of its availability requires planners to be conservative in assumptions about its presence in the future. Merchant capacity may be purchased by other load serving entities in the region, may not have firm transmission, or may not have firm fuel supply. For these reasons, merchant capacity was assumed to be unavailable in the base case simulations.

E. Load Forecast Uncertainty

In addition to variation from normal weather, there remains uncertainty in the peak load projections when looking several years into the future. If load grows more quickly than expected, the reserve margin may not be sufficient unless that growth potential was properly considered in the reserve margin assumptions. Unexpected strength or weakness in the economy is a primary source of this load forecast error ("LFE"). An unforeseen change in electricity utilization and technology (*e.g.* heat pumps, electric transportation, and energy efficiency) can also be a source of LFE.

The LFE assumptions used in the 2018 Reserve Margin Study were updated in the fall of 2017. Load forecast uncertainty [redacted] into the future was estimated using [redacted] of historical data. The System has based its load forecast error assumptions on the [redacted] forecast growth of the economy and the assumption that there [redacted]. For the period [redacted], the forecasts of [redacted] for [redacted] into the future were compared with actual [redacted] to determine 21 economic forecast errors. The economic forecast errors were multiplied by [redacted] to determine 21 load forecast errors ranging from a maximum under-forecast error of [redacted] to a maximum over-forecast error of [redacted]. Each of the 21 LFEs has a [redacted] ([redacted]) chance of occurring. By combining and averaging similar LFEs, the 21 LFE points were converted to six LFE points as shown in the following table. For example, points 2 (LFE = [redacted]), 3 (LFE = [redacted]), and 4 (LFE = [redacted]) were combined and averaged to yield [redacted], and the combined probabilities were summed to achieve a combined probability of [redacted]). This was done to minimize the total number of runtime simulations that would be required while still considering an accurate distribution of LFE possibilities.

Table I.3. Load Forecast Error

	21 LFEs		6 LFEs	
	LFE	**Probability**	**LFE**	**Probability**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		

Using this distribution, the minimum and maximum LFE values used in this study are [redacted] and [redacted] of the expected value, respectively.

F. Generating Unit Capacity Ratings

Unit ratings are traditionally established for both the summer and winter seasons. Summer ratings are generally established to correspond to output under 95ºF ambient temperatures. Table I.4 below shows the summer ratings associated with the nuclear, coal, and gas steam resources on the System. Only resources for which Alabama Power has ownership or contractual rights are specifically named. Other System resources are designated “SOCO Resource” in Table I.4.

Table I.4. Nuclear, Coal, and Gas Steam Unit Ratings

Unit Name	Unit Category	Peak Rating@95F (MW)
BARRY_4	Coal	362
BARRY_5	Coal	738.5
FARLEY_1	Nuclear	874
FARLEY_2	Nuclear	877
GASTON_5	Coal	832
GORGAS_10	Coal	718.7
MILLER_1	Coal	656.24
MILLER_2	Coal	651.74
MILLER_3	Coal	658.83
MILLER_4	Coal	658.83
SOCO RESOURCE	Coal	700

SOCO RESOURCE	Coal	700
SOCO RESOURCE	Coal	876
SOCO RESOURCE	Coal	876
SOCO RESOURCE	Nuclear	438.88
SOCO RESOURCE	Nuclear	442.38
SOCO RESOURCE	Coal	72.24
SOCO RESOURCE	Coal	72.24
SOCO RESOURCE	Coal	860
SOCO RESOURCE	Coal	75
SOCO RESOURCE	Coal	299
SOCO RESOURCE	Coal	475
SOCO RESOURCE	Coal	502
SOCO RESOURCE	Coal	502
SOCO RESOURCE	Coal	128.76
SOCO RESOURCE	Coal	134.55
SOCO RESOURCE	Coal	74.94
SOCO RESOURCE	Coal	74.94
SOCO RESOURCE	Nuclear	79
SOCO RESOURCE	Nuclear	83.47
SOCO RESOURCE	Nuclear	84.12
SOCO RESOURCE	Nuclear	102.89
SOCO RESOURCE	Nuclear	103
SOCO RESOURCE	Nuclear	41.54
SOCO RESOURCE	Nuclear	41.54
SOCO RESOURCE	Nuclear	538.2
SOCO RESOURCE	Nuclear	539.14
SOCO RESOURCE	Nuclear	503.61
SOCO RESOURCE	Nuclear	503.61
SOCO RESOURCE	Coal	459.03
SOCO RESOURCE	Coal	459.03
SOCO RESOURCE	Gas	350.5
SOCO RESOURCE	Gas	348.5

Winter ratings for nuclear and steam units are generally unchanged from the summer ratings. Ratings for CT and CC resources, however, can vary significantly depending upon the ambient temperature.

Official winter ratings for CT and CC resources are established to correspond to output at 40ºF ambient temperatures. Those ratings are shown in Table I.5 and Table I.6 below.

Table I.5. System CT Ratings

SYSTEM CT RATINGS		
Unit Name	**Peak Rating@95F (MW)**	**Peak Rating@40F (MW)**
AMEA_SYLAC_1	47.5	54.6
AMEA_SYLAC_2	47.5	54.6
Calhoun_CT_1	158	181.7
Calhoun_CT_2	158	181.7
Calhoun_CT_3	158	181.7
Calhoun_CT_4	158	181.7
GASTON_A	16	18.4
GREEN_CT_10	85	97.8
GREEN_CT_2	84	96.6
GREEN_CT_3	82	94.3
GREEN_CT_4	81	93.2
GREEN_CT_5	82	94.3
GREEN_CT_6	81	93.2
GREEN_CT_7	80	92
GREEN_CT_8	83	95.5
GREEN_CT_9	82	94.3
SOCO RESOURCE	149	171.4
SOCO RESOURCE	148	170.2
SOCO RESOURCE	14	16.1
SOCO RESOURCE	75.2	86.5
SOCO RESOURCE	74	85.1
SOCO RESOURCE	73.5	84.5
SOCO RESOURCE	74.9	86.1
SOCO RESOURCE	74	85.1
SOCO RESOURCE	157.5	181.1
SOCO RESOURCE	157.5	181.1
SOCO RESOURCE	157.5	181.1

SOCO RESOURCE	157.5	181.1
SOCO RESOURCE	157.5	181.1
SOCO RESOURCE	157.5	181.1
SOCO RESOURCE	36	41.4
SOCO RESOURCE	36	41.4
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	150.9	173.6
SOCO RESOURCE	158.4	182.2
SOCO RESOURCE	149	171.4
SOCO RESOURCE	149	171.4
SOCO RESOURCE	148.9	171.2
SOCO RESOURCE	155	178.3
SOCO RESOURCE	154.6	177.7
SOCO RESOURCE	80	92
SOCO RESOURCE	80	92
SOCO RESOURCE	180	207
SOCO RESOURCE	185	212.8
SOCO RESOURCE	183	210.5
SOCO RESOURCE	183	210.5
SOCO RESOURCE	149	171.4

SOCO RESOURCE	146	167.9
SOCO RESOURCE	74.8	86
SOCO RESOURCE	74.7	85.9
SOCO RESOURCE	74.7	85.9
SOCO RESOURCE	55	63.3
SOCO RESOURCE	40	46
SOCO RESOURCE	15	17.3
SOCO RESOURCE	20.6	23.7
SOCO RESOURCE	19.6	22.5
SOCO RESOURCE	20.3	23.3
SOCO RESOURCE	25.3	29.1
SOCO RESOURCE	25.3	29.1
SOCO RESOURCE	36.4	41.8
SOCO RESOURCE	35.5	40.8
SOCO RESOURCE	108	124.2
SOCO RESOURCE	49.9	57.4
SOCO RESOURCE	48.8	56.2
SOCO RESOURCE	68.3	78.5
SOCO RESOURCE	69.3	79.7
SOCO RESOURCE	27.1	31.1
SOCO RESOURCE	27.1	31.1
SOCO RESOURCE	25	28.8
SOCO RESOURCE	25.8	29.7
SOCO RESOURCE	25.6	29.4
SOCO RESOURCE	25.3	29.1
SOCO RESOURCE	26.1	30
SOCO RESOURCE	26.1	30
SOCO RESOURCE	3.2	3.7
SOCO RESOURCE	154	177.1
SOCO RESOURCE	100	115
SOCO RESOURCE	75	86.3
SOCO RESOURCE	32	36.8
SOCO RESOURCE	32	36.8
SOCO RESOURCE	29.9	34.4
SOCO RESOURCE	33	38
SOCO RESOURCE	41	47.2

SOCO RESOURCE	56	64.4
SOCO RESOURCE	49	56.4
SOCO RESOURCE	41	47.2
SOCO RESOURCE	54	62.1
SOCO RESOURCE	54	62.1

Table I.6. System CC Ratings

SYSTEM CC RATINGS		
Unit Name	**Peak Rating@95F (MW)**	**Peak Rating@40F (MW)**
BARRY_6	550	616
BARRY_7	557.1	624
SOCO RESOURCE	628	697.1
SOCO RESOURCE	567	629.4
SOCO RESOURCE	821	911.3
SOCO RESOURCE	823	913.5
SOCO RESOURCE	826	916.9
SOCO RESOURCE	660.6	733.3
SOCO RESOURCE	657.6	729.9
SOCO RESOURCE	885	885
SOCO RESOURCE	537.7	602.2
SOCO RESOURCE	556.8	623.6
SOCO RESOURCE	128.1	128.1
SOCO RESOURCE	140.1	140.1
SOCO RESOURCE	595	660.5
SOCO RESOURCE	242.5	269.2
SOCO RESOURCE	213.2	236.7
SOCO RESOURCE	679.4	754.1
SOCO RESOURCE	328	370.6
SOCO RESOURCE	577	640.5
SOCO RESOURCE	594.5	659.9
SOCO RESOURCE	379	420.7

Nevertheless, SERVM has features that can utilize the ambient temperature curves so that the actual output at the simulated system temperature can be modeled. Figure I.5 below shows the ambient temperature curves (on a per unit output basis) that were modeled within SERVM.[10]

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Figure I.5. Ambient Temperature Output Curves

G. Generating Unit Outage Rates

Generating units typically operate for a period, fail, are repaired, and then operate again. For example, a unit may run from 500 to 1,500 hours before it fails, take from 3 to 500 hours to repair, then run again for 500 to 1,500 hours.

Forced outage and maintenance outage data for the 2018 Reserve Margin Study consist of a series of observations of historical outage events from 2006-2016. This data is assembled into time-to-fail ("TTF") and time-to-repair ("TTR") distributions.

[10] One or two CCs have unique designs resulting in their own, unique ambient temperature output curve. Those curves are not shown on the chart.

Typical data for a unit might have up to five dozen entries in the TTF input data record, ranging from just a few hours to as many as 12,000 hours. Likewise, the typical data will contain a corresponding amount of entries in the TTR distribution, ranging from one to 2,500 hours. As the model processes chronologically, it will randomly choose a TTF duration from the first data record and then randomly choose a TTR duration. Individual unit operation, therefore, is a direct reflection of what has happened over approximately ten years. Since units are independent of each other, it is possible that many units can be down at once. An example of this type of input data for a steam unit is shown in Table I.7.

Table I.7. Steam Unit Sample Time to Fail and Time to Repair Data

Unit Name	Time-to-Fail (hours)	Time-to-Repair (hours)
Sample Plant	2747	4
	1839	5
	6710	11
	573	4
	333	5
	530	1
	233	2
	215	2
	752	1
	3710	6
	1338	2

Most steam units have their own specific outage history. However, the outage history of similar units has been combined to get a robust set of data from which to take random outage draws. Units with similar history and units for which no outage history was available were modeled using a similar reference unit.

Partial outages are modeled using the same rigorous approach that is used for full outages. A distribution is built for TTF events, TTR events, and the percentage derate. During the simulation, full outages and partial outages are tracked and randomly drawn.

The availability data for the System's "CC" units are modeled similarly to steam, with appropriate outage and derate TTF and TTR data. Additionally, in real-time operations, the supplemental modes (*i.e.,* full pressure ("FP") and power augmentation ("PA") of a CC) are dispatched separately from the base operating mode. The supplemental modes have a higher heat rate value and, therefore, tend to be dispatched during the same demand periods as CTs.

CT unit availability is generally driven by start failures. Once a CT starts, it is rare that it fails during run-time. Within SERVM, all CT availability data has been modeled as a startup probability with TTR data based on real observations. CT data include startup probabilities ranging from 85% to 99%. Repair data range from 8 to 93 entries in the TTR input data records with values ranging from less than an hour to nearly 100 hours.

To further refine outage rates, SERVM allows these historical TTF and TTR values to be scaled in aggregate to achieve an expected outage rate. The historical TTF and TTR values were thus scaled to get outage rates expected for each unit class (see Table I.8 below).

As the model progresses chronologically, it randomly chooses a time to fail duration from the TTF data record and then randomly chooses TTR duration (for CTs, the failure is determined by a probability draw when the startup is initiated and then the TTR is chosen randomly). Individual unit operation, therefore, is a direct reflection of what has happened over the selected sample years of data. The resulting forced outage rates, ratios of failed hours to operating hours, or ratios of failed hours to total hours are thus outputs of the model rather than inputs. Because forced outage rates are an output of the model, there can be minor differences in the resulting EFOR from case to case, but with sufficient outage draw iterations in the simulation, the resulting EFOR should converge to an expected value. The table below shows the resulting EFOR from one of the simulated runs, excluding any impacts from cold weather-related outages, which should be approximately the same in all cases.

Table I.8. Approximate EFOR by Unit Class

Unit Class	EFOR (%)
Nuclear	1.9
Coal	2.9
Gas Steam	2.2

Combined Cycle	1.6
CTs	5.2
Total System	2.7

The SERVM simulation randomly selects failure events and operating events for each unit. For every hour, certain units will be operating, and other units will be in a failure state. To ensure the model predicts these events accurately, a comparison was made of the simulated outage probability to the actual outage probability. This comparison, shown in Figure I.6, confirms that the modeled outage rate is consistent with the historical outage rate and indicates that the impact of outage events is adequately modeled.

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Figure I.6. Unplanned Outage Probability

H. Incremental Cold Weather Outages

The discussion of outage data in the previous sections describes the "base" level of outage expected across the year. However, history has demonstrated that under extremely cold conditions, outage rates can increase as coal piles and pipes begin to freeze, as oil thickens to the point that it will not flow sufficiently to operate a facility, or as instrumentation and controls or other plant equipment begin to freeze. These situations do not materialize until weather conditions are extreme, and these extreme weather conditions are less common. When they occur, however, the outage impacts can be significant and can increase in an exponential manner. Historically, these incremental outages have materialized at system weighted temperatures roughly [redacted] and below. However, efforts to minimize these impacts have been made in recent years and implemented across the system. Based on these efforts, it is expected that performance improvements will be such that these incremental outages will not begin to materialize until approximately [redacted], as shown in Figure I.7 below. The figure shows (a) a trend of historical unit outages under various cold weather conditions (see Appendix A for more detailed explanation of this trend), (b) an incremental trend of these outages assuming a [redacted] underlying system "EFOR", and (c) a trend representing the assumptions used in this study that includes expected performance improvements.

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Figure I.7. Cold Weather Outage Assumptions

I. Planned Outage Patterns

Planned outages occur most often in the shoulder months because the demand on the units to run during the peak demand months does not allow for a lot of down time. Traditionally, planned maintenance events are not scheduled during either the summer months (June-September) or January and February unless it cannot otherwise be avoided or for oil units in noncompliance zones. While maintenance schedules are generated annually for the upcoming 5 years, the Reserve Margin

Study is looking more generically and therefore allows the model to schedule maintenance around anticipated peak load periods. The model schedules these maintenance outages during low demand periods in such a way that the maintenance outage rate achieves the desired rate for the year. In general, this results in planned maintenance modeled relatively consistent with actual practice. Figure I.8 below shows the likelihood that a resource will be assigned a planned outage in any given month.

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Figure I.8. Planned Outage Probability by Month

J. Commitment and Operating Reserves

Resources are committed to match current operating practices. Each week during a simulation, the loads for each hour of the week are examined and the optimum dispatch is set to meet the system peak load while maintaining the required operating reserves for every hour. The optimum dispatch takes into consideration which units are available, the minimum uptimes and downtimes for each unit, the startup costs and times for each unit, and the necessary required operating reserves. Operating reserves are required by the Southern Balancing Authority, which is the entity responsible for balancing load and generation in the region, to meet North American Electric Reliability Corporation

("NERC") Reliability Standards. The Southern Balancing Authority provides guidance regarding the amount of operating reserves that should be modeled based on their operational requirements. That guidance included a total operating reserve requirement of [redacted], broken down according to the following components:

- Regulating Reserves: [redacted] of nominal solar capacity or [redacted]
- Contingency Reserve-Spinning: [redacted]
- Contingency Reserve-Supplemental (or Non-Spinning): [redacted]

In addition, the Southern Balancing Authority's guidance established a firm load curtailment threshold of [redacted] of total operating reserves, meaning that firm load should be curtailed to maintain a minimum total operating reserve requirement of [redacted]. However, SERVM cannot model a fixed MW operating reserve value for the purposes of firm load curtailment. Rather, SERVM can be configured to curtail firm load to maintain Regulating Reserves plus Contingency Reserve-Spinning. Therefore, only 496MW of Contingency Reserve-Spinning was modeled so that the sum of Regulating Reserve and Contingency Reserve-Spinning did not exceed [redacted]. The remaining [redacted] of the [redacted] of operating reserves was modeled as Contingency Reserve-Supplemental, such that the final modeled operating reserves were as follows:

- Regulating Reserves: [redacted]
- Contingency Reserve-Spinning: [redacted]
- Contingency Reserve-Supplemental (or Non-Spinning): [redacted].

K. Dispatch Order

Generation resources are generally dispatched economically based upon dispatch prices. The exceptions include energy-limited resources and non-dispatchable resources. Energy-limited resources, such as hydro and pumped storage hydro, are typically scheduled based on availability of water and expected system costs. Non-dispatchable resources, such as solar and wind vary with the weather. Therefore, the dispatchable resources are typically optimized around the output of these other non-dispatchable or pre-scheduled resources. Demand response resources either self-curtail based upon price (*e.g.*, Real Time Pricing programs) or are called whenever the system reaches certain reliability conditions (such as a system alert). Figure I.9 below shows the dispatch stack order for the dispatchable resources modeled in the 2018 Reserve Margin Study. The chart excludes the energy-limited, non-dispatchable, and demand response resources.

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Figure I.9. System Dispatch Stack

L. Dispatchers' Peak Load Estimate Error

The dispatchers' peak load estimate error consists of three separate time periods, including day ahead, four-hour ahead, and hour ahead. The amount of dispatcher's peak load estimate error modeled for each of these time periods was based on actual, historical forecast error data for the years 2012 through 2015. The table below shows the resulting mean and standard deviation that served as the basis for the modeled dispatcher's peak load estimate error.

Table I.9. Historical Dispatcher's Peak Load Forecast Error

	Day Ahead Mean	Day Ahead Std Dev	4-Hour Mean	4-Hour Std Dev	Hour Ahead Mean	Hour Ahead Std Dev
January	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
February	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
March	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

April	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
June	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
August	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
September	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
October	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
November	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

M. System-Owned Conventional Hydro Generation

System-owned hydro capacity of 2,400 MW (projected for the year 2025) was divided into two components:

1) Scheduled Hydro
2) Emergency or "Unloaded" Hydro

This study includes 54 different hydro scenarios that are matched with the 54 weather scenarios. The 54 scenarios chosen are based on the past 54 years (1962-2015) of weather and hydro data. For each of the scenarios, scheduled hydro capacity is modeled based on actual history.

The optimal dispatch of hydro resources is not solely an economic decision. Planners must consider river flow requirements and impacts on other reservoirs in the same river system. During drought conditions, it is rare that the full capacity of all hydro resources would be dispatched at the same time. The total hydro capacity that is not used as part of the daily schedule would be available as emergency hydro. Only in cases of extreme need is the emergency hydro capacity called upon to operate. Also, the emergency hydro block is only available for a small number of events per year. To model this within SERVM, the emergency hydro block is tied to a flex energy account to reflect the limited availability of this emergency hydro energy. If the emergency hydro capacity is needed to meet load during emergencies, the model will pull energy from this account. If the energy account becomes depleted, the capacity will not be available during subsequent emergencies.

Figure I.10 depicts the monthly energy produced by the two components of System-owned hydro generation in a representative year, 1998. The figure illustrates the typical distribution of available hydro energy across the months of the year.

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Figure I.10. Hydro Energy Availability (1998 Example Data)

As with the weather data, the availability of hydro energy can vary year to year. Figure I.11 below illustrates the total available scheduled hydro energies from the past 54 weather years (1962-2015).

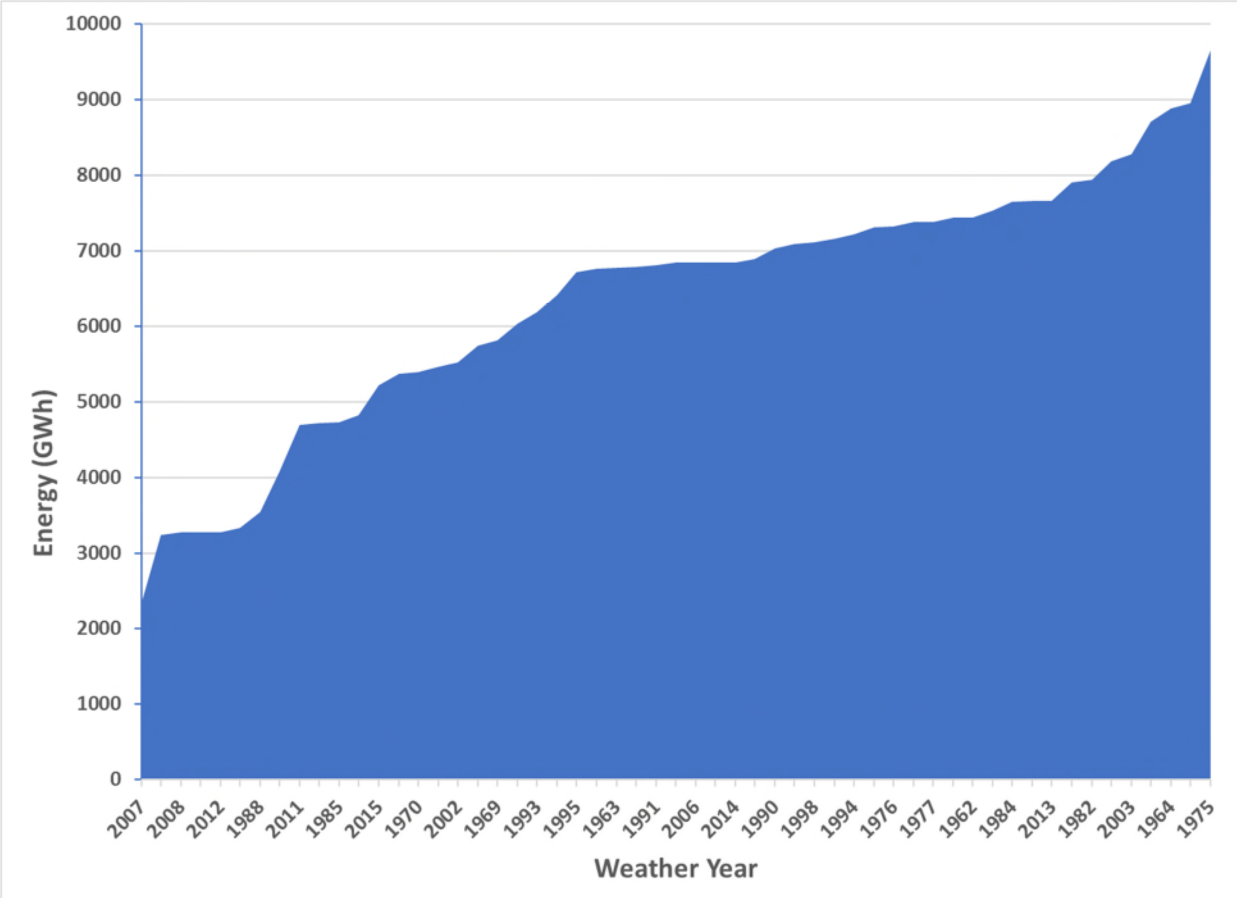

Figure I.11. Annual Scheduled Hydro Energies

N. SEPA Conventional Hydro

The Southeastern Power Administration ("SEPA") conventional hydro is less flexible in its operation than the System-owned hydro. The System has a contractual right to an allocation of the SEPA hydro capacity. Within SERVM, SEPA conventional hydro is modeled as a standard hydro unit with minimum daily dispatches. As currently modeled, the System is entitled to 477 MW taken over four hours per weekday, with a minimum daily schedule of 637.8 MWh and a maximum monthly energy allocation of 14.162 GWh.

O. Pumped Storage Hydro

Pumped storage hydro is a resource that is designed to pump water to an elevated reservoir using energy at off-peak periods when prices are low, and to generate electricity by releasing that water at times when prices are high. The dispatch of pumped storage is not simply a reliability decision, although the reservoir should always be kept at a level where energy will be available for emergency conditions. The System has a total of 540 MW of pumped storage resources spread across two different locations (Wallace Dam and Rocky Mountain Pumped Storage Facility). The Rocky Mountain Pumped Storage Facility is co-owned with Oglethorpe Power Corporation ("OPC").

P. Demand Response Resources

Approximately [redacted] of DRR capacity (contract value) is included in the analysis for the summer, and approximately [redacted] are included for the winter. These DRR include such programs as Interruptible Service ("IS"), Real-Time Pricing ("RTP"), Direct Load Control ("DLC"), Conservation Voltage Reduction ("CVR"), and Stand-by Generation ("SBG"). The model reflects both the seasonal availability as well as the contract constraints (*e.g.,* hours per year, days per week, and hours per day) for these energy-limited resources, so there is no need to adjust the contracts in the model by multiplying by Incremental Capacity Equivalent ("ICE") factors. In general, ICE factors represent the worth of load management resources, such as an interruptible service contract, relative to the value of incremental generating capacity that can be added to the system.

These resources occupy specific positions in the dispatch order as established by an assumed dispatch price. The position in dispatch affects their ability to reduce EUE and alters the frequency with which they are called. Some of these resources, such as RTP, are called based on economics and have an assumed dispatch price associated with them that is consistent with the expectation of the market prices that would result in self-curtailment by the customer. Others are called only to avoid EUE, and their assumed dispatch price is used mainly to establish the priority in which these programs are called. That priority is established based on how operations would anticipate them to be called in a generation shortfall event and would result in CVR being called first, followed by DLC, then IS, and finally SBG. Within the IS category, the programs are split into three blocks so that not all contracts are called simultaneously.

Q. Renewable Resources

NOTE: Except as otherwise stated, the Southern Companies maintain the right to use the electricity and all environmental attributes associated with all renewable projects discussed in this report for the benefit of its customers. This includes the right to use the electricity and the environmental attributes for the service of customers, as well as the right to sell environmental attributes, separately or bundled with electricity, to third parties.

The amount of renewable resources modeled for the System includes

- Biomass: 248 MW
- Landfill Gas: 43 MW
- Solar: 3,144 MW, and
- Wind: 588 MW.[11]

Biomass and landfill gas resources were modeled like other resources with a fixed output level based on their nominal capacity. However, the output of wind and solar resources are dependent upon weather conditions and location. Except for a few of the wind resources on the System that have been contracted based on a fixed hour-by-hour schedule, the output of the wind and solar resources varies moment-by-moment, hour-by-hour, and year-by-year. These wind and solar resources have been modeled with 8,760-hour profiles that are consistent with each of the 54 weather years as well as consistent with their location. Because the profiles included in the model for these resources reflect the hour-over-hour and year-over-year variances in output, there is no need to adjust the resources by multiplying by ICE factors.

R. Natural Gas Availability

Natural Gas operates in accordance to the Gas Day (*i.e.*, 9AM-9AM), whereas electricity operates according to the Electric Day (*i.e.*, Midnight to Midnight). Firm gas transportation is procured for the fleet's gas-fired units, but 24-hour Gas Day coverage is not procured for every plant. The amounts to be procured are generally driven by the System's Fuel Policy. Although case-specific situations may

[11] Wind capacity listed includes certain fixed delivery wind energy contracts. The total wind capacity shown includes the amounts delivered from these contracts coincident with the System peak.

allow for deviations from the Fuel Policy, for purposes of the 2018 Reserve Margin Study, all facilities under control of the Operating Companies were modeled in compliance with the Fuel Policy unless they had no contractual rights to dictate the amount of gas transportation to be purchased for the facility.

SERVM models both firm and non-firm gas transportation and its associated availability. During periods of high demand for natural gas, the System is limited to firm transportation contracts since interruptible transportation is not available. This constraint has been incorporated into the modeling process. The model begins phasing out interruptible transportation (*i.e.*, it starts becoming unavailable) when the daily minimum system weighted temperature falls below [redacted] or when the daily maximum system weighted temperatures rises above [redacted]. When the daily minimum temperature falls below [redacted] or the daily maximum temperature rises above [redacted], no interruptible transportation is available for that Gas Day. Figure I.12 below illustrates the availability of interruptible transportation as modeled within SERVM.

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Figure I.12. Interruptible Gas Transportation Availability Model

S. Oil Availability

For dual-fuel (gas/oil) and oil-fired units, oil availability is dependent upon onsite storage. Storage capacity is limited, so when gas is not available, onsite oil supply will deplete quickly. This may limit a unit's availability if refilling efforts cannot keep up with usage.

T. Capacity Cost

For the type of analysis performed in this study where the objective is to balance the cost of the incremental capacity with the reliability benefits achieved by that capacity addition, it is necessary that the capacity considered represents a true reliability addition, not an addition for both reliability and energy economics. As such, simple-cycle CT technologies are the appropriate resources to be utilized for the evaluation. Therefore, the cost associated with advancing a CT one year is the cost of capacity used in the analysis. This cost is also known as the "economic carrying cost" or one-year deferral cost associated with that resource. Since both summer and winter evaluations were performed in the 2018 Reserve Margin Study, economic carrying costs based on both summer and winter performance characteristics were needed. The CT cost model is a green-field site of four dual-fueled units each with a 95°F ambient temperature summer rating of [redacted] MW and a 40°F ambient temperature winter rating of [redacted] MW, resulting in a summer performance economic carrying cost in 2025 dollars of [redacted] and a winter performance economic carrying cost in 2025 dollars of [redacted].

U. Cost of Expected Unserved Energy

To estimate the cost of EUE, Freeman, Sullivan & Company conducted an outage cost survey of Georgia Power Company and Mississippi Power Company customers in 2011.[12] This survey was conducted among the following four customer classes:

- Residential;
- Commercial (below 1 MW average demand);
- Industrial (below 1 MW average demand); and
- Large business (commercial and industrial customers above 1 MW average demand).

[12] While the survey only included customers from two Operating Companies, the results are considered appropriate for all Operating Companies, and so the cost of the survey was shared by all Operating Companies.

The cost of EUE (in 2012$) for these four customer classes is shown in Table I.10 for both the summer and winter periods. The cost of EUE was then adjusted by the customer weighting factor representing recent relative weighting of customers in that class. The results of that weighting are also shown.

Table I.10. EUE Cost

EUE COST IN 2012 $					
Outage Scenario	**Residential ($/kWh)**	**Commercial ($/kWh)**	**Industrial ($/kWh)**	**Large Business ($/kWh)**	**Weighted Average ($/kWh)**
Weighting Factor (%)	[redacted]	[redacted]	[redacted]	[redacted]	
1 hour, no warning, summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contribution to Weighted Average	[redacted]	[redacted]	[redacted]	[redacted]	
1 hour, no warning, winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contribution to Weighted Average	[redacted]	[redacted]	[redacted]	[redacted]	

These estimated weighted costs of EUE were then escalated to 2025 dollars for use in the 2018 Reserve Margin Study. The result was a Value of Loss Load ("VOLL") of [redacted] for summer and [redacted] for winter.

II. SIMULATION PROCEDURE

A. Case Specification

The simulations performed for the 2018 Reserve Margin Study were designed to estimate System generation reliability across a wide range of weather conditions, LFEs, and reserve margins. Eleven discrete reserve margin levels were simulated to calculate the expected costs over a broad range of scenarios. Load shapes corresponding to the 108 weather datasets (54 weather years, each with Tuesday and Saturday start days), were run in combination with varying LFEs. Weather years were paired such that loads, hydro scenarios and renewable profiles were consistent. The simulation variables were as depicted in Table II.1.

Table II.1. SERVM Case Variables

Weather and Hydro Years	Summer/Winter Reserve Margins	LFEs
1962-2015	10%/17.0%	[redacted]
	11%/18.2%	[redacted]
	12%/19.5%	[redacted]
	13%/20.7%	[redacted]
	14%/21.9%	[redacted]
	15%/23.1%	[redacted]
	16%/24.4%	
	17%/25.6%	
	18%/26.8%	
	19%/28.0%	
	20%/29.3%	

The winter reserve margins are the equivalent of their summer counterparts. Thus, the winter reserve margins are not listed in whole percentage point increments.

Positive LFE represents an over forecasted load, meaning actual load was less than forecasted load.

Without accounting for load forecast uncertainty, the total number of combinations for the analysis would be 54 × 2 × 11, or 1,188 cases. Considering the six load forecast points yields 7,128 cases (54 × 2 × 11 × 6 cases). Each of these cases were then evaluated 100 different times, each with a different set of random forced outage draws on the generating resources, yielding 712,800 production cost simulations (54 x 2 x 11 x 6 x 100 cases). Estimating EUE for each of the 712,800 simulations provides sufficient data for regression analysis of other combinations not specifically simulated. This set of simulations was performed for both the traditional analysis as well as the winter focus analysis and the summer focus analysis.

B. Probabilities of Occurrence for Input Variables

As discussed in the previous sections, the chronological variable inputs into the model are used to represent appropriate ranges of data. For example, the weather years selected to exemplify load variations due to temperature changes represent 54 years of historical data. This is also true for the hydro patterns and solar profiles developed. Each, however were modeled twice – once with a Saturday start and once with a Tuesday start – resulting in 108 different weather/hydro datasets. The implementation of load forecast uncertainty into the evaluation is representative of the potential (supported by historical information) LFEs when considering the future. Each of the six forecast errors has its own probability of occurrence that is related to the probability of error in forecasted economic indicators. For each reserve margin studied, the combined set of input variables results in 648 individual cases having their own designated probability of occurrence to be used in the probabilistic evaluation. Table II.2 depicts the probabilities assigned to each of these variables and the resulting probability for each case. This total case probability is determined by combining the probabilities of the determinant variables. The weather years and start days all have equal probability of occurrence.

Table II.2. Simulation Case Probability

LFE	LFE Probability	Weather/Hydro Probability	Start Days Probability	Total Case Probability
[redacted]	0.0952	0.018519	0.5	0.000882
[redacted]	0.1429	0.018519	0.5	0.001323
[redacted]	0.2381	0.018519	0.5	0.002205
[redacted]	0.3333	0.018519	0.5	0.003086
[redacted]	0.1429	0.018519	0.5	0.001323
[redacted]	0.0476	0.018519	0.5	0.000441

C. Reliability Model Simulations

SERVM incorporates Monte Carlo techniques to conduct generation reliability simulations. Monte Carlo analysis uses a random number generator to determine generating unit availability for the System. For each iteration, the model simulations will randomly select the state of a generating unit as fully operational, partially failed, or completely failed and determine if the system experiences loss of load and associated EUE.

For each of the 648 cases, each hour of the year was modeled with 100 draws from the distribution of generating unit outage and duration data to determine if there exists a deficiency of generating capacity to meet load demand. The 100 iterations were averaged together to establish a case-specific result. A deficiency of generating capacity in any hour is recorded as a loss of load hour. The magnitude of the outage during that hour is measured by EUE. The EUE is then aggregated by month and multiplied by the respective value of lost load for that month to determine the EUE cost. The monthly EUE costs are then summed together for the year to determine EUE cost for that case. The case EUE cost is then multiplied by the probability of occurrence for that case and the results for all cases are summed to determine the expected value of EUE cost for that reserve margin simulation. This process is repeated to determine the expected value of generation costs, import costs, emergency purchase (or sales) costs, the cost of non-firm outages (i.e., demand response costs), and costs associated with non-spinning reserve shortfalls.

For each reserve margin simulation, the expected value of generation costs and import costs are then summed together to establish “Production Cost”. Likewise, the expected value of emergency purchases (or sales), demand response costs, costs associated with non-spinning reserve shortfalls, and EUE costs are summed together to establish “Reliability Cost.” Figure II.1 shows the formula used for calculating EUE. Other components are calculated similarly.

$$\boldsymbol{Expected\,Y} = \sum_{\boldsymbol{i=1}}^{\boldsymbol{n}} (\boldsymbol{Y_i} * \boldsymbol{Probability_i})$$

where

$$\boldsymbol{Y = EUE\ and,}$$

$$\boldsymbol{n = number\ of\ cases}$$

Figure II.1 Variable Calculation Formula

Table II.3 thru Table II.6 provide an example of implementing the formula for a sample data set containing the 10 worst Reliability Cost cases. Table II.3 shows the Reliability Cost components with their per unit weighted costs. Table II.4 shows the probability weighting of the Total Reliability Cost. For illustrative purposes, all calculations are for a 17% summer reserve margin simulation.

Table II.3. Sample Calculation Top 10 Worst Reliability Costs at 17% Summer Reserves

Data Set	Emergency Purchases (MWh)	Emergency Purchases Cost ($/MWH)	EUE (MWh)	EUE Cost ($/MWH)	Demand Response Calls (MWh)	Weighted DR Cost ($/MWH)	Loss of Non-Spin Reserve (MWh)	Loss of Non-Spin Cost ($/MWH)
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table II.4. Worst Reliability Costs Weighted Probability

Data Set	Probability	Emergency Purchases ($M)	EUE ($M)	Demand Response Calls ($M)	Loss of Non-Spin ($M)	Total Reliability Cost ($M)	Weighted Reliability Cost ($M)
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

A similar calculation is performed for the components of Production Cost as demonstrated in Table II.5 and Table II.6 for the same 10 cases shown above.

Table II.5. Production Cost Components for Sample Data Set

Data Set	Generation Costs ($M)	Purchases (MWh)	Purchase Cost ($/MWH)
1	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]

Table II.6. Production Cost Weighted Probability

Data Set	Probability	Generation Costs ($M)	Purchase Cost ($M)	Total Production Cost ($M)	Weighted Total Production Cost ($M)
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

By applying regression analysis to the expected values of Production Cost and Reliability Cost, a curve summarizing the Production Cost, Reliability Cost, and Incremental Capacity Cost as a function of reserve margin was developed. These results are discussed in detail in the next section.

III. <u>BASE CASE RESULTS</u>

A. Traditional Study Results

In theory, the economic optimum reserve margin, or the EORM, should be the reserve margin that results in the minimum total system costs. The three components of total system costs (Production Cost, Reliability Cost, and Incremental Capacity Cost) that vary across reserve margin levels were added together to create an aggregate total system cost curve (the “U-Curve”). The minimum point on the resultant U-Curve, which is at 15.25%, represents the EORM. This graph is presented below.

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Figure III.1. Traditional EORM U-Curve

B. Winter-Focused Reserve Margin Results

The 2015 Reserve Margin Study identified several drivers associated with issues during extreme cold weather. Those drivers included:

a. the narrowing of summer and winter weather-normal peak loads,
b. the distribution of peak loads relative to the norm,
c. cold-weather-related unit outages,
d. the penetration of solar resources, and
e. increased reliance on natural gas.

In addition to these same drivers, the 2018 Reserve Margin Study identified an additional constraint – the availability of market purchases (see Assumptions section of this report). Because all these drivers will impact winter reliability, it has been determined that even though the System remains a summer peaking utility for the time being, the System's primary reliability risk is in the winter, resulting in the need for a Winter TRM. Appendix A addresses this need for a Winter TRM more thoroughly, but as an example of this need, Figure III.2 below shows seasonal EUE by reserve margin. As indicated by the chart, at low reserve margins, summer and winter have relatively equal expectations of EUE – with summer being higher at very low reserve margins. However, as reserve margins increase, the expectation of EUE in the summer reduces drastically. Similarly, the expectation of EUE in the winter falls as reserve margin increases, but not as drastically and even at 20% reserve margin, there is still a significant expectation of potential loss of load.

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Figure III.2. Seasonal EUE by Reserve Margin

To address this winter reliability risk, a Winter TRM is necessary. Therefore, a separate analysis was performed where the focus of the study was on a winter reserve margin. Traditionally, the reserve margin is stated in summer terms – that is, stated in terms of summer peak loads and summer resource ratings. For example, the reserve margins in Figure III.2 above are all stated in summer terms. The traditional analysis is performed by developing the 108 historical weather load shapes in such a way as to ensure the average summer peak load from all 108 load shapes equals the summer peak demand forecast for the study year. To perform the winter focused reserve margin analysis, the 108 load shapes were adjusted such that the average of the winter peak loads equaled the winter peak demand forecast. The results of the study were then stated in winter reserve margin terms rather than summer reserve margin terms (i.e., stated in terms of winter peak loads and winter resource ratings). The minimum point on the resulting U-Curve was established as 22.5% as shown in the graph below.

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Figure III.3. Winter EORM U-Curve

It is important to recognize that while the EORM from the winter U-Curve occurs at a reserve margin that appears to be significantly higher than the EORM from the traditional, summer-oriented U-Curve, the EORM from the two cases represent similar levels of reliability and cost for the same underlying system. Each study contains a full year of hourly production cost simulations which inherently reflect 8,760 reserve margin levels. Therefore, the difference in absolute value (22.5% versus 15.25%) primarily a function of stated terms, with the summer EORM being stated in terms of summer capacity ratings and the summer weather-normal peak load and the winter EORM being stated in terms of winter capacity ratings and winter weather-normal peak load.

C. Summer-Focused Reserve Margin Results

Given that the System's primary reliability risk is in the winter, it is possible to determine a summer-focused reserve margin without consideration of some of the key winter drivers, specifically without the incremental cold-weather generation outages or the natural gas fuel constraints. The idea behind this analysis is to determine the corresponding Summer TRM once the Winter TRM has been established. The following graph shows that a summer-focused EORM without those key drivers would be 14%.

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Figure III.4. Summer EORM U-Curve (Without Key Winter Drivers)

D. Risk Analysis

The winter-focused combination of Production Cost, Reliability Cost, and Incremental Capacity Cost results in a EORM of 22.5%. However, since Production Cost and Reliability Cost are highly dependent on the selected scenario, consideration of only the EORM does not give a complete picture. Figure III.5 illustrates the volatility in Production Cost and Reliability Cost exposure. In scenarios in which load grows faster than expected, temperatures are higher than expected, or unit performance is poorer than expected, the cost exposure can be much higher than the expected case.

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Figure III.5. Production and Reliability Cost Distributions for Winter Reserve Margins

Zooming in on the most extreme cases shown in Figure III.5 for each reserve margin further highlights the risk in carrying low reserves. Figure III.6 shows the exposure for the top 10% of all cases as ranked by Production Costs and EUE cost exposure. The most extreme case simulated at a 17% winter reserve margin shows over [redacted] per year in total exposure, while the most extreme case at a 26% reserve margin is approximately [redacted].

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Figure III.6. Top 10% Distribution for Winter Reserve Margins

To more appropriately perform a comparison between highly volatile Production Costs and Reliability Costs and fixed Incremental Capacity Cost, thus protecting against the potential for an extremely high cost outcome, additional risk analyses should be performed. In the casualty insurance business, customers have the option of paying an insurance premium to cover the impact of a catastrophic loss. In this example, the annual insurance premium is higher than the cost of the loss times its probability. Customers and regulators are comfortable with paying an amount greater than the average loss because it makes the payments fixed. In the same way, utilities can procure capacity at fixed rates slightly above the EORM to prevent the possibility of certain high cost outcomes. The approach taken to evaluate the risk of these potential high cost outcomes and thus determine how much of an "insurance premium" to pay is to use a risk metric called Value at Risk ("VaR").

VaR is defined as the difference in cost at the expected value and the cost at some specified confidence interval (e.g., the 85th percentile of risk). The VaR accounts for the customers' exposure to higher costs above normal conditions. The VaR analysis looks at the incremental increase in expected cost to move from one reserve margin to the next reserve margin and compares that with the incremental decrease in VaR. So long as the incremental increase in expected cost is less than the incremental decrease in VaR, the premium (*i.e.*, the increased expected cost) is justifiable to protect against the potential high cost outcomes. The point at which the incremental increase in cost equals the incremental decrease in VaR represents the EORM at that confidence interval (as opposed to the EORM at the weighted average).

The table below illustrates the VaR at the 80th (VaR80), 85th (VaR85), 90th (VaR90), and 95th (VaR95) percentiles of confidence for a range of winter reserve margin targets.

Table III.1. Value at Risk

Reserve Margin	Expected Cost (M$)	VaR80 (M$)	VaR85 (M$)	VaR90 (M$)	VaR95 (M$)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For the 80th percentile of risk (VaR80), the incremental increase in expected cost roughly equals the incremental decrease in VaR80 when moving from 25.75% reserve margin to 26% reserve margin. At this point, the incremental increase in cost is [redacted]; and the decrease in VaR80, or decrease in customers' exposure to higher cost outcomes, is [redacted]. Moving from 26% to 26.25% results in an increase in expected costs [redacted] that is greater than the decrease in VaR80 [redacted]. Thus, 26% represents the EORM at the 80th percentile of risk. Compared to the expected case TRM of 22.5%, a 26.0% reserve margin reduces the VaR80 exposure by [redacted] while only increasing the expected case cost by [redacted]. Higher confidence intervals were also examined. At the 85th percentile of risk, it would be justifiable to establish a reserve margin of 26.25%. At the 90th percentile of risk, it would be justifiable to establish a reserve margin of 27.25%. Likewise, at the 95th percentile of risk, it would be justifiable to establish a reserve margin of 28.5%. However, the increased expected cost for these three confidence intervals are [redacted], [redacted], and [redacted], respectively. While justifiable from a cost/risk reduction perspective, the absolute increase in expected cost suggests use of the 80th or 85th confidence interval as there is a much bigger jump in expected costs moving to the 90th confidence interval.

Another way to explain and understand the risk analysis used in this study is to realize that the VaR analysis essentially establishes the EORM at the specified confidence interval. In other words, the Operating Companies calculate the EORM at the expected value of cost. However, because of risk, it would be justifiable to calculate the EORM at, for example, the 80th percentile of cost. This is precisely what the Var80 analysis accomplishes – the economic balance between cost and risk. Figure III.7 below shows the total cost (Production Cost plus Reliability Cost plus Incremental Capacity Cost) at the 80th confidence interval. The resulting "U-Curve" confirms that the EORM at the 80th confidence interval is 26.0% - that is, 26.0% is the risk-adjusted EORM at the 80th confidence interval.

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Figure III.7 80% Confidence Interval U-Curve

E. Loss of Load Expectation

Some regions throughout the country utilize Loss of Load Expectation (LOLE) as their primary resource adequacy reliability metric, while others either do not consider it or consider it as a secondary metric to the EORM. LOLE is the probabilistic count of the number of days in the study year in which the system experiences firm load shed of any duration. This metric does not measure the magnitude of the event and is relatively sensitive to several input assumptions. The most common business practice for those who use this metric is an LOLE value of 0.1 days per year, which is sometimes referred to as a one day in ten years (1:10 LOLE) reliability criterion. An LOLE of 0.1 days per year presumes there is a 10% probability of a loss of load due to generation shortfall in any one year or an expectation that there would only be one loss of load event every 10 years.

Historically for the Southern Company System, this 1:10 LOLE threshold has occurred at reserve margins below the EORM. Thus, the primary focus has historically been on the risk-adjusted EORM to establish the TRM. However, as the Company continues to incorporate new reliability risks in its reliability modeling, more recent analyses have indicated that the LOLE for the System is much higher than previously expected. Thus, the reserve margin necessary to maintain the 1:10 LOLE threshold is also higher. Figure III.8 below illustrates how this metric looks for the System over the range of reserve margins studied for the 2018 Reserve Margin Study as compared to the 2012 and 2015 reserve margin studies. The reserve margins are shown in summer terms since neither the 2012 nor the 2015 studies included a winter analysis.

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Figure III.8. Loss of Load Expectation by Summer Reserve Margin

At its current approved Target Reserve Margin of 16.25% (which is equivalent to a 24.7% winter reserve margin), the System has an LOLE of [redacted] or an expectation of one event in [redacted], which is below the 1:10 LOLE threshold. As indicated by the chart, to achieve a 1:10 LOLE threshold would require a 17% Summer TRM. Figure III.8 was shown in summer terms as a comparison to previous, traditional studies. However, since the increase in observed LOLE is associated with winter reliability issues, it is necessary to review these metrics as generated by the winter focus study. Figure III.9 below shows the LOLE for the winter reserve margins evaluated.

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Figure III.9 LOLE for Winter Reserve Margins

At the winter EORM of 22.5%, the LOLE is [redacted] or an expectation of one event every [redacted]. To achieve a 1:10 LOLE threshold would require a winter reserve margin of 25.25%. In both the traditional study and the winter focus study, the 1:10 LOLE threshold is above EORM but still below the VaR85 reserve margin. At the VaR85 reserve margin of 26.25%, the LOLE expectation is one event every [redacted].

It would not be appropriate to establish a TRM that has an expected level of reliability that is lower than common industry practice. For this reason, consideration of the 1:10 LOLE threshold as a determinant in making a final TRM recommendation is necessary and appropriate.

F. Total System Cost Components

The total system cost is the sum of three components:

1) The annual carrying cost of CTs added for reserve margin (Incremental Capacity Cost);
2) Reliability Costs; and
3) Production Cost.

Following is a discussion of each component.

1) Annual Carrying Costs of CTs

The incremental annual capacity carrying cost of the added capacity at any given reserve margin is determined by multiplying the incremental CT kW capacity by its economic carrying cost. For the traditional and summer focus studies, this cost was determined using summer performance values, resulting in a carrying cost of [redacted]. To achieve an increase of one percent reserve margin in the summer studies requires the addition of [redacted] or [redacted] in carrying cost. For the winter focus study, the cost was determined using winter performance values, resulting in a carrying cost of [redacted]. To achieve an increase of one percent reserve margin in the winter focus study requires the addition of [redacted] or [redacted] in carrying cost. As more CTs are added to achieve a higher reserve margin, these carrying costs accumulate with the megawatts added. This is represented in Figure III.10 (for the winter focus study), which shows a linear increase in costs when graphed as a function of reserve margin.

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Figure III.10. Incremental Capacity Cost (Winter Focus)

2) Reliability Costs

Reliability Costs are the sum of the cost of EUE, the cost of any shortfalls in meeting required operating reserves, the cost of emergency purchases (or sales), and cost of demand response calls. The cost of EUE is determined by multiplying the amounts of EUE in MWh at each reserve level created in the analysis by the assumed cost of EUE in $/MWh (with EUE in the winter being multiplied by the winter cost of outage and EUE in all other months multiplied by the summer cost of outage). The cost of meeting shortfalls in spinning and regulating reserves are included in the cost of EUE as the model curtails load to maintain these requirements. The cost of meeting supplemental (*i.e.*, non-spin) reserve requirements is determined by the scarcity price at the time of the shortfall. The cost of demand response calls is determined by the presumed dispatch price for each demand response program as established by the Operating Companies. Figure III.11 illustrates Reliability Cost as a function of winter reserve margin.

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Figure III.11. Reliability Cost

3) Production Cost

Production Costs include the variable operating costs of units plus the cost of any purchases with neighboring regions less the cost of any sales with neighboring regions. Production costs at each reserve margin level can be seen in Figure III.12.

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Figure III.12. Production Cost

As expected, Reliability Costs and Production Costs decrease as reserve margin increases. Conversely, their costs increase as the reserve margin is reduced.

IV. SENSITIVITY ANALYSES

The basis of the data for unit performance, weather, load forecast error, hydro availability, market prices, and other inputs is from historical information. Other data such as market availability is based on forecasted information. While the broad range of scenarios analyzed capture extreme events and market prices, there remains risk that conditions could occur in the future that extend beyond the range of what is contemplated in the base case model. Each of the following sensitivities were modeled to examine their impact on both the EORM and the 1:10 LOLE threshold.

In addition to the sensitivities related to the uncertainties above, a sensitivity was modeled to determine how the optimum reserve margin would change if the load forecast uncertainty was reduced to determine a short-term reserve margin target.

A. Capacity Price

Capacity price has an inverse impact on the EORM. The EORM calculation assumes the addition of a reliability resource (i.e., a CT) that has little or no energy value. This ensures a fair comparison of capital cost against Production Cost and Reliability Cost. At lower capacity prices, it is economically justifiable to have a higher TRM. Conversely, if capacity prices are higher, the EORM will be lower. The capacity price used in the 2018 Reserve Margin Study represents the economic carrying cost of a CT. The capacity price sensitivity examined a range of capacity costs from values as low as the Budget 2018 Retail Capacity Price Forecast (“RCPF”) to values higher than the economic carrying cost of a dual fuel CT. Figure IV.1 shows how capacity costs across these ranges affect the Winter EORM. For example, at the 2025 RCPF of [redacted], the Winter EORM moved from 22.5% to more than 29%. Capacity price does not impact the 1:10 LOLE threshold.

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Figure IV.1. EORM as a Function of Capacity Price

B. Minimal Cost of EUE

Two cost-of-EUE sensitives were evaluated. The first was a minimum value assuming only impacts from residential class customers. This resulted in a cost of EUE of approximately [redacted] of outage (in 2025$). The Winter EORM for this sensitivity moved from 22.5% to 20.5%. There was no change in the 1:10 LOLE threshold.

C. Publicly Available Cost of EUE

The second cost of EUE sensitivity was one that was developed based on publicly available cost of EUE data. Using the Interruption Cost Estimate Calculator, developed by Nexant and funded by Lawrence Berkeley National Laboratory and the Department of Energy and is publicly available at http://icecalculator.com, a cost of EUE for the System was estimated to be approximately [redacted]. The Winter EORM for this sensitivity moved from 22.5% to 23.0%. There was no change in the 1:10 LOLE threshold.

D. No Cold Weather Outage Improvements

As indicated in the Section I, Assumptions, the cold weather outage assumptions used in the 2018 Reserve Margin Study incorporated substantial unit performance improvements over historical actual performance. This sensitivity assumes those performance improvements are not realized and the future cold-weather outage performance is consistent with historical performance. The Winter EORM for this sensitivity did not significantly change from the base case. However, the 1:10 LOLE threshold moved from 25.25% to 25.75%.

E. Higher Scarcity Price Curve

For the 2018 Reserve Margin Study, the scarcity price curve was updated, resulting in significantly lower scarcity price curves. Because the scarcity price curve is based on recent historical market conditions, it is possible that the current assumptions for the scarcity price curve are biased low due to the general high levels of current reserve margins throughout the neighboring regions. As the actual reserve margins in the neighboring regions all decrease towards their respective target reserve margins, it is anticipated that scarcity prices could return to levels seen previously. This sensitivity assumes that the scarcity price curve would be more consistent with that used in prior reserve margin studies (2012 and 2015). The Winter EORM for this sensitivity moved from 22.5% to 23.75%. The 1:10 LOLE threshold moved from 25.25% to 24.75%.

F. 50% Reduced Transmission

For this sensitivity, transmission capabilities with neighboring regions were reduced by 50%. This resulted in an increase in the Winter EORM from 22.5% to 23%. It also resulted in an increase in the 1:10 LOLE threshold from 25.25% to 25.5%.

G. 50% Increased Transmission

For this sensitivity, transmission capabilities with neighboring regions were increased by 50%. The results of the 50% increased transmission scenario showed no change in the Winter EORM. However, the 1:10 LOLE threshold decreased from 25.25% to 25%.

It should be noted that both the 50% Reduced Transmission sensitivity and 50% Increased Transmission sensitivity only resulted in marginal changes in reliability (with little or no change in economics). Together, this indicates that transmission interface capability with the interconnected regions is adequate from a reliability standpoint.

H. 50% Higher Base EFOR

For this sensitivity, base level unit outages were increased by 50%. Incremental cold-weather outages were not impacted by the sensitivity. The 50% higher unit outage scenario resulted in an increase in the Winter EORM from 22.5% to 23.25%. Similarly, the 1:10 LOLE threshold increased from 25.25% to 26.75%.

I. 50% Lower Base EFOR

For this sensitivity, base level unit outages were decreased by 50%. Incremental cold-weather outages were not impacted by the sensitivity. The 50% lower unit outage scenario resulted in a reduction in the Winter EORM from 22.5% to 21.55%. Similarly, the 1:10 LOLE threshold decreased from 25.25% to 23.75%.

Summary of Sensitivity Analyses

Figure IV.2 below shows a graphical representation of the results of all the sensitivity analyses (i.e., Sensitivities A through I). For Sensitivity A (capacity costs), two results are shown, representing capacity prices associated with the Budget 2018 RCPF (A) and ½ of the economic carrying cost of a CT (A'). The chart shows both Winter EORM and the 1:10 LOLE threshold. Together, they demonstrate that the sensitivity analyses validate the base case results of the 2018 Reserve Margin Study and indicate that its results are robust against those sensitivities.

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Figure IV.2. Summary of Winter Sensitivity Results

Short-Term Load Forecast Error

For this sensitivity, short-term load forecast errors were used. This sensitivity resulted in the Winter EORM decreasing from 22.5% to 22.0%, reflecting a difference in long-term and short-term reserve margins of 0.5%. The short-term load forecast errors used are in the following table.

Table IV.1. Short-Term Load Forecast Error

SHORT-TERM LOAD FORECAST ERROR	
LFE	**Probability**
[redacted]	0.0833
[redacted]	0.1250
[redacted]	0.25
[redacted]	0.2917
[redacted]	0.1667
[redacted]	0.0833

V. CONCLUSION

Winter reliability issues drive the 2018 Reserve Margin Study results. Therefore, a Winter TRM is required to ensure the appropriate level of resource adequacy.[13] However, it is necessary to establish both a Winter TRM and a Summer TRM for several reasons. It is possible that capacity needs can be driven by either season and should be considered when adding new capacity. In addition, there is the potential that, over time, changes in rate structures, demand-side programs, and other initiatives could alter the dynamics of the system such that the primary risk shifts between seasons. Therefore, it is recommended, that a TRM be set for both seasons, with the Winter TRM established based on the results of the winter focused study and the Summer TRM established based on the summer focused study with 1:10 LOLE threshold considerations for both as discussed below.

Winter Target Reserve Margin

The 2018 Reserve Margin Study recommends a long-term Winter TRM of 26% based on the following:

1. The TRM should be greater than the 1:10 LOLE threshold of 25.25% to ensure an adequate level of reliability on the System;
2. A reserve margin of 26% represents the risk-adjusted EORM at the 80th confidence interval (the 80th percentile of risk – i.e., VaR80);
3. Compared to the 22.5% expected case EORM, a 26% risk-adjusted EORM reduces VaR at the 80th confidence interval by [redacted] while only increasing expected cost by [redacted];
4. Compared to the 25.25% 1:10 LOLE threshold, a 26% risk-adjusted EORM reduces VaR at the 80th confidence interval by [redacted] while only increasing expected cost by [redacted]; and
5. A 26% Winter TRM is consistent with results from the 2015 Reserve Margin Study,[14] confirming the results of that study.

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[13] See Appendix A for further justification of the need for a Winter TRM.

[14] In the 2015 Reserve Margin Study, "An Economic Study of the System Planning Reserve Margin for the Southern Company System" (January 2016), the winter equivalent of the approved 16.25% TRM would have been 26%.

Summer Target Reserve Margin

The Summer EORM from the summer focus study is 14.0%, with the VaR85 reserve margin being 18%. However, the Summer TRM cannot be determined without consideration of the Winter TRM. If the System is meeting its 26% Winter TRM requirement with resources that provide year-round capacity, the summer reserve margin will generally be at or above 17.3%. This means that the Winter TRM is driving the System reliability, even though the next capacity need for one or more of the Operating Companies may still be in the summer. However, in the event seasonal resources (such as winter-only resources) are made available, it may be possible to lower the Summer TRM below 17.3% - so long as the combined annual reliability remains above the 1:10 LOLE threshold. The following graph demonstrates the minimum acceptable Summer TRM as a function of Winter TRM. For a Winter TRM of 26%, the minimum acceptable Summer TRM is [redacted].

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Figure V.1. Minimum Acceptable Summer Target Reserve Margins

The recommendation, therefore, is to establish a Winter TRM of 26%, while maintaining the currently approved 16.25% as the Summer TRM. This recommendation would apply for studies looking out four or more years. For studies looking inside a three-year window, the recommended Winter and Summer TRM are 25.5% and 15.75% respectively, reflecting a 0.5% reduction from the long-term TRM resulting from the difference between the long-term forecast error and the short-term forecast error.

These recommendations are designed to provide guidance for resource planning decisions but should not be considered absolute requirements. The large size of capacity additions, the availability and price of market capacity (as indicated by the Capacity Cost sensitivity), or economic changes may justify decisions that result in reserve margins above these targets.

Components of the Target Reserve Margin

Figure V.2 shows the contribution of each of the components of uncertainty (weather, market risk, unit performance, load forecast error, and fuel supply) toward the overall required Winter TRM of 26%.

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Figure V.2. Economic Components of Winter TRM

Likewise, Figure V.3 shows how each of the components contribute to the minimum Summer TRM of 16.25%.

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Figure V.3. Economic Components of Summer TRM

The 26% Winter Target Reserve Margin recommended for the System reflects the results of the economic study and a variety of other information available and is extremely important in planning to best meet customer needs and provide for a more reliable generation system. The 16.25% minimum Summer TRM is necessary to ensure the combined summer and winter reserve margins remain at about the 1:10 LOLE Threshold.

Appendix A – Examining the Need for a Winter Target Reserve Margin

A. Background

The last time that the "System" experienced an outage due to a generation shortfall was on January 17, 1977 – a winter reliability event. Since that time, the System has delivered reliable, low-cost generation even through some of the coldest weather on record during the mid-1980s. The ability to maintain reliable service during those extreme periods was primarily because the System's summer peaks were significantly higher than the System's winter peaks in that era as demonstrated in the figure below.

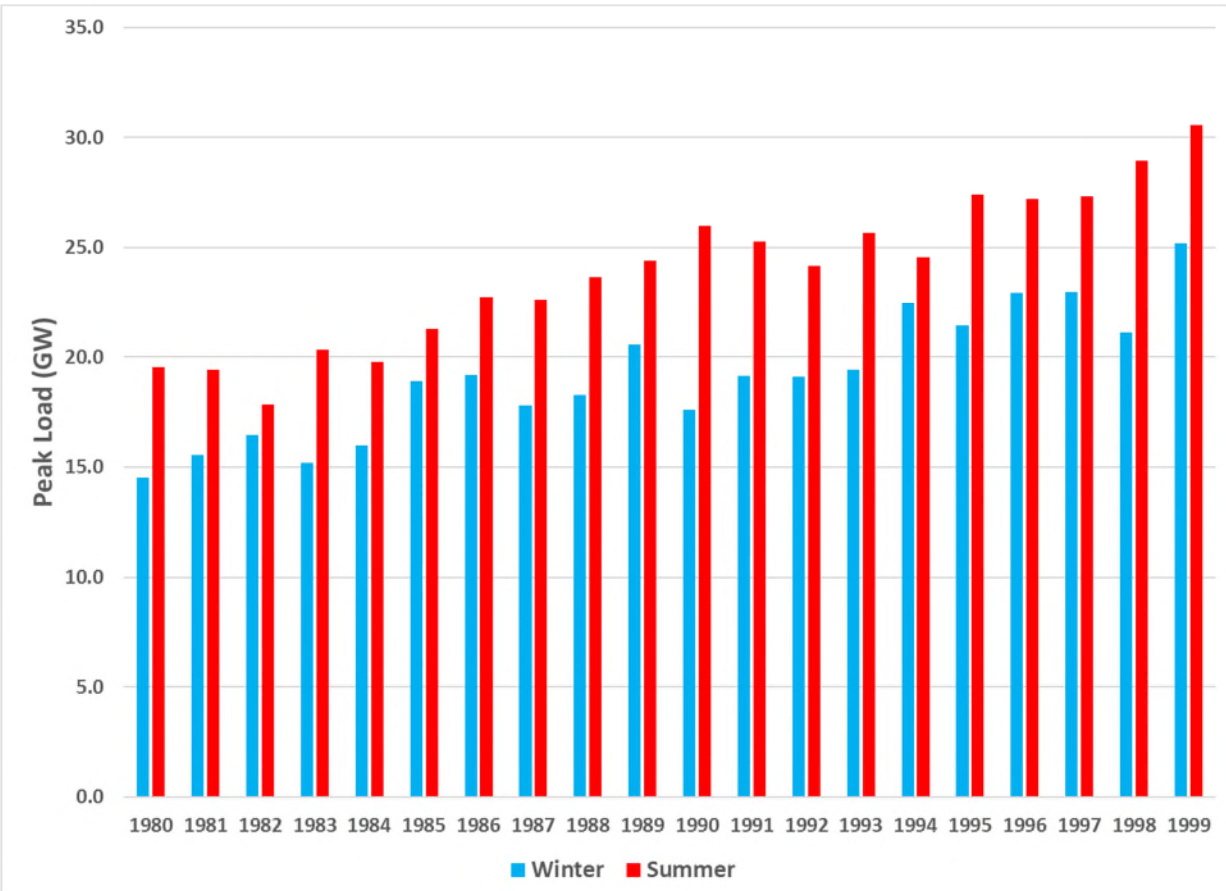

Figure A. 1. Summer and Winter Historical Peak Demands

In addition to being primarily summer peaking, during the 1990s and 2000s, the System only experienced one year, 1996, where system-weighted temperature fell below 10ºF. During that same stretch of time, customer technology and behavior began to change. Emphasis on energy efficiency and summer demand response programs began to alter the dynamics of customer response to extreme summer and winter temperatures. That evolving response (at least as it relates to winter) was never observed due to the absence of the extreme cold-weather events. The streak without extreme cold weather ended in January 2014 with the Polar Vortex event when system-weighted temperatures reached 9ºF. The chart below shows the minimum system-weighted temperatures observed on the System between 1962 and 2015.

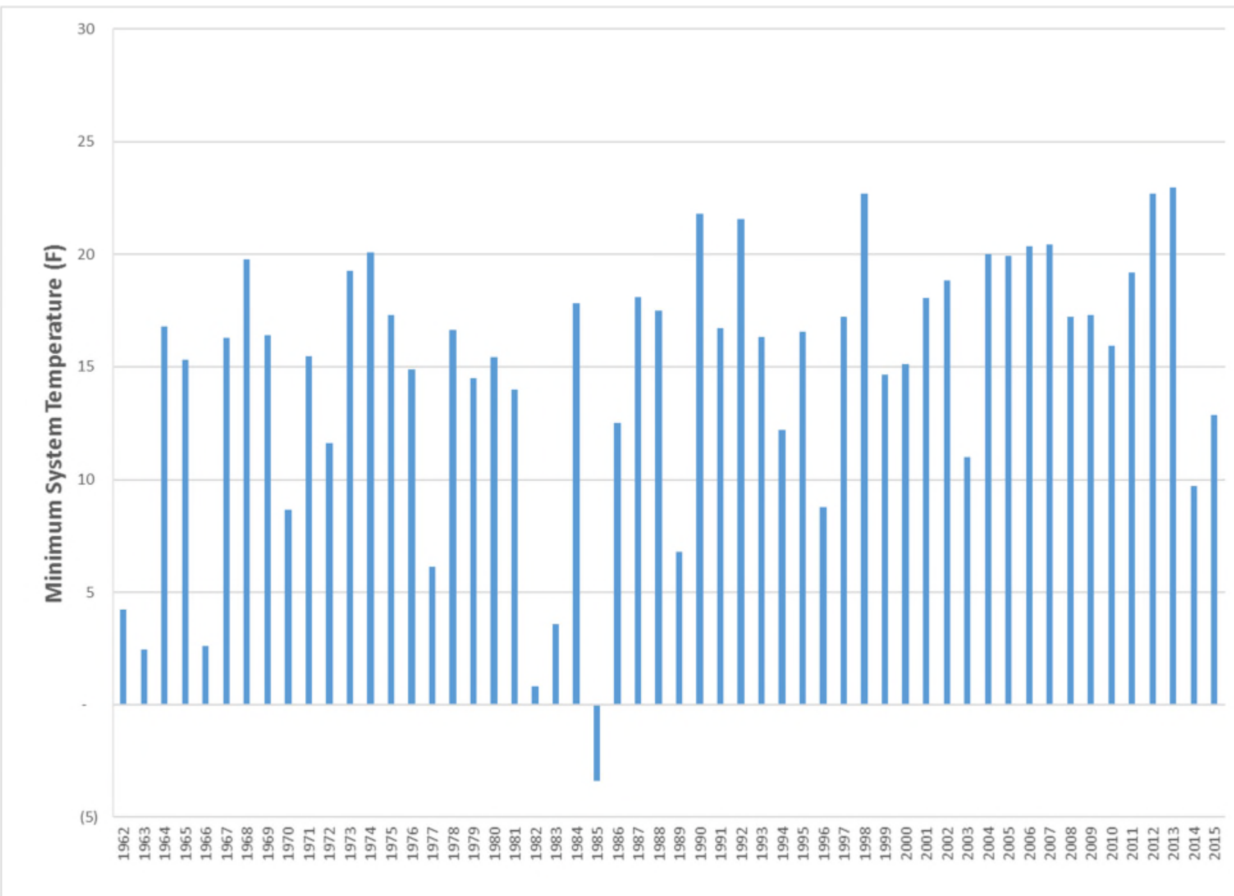

Figure A. 2. Historical Minimum System Temperatures

It was the 2014 Polar Vortex event in which this change in load response was first observed. At that time, the System had a reserve margin of approximately [redacted], representing approximately [redacted] of more reserves in 2014 than what was required by the short-term TRM at that time of 13.5%. Without these additional reserves the System would have experienced a significant loss of load event during the 2014 Polar Vortex, which could have been as large as [redacted]. Similarly, the System may have also experienced such an event in the winter of 2015 but for the approximately [redacted] plus of reserves above the 13.5% short-term TRM. Between 2014 and 2018, there have been 23 winter-weather-related operations advisories,[15] including 20 times when a Conservative System Operations ("CSO") Watch[16] advisory was issued, once when the System declared Alert Level 1A,[17] once when the System declared Alert Level EEA1, and once when the System declared Alert Level EEA2.[18] By comparison, during the same period, there have been only three CSO events directly related to summer peak load conditions.

Even prior to the Polar Vortex event of 2014, operations personnel began expressing concern over reliability risks during the winter peak period. On August 16, 2011, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) issued a report and guidance document expressing the need to be concerned with winter reliability issues. That report, *Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices*,[19] was developed after a February 2, 2011 event in ERCOT in which approximately 1.3 million electric customers did not have service during the winter peak demand of that day. The Operating Companies, however, had already been performing such assessments beginning in 2007 for the 2008 Winter Peak Period. Those assessments first began indicating the potential for a reliability concern when the assessment performed in 2009 for the 2010 winter peak noted "Possible Gas Scheduling Restrictions" as a challenge. The list of challenges expanded each year forward from that point.

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[15] Based upon report generated by Southern Balancing Authority Area.
[16] A CSO is issued when there is an expectation of high load that warrants extreme caution during operations.
[17] A Southern Balancing Authority Area internal "alert" that occurs just prior to NERC Alert Level EEA1.
[18] EEA1 and EEA2 are system alert levels defined by the North American Electric Reliability Corporation ("NERC").
[19] Document accessible from NERC at https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Generating_Unit_Winter_Weather_Readiness_final.pdf.

Currently, there are six primary determinants (discussed in more detail below) that have been identified as key drivers affecting the winter reliability risk concerns on the System, including

- the narrowing of summer and winter weather-normal peak loads,
- the distribution of peak loads relative to the norm,
- cold-weather-related unit outages,
- the penetration of solar resources,
- increased reliance on natural gas, and
- market purchase availability.

Prior to the 2015 Reserve Margin Study, [20] most of these drivers were unobserved and unmodeled in the reliability planning model. The 2015 Reserve Margin Study made a first attempt at modeling these drivers, resulting in an increase in Target Reserve Margin from 15% to 16.25%. Since the 2015 Reserve Margin Study, planners have continued efforts to refine both the modeling assumptions and the modeling techniques surrounding these drivers. In the process, it has become evident that the most effective way to plan for and manage these reliability risks is to establish a Winter Target Reserve Margin.

B. Key Drivers

The six primary drivers affecting the winter reliability risk issue are discussed in the following sections.

B.1 Narrowing of Summer and Winter Weather-Normal Peak Loads

On a weather-normal basis, the System remains a summer peaking utility. However, over the course of the last 10-15 years, the gap between the weather-normal summer peak load and the weather-normal winter peak load has narrowed. Figure A. 3 below shows the one-year ahead forecasted peak loads since 2006 as well as the Budget 2018 forward-looking longer-term forecast. The graph shows how the gap between the summer and winter weather-normal forecasted peak loads has narrowed since 2006 from greater than [redacted] to less than [redacted].

[20] An Economic Study of the System Planning Reserve Margin for the Southern Company System, January 2016.

Because the gap between these peaks has narrowed – and are likely to remain closer in the future – the System has less flexibility to handle any significant variations in seasonal reliability such as those described in the remaining sections below. Therefore, it becomes necessary to examine System performance in the winter independently from the summer through a Winter Target Reserve Margin.

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Figure A. 3. Historical Forecasted Weather Normal Peak Loads

B.2 Distribution of Peak Loads Relative to the Norm

As discussed in the Background section above, customer load response has changed such that response to abnormal weather conditions in the winter is more volatile than the summer. One of the primary purposes of the TRM is to have the resources necessary to handle these abnormal weather conditions. In both the summer and the winter, there is a probability distribution around the forecasted weather-normal peak load. This distribution is determined by the expectation of non-weather-normal conditions, represented within SERVM[21] by the 108 modeled load shapes for the 54 historical weather years. Figure A. 4 below shows the distribution of the modeled summer and winter non-weather-normal peak loads about their respected weather-normal peak load forecast. This chart shows that in the summer the peak load can be either 6.6% higher than the average or 6.8% lower than the average. In the winter, however, the peak load can as much as 22% higher than the average or 14.4% lower than the average. The chart also demonstrates that there is a significant possibility that the winter peak load in any given year can even be higher than the summer peak load.

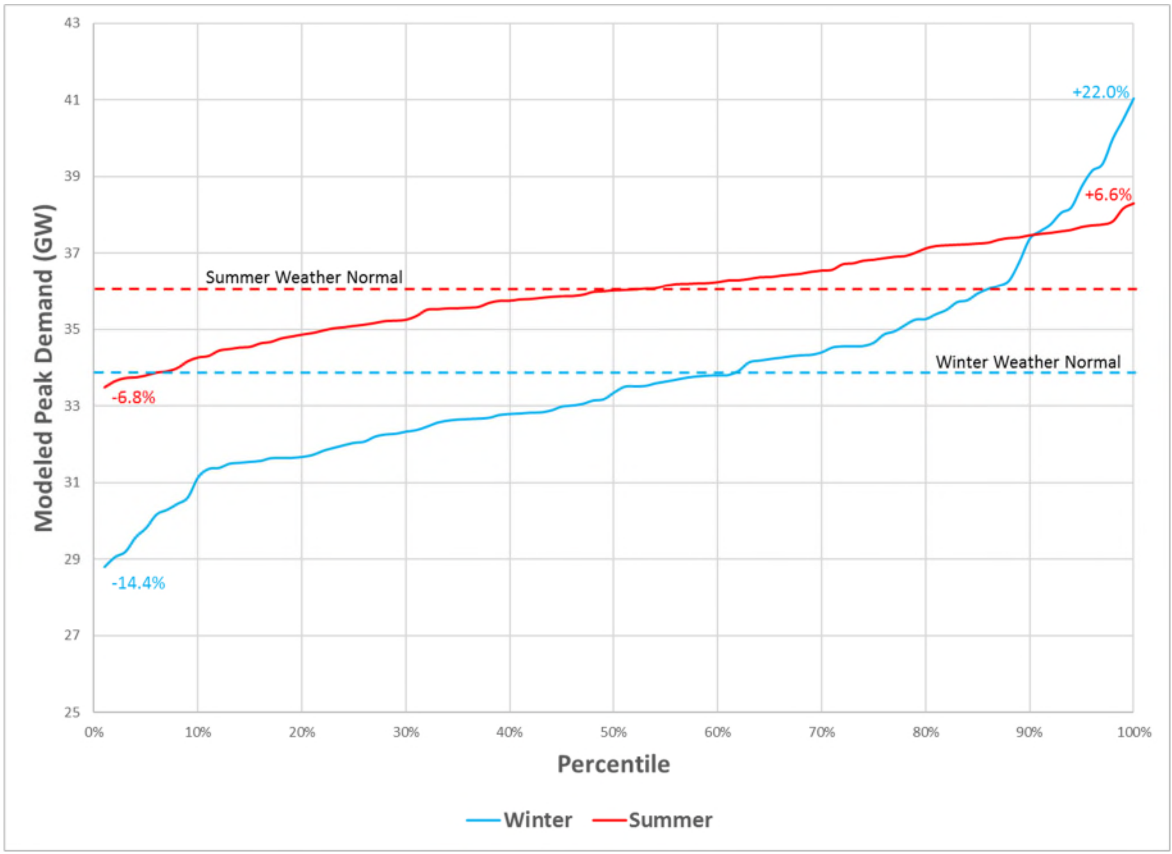

Figure A. 4. Distribution of Modeled Summer and Winter Peak Loads

[21] SERVM is a probabilistic reliability risk evaluation tool used in the Reserve Margin Study and other reliability analyses.

Southern Company

Of the 108 peak loads *modeled* in SERVM, there are 23 winter peaks greater than their respective summer peaks, representing roughly a 20% probability that the winter peak will be higher than the summer peak in any given year. This is consistent with what has been historically experienced. As shown in Figure A. 5 below, there have been two out of the last 10 years (2014 and 2015) in which the *actual* winter peak was higher than the actual summer peak.

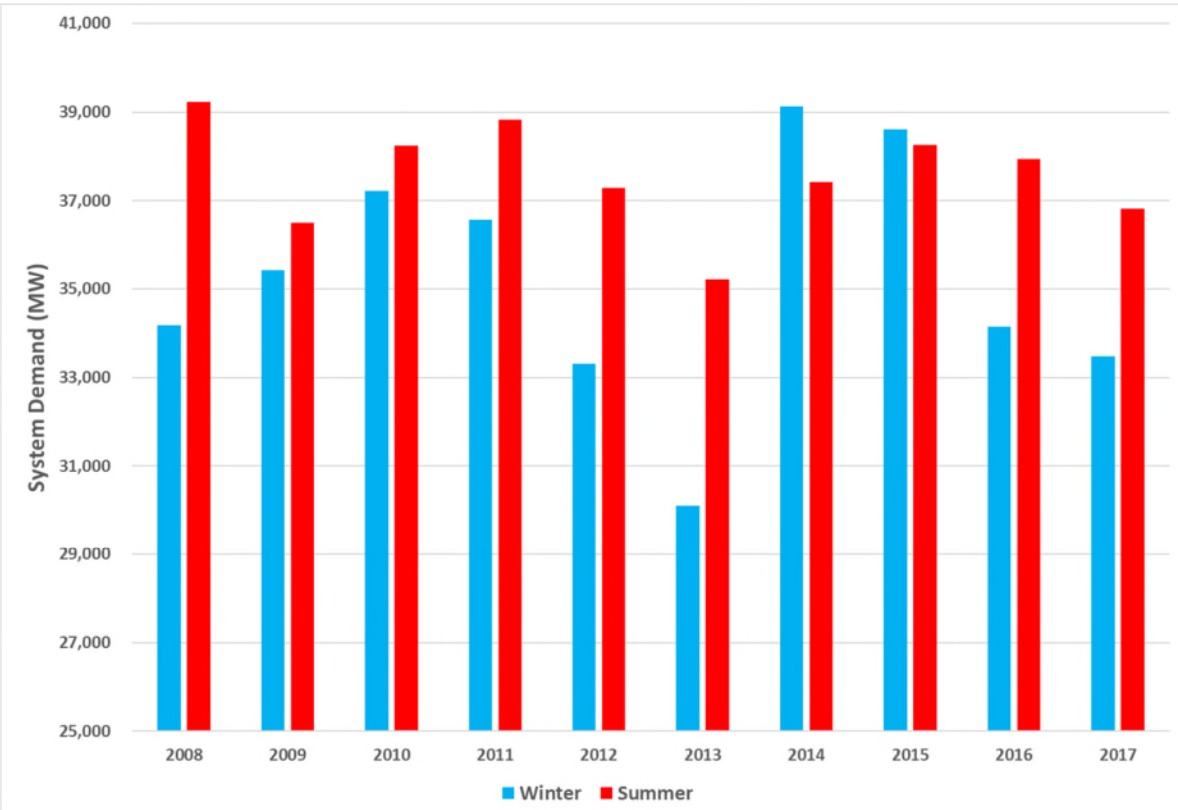

Figure A. 5. Historical Summer and Winter Peak Loads

Note: Figure shows total aggregate load dispatched within the Southern Company Pool.

B.3 Cold-Weather-Related Unit Outages

Extreme cold-weather conditions often result in increased unit outage rates. History has demonstrated that as temperatures continue to decrease the outage rate tends to increase exponentially. While the causes (*i.e.*, the components impacted by the cold weather) may be different for each, steam generators, CCs, and CTs all have vulnerabilities to extreme cold temperatures. Table A. 1 below shows several historical dates when extreme temperatures have occurred on the system. Many of these caused significant outages on the system. The table demonstrates that the colder the temperature, the more likely weather-related outages will occur.

Table A. 1. Historical EFOR During Cold-Weather Events

Date of Event	System Weighted Temperature (F)	EFOR (% of System Capacity)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

After the 2014 Polar Vortex event, the Operating Companies began implementing measures to improve the performance of its resources under extreme conditions. Those measures included the development of Standards of Excellence procedures for preparing generating facilities for cold weather and the addition of freeze protection on certain vulnerable equipment. System plant performance experts are confident that these efforts to improve cold-weather performance will ultimately result in a reduction in cold-weather outages relative to historical trends. However, even with these improvements, there will always remain an exponentially increasing probability of performance risk as system-weighted temperatures reach the more extreme cold levels. Figure A. 6 below shows the trend of the total System outages from Table A. 1. It also shows that same trend adjusted by an assumed average base EFOR of [redacted], representing the incremental outage rate associated with cold weather. Finally, it shows those same incremental outage rates adjusted to reflect the expectation of improved performance over time.

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Figure A. 6. Cold Weather Unit Outage Performance

B.4 Penetration of Solar Resources

While reasonably correlated to summer peak load periods, solar generation is not well correlated to winter peak load periods, which occur around dawn or dusk. Thus, solar resources contribute significantly more toward summer reliability than they do toward winter reliability. Therefore, unless planners are looking at the System from both a summer and winter TRM perspective, the addition of solar resources can give the false impression of increased overall reliability. If only the Summer TRM is considered, a significant penetration of solar resources may contribute toward meeting summer reliability needs but would not contribute significantly toward meeting winter reliability needs, leading to possible winter reliability concerns. Figure A. 7 below shows the expected penetration of solar resources on the System through 2021 along with their corresponding Incremental Capacity Equivalent ("ICE") summer and winter capacity values.

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Figure A. 7. Solar Resource Penetration

This relative seasonal performance of solar resources can be confirmed by observation of actual historical solar output across the top 20 load hours of the summer and winter peak seasons for the solar resources currently installed on the System. Figure A. 8 below shows the relative summer and winter output (as a percentage of nominal installed solar capacity) on the System since 2015 averaged over the highest 20 load hours in the summer and winter periods. Note that the comparison of the average output across the top load hours cannot be used to validate or compare with the ICE values because the two metrics have different meanings, and the historical observations are for only a few sample years. However, both metrics do indicate solar has significantly different contributions to reliability in the summer versus the winter, with significantly less in the winter compared to the summer.

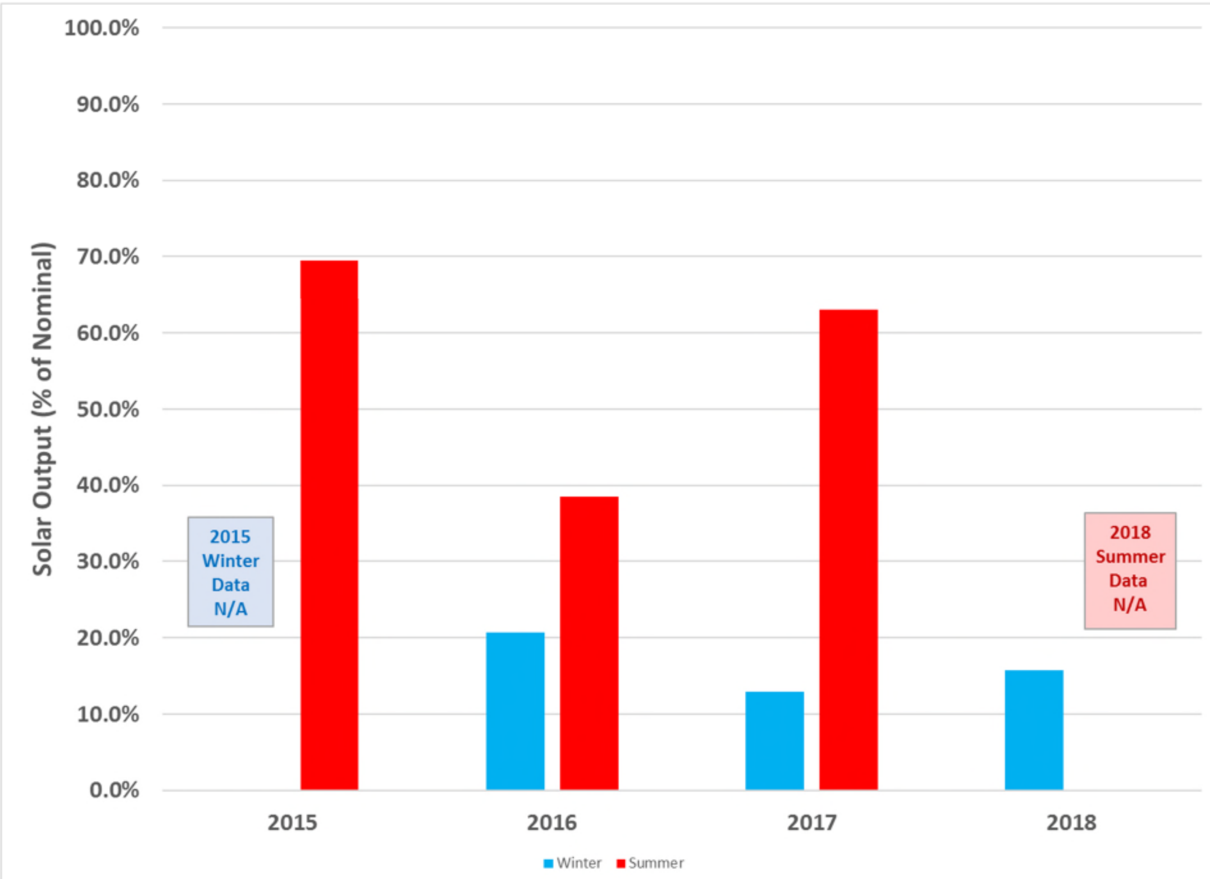

Figure A. 8. Solar Output During Highest 20 Load Hours

B.5 Increased Reliance on Natural Gas

Over the last decade, the System has increased its reliance on natural gas as a fuel source to meet its energy and demand needs. Figure A. 9 below shows the historical and future projected breakdown of energy by fuel type for the System, demonstrating the increased expectation for reliance on natural gas. The "coal or gas" slice in the 2027 Projected pie chart indicates uncertainty in coal vs. gas usage based on uncertainties in the forecasted price of natural gas.

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Figure A. 9. Historical and Projected Energy Use by Fuel Type

This increased reliance on natural gas increases exposure to gas delivery constraints, especially during winter peak conditions, because gas pipelines limit usage to firm transportation contracts. Figure A. 10 below demonstrates that over the last 6 years (2012 thru 2017), most operational flow orders[22] issued by the two primary pipelines that serve the System have occurred during the winter months.

[22] Operational flow orders are issued by pipeline operators when demand for natural gas causes constraints on the pipeline such that only those holding firm gas transportation contracts can utilize the pipeline.

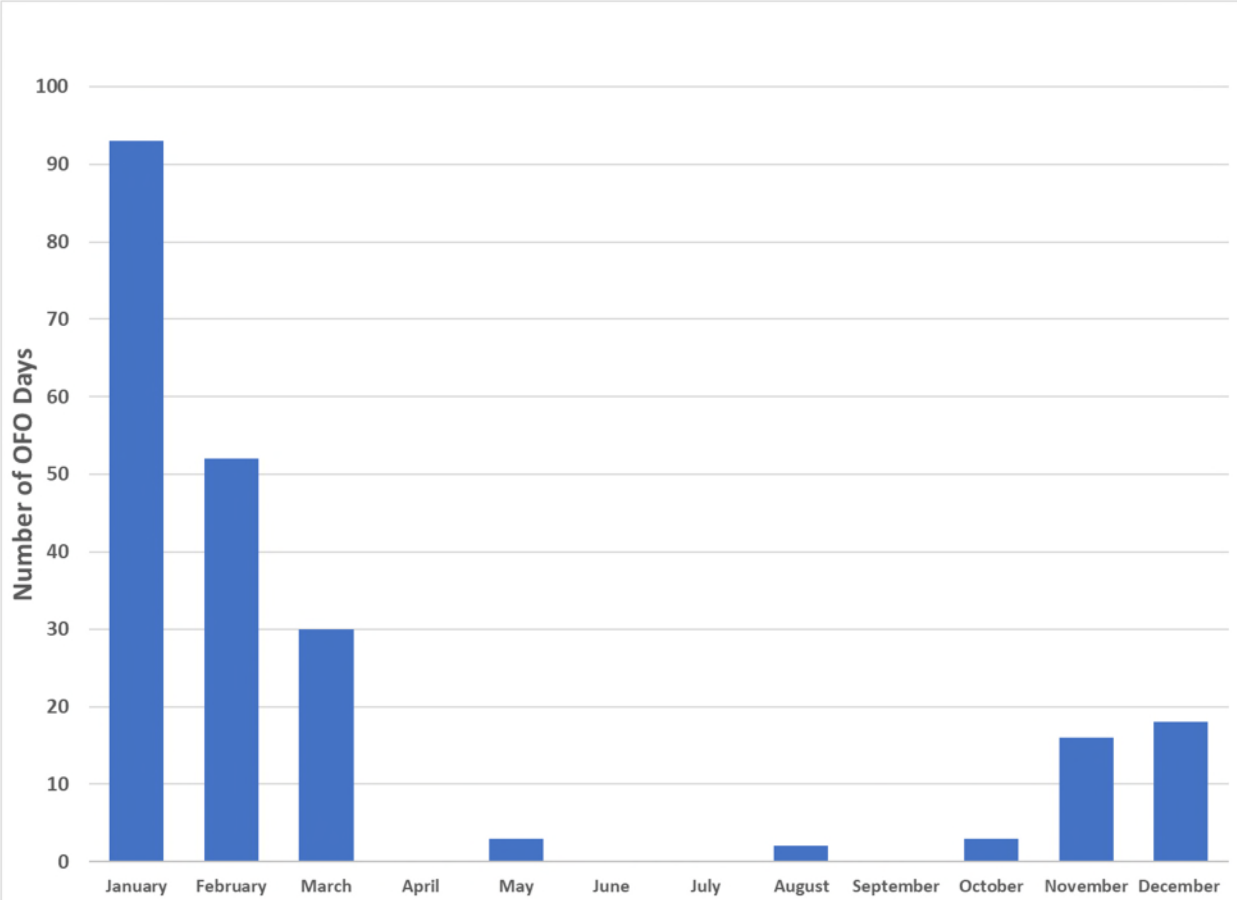

Figure A. 10. Monthly Distribution of Operational Flow Orders

To model the constraints associated with these operational flow orders, SERVM allows the user to phase out the availability of interruptible gas transportation based on the minimum and maximum daily temperature. When no interruptible transportation is available, the model only allows the unit to operate to the extent it has firm gas transportation or an alternative fuel supply such as on-site fuel storage. Figure A. 11 below shows the phase-in and phase-out of interruptible gas transportation as modeled in SERVM.

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Figure A. 11. Interruptible Gas Transportation Model

To mitigate the risk against these operational flow orders, the Operating Companies have a Fuel Policy that requires either on-site backup fuel (such as oil) or the acquisition of firm gas transportation from the pipeline. For CTs, the policy requires the equivalent of [redacted] of firm transportation. For CCs, the policy requires the equivalent of [redacted] of firm transportation for base mode operation and [redacted] of firm transportation for operation in full pressure modes. Unfortunately, while this policy is sufficient for typical (*i.e.*, normal) weather conditions, it can be insufficient for the most extreme weather conditions. As temperatures fall during the more extreme winter conditions, CTs may need to operate greater than [redacted] and CCs may need to operate in full pressure mode more than [redacted]. However, if the pipeline has issued an operational flow order, these resources will not be able to serve load once their firm gas transportation allocation has been fully utilized, resulting in unit outages during critical times causing either the need to operate more expensive oil facilities or, in the worst case, loss of load events. Additionally, the pipeline operators may limit the ability of the CTs to take the nominated natural gas across the [redacted] and force them to take the natural gas in equal increments across 24 hours, limiting the ability to use these resources to meet peak load. The Operating Companies continue to evaluate the risk of such events against the expense of additional firm gas transportation.

B.6 Market Purchase Availability

Traditionally, the reserve margin studies have modeled the regions surrounding the System to incorporate the availability of economic and reliability purchases from those regions. To avoid bias in the analysis results and not include purchases that might not be available in the real world, these regions are generally modeled at or near a reasonable level of reliability – specifically, they are modeled at or near a Loss of Load Expectation ("LOLE") of 0.1 days per year. This modeling effort already results in fewer purchases during the winter than in the summer. This is due primarily to the fact that when the System experiences very high demands resulting from extreme cold temperatures, the surrounding regions also experience those extreme temperatures and demands. Figure A. 12 below shows several recent cold-weather events and the amount of purchases that were available to the System at the time of the event.

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Figure A. 12. Historical Purchases During Cold-Weather Events

This kind of purchase availability restriction can occur during extreme summer temperatures as well, but not to the same degree as in the winter. This creates greater relative market availability risk in the winter than in the summer, further supporting the need to monitor and review winter reliability independently from summer. While absolute limits on purchases are not easily modeled within SERVM, operations personnel did provide purchase availability “targets” (rather than absolute limits) for use in the 2018 Reserve Margin Study. Those targets were implemented by a combination of sales price limitations and hurdle rates between regions.

C. Aggregate Impacts of Drivers on Winter Reliability

Over the past several years, significant efforts have been made to model these winter reliability drivers. The result has been an improvement in the reliability model that more closely matches what has been seen historically in the operational world. The following demonstrates how the modeling of these key drivers has impacted winter reliability.

C.1 Total Available Capacity by Season

In updating unit and system assumptions, one of the impacts that has resulted is a reduction in relative capacity during the winter months as compared to the previous study. In the 2015 Reserve Margin Study, there was considerably more total available capacity at lower winter temperatures than at summer temperatures. It is still true that many resources, such as CTs and CCs, have greater capacity output during cold temperatures than they have during hot temperatures – and were modeled as such in the 2018 Reserve Margin Study. However, not all resources can be depended upon for that additional capacity. Several of the CT and CC resources available to the System are Power Purchase Agreements (“PPA”) that have contractual limitations on the amount of capacity that can be depended upon on a firm basis. While the resource may be able to produce more during the winter, the System does not have firm access to that additional capacity and the counterparty may not be obligated to provide the additional capacity available in the winter. Furthermore, the additional capacity that is available from other CT and CC resources is offset by the lower capacity contributions of solar and demand-side resources in the winter relative to summer. Figure A. 13 below shows that there is very little difference in the available capacity at a System-weighted temperature of 95ºF than there is at either 40ºF, 20ºF, or even at 10ºF.

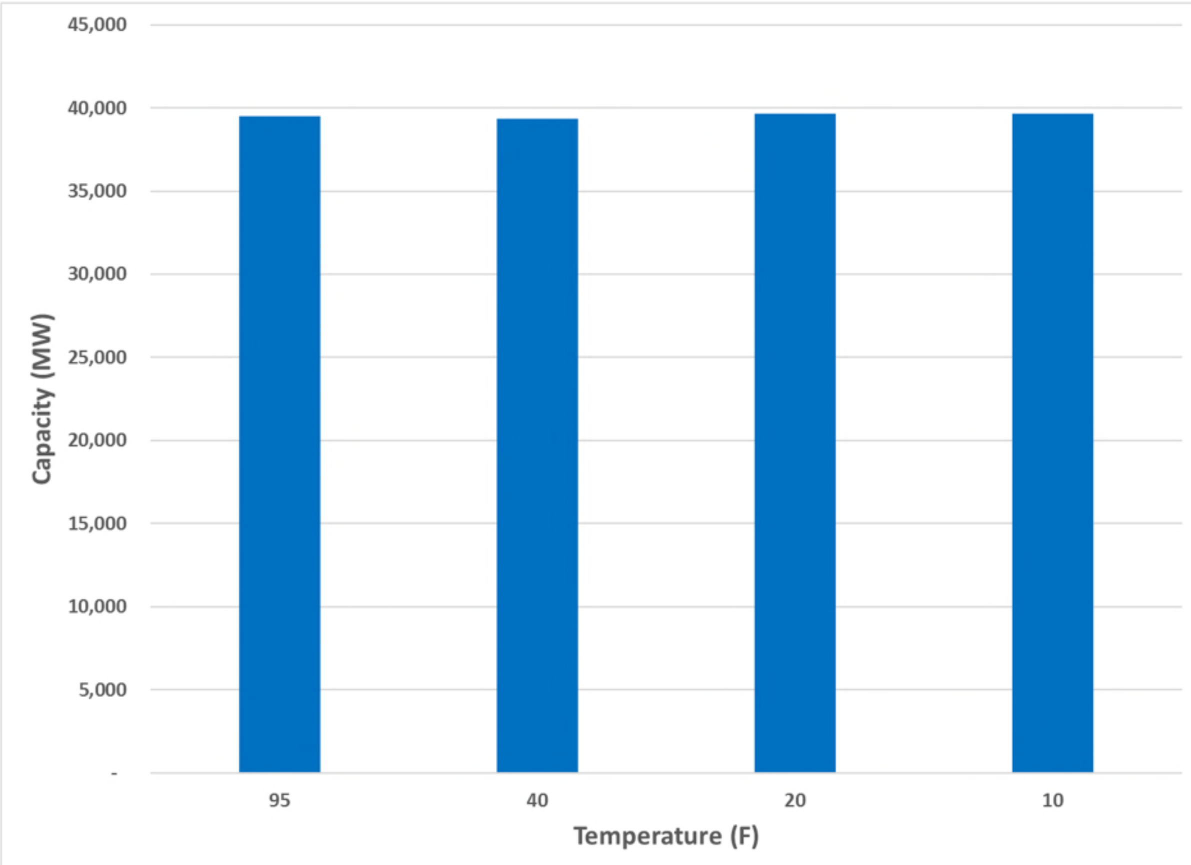

Figure A. 13. Total Available Capacity by Temperature

C.2 EUE by Season

Upon modeling these key drivers, the reliability model shows greater probability of EUE in the winter than has been previously shown. Figure A. 14 below shows the seasonal distribution of EUE at various (summer-oriented) reserve margins. The chart shows that at very low reserve margins, there is significant EUE in both the summer and winter periods. As reserve margin increases, the EUE in both the summer and the winter decreases. However, the EUE decreases much more rapidly in the summer than in the winter. In the winter, there is a probability of substantial EUE even at higher reserve margin levels. This is because the most extreme winter conditions in the model, while having a very low probability of occurrence, have a very high impact on EUE.

REDACTED

Figure A. 14. Seasonal EUE by Reserve Margin

C.3 LOLE by Season

Another way to view the relative risk between summer and winter is through the LOLE. LOLE, expressed in number of days of outage per year, shows the probability that an EUE event will occur in any given month or year. Therefore, while the EUE metric shows both the magnitude and probability of risk, LOLE focuses only on the probability of event, so it is not biased by the occurrence of large EUE events. The figure below shows the relative LOLE for both summer and winter. This chart demonstrates that at lower reserve margins, there is a significantly higher probability of a summer-related event, but at the higher levels, the probability of a winter-related event is greater. Taking Figure A. 14 and Figure A. 15 together, it can be concluded that the summer-related events are relatively small in magnitude while the winter-related events are very large in magnitude. Because the probability of those events remains even at high reserve margins, it becomes necessary to give particular attention to those winter-related risks.

REDACTED

Figure A. 15. Seasonal LOLE by Reserve Margin

D. The Nature of the Winter Reserve Margin

Traditionally, reserve margins have been stated in terms of summer peak demands and summer capacity ratings as stated in the following formula:

$$TRM = \frac{TSC - SPL}{SPL} x\ 100\%$$

Where:

TRM = Target Reserve Margin;

TSC = Total Summer Capacity; and

SPL = Summer Peak Load.

This traditional representation is essentially a Summer TRM and has been the only reserve margin considered because the System (in aggregate) has always been, and remains, summer peaking on a weather-normal basis. These traditional reserve margins stated in summer terms have historically been in the 15-17% range.

However, reserve margins can just as easily be stated in alternate terms. In fact, the traditional Reserve Margin Study is based on an evaluation representing the simulation of an entire year – in fact thousands of alternative simulations of that one year. When the traditional reserve margin is calculated, what is being determined is a specific number of megawatts that are needed relative to peak load. Those megawatts include an underlying existing system (at a 10% reserve margin) and a certain number of reliability CTs added that represents the minimum total cost across the entire year. Once that has been established, a reserve margin can be calculated. That reserve margin is traditionally calculated based on a snapshot of a single hour in that year-long evaluation – the weather-normal summer peak against the official summer unit ratings. However, there are 8,760 hours in the case, each representing different load values and different amounts of total capacity because rated output of the resources in the case changes due to variations in temperature. Therefore, one could theoretically say there are 8,760 different reserve margins in that case – one for each hour of the year. Of present interest, however, are just the summer peak and the winter peak. Just as a summer reserve margin is a snapshot of the summer peak hour against summer capacity ratings, the winter reserve margin is a snapshot of the winter peak hour against the winter capacity ratings. That winter reserve margin is represented by the following formula:

$$Winter\ TRM = \frac{TWC - WPL}{WPL} x\ 100\%$$

Where:
TRM = Target Reserve Margin;
TWC = Total Winter Capacity; and
WPL = Winter Peak Load.

Because winter peak loads are different (lower for a summer peaking utility) than summer peak loads and because winter generating capacity can be different than summer generating capacity, the Winter TRM can be higher than the Summer TRM. The extent to which the Winter TRM is higher than the Summer TRM depends on the relationship between the total available capacity in the summer versus the total available capacity in the winter as well as the differences in the weather-normal summer and winter peak loads. It is not out of the question for a Summer TRM of 15% or 16% to have an equivalent Winter TRM in the mid-to-upper 20s. ***However, this Winter TRM represents both the same cost and the same level of reliability as its Summer TRM equivalent*** – despite the appearances of being a “higher” reserve margin.

To illustrate this relationship, it is possible to take a snapshot of the System at a given moment in time and create a waterfall chart that demonstrates how to translate a summer reserve margin into a winter reserve margin. Figure A. 16 below illustrates this reserve margin translation from summer to winter. Reading the chart from left to right, a 16.25% summer reserve margin is based on summer total available capacity and the summer peak load. However, when moving from summer to winter there are various changes associated with increases or decreases in capacity. This is because some resources have higher capacity ratings in the winter versus the summer and others have lower capacity ratings in the winter versus the summer. Finally, there is a difference in the summer peak load and the winter peak load as well. In the example of Figure A.16, a 16.25% summer reserve margin is equivalent – that is, it has the same cost and the same level of reliability – to a 24.7% winter reserve margin.[23] In other words, if a Reserve Margin Study indicated the need for a 16.25% summer TRM, then it likely also indicated the need for a 24.7% TRM in the winter – especially if the study showed significant EUE potential in the winter.

[23] The 24.7% winter equivalent is based on the study case where the system is reduced to a summer reserve margin of 10% and restored to 16.25% using incremental CTs (consistent with how the Reserve Margin Study is performed).

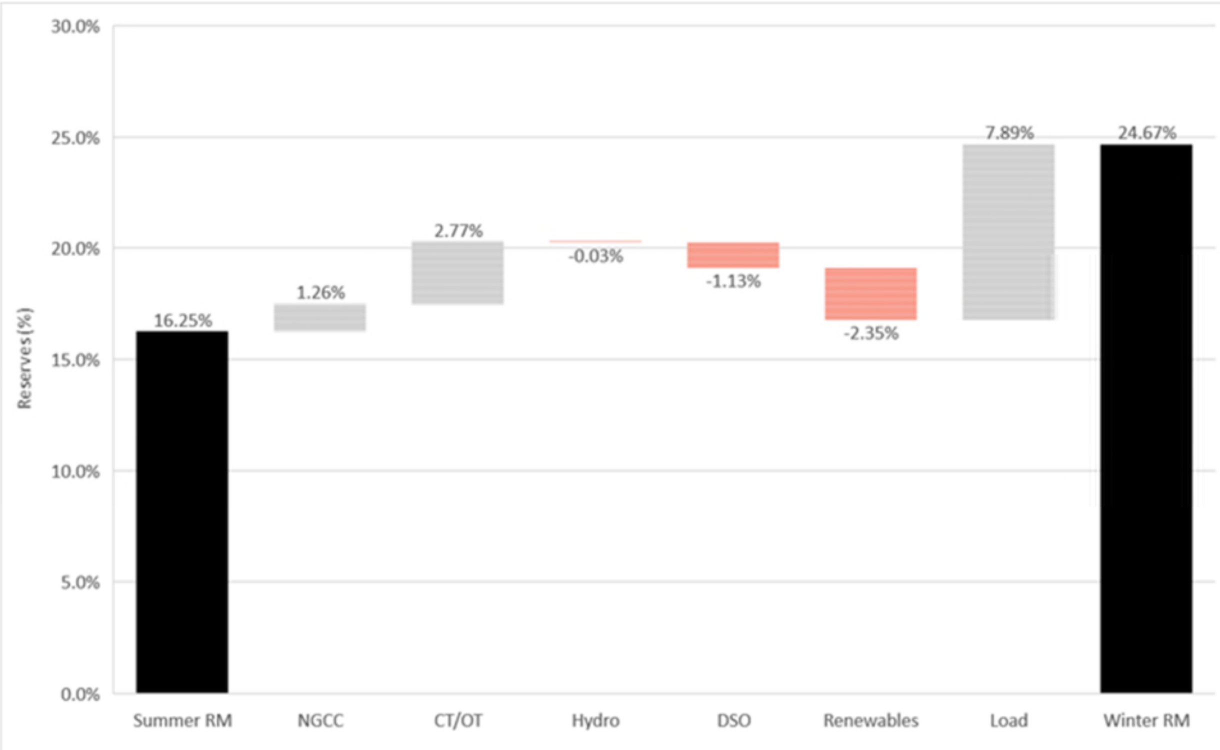

Figure A. 16. Winter Equivalent Waterfall

It should be carefully noted, however, that this waterfall chart is based on a snapshot in time. If anything changes on the System that changes the relationship between summer and winter, this equivalency changes.

E. Resulting Need for Winter Target Reserve Margin ("TRM")

Because the equivalency between summer and winter can change depending upon System conditions, it would be dangerous to only consider the summer TRM of 16.25% when planning the System and presume the winter will always have the necessary 24.7%. For example, if a coal unit were retired and replaced with a CC of equal summer capacity, the winter reserve margin would be higher than 24.7%. This is because a coal unit has the same ratings for both summer and winter while a CC may have more capacity in the winter. Similarly, if a CT were retired and replaced with a solar facility, the winter reserve margin would be lower than 24.7% because the CT has higher capacity in the winter relative to summer, but a solar facility's capacity contribution is less in the winter. Likewise, if the winter peak load forecast increased relative to the summer, the winter reserve margin would be lower than the 24.7%.

Southern Company

This changing winter equivalency phenomenon can be demonstrated by examining how the winter equivalent of the currently approved 16.25% TRM (a summer-oriented value) has changed since the 2015 Reserve Margin Study. The 2015 Reserve Margin Study first introduced some of these winter reliability risks as the reason for the increase in reserve margin at that time from 15% to 16.25%. The winter equivalent of 16.25% from that study – if it would have been calculated at that time – would have been 26% for a study year of 2019.[24] That reliability case was based upon Budget 2016. When reliability cases were updated for Budget 2017, the study year was moved to 2024 and the winter equivalent of 16.25% reduced from 26% to 25.6%.[25] When reliability cases were updated for Budget 2018, the study year was moved from 2019 to 2025; and the winter equivalent of 16.25% dropped again to the 24.7% shown in Figure 16 above. However, that 24.7% is based upon the theoretical situation in which the System is reduced to 10% and restored to 16.25% using incremental CTs. The actual winter equivalent of the existing system if it were reduced from its current state down to 16.25% would only be 23.7%. In other words, if planners only evaluate the system using the 16.25% Summer TRM, they could be misled into believing the system had adequate reliability in the winter (i.e., the presumed 26% winter equivalent required by the 2015 Reserve Margin Study) when the reality would be that the System only had 23.7% in the winter. This could lead to an unexpected and unforeseen reliability event in the winter such as what happened with the Polar Vortex event of 2014.

The Reserve Margin Study identifies the amount of reserves needed to maintain the proper economic and reliability balance in both the summer and winter seasons. It is the requirement identified by the study, not the changing equivalence, that should be considered as part of the planning process. Only considering the Summer TRM from the study essentially plans to the changing equivalence, not the requirement identified in the study, which could be misleading. Therefore, it is necessary to calculate both the Summer TRM and the required Winter TRM and then monitor and plan to both accordingly.

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[24] This winter equivalent is based on reducing the system to 10% and restored to 16.25% using incremental CTs.
[25] This winter equivalent is based on reducing the existing system down to 16.25%; reducing the system to 10% and restoring with incremental CTs would result in a winter equivalent of 26.5%.

F. Conclusion

In conclusion, when the determinants and the resulting impact on seasonal reliability are carefully considered, continuing to plan the System using only a single (summer-oriented) TRM will increase the likelihood of an unforeseen loss of load event like the one that occurred in January 1977 and like what could have happened in January 2014. Therefore, while it may not be possible or cost-effective to completely eliminate the possibility of a winter loss of load event, it is necessary to establish and plan the System on a seasonal basis, with both a Summer TRM and a Winter TRM, to provide the appropriate level of mitigation against such risks.

Appendix B – Capacity Worth Factors

A. Background

Capacity Worth Factors ("CWFs") represent the relative worth of capacity from one period to another (*i.e.*, hour, month, season, etc.). As such, they represent the relative risk of a reliability event from one period to another. CWFs are developed hourly using the SERVM reliability model and from that model, represent the hourly improvement in reliability associated with a "perfect" megawatt (i.e., a megawatt that is available every hour of the year). CWFs can be represented hourly or they can be aggregated and represented monthly or even seasonally. CWFs are calculated at the Target Reserve Margin and so are a downstream output of the Reserve Margin Study and the associated approved Target Reserve Margin.

CWFs in some form are used in almost all System-wide analyses when deriving capacity value, including:

- IIC reserve sharing,
- PRICEM analyses,
- Retirement studies,
- Power Purchase Agreements,
- ICE Factors for the IRP, and
- Renewable Cost Benefit Analyses.

B. The SERVM Reliability Cost Report

The Capacity Worth Factor Table ("CWFT") is derived from the Reliability Cost report produced by the SERVM model. The Reliability Cost report generates the weighted sum of:

(a) the cost of EUE, plus
(b) the cost of expected Reliability Purchases, plus
(c) the cost of any Spinning, Supplemental, or Regulating Reserve shortfall.

Unlike the Reserve Margin Study, when calculating the CWFT, the Company is not interested in cost impacts, but rather in reliability impacts. Therefore, the CWFT is calculated only considering the probability and magnitude (not cost), resulting in a MW-weighting of the potential events identified above. To accomplish this, these events are all modeled with equal costs so that the Reliability Cost report is effectively only weighting these components based on MW impact, not relative cost, using the following modeling techniques:

- Reliability Purchases (defined as any purchase that avoids EUE) are determined by running the SERVM simulation as a “Southern-Only” case; this eliminates the model’s ability to make reliability purchases which, in effect, treats Reliability Purchases as EUE.
- Spinning, Supplemental, and Regulating Reserves are modeled such that load will be curtailed to prevent a shortfall, thus also valuing those shortfalls as EUE.

Figure B.1 below shows all reliability components and which ones are included in the Reliability Cost report as inputs into the CWFT calculation.

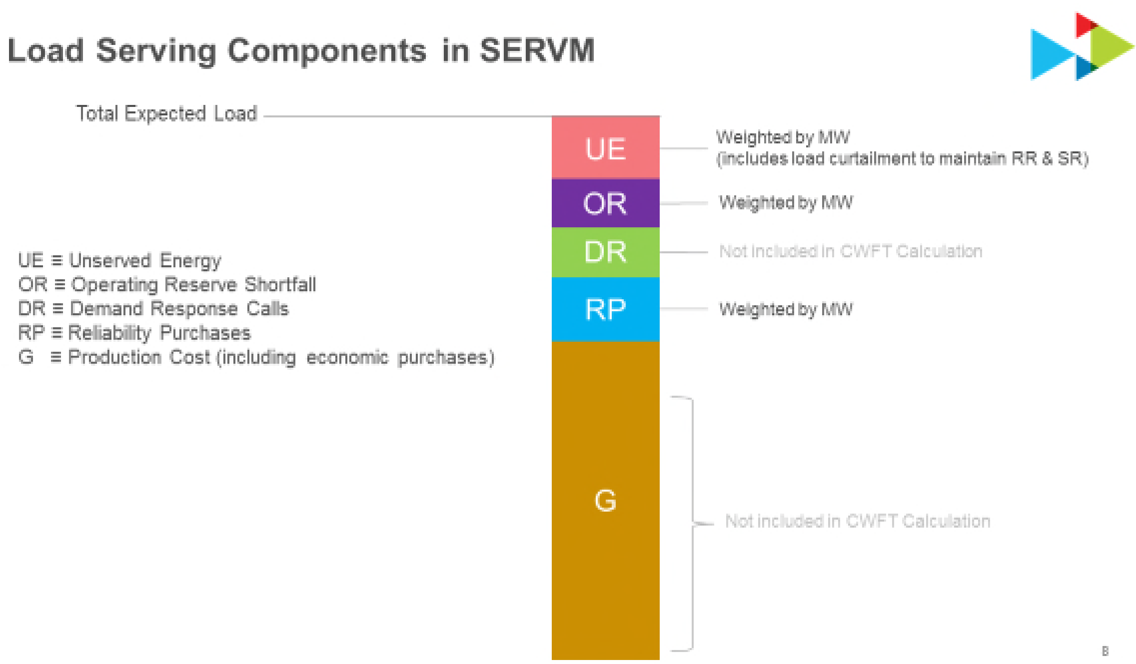

Figure B. 1 Treatment of Reliability Components in the CWFT Calculation

The Reliability Cost report can be generated using a combination of EUE Capacity, EUE IntraHour, EUE MultiHour, Net Purchases, and Production Cost. To generate the appropriate CWFT using this methodology, the Reliability Cost report is generated using EUE Capacity, EUE Intra-Hour, and EUE Multi-Hour (not Net Purchases and not Production Cost).

C. Capacity Worth Factor Results

CWFs are updated with each budget cycle. The 2018 Reserve Margin Study was performed using Budget 2018 ("B2018") vintage data for inclusion in the 2019 IRP. CWFs resulting from the 2018 Reserve Margin Study will not be officially available until after the Budget 2019 ("B2019") Reliability Base Case has been developed and so should be available in the first quarter of 2019. However, a 12x24 representation of the CWFs associated with the B2018 vintage data are shown in Tables B.1 and B.2 below.

Table B.1 shows the CWFT assuming the currently approved 16.25% TRM without Seasonal Planning.

REDACTED

Table B. 1 B2018 Vintage CWFT at 16.25% Summer TRM (Central Prevailing Time)

Table B-2 shows the B2018 Vintage CWFT assuming the approval of the proposed 26% Winter TRM.

REDACTED

Table B. 2 B2018 Vintage CWFT at 26% Winter TRM (Central Prevailing Time)

These tables will change once the Reliability Base Case has been updated for B2019 vintage planning assumptions. Furthermore, Table B-2 should be considered preliminary and indicative only. Table B-2 as shown above has not been used for the purposes of evaluating any renewable resource or any other resources.

Because the 26% Winter TRM is the dominant factor for System reliability, upon approval of seasonal planning, the official CWFT for the System will be the CWFT associated with the 26% Winter TRM.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	**)**	**PETITION**
	)	
Petitioner	**)**	
	)	**Docket No. 32953**

REBUTTAL TESTIMONY OF MARIA J. BURKE
ON BEHALF OF ALABAMA POWER COMPANY

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Maria Burke. I am the Forecasting Manager for Alabama Power Company ("Alabama Power" or the "Company"). My business address is 600 18^{th} Street North, Birmingham, Alabama 35203.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I graduated from Auburn University in August 1986 with a Bachelor of Science degree in Chemical Engineering, and completed my Masters in Business Administration from Samford University in 2001. In 1986, I began my career with the Southern Company at a research facility in Wilsonville, Alabama as a process engineer, and then as an environmental engineer.

I continued my environmental permitting work with Southern Electric International in 1990, helping to develop independent power projects both domestically and internationally. I joined the System Planning Department of Southern Company Services, Inc. ("SCS") in November 1992 and spent the next six years in various engineering and supervisory positions. I was involved in supply-side bid evaluation from December 1996 through March 2000. After working for three years in SCS Transmission and a short time in SCS Engineering as the Scrubber Program Manager, I moved to Alabama Power as the Forecasting Manager, where I have been since 2005.

Q. WHAT ARE YOUR CURRENT JOB DUTIES AND RESPONSIBILITIES?

A. As Forecasting Manager, I have direct responsibility for the development of Alabama Power's demand, energy, customer and revenue forecasts. I am part of the Company's Forecasting and Resource Planning group, which is under the direction of John B. Kelley.

Q. HAVE YOU PREVIOUSLY PRESENTED DIRECT TESTIMONY ON BEHALF OF ALABAMA POWER IN THIS PROCEEDING?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address claims raised by various intervenors, particularly Mr. Wilson and Mr. Howat on behalf of Energy Alabama and Gasp, Inc. While I have made every effort to be comprehensive in my responses to these claims, the absence of any specific rebuttal to each and every aspect of an intervenor's testimony on a given issue should not be construed as acceptance of such position.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. As detailed in the testimony of other Company witnesses, Alabama Power has evolved from a summer-peaking utility to a winter-peaking utility. The load forecast is a critical component in the Company's 2019 Integrated Resource Plan ("IRP") and its determination of the amount and timing of needed resources, as reflected in the Company's petition in this proceeding. My team and I have worked diligently to ensure that we adapt the analytical approach Alabama Power used to prepare the load forecast to accommodate this shift, thereby positioning the Company to continue to provide reliable service to our customers in the winter months. Our analytically rigorous process produced B2019 peak forecast results that are reasonable and reliable. As further verification, we later compared the B2019 peak forecast results against those derived through the application of a newer model, finding them to be quite consistent.

My rebuttal testimony also explains the errors underlying Mr. Wilson's criticisms of the Company's process, criticisms that I find indicative of a fundamental misunderstanding of peak load forecasting by a utility obligated to provide reliable service to customers. Specifically, I address his arguments regarding the Company's weather normal calculation of historical peaks, the adjustments to the Company's Peak Demand Model ("PDM") and the industrial energy forecasting process. Mr. Wilson's testimony makes clear that he would prefer a lower peak demand forecast, and his arguments appear designed to chip away at our methods until he reaches his desired outcome. But Mr. Wilson's result-driven approach is contrary to a fundamental principle of load forecasting; we allow the data inputs and analysis to drive our results, and not the other way around.

Finally, my rebuttal testimony discusses the typical energy consumption patterns of residential customers in the state of Alabama. Alabama residents consume a larger amount of electricity than residential consumers in other states. However, when all forms of energy are considered, Alabama's total residential energy consumption is among the lowest in the nation.

WEATHER NORMALIZATION PROCESS

Q. MR. WILSON CLAIMS THAT THE WEATHER NORMALIZATION PROCESS USED BY THE COMPANY EXHIBITS "ERRORS AND INCONSISTENCIES." IS HIS STATEMENT ACCURATE?

A. No. Mr. Wilson mischaracterizes the Company's weather normalization process. He also makes several erroneous statements regarding practices that he claims the Company should have utilized.

Q. WHY DOES THE COMPANY UTILIZE WEATHER NORMALIZATION OF SUMMER AND WINTER PEAKS?

A. The Company uses weather normalization to enhance its understanding of seasonal peak loads. Weather normalized historical peaks do not, however, serve as the driver for the forecast of peak demand. Instead, the peak demand forecast properly is calculated "bottom up" using the energy forecasts developed by class and by industrial segment.

Q. HOW DID THE COMPANY UNDERTAKE TO WEATHER NORMALIZE WINTER PEAK DEMANDS?

A. The first step involved the determination of how our customers' demand for electricity responds to low temperatures, focusing specifically on temperature-sensitive load that includes residential, commercial and wholesale customers. To do this, we gathered the daily peaks on weekdays in which the temperature was at or below 25 degrees. We also captured the effects of cold build-up by examining data for the following weekday. Then we applied a temperature response slope of -160.33 MW per degree to determine what the identified daily peaks would have been if the system had experienced a temperature of

16.59 degrees,[1] which reflects the typical minimum temperature expected in Alabama Power's service territory in the winter.

Q. HOW DID YOU DERIVE THE TEMPERATURE RESPONSE SLOPE?

A. We developed a regression model by plotting a set of system hourly loads, less industrial loads, against the coincident hourly Alabama Power service area weighted temperatures. The loads used were those occurring on weekdays, during the hours of 6 AM through 8 AM, at temperatures at or below 25 degrees. Industrial loads were excluded from this calculation because our data and experience have shown that electricity consumption by the industrial class is not weather sensitive. This resulted in the referenced temperature response slope of -160.33 MW per degree. I would emphasize that this slope showed a correlation of greater than 75 percent at temperatures below 25 degrees. We then used the -160.33 MW per degree slope as the weather factor to weather normalize our winter peak load. This factor, which can be referred to as the coincident or weather adjustment factor, tells us that for every degree that the cold weather temperature drops below 25 degrees, the demand should increase by approximately 160 MW. In formulaic terms, it can be stated as follows:

Coincident Adjustment Factor = (16.59 – t) * -160.33MW/degree

[where t is the temperature coincident with the peak demand]

Q. WHAT IS THE SIGNIFICANCE OF A 75 PERCENT CORRELATION FACTOR?

A. A correlation factor measures the statistical relationship between an independent and a dependent variable; in this case, temperature and load. The higher the factor, the more

[1] All degree references in this testimony are in Fahrenheit.

direct the correlation. A correlation of 75 percent indicates a strong linear relationship between temperature and Alabama Power's weather-sensitive load.

Q. DOES MR. WILSON CRITICIZE THIS -160.33 MEGAWATT PER DEGREE ADJUSTMENT FACTOR?

A. Yes. First, he expresses consternation over the Company's use of data only from the years 2010, 2014 and 2015. The reason for this is straightforward and consistent with proper evaluative techniques. Specifically, these years provided me with sufficient information to analyze the behavior of system loads in response to cold temperatures. The other years did not contain enough data points from which I could develop a reliable data set. Nonetheless, as the analyses of the three years all yielded consistent results, I find the -160.33 MW temperature response slope to be well supported using the data from these years.

Mr. Wilson also claims that it "is questionable that a parameter based on non-industrial loads was applied to adjust all loads . . . ."[2] However, as a matter of simple math, the weather adjustment was not "applied" to the industrial class load, which as I previously stated, is not weather sensitive. The weather normalized peak load forecast is the sum of the industrial, residential and commercial loads, *plus* the weather adjustment that reflects only the response of weather-sensitive load to changes in temperature. Because this coincident adjustment is additive in nature, it has no effect on the industrial loads. This can be proven as follows:

[2] J. Wilson Testimony, page 18, lines 11-12.

Equation 1:

Weather-Adjusted Peak = Coincident Peak – Coincident Adjustment Factor

Equation 2:

Coincident Peak = Coincident Peak Contribution from Weather-Sensitive Classes + Coincident Peak Contribution from Non-Weather-Sensitive Classes

Substituting Equation 2 Into Equation 1 Yields Equation 3:

Weather-Adjusted Peak = Coincident Peak Contribution from Weather-Sensitive Classes + Coincident Peak Contribution from Non-Weather-Sensitive Classes – Coincident Adjustment Factor

Q. MR. WILSON ALSO CLAIMS THAT THE IMPACT OF INCREMENTAL COLD ON LOAD IS REDUCED AT VERY LOW TEMPERATURES. DOES THE COMPANY'S ACTUAL EXPERIENCE CONFIRM HIS ASSUMPTIONS?

A. No. As evidenced by my Rebuttal Exhibits MJB-1 and MJB-2, the temperature response slope does not change at the low end of the temperature graph. This means that customer response conditions in Alabama Power's service territory continued to grow at a steady rate in response to cold temperatures. As both graphs clearly indicate, the current winter relationship for Alabama Power customers remains linear even at the lowest temperature points.

Q. HOW DO ALABAMA POWER'S WEATHER NORMALIZATION PRACTICES ALIGN WITH THE METHODS OF INDUSTRY PEERS DESCRIBED IN THE ITRON STUDY THAT MR. WILSON REFERENCES?

A. Very well. Alabama Power uses standard industry approaches for weather normalizing historical peak data. Mr. Wilson cites the Itron study to support the proposition that utility peak demand forecasting methods generally show a year-over-year linear trend. This is not the case, however, and there is nothing in Alabama Power's forecasting approach that is inconsistent with the Itron study. For whatever reason, Mr. Wilson misrepresents the Itron study.

Q. HOW DID MR. WILSON MISREPRESENT THE ITRON SURVEY?

A. The Itron study compiles responses to a thirty-question survey of 135 utilities across North America regarding only their weather normalization practices – not the results or the presence or absence of historical trends arising from the utilization of those practices. Moreover, the survey primarily focused on energy weather normalization, with little emphasis on normalization practices for system peak demands. In fact, only seventy-four of the 135 respondents reported that they perform weather normalization of their system peak. Further, the survey question related to peak demand inquired about the kind of weather used to normalize historical peaks—not whether utilities' historical peaks follow a trendline.[3]

In introducing the Itron study, Mr. Wilson claims that "[i]f an effective approach to weather-normalization approach is applied, the weather-normalized past peaks should reflect and reveal trends due only to trends in economic and demographic drivers."[4] There are two problems with this statement. First, his positioning of the statement in proximity

[3] The Itron survey is attached as Reb. Ex. MJB-3.

[4] *Id.*, page 13, lines 4-6.

to the discussion of the Itron study creates the implication that his opinion is also a conclusion of the survey, which it is not. Second, his statement suggests that there will be smooth trends in the non-weather load impacts, which in our experience is not the case.

Q. WHY IS MR. WILSON INCORRECT TO EXPECT ALABAMA POWER'S HISTORICAL WEATHER NORMAL PEAK DEMANDS TO FOLLOW A TRENDLINE?

A. There are several reasons why this is so. For example, Alabama Power's wholesale loads fluctuate, as contractual demands end or wholesale customers elect to meet their needs through resources other than the Company. Also, the industrial class load is volatile, a fact that Mr. Wilson appears to appreciate.[5] These customers, which comprise 40 percent of Alabama Power's retail energy sales, are heavily dependent on regional, national and global economics. Moreover, industrial customers may choose to operate at full production capacity in one hour, but reduce their production the next, for reasons such as an emergency maintenance requirement or an operational parameter change. Such operational fluctuations can occur quickly and significantly alter peak demand, further disrupting any "trend" that might be drawn from historic behavior.

Q. MR. WILSON ASSERTS THAT ALABAMA POWER HAS "DEVIATED FROM ITS USE OF MINIMUM TEMPERATURES" BY SUBSTITUTING CONTEMPORANEOUS TEMPERATURES. IS HIS STATEMENT ACCURATE?

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[5] *Id.*, page 28, lines 4-5 ("Industrial sales are more variable, primarily due to higher sensitivity to economic conditions.").

A. No. Alabama Power's weather normalization calculation is not based on minimum temperatures; rather, it is typically based on temperatures coinciding with peak load. The Company provided Mr. Wilson the appropriate concurrent temperature for each peak in our workpapers.[6] While it is often true that the minimum temperature occurs at the same hour as the winter peak demand, this is not always the case. Relying on the minimum temperature regardless of the coincidence, as Mr. Wilson advocates, would bias the observation of weather normalized winter loads downward. Further, from a technical standpoint, if Mr. Wilson really had concerns regarding Alabama Power's use of coincident—not minimum—temperatures, one would expect him to use the data provided in discovery to develop his own temperature response slope and not to use the Company's -160.33 MW factor.

Q. DOES MR. WILSON OFFER ANY OTHER CRITICISMS OF THE COMPANY'S WEATHER NORMALIZATION METHODS?

A. Yes. Mr. Wilson also states that the Company "does not recognize the impact of cumulative cold weather."[7] This is not true. As I described earlier, Alabama Power's quantification of the peak response on the second day of a cold weather front, or what I termed cold weather build-up, allows us to evaluate the cumulative impact of several consecutive days of cold temperatures. On the first day of a cold weather event, homes and buildings may still retain heat from temperatures prior to the event. However, by the second day, this residual effect

[6] *See* Ex. JFW-8. As reflected in these workpapers, the Company did use an average of temperatures adjacent to the peak hour for 2018, which had the effect of dampening (i.e., lowering) the weather-adjusted peak. The decision to employ a more conservative adjustment was based on the conclusion that an application of the temperature response slope to the temperature reported for the coincident peak would not have been representative of the load's response to a rapid change in temperature.

[7] J. Wilson Testimony, page 17, lines 19-20.

has diminished, and actual electricity demand may register just as strong as the first day, even if outdoor temperatures are somewhat milder. Hence the importance of testing the weather normal magnitude of this second day of the weather event.

Q. WHAT IS YOUR REACTION TO MR. WILSON'S ALTERNATIVE APPROACHES TO WEATHER NORMALIZATION?

A. I find each of them to be a poor substitute. His varying approaches all yield correlation coefficients below 50 percent, with only one above 35 percent.[8] The reason for this lack of correlation is that his analysis is inclusive of all loads and fails to exclude the non-weather-sensitive industrial class. In contrast, and as I discussed earlier, Alabama Power's approach results in a much greater correlation (75 percent) by excluding the industrial class, and thus is a much more accurate approach.

PEAK DEMAND MODEL ADJUSTMENTS

Q. MR. WILSON RECOMMENDS THAT THE OUTPUT OF THE PEAK DEMAND MODEL FORECAST BE USED WITHOUT ANY ADJUSTMENTS. WERE THESE ADJUSTMENTS APPROPRIATE?

A. Yes. The Peak Demand Model ("PDM") is a univariate tool that was developed to forecast system peaks. The term "univariate" means the tool is designed to respond to a single variable, in this case temperature. The PDM does a good job of forecasting summer coincident peak demands because summer temperatures (and customer behavior in response to those temperatures) are relatively stable from hour to hour. However, in the

[8] *Id.*, page 20, Table JFW-1

winter, customer usage in the early morning hours can be quite volatile and temperatures can change rapidly. As a result, developing the appropriate load shape response equations in the PDM model for the winter is more challenging. In recognition of this issue, and in preparation for the B2019 forecasting cycle, Alabama Power identified appropriate modifications to improve PDM's performance in capturing winter peak demand in the Company's service territory. Predictably, Mr. Wilson disagrees with all of them, concluding that none are warranted.

Q. WHAT MODIFICATIONS WERE REQUIRED TO ADDRESS THE ISSUE?

A. We made three modifications: a monthly benchmark adjustment; a January-specific adjustment based on observed conditions in 2018; and an adjustment to reflect known industrial class load additions on the horizon.

Q. PLEASE DESCRIBE THE MONTHLY BENCHMARK ADJUSTMENT.

A. This adjustment benchmarks the output of the PDM against known loads and concurrent temperatures on our system. Specifically, we compared our 2017 actual hourly peak demand and actual hourly temperatures with the hourly modeled results from PDM for the weather-sensitive classes. Differentials were determined for each month, with 349 MW reflecting the value for the peak month of January.[9] The addition of this benchmark adjustment to the results of the PDM model made them more reflective of our specific winter-related issues and, consequently, more representative of our winter peak period.

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[9] Benchmark adjustments were determined for every month; however, the 349 MW adjustment reflects that determined for January, the peak system month.

Q. WITH THIS ADJUSTMENT PERFORMED, WHY DID YOU NEED TO MAKE FURTHER MODIFICATIONS?

A. This adjustment, on its own, did not resolve all issues related to the development of the B2019 forecast, a fact evident to us through an application of known system conditions for January 2018.

Q. PLEASE EXPLAIN.

A. On January 18, 2018, the system experienced an actual peak under conditions virtually equivalent to the design temperature of 16.59 degrees, which I discussed earlier. The actual peak demand was 11,989 MW. The weather normalized peak demand was 12,014 MW. The Company then estimated the expected peak load for 2019, accounting for expected class-specific load changes and losses, which yielded an expected weather normal 2019 peak demand of 11,998 MW. PDM, however, only projected a peak demand of 11,519 MW. With the additional benchmark adjustment of 349 MW, the modified PDM projection for January still fell short of our weather normal expectation by 130 MW.

Q. DOES MR. WILSON HAVE ANY COMMENTS ON THE COMPANY'S 130 MW JANUARY ADJUSTMENT?

A. Yes. Although he does not refute the January adjustment in principle, he contends that the Company miscalculated the January 2018 peak value upon which the calculation is based, claiming it used the "wrong temperature measure."[10] Were I to use Mr. Wilson's approach, however, I would not capture the actual peak experienced by the Company. Accordingly, his argument is without merit.

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[10] J. Wilson Testimony, page 23, line 20 through page 24, line 1.

Q. ANOTHER CLAIM OF MR. WILSON IS THAT THE COMPANY "DOUBLE COUNTED" A FURNACE ADJUSTMENT. IS HIS ASSERTION CORRECT?

A. No. I have reviewed my underlying analysis and have confirmed that the forecasted winter peak value for January 2019 only reflects a single 20 MW furnace adjustment.[11] Specifically, the January 2019 peak value (11,998 MW) is the sum of the unadjusted PDM output (11,519 MW), plus the benchmark adder (349 MW), plus the January-only adjustment (130 MW). As the January-only adjustment includes the furnace, the separate 20 MW furnace adjustment was properly applied only to the remaining eleven months of the year.[12]

Q. DID MR. WILSON HAVE ANY ADDITIONAL CRITIQUES OF THE COMPANY'S PDM MODEL ADJUSTMENTS?

A. Yes. Mr. Wilson also questioned two adders applied to the peak demand, one in 2021 and a second in 2022. These additions reflect the expected arrival of two new industrial loads, one in mid-2020 and a second in mid-2021. The adders were necessary in order for the PDM results to accurately account for the new load.

Q. DID THE COMPANY TAKE ADDITIONAL STEPS TO VALIDATE ITS FORECAST?

A. Yes. While we had a high degree of confidence in our PDM-adjusted results, we decided to pursue a new modeling framework. In furtherance of these efforts, we contacted Itron,

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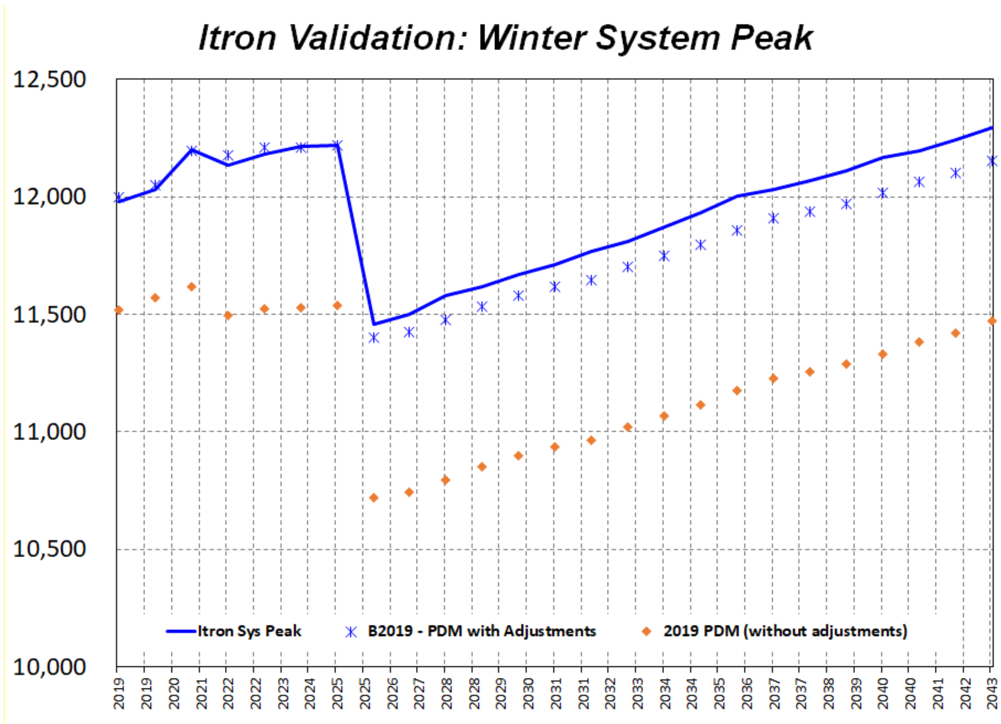
[11] Perhaps the confusion is traceable to his Exhibit JFW-2, which includes a table that erroneously shows the specific furnace adjustment in January. Attached as Reb. Ex. MJB-4 is a table that provides corrected information in this regard.

[12] *See* JFW-10, Row 21.

a well-regarded industry consultant whose work Mr. Wilson referenced in his testimony, to help us develop a tool that would better capture the impact of multiple variables, in addition to temperature, that drive hourly peak demand. Upon completion, we calibrated the tool using our B2019 energy projections. As shown below, use of the Itron tool validated our PDM-adjusted results.



Q. CAN YOU ADDRESS MR. WILSON'S ASSERTION THAT ALABAMA POWER HAS HISTORICALLY OVERFORECASTED ITS PEAK?

A. Yes. Mr. Wilson bases this assertion on his Figure JFW-2, which includes peak demand forecasts from B2007, B2010, B2013, B2016 and B2019.[13] Alabama Power's load forecasts rely in large part on third-party economic forecasts. It should come as no surprise

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[13] *See* J. Wilson Testimony, page 11.

to anyone that the B2007 forecast, compiled in 2006, did not anticipate the magnitude of the economic downturn resulting from the Great Recession that struck in 2008.

After the Great Recession, these economic forecasts consistently underestimated recovery time for the state of Alabama and thus overestimated employment growth for our state. Despite recurring projections of optimistic economic growth, Alabama did not reach its pre-recession employment numbers until mid-2018. Nevertheless, Alabama Power has managed to achieve a high degree of forecast accuracy, as demonstrated in the table below. To the extent the forecast has deviated from actual load, Alabama Power has both over-forecasted *and under-forecasted* peak loads.

Booked Forecast Accuracy

	2012	2013	2014	2015	2016	2017	2018
Residential	-3.4%	-4.4%	-2.3%	-0.2%	-0.8%	-1.3%	-0.2%
Commercial	-1.9%	-1.0%	-1.4%	-1.6%	-2.4%	-2.6%	0.6%
Industrial	-0.6%	-1.8%	4.3%	-2.0%	-6.5%	-0.9%	2.4%
Street Lighting	-0.8%	0.5%	0.3%	-5.1%	-0.5%	-5.5%	-9.9%
Total Retail	-1.9%	-2.5%	0.6%	-1.4%	-3.6%	-1.5%	1.0%
Summer Peak	-6.5%	-3.3%	-1.0%	-0.3%	-3.6%	1.3%	-0.2%
Winter Peak	8.0%	3.5%	12.1%	10.5%	-2.5%	2.7%	1.0%

Negative values denote over forecast (weather adjusted Actuals lower than Forecast)

INDUSTRIAL ENERGY FORECAST

Q. EXPLAIN HOW ALABAMA POWER DEVELOPS ITS INDUSTRIAL LOAD FORECAST.

A. Alabama Power's monthly industrial energy forecast relies on three sources of industrial information: first, near-term survey data drawing directly from existing large customers' operational expectations; second, near-term equipment estimates associated with new customers; and third, monthly econometric regression models developed by segment for the longer term. Through the survey process, the Company collects specific information about its customers' anticipated facility expansions, long-term maintenance and modernization plans and other courses impactful to expected electricity needs.

Q. IS MR. WILSON CRITICAL OF THE COMPANY'S USE OF SURVEYS AS PART OF THE DEVELOPMENT OF THE INDUSTRIAL LOAD FORECAST?

A. Yes. Mr. Wilson questions the Company's use of customer surveys, but his concerns strike me as superficial. The surveys provide us critical insight into specific customer business and operational plans that are not captured in third-party economic data. As noted above, these interviews reveal details such as facility expansions, equipment modifications, efficiency measures and other actions that influence load forecasts—details that are not included in the data Mr. Wilson would have the Company employ. Aside from giving the Company insight into customer-specific operational plans, the surveys also allow Alabama Power to continue to cultivate and support its relationships with industrial customers, further promoting economic development in the state of Alabama.

Q. WHY DOES ALABAMA POWER USE BOTH ECONOMETRIC AND SURVEY DATA IN INDUSTRIAL FORECASTING?

A. Industrial sales represent more than 40 percent of Alabama Power's retail sales and, as noted earlier, are not highly temperature sensitive. Relative to residential and commercial sales, industrial hourly demand can be quite volatile, as customer composition changes, as product demand and manufacturing schedules ebb and flow, as maintenance occurs and as individual customers make plans to grow and expand their businesses. In fact, in his testimony, Mr. Wilson acknowledges that "industrial sales are more variable."[14] Given the complexity inherent in forecasting industrial load, the significant amount of such industrial load and the importance of our industrial customers to the economic health of our state, the Company makes every effort to ensure that this forecast is as accurate as possible. We believe that layering econometric analysis and survey results enables us to better assess our industrial customers' future needs.

Q. DO THE ECONOMETRIC REGRESSION AND SURVEY RESULTS EVER DIFFER?

A. Yes. One example is our military installations, which are included in Alabama Power's industrial customer class. Alabama has been through several rounds of military Base Re-Alignment and Closures, which economic forecasts historically have had difficulty capturing. At one time, the economics showed declines due to national reductions in government spending, but our surveys reflected growth because Alabama installations were chosen to continue programs previously housed at other locations slated for closure. Our surveys gave us the ability to better quantify the energy expectations of our military customers, who were in a position to provide more information than economic forecasts.

Q. WHAT IS MR. WILSON'S PRINCIPAL CRITICISM OF THE COMPANY'S INDUSTRIAL LOAD FORECAST?

A. First, it should be noted that Mr. Wilson rejects the B2019 forecast but embraces the B2018 forecast—which is lower—as "more reasonable," although both forecasts use the same

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[14] *Id.*, page 28, line 4.

methodology.[15] This is yet another instance of Mr. Wilson appearing to select those elements of Alabama Power's forecasting methodology that support his narrative of lower peak demand forecasts.

Mr. Wilson attacks the data underlying the variables used in the econometric industrial load forecast. He strongly advocates for the use of "available, highly relevant" yearly industrial production data supplied by IHS Markit.[16] However, these data provide annual variables, while Alabama Power's monthly forecast requires monthly equations. In addition, our experience with such granular data has proven that they do not yield more accurate forecasts. Thus, the utilization of these same economic variables, but on a national level instead of a state level, provides reasonable econometric modeling results.

Q. BASED ON YOUR EXPERIENCE AS FORECASTING MANAGER, DO YOU HAVE ANY FINAL OBSERVATIONS REGARDING OTHER INTERVENOR TESTIMONY?

A. I find a number of suggestions in the testimony of Energy Alabama and Gasp witness Mr. Howat regarding residential energy use to be misleading.

Q. CAN YOU EXPLAIN?

A. Mr. Howat dedicates much of his testimony to the notion of "home energy security", with a focus on the impact of higher than average electricity bills on residential consumers in the state of Alabama. Electricity bills are driven by two components, the <u>price</u> of electricity and the <u>amount</u> of electricity used by the customer. Mr. Howat confirms that residential

[15] *Id.*, page 6, line 17.

[16] *Id.*, page 30, line 13.

electricity prices in the state of Alabama are relatively modest, ranking 25th out of the 51 jurisdictions reviewed.[17] As he points out, this leaves high customer usage in Alabama as the driver of the higher than average electricity bills.[18] He provides data showing that in 2018, residential customer electricity usage in Alabama ranked 48th among the 51 jurisdictions represented.[19] Mr. Howat concludes that this higher than average electricity usage represents a lack of energy efficiency and creates a financial burden for Alabamians that threatens their home energy security.[20]

Q. IS THIS A FAIR CONCLUSION?

A. No. It is misleading to draw such a conclusion regarding home energy security, or efficient choices respecting energy use, solely on the basis of <u>electricity usage</u>. Residential customers use <u>energy</u> for many purposes, including home cooling and heating, water heating, lighting, cooking and powering other common household appliances. Many of these purposes can be accomplished through a variety of energy sources — not only electricity, but also natural gas, propane or oil. Moreover, while one customer may choose to use electricity for all household energy needs, another customer may use natural gas for home heating, water heating and cooking needs, leaving only the remaining load to be supplied by electricity. A customer's choice regarding the energy source used for each purpose is driven by many variables and differs significantly from state to state and region to region. Obviously, the resulting electricity usage will be different in virtually every

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[17] Howat Testimony, page 8, lines 13-14.

[18] *Id.*, page 8, lines 18-20.

[19] *Id.*, page 8, lines 16-18.

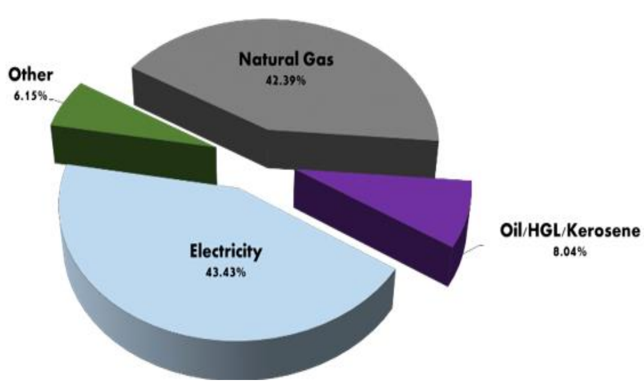
[20] *Id.*, page 8, lines 18-20. *See also id.*, page 4, lines 9-17 & page 15, lines 20-21.

location. Comparing only electricity usage — instead of the total household energy usage — is an incomplete analysis of the factors impacting both energy efficiency and the financial burden associated with a residential customer's home energy security.

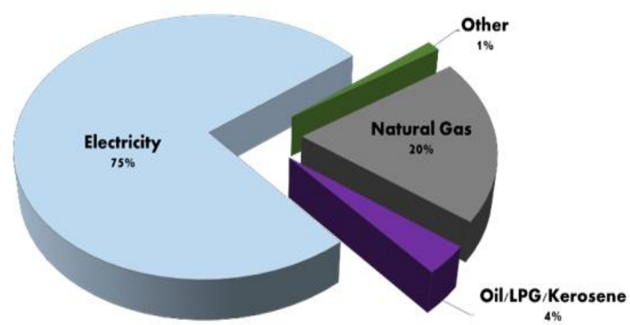
Q. CAN YOU DESCRIBE THE TYPICAL ENERGY CONSUMPTION PRACTICES OF ALABAMA RESIDENTS?

A. In Alabama, customers typically choose electricity as the energy source for more of their household needs, as compared to consumers in other states. For example, many customers in Alabama choose to use an electric heat pump to heat their homes because it is more efficient and cost-effective than other heating options. Put simply, customers in Alabama find that electricity is the best value for meeting many of their household energy needs. According to data gathered by the U.S. Energy Information Administration ("EIA") (depicted in the charts below), approximately 43 percent of nationwide household energy consumption comprises electricity. In contrast, 75 percent of household energy consumption in Alabama is provided by electricity.[21]

National

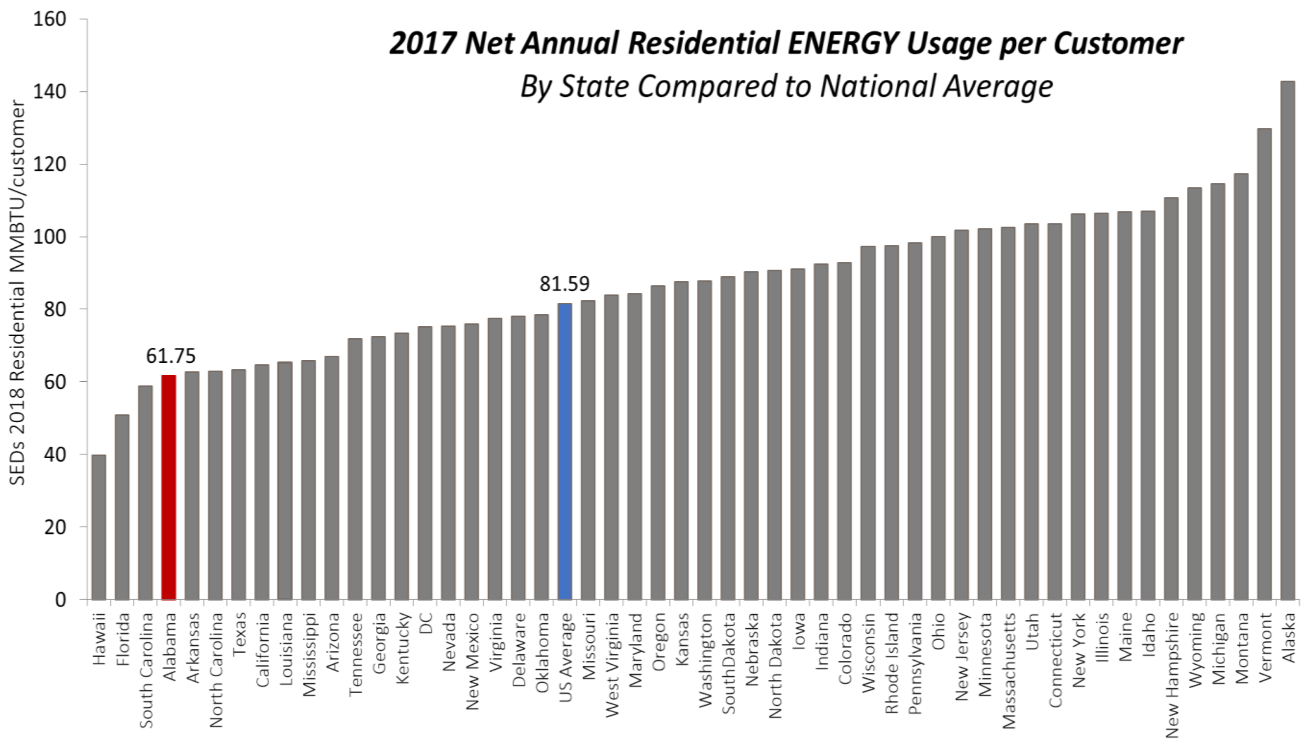


Alabama



[21] *See* U.S. Energy Info. Admin., *Residential Sector Energy Consumption Estimates, 2017*, https://www.eia.gov/state/seds/sep_sum/html/sum_btu_res.html (attached as Reb. Ex. MJB-5).

Accordingly, a fair comparison of energy consumption practices of residential customers across the nation requires consideration of all forms of energy consumed in the household – not just electricity, as Mr. Howat has done. When all forms of energy are considered, Alabama's residential household energy consumption per customer is among the lowest in the country.[22] Specifically, EIA source data for 2017 depicted in the chart below shows that Alabama ranks fourth lowest in total energy consumption per residential customer.



Mr. Howat's focus on electricity usage in isolation makes it appear that Alabama's residential customers are not energy efficient. This is not the case, as evidenced by the

[22] *Id. See also* U.S. Energy Info. Admin, *Electric Sales, Revenue, and Average Price*, 2017 Table 1, https://www.eia.gov/electricity/sales_revenue_price (former data set divided by latter data set).

data depicted above. To the contrary, Alabama energy consumers simply choose to use one energy source (electricity) more frequently than others, but their total energy usage (on a per customer basis) is lower than most consumers across the country.

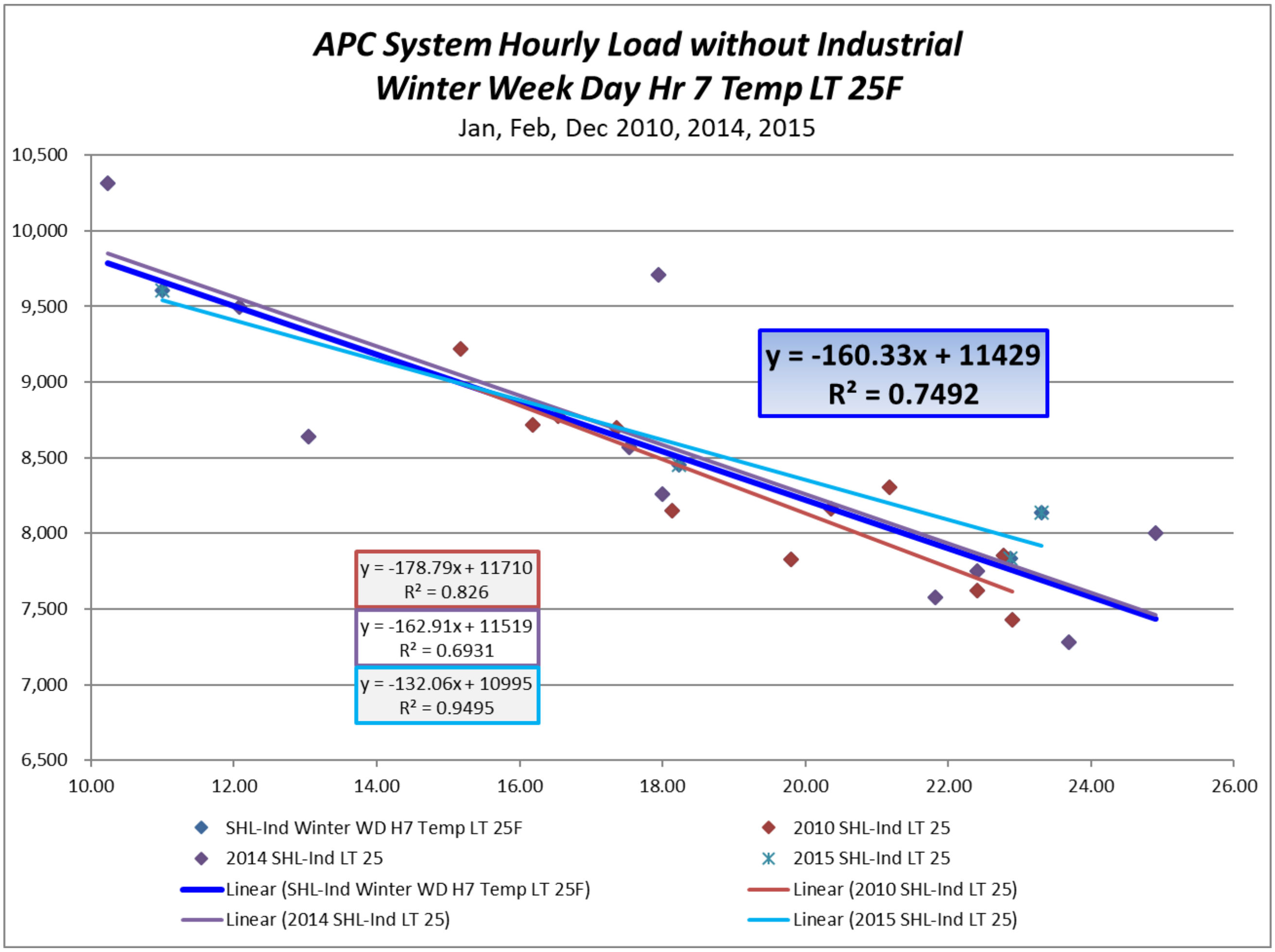
Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Rebuttal Testimony for Maria Burke

Reb. Ex. MJB-1

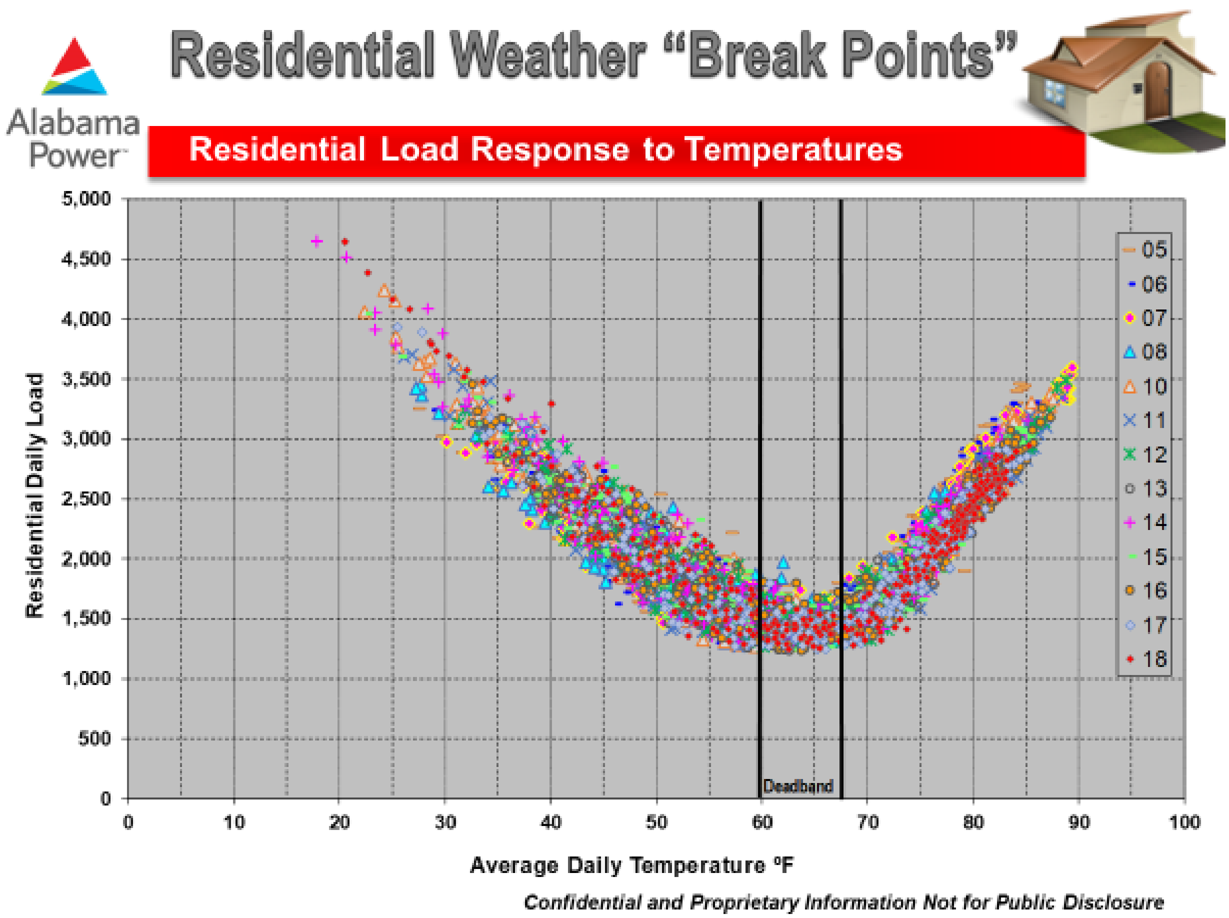
System Hourly Load without Industrial versus Temperature – Low Temperature data does not exhibit a reduced impact of incremental cold on load at lower temperatures. The relationship remains linear at the lowest temperature points.



Rebuttal Testimony for Maria Burke

Reb. Ex. MJB-2

Residential Weather “BreakPoints” Graph illustrates the Residential Load response to Temperature. The APC data on this graph do not exhibit a reduced impact of incremental cold on load at lower temperatures. The relationship remains linear at the lowest temperature points.



Rebuttal Testimony for Maria Burke

Reb. Ex. MJB-4

Corrected Table of Adjustments to PDM for B2019 Monthly Peaks

2019	From PDM Model MW	MW Calibration Factors	January Check (Top Down)	Furnace Correction	DSM Adjustment	Monthly Peak MW
January	11,519	349	130			11,998
February	10,244	56		20		10,321
March	9,106	59		20		9,186
April	8,278	-231		20		8,068
May	9,710	-173		20		9,558
June	10,633	-233		20	-9	10,412
July	10,958	-40		20	-9	10,930
August	11,096	164		20	-9	11,272
September	10,673	-402		20	-9	10,283
October	8,563	225		20		8,809
November	9,200	-156		20		9,065
December	10,307	-258		20		10,070