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May 1, 2020

VIA E-FILE & OVERNIGHT MAIL

Mr. Walter L. Thomas, Jr., Secretary
Alabama Public Service Commission
RSA Union Building
100 North Union Street, Suite 950
Montgomery, AL 36104

RE: Alabama Power Company Petition for Certificate of Convenience and Necessity; Docket No. 32953

Dear Secretary Thomas:

On behalf of Intervenors Energy Alabama and Gasp, please find the enclosed redacted and public version of *Brief of Energy Alabama and Gasp in the Form of Proposed Order* for the above referenced matter. This document is being filed pursuant to the April 17, 2020 deadline for submission of post-hearing draft orders established on March 11, 2020, at the conclusion of the evidentiary hearing, and a subsequent procedural ruling, dated April 14, 2020, altering that schedule. The original and one copy of this public filing are being delivered to the Commission via overnight mail.

A confidential version is being sent via overnight mail to the Commission's Legal Division. Both versions will be served on counsel for Alabama Power Company, and a service copy of the public filing will be served on parties on the service list in this matter.

Please contact me if you have any questions or concerns regarding the enclosed.

Sincerely,

Keith Johnston

Keith Johnston
Southern Environmental Law Center

Enclosures

BEFORE THE
ALABAMA PUBLIC SERVICE COMMISSION

In re: Petition for a Certificate of Convenience and Necessity by Alabama Power Company	))))))))	**Docket No. 32953**

BRIEF OF ENERGY ALABAMA AND GASP IN THE FORM OF PROPOSED ORDER

BY THE COMMISSION:

INTRODUCTION

Alabama Power Company ("Alabama Power" or "Company") has filed with the Alabama Public Service Commission ("Commission" or "PSC") a Petition for a Certificate of Convenience and Necessity ("Petition") seeking authorization to build or procure several proposed resource additions, including almost 1,900 megawatts (MW) of gas-fired capacity, five solar photovoltaic facilities paired with battery energy storage totaling 400 MW,[1] and 200 MW of additional but unspecified demand-side management and distributed energy resource programs. The Petition has been properly noticed, and an evidentiary hearing has been held, at which the Company and various intervening parties submitted evidence for and against the Petition. On the basis of the record compiled at the hearing and other available information, the Commission concludes that the Company's Petition should be denied in part, granted in part, and subject to the conditions set forth below.

[1] This refers to total nameplate capacity of the solar plus battery storage projects.

PROCEDURAL BACKGROUND

On September 6, 2019, pursuant to Alabama Code § 37-4-28 and Parts A and B of Rate CNP – Adjustment for Commercial Operation of Certificated New Plant, Alabama Power filed a Petition for a Certificate of Convenience and Necessity with the Commission. In its Petition, the Company requested that the PSC issue an order granting the Petition, which would authorize the Company to: (1) construct and install combined cycle generating capacity at the site of Alabama Power's Barry Steam Plant located in Mobile County, Alabama ("Barry Unit 8"), with an ultimate winter capacity rating of 743 MW; (2) acquire the Central Alabama Generating Station, a combined cycle generating facility located in Autauga County, Alabama, with a winter capacity rating of 915 MW; (3) acquire rights and assume payment obligations under a power purchase agreement (PPA) pertaining to the Hog Bayou Energy Center, a combined cycle generating facility located in Mobile County, Alabama, with a winter capacity rating of 238 MW; and (4) acquire rights and assume payment obligations under five PPAs pertaining to solar photovoltaic facilities paired with battery energy storage systems ("solar BESS"), located in Calhoun, Chambers, Dallas, Houston and Talladega Counties, said resources having a cumulative winter capacity equivalence of 340 MW (68 MW each). Additionally, Alabama Power seeks authorization to pursue 200 MW of unspecified demand-side management and distributed energy resources. Collectively, these resources total over 2,400 MW, or approximately 19% of current Company capacity, making this the largest single capacity increase the Company has ever proposed for approval by this Commission.

I. Petitions to Intervene

Following Alabama Power's submission, the Commission issued a Notice of Pending Petition, notifying interested parties of the Petition and requiring all petitions for leave to intervene be filed by September 27, 2019. In accordance with this Notice, the following parties filed petitions to intervene: the Attorney General (AG) for the State of Alabama, Alabama Coal Association, Alabama Industrial Energy Consumers (AIEC), Alabama Solar Industry Association (AlaSIA), American Senior Alliance, Energy Alabama and Gasp (Energy Alabama/Gasp),[2] Energy Fairness, Manufacture Alabama, Sierra Club, and Southern Renewable Energy Association (SREA). The Commission subsequently issued an Order denying SREA's petition to intervene based on its failure to demonstrate that its members have a direct personal interest in the docket. The other prospective intervenors, having sufficiently demonstrated their standing to participate in the proceeding, were permitted to intervene.

II. <u>Discovery</u>

Several parties conducted written discovery prior to the hearing. Intervenors, including Energy Alabama/Gasp, Sierra Club, AIEC, AlaSIA, and Alabama Coal Association filed with the Commission and served on Alabama Power interrogatories and/or requests for the production of data and documents. Alabama Power also filed with the Commission and served on AIEC, Energy Alabama/Gasp and Sierra Club separate document production requests.

In addition, Alabama Power, Energy Alabama/Gasp, and Sierra Club noticed and took the depositions of several witnesses in early 2020. Alabama Power noticed and took the depositions of Sierra Club witnesses Mark Detsky and Rachel Wilson. Energy Alabama/Gasp noticed and took the depositions of Alabama Power witnesses Kevin Carden, Jeffrey Weathers, Maria Burke, and Christine Baker. Sierra Club noticed and took the depositions of Alabama Power witnesses John Kelley, Brandon Looney, and Michael Bush, as well as AIEC witness Jeffry Pollock.

[2] Energy Alabama and Gasp were both represented by the Southern Environmental Law Center.

In accordance with the PSC's prior Order concerning hearing procedures, Energy Alabama/Gasp filed a list of deposition designations for the Commission's record and consideration in its final decision. Alabama Power filed deposition designations in response, and Energy Alabama/Gasp filed a reply. Neither party filed objections to the respective deposition designations. To the extent any designated excerpts included a stated objection by Alabama Power counsel, the Company withdrew that objection.

III. Evidentiary Submissions

A. Alabama Power's Direct Testimony

In support of its Petition, Alabama Power submitted the pre-filed direct testimony of five witnesses: John B. Kelley, Director of Forecasting and Resource Planning for Alabama Power; Jeffrey B. Weathers, Manager of Resource Planning for Southern Company Services (SCS); Michael A. Bush, Manager of Generation Planning and Development for SCS; M. Brandon Looney, Manager of Reliability and Resource Procurement for SCS; and Christine M. Baker, Director of Regulatory Pricing and Costing Services for Alabama Power. Mr. Kelley's testimony discussed the Integrated Resource Planning (IRP) process used by the Company to determine the need for new capacity, summarized the proposed resource additions that the Company selected for certification, and discussed the Company's request to pursue 200 MW of unspecified demand-side management (DSM) and distributed energy resource programs. Mr. Weathers' testimony discussed SCS's *An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System*, known as 2018 Reserve Margin Study, and the adoption of a winter target reserve margin. Mr. Bush described the development of the Barry Unit 8 project. Mr. Looney provided an overview of how the resource options were analyzed, including SCS's financial analysis of the various resource options. Finally, Ms. Baker addressed how various rate mechanisms and accounting authorizations would be applied to the proposed resources.

B. Intervenor Testimony

Testimony by intervening parties was due December 4, 2019. The following parties submitted testimony: AIEC, AlaSIA, Energy Alabama/Gasp, Manufacture Alabama and Sierra Club. Several intervening parties did not submit any testimony, including the AG's office, Alabama Coal Association, American Senior Alliance and Energy Fairness.

AIEC filed the direct testimony of Jeffry Pollock, an energy advisor and President of J. Pollock, Inc. Mr. Pollock noted that the Company's proposed capacity additions are not being driven by projected growth in retail peak demand, but instead by the Company's proposed substantial increase to its target reserve margin, along with an expiring PPA (the Calhoun Power Company PPA), generation retirements, and other contractual obligations over the next several years. Mr. Pollock testified that Southern Company has no immediate capacity need, and that for the next few years Alabama Power can meet its capacity obligations by sharing capacity reserves with other Southern Company subsidiaries. Mr. Pollock recommended that the Commission not adopt the Company's proposed 26% long-term winter reserve margin until such time as the Company can re-run or revise its reserve margin study to demonstrate that 26% is the appropriate target. He further recommended that the Commission deny Alabama Power's proposed Petition until capacity is needed. In the alternative, Mr. Pollock recommended that the Commission only approve the proposed resources needed to replace capacity associated with the expiring Calhoun Power Company PPA (specifically, Barry Unit 8).

AlaSIA filed the direct testimony of Maggie Clark, the Senior State Affairs Management for the Solar Energy Industries Association. Ms. Clark provided an overview of solar power in the southeast, solar power's role in economic development, the current cost of solar power, and the benefits of corporate procurement through "green tariff" programs.

Energy Alabama/Gasp filed the direct testimony of three witnesses: James F. Wilson, Karl R. Rábago and John Howat. Mr. Wilson, an economist and independent consultant doing business as Wilson Energy Economics, focused on flaws in Alabama Power's peak load forecast and Southern Company's 2018 Reserve Margin Study that caused the Company to overstate its capacity need. Mr. Wilson opined that Alabama Power's winter peak forecast includes upward adjustments that are methodologically flawed and should be rejected. As for the 2018 Reserve Margin Study, Mr. Wilson asserted that it contains various flawed assumptions that lead to the study substantially overstating the reserve margins necessary to satisfy reliability or economic objectives. Mr. Wilson concluded that Alabama Power's future capacity needs are overstated by roughly 1,400 MW.

Mr. Rábago, principal of Rábago Energy LLC, focused on the flaws in Alabama Power's planning and justification processes and concluded that Alabama Power has continued a long-standing effort to build rate base and revenue requirements through excessive, unnecessary, and expensive new central station fossil-fired generation. He recommended that the Commission deny and indefinitely defer the Company's proposals to construct and acquire gas-fired generation, while approving the solar BESS projects. Mr. Rábago also recommended that the Commission order the Company to conduct a solicitation for additional solar BESS resources, and to develop a plan for identifying and procuring cost-effective DSM and distributed energy resources.

Mr. Howat, Senior Policy Analyst at the National Consumer Law Center, focused on the economic impact that Alabama Power's Petition will have on customers, especially low income customers. Mr. Howat noted that Alabama Power residential customers' electricity usage and bills are among the highest in the nation, and that low-income Alabamians carry very high electricity burdens. Observing that the Company spends much less than the national average on energy savings programs, Mr. Howat recommended that the Commission require Alabama Power to continuously approve all cost-effective energy efficiency. Mr. Howat also recommended that the Commission require the Company to collect, and make publicly available, various data points on general residential and low-income residential billing, arrearages, late payment charges and disconnections for nonpayment.

Manufacture Alabama's President and CEO, George Clark, filed direct testimony in support of the Petition, with particular interest in the new gas generation, Barry Unit 8.[3]

Sierra Club filed the direct testimony of Rachel Wilson, Principal Associate with Synapse Energy Economics, Inc., and Mark Detsky, an attorney and partner at Dietze and Davis, P.C., as well as the direct testimony of six witnesses to establish its standing to participate in the proceeding.[4] Ms. Wilson concluded that the proposed gas units are a mismatch for the Company's projected need and that Alabama Power has not demonstrated that its Petition is the least-cost option. Ms. Wilson conducted her own analysis to show that using a portfolio of 50% demand side management and 50% renewable resources had a lower levelized cost of energy than the proposed Barry Unit 8. Ms. Wilson also discussed the risks associated with gas plants.

Mr. Detsky argued that Alabama Power did now allow the market to decide the best resources. He recommended that the Commission approve the five solar BESS projects, require

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[3] Alabama Power is a dues-paying member of Manufacture Alabama. Tr. 956:5-15.

[4] On March 2, 2020, Sierra Club and Alabama Power entered into a stipulation regarding Sierra Club's standing to intervene and standing witness testimony. The Company agreed to forego cross-examination of these witnesses and allow their pre-filed testimony to be admitted into the record, with the condition that the testimony is offered only for establishing Sierra Club's standing.

Alabama Power to conduct the 2020 request for proposals (RFP) for renewable resources as required by the Order in PSC docket 32382, extend that Order until 2026, and issue new guidance on RFPs to ensure market competition.

C. Alabama Power's Rebuttal Testimony

On January 27, 2020, in response to the testimony filed by intervening parties, Alabama Power filed rebuttal testimony of the five witnesses who submitted initial testimony, as well as two new rebuttal witnesses, Kevin Carden, Director of Astrapé Consulting, LLC and Maria Burke, the Forecasting Manager for Alabama Power.

Mr. Kelley focused on the Company's claimed capacity need, the Southern Company System Intercompany Interchange Contract (IIC), the projected decline in peak load between 2019 and 2031, the Company's resource identification process, and the Company's demand-side management programs. Ms. Burke emphasized the importance of the load forecast in determining the timing of resource needs while responding to criticisms of the Company's weather normal calculations, adjustments to the Company's peak demand model forecast, and the industrial energy forecasting process.

Mr. Weathers reiterated the Company's reasons for implementing a winter-specific target reserve margin and responded to several criticisms of the reserve margin study, including the risk-adjusted Economic Optimum Reserve Margin, the value of lost load, winter outage assumptions, and the use of 54 years of weather data. Mr. Carden, who is a former employee of Southern Company and whose Company is the licensor of SERVM, the software used by SCS to perform its reserve margin study, performed an after the fact review of SCS's inputs and methods used in the reserve margin study, determining that, in his judgment, they were reasonable and appropriate.

Mr. Bush reiterated the Company's position that Barry Unit 8 will be a reliable and valuable resource through its 40-year lifespan. Mr. Looney responded to criticisms of the methods, assumptions and tools used to evaluate the economics of the proposed resources. Finally, Ms. Baker responded to claims and arguments set forth by Mr. Pollock, explaining how the Company is correctly applying its rate mechanisms.

IV. <u>Pre-Hearing Motions</u>

Sierra Club filed a Motion to Deny on March 2, 2020. Sierra Club's motion asserted that Alabama Power has failed to carry its burden of proof in this matter and that the proposed expansion is not supported by the facts. Sierra Club moved for the entry of an order denying the Petition at the conclusion of the hearing. Alabama Power filed a response stating that it would address Sierra Club's arguments in its post-hearing brief.

V. <u>Hearing</u>

The Commission held an evidentiary hearing from March 9, 2020 to March 11, 2020. At the outset, the parties gave limited, three-minute opening statements. Alabama Power, as the party with the burden of proof, then presented its case, with its witnesses appearing in the following order: Jeffrey Weathers, Kevin Carden, Maria Burke, John Kelley, Michael Bush, Brandon Looney and Christine Baker. Each gave a short, one minute overview of his or her testimony, and was then tendered for cross-examination by intervening parties. On the final day of the hearing, the intervening parties presented their witnesses in the following order: George Clark for Manufacture Alabama; Maggie Clark for AlaSIA; Jeffry Pollock for AIEC; Rachel Wilson and Mark Detsky for Sierra Club; and James Wilson, Karl Rábago and John Howat for Energy Alabama/Gasp. Each intervenor witness was allowed to give a one minute summary of his or her testimony prior to being tendered for cross-examination.

At the conclusion of the hearing, the Commission directed the parties to submit post-hearing briefs in the form of proposed orders by April 17, 2020. Following a motion by Energy Alabama/Gasp and Sierra Club, the Commission granted an extension until May 1, 2020 to file proposed orders.

GOVERNING LEGAL STANDARDS

The Commission has general supervisory jurisdiction over Alabama Power pursuant to Alabama Code § 37-1-32. Pursuant to that authority, the Commission has a statutory duty to "inquire into the management of the business and [to] keep itself informed as to the manner and method in which the business is conducted." *Id.* The Commission likewise has a statutory duty to perform ongoing supervision of the Company's overall financial health, the needs of its generating fleet, and its responsibility to render adequate service. *Id.* The Commission has authority to grant or deny the Company's Petition, in whole or in part, and to prescribe any conditions it deems advisable to accompany its grant of approval. Ala. Code § 37-4-28.

As a regulated public utility, Alabama Power has a statutory duty to "render adequate service to the public and [to] 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." Ala. Code § 37-1-49. The Company may not proceed with the construction or acquisition of generating units without this Commission's approval in the form of a certificate of convenience and necessity. *Id.* § 37-4-28.

In a certificate proceeding such as this, the Commission has historically viewed its role as involving two fundamental determinations. First, it must determine whether the Company has shown a need for additional capacity. Report and Order at 3, *Ala. Power Co. Petition for a Certificate of Pub. Convenience & Necessity,* Docket No. 26115 (Ala. P.S.C. Dec. 31, 1997).

Second, the Commission must determine whether the proposed facilities are a reasonable means of satisfying that need. *Id.* The Commission has consistently interpreted the latter element as requiring the most cost-effective solution to the Company's capacity need. *See, e.g.*, Order at 2, *Ala. Power Co. Petition to Amend an Existing Certificate of Convenience & Necessity*, Docket 27785 (Ala. P.S.C. Apr. 22, 2009). Cost-effective in this context is synonymous with least-cost. Tr. 322:10-21. Ultimately, the Commission must determine, under the totality of the circumstances before it, whether granting the certificate is just and reasonable and in the public interest. Order at 11, *Ala. Power Co. Petition for a Certificate of Convenience & Necessity*, Docket No. 32382 (Ala. P.S.C. Sept. 16, 2015).

DISCUSSION

In accordance with the above legal standards, the Commission must evaluate whether Alabama Power has carried its burden to demonstrate both a capacity need and that its proposed resource additions are the least-cost means of meeting that need. As the Commission undertakes this evaluation, it notes from the outset that this is the largest single capacity expansion ever proposed by the Company, approximately 19% of the current fleet, and that it is driven by a new winter reliability standard for which the Company also seeks Commission approval. Tr. 319:16-21. The Commission also notes that, unlike prior certification proceedings, there is substantial opposition to the Company's request, including from industrial customers. Intervening parties have challenged both the amount and timing of the Company's alleged capacity need, as well as whether the proposed additions are least-cost and in the public interest.

I. Alabama Power's Claimed Capacity Need

The Company's claimed capacity need arises from its IRP process. Tr. 458:22–459:2. The IRP process is the analytical tool used by the Company to identify the timing, amount, and types of resources necessary to serve long-term expected energy and demand requirements of customers. Kelley Direct Test. 5:21-23. The Company describes it as 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 customers." *Id.* at 6:10-21. Using updated marginal cost projections, the Company evaluates both supply-side and demand-side options. The Company asserts that it looks to achieve an "optimum combination" of both resource types to meet projected demand and energy needs in a reliable and cost-effective manner. *Id.* at 7:6-9.

The Company engages in integrated resource planning on an annual basis, and each time, considers a 20-year load forecast. Tr. 164:11-16. However, the Company presents its IRP results to the public only once every three years in the form of a short summary document, and no public meetings or hearings are held concerning the development of the Company's IRP, even if the IRP identifies a substantial capacity need. Tr. 459:6-10, 460:13-18.[5]

The Company's 2019 IRP is the basis for the capacity need asserted here. Tr. 458:22–459:2. The Company's prior IRP, from 2016, forecasted adequate capacity out to 2035. Energy Ala./Gasp Hr'g Ex. 57, at 5 [hereinafter 2016 IRP] ("Alabama Power's customer electrical requirements can be met reliably with the Company's current supply-side and demand-side resources until 2035, at which time there is an indicated need to add intermediate generating capacity to reliably meet projected demand."). The Company now projects an immediate winter capacity need and says its needs will continue to grow until the 2023/2024 winter season. Tr. 440:2-12. However, it should be noted that the 2016 IRP discussed many of the same emerging

[5] This contrasts the IRP processes in the neighboring jurisdictions of the Tennessee Valley Authority and Georgia Power Company, Alabama Power's sister company. In these jurisdictions, the public has an opportunity to provide input into the development of the IRP. *See* Tr. 460:21–461:4.

winter reliability concerns as the 2019 IRP while still projecting no new capacity need until well into the next decade. *See, e.g.*, 2016 IRP at 9 (noting that "customer demands have been growing in winter months" and that "in recent years, with colder weather, Alabama Power's winter peak demand has exceeded the summer peak demand").

The determination of the amount and timing of needed resources begins with an update to the Company's load forecast—i.e., its forecast of future energy and peak demand requirements for the next 20 years. Kelley Direct Test. 7:12-14. As Mr. Kelley testified, the Company uses its updated load forecast to identify a schedule of resources required to serve that load reliably. The question of need includes consideration of an appropriate target reserve margin, i.e., a margin of generating capacity above the Company's anticipated peak load. *Id.* at 7:20-21. According to the Company, the target reserve margin allows it to "maintain sustained reliability for its customers, notwithstanding unpredictable events such as equipment failures or extreme weather." *Id.* at 7:21-22.

In the 2016 IRP, the Company cited a need to increase its long-term (i.e. greater than three years) target planning reserve margin from 15% to 16.25% for several reasons, "including the predicted effects of extreme cold weather events." 2016 IRP at 4. Now, however, in the 2019 IRP that underlies this Petition, the Company cites the need for a separate 26% long-term winter reserve margin for the Southern Company System ("System"). The proposed new winter target reserve margin is based on results from the 2018 Reserve Margin Study performed by SCS for the Southern Retail Operating Companies, including Alabama Power.[6] Ala. Power Co. Hr'g Ex. 20, at 2-3 [hereinafter 2019 IRP]. As Mr. Kelley testified, the 2018 Reserve Margin Study

[6] With SCS at its agent, the Company engages in coordinated resource planning with the other retail operating companies in the Southern System, i.e., Georgia Power and Mississippi Power. Kelley Direct Test. 5:6-10. SCS performs the Reserve Margin Study every three years as part of that process. Tr. 65:9-12.

confirmed a "significant increase in winter reliability risks." Kelley Direct Test. 8:10-11. As Mr. Kelley acknowledges, however, this same increase in winter reliability risks was first identified in the 2015 Reserve Margin Study accompanying the 2016 IRP, and as noted, that prior IRP identified no capacity need prior to 2035. *Id.*; *see also* 2019 IRP at 24 (stating that "the 2015 Reserve Margin Study results shown in the 2016 IRP identified a significant increase in winter reliability risk due to several factors . . .").

Now, as in 2016, the Company identifies several factors as driving the increase in winter reliability risks: (1) a narrowing of the difference between summer and winter weather-normal peak loads; (2) higher volatility of winter peak demands relative to summer; (3) increased unit outages due to cold weather; (4) greater penetration of solar resources; and (5) increased risk of fuel delivery disruption due to winter conditions. 2019 IRP at 24-25. To this pre-existing list, the Company adds a sixth, previously unidentified factor—decreased supply alternatives from wholesale power markets. *Id.* at 25.

The Company's claimed winter capacity need ultimately results from a combination of its updated load forecast and proposed target winter reserve margin. Tr. 60:6-9. Taking the two together, the 2019 IRP revealed a projected resource deficit for the 2019-2020 winter of 1,650 MW, which grows to over 2,400 MW by 2023-2024. 2019 IRP at 27, Figure III-D-2. Given the size of the claimed capacity need, it is important to examine the assumptions underlying the updated load forecast and 2018 Reserve Margin Study.

A. Problems with Alabama Power's Winter Peak Load Forecast

The Company uses its peak demand forecast to determine its projected capacity needs. Tr. 245:12-15. The Company uses a model it refers to as the Peak Demand Model (PDM) to project its future weather normalized winter and summer peak demands. *See* Tr. 284:5-11. As part of its peak load forecasting, the Company also calculates weather normalized historical peak loads, which are estimates of what peak loads would have been had those peaks occurred under typical peak-producing weather. Tr. 245:16-20; *see* 2019 IRP at Fig. III-B-1.

Calculating historical weather normal peaks is a relatively new endeavor for Alabama Power. The Company did not begin calculating weather normalized historical peak loads until 2015, Tr. 249:15-18, and used actual historical peaks for its winter peak demand forecast in the 2016 IRP. Tr. 249:23–250:8, 2016 IRP at Fig. III-B-1. The 2019 IRP was the first IRP to use the weather normalization approach. Tr. 250:9-11.

Typically, a utility's load forecast is reasonably consistent with recent trends in weather normalized peaks, unless there are reasons to expect deviations. J. Wilson Test. 4:3-9. Over the past several years, economic and demographic drivers have been reasonably stable, and, until the recent coronavirus pandemic, were expected to remain so. *Id.* at 12:8-18. Therefore, Alabama Power's 2019 forecast, as reflected in the 2019 IRP, should be reasonably consistent with recent weather normalized peak loads. *Id.* at 12:16-17.

Here, however, the Company's winter weather normalized peak values indicate large fluctuations from year to year—including over 900 MW in two recent years. 2019 IRP at Fig. III-B-1. This pattern would be atypical under a reasonable methodology and is indicative of errors and inconsistencies in the Company's approach to estimating peak demand. In addition, the Company applied several questionable upward adjustments to the PDM's winter peak projections. As a result of these flawed upward adjustments, the Company's peak demand forecast appears overstated by roughly 700 MW, which is almost equivalent to the capacity of the proposed Barry Unit 8.

1. Errors and inconsistencies in the Company's forecast methodology.

The following is a summary of errors and inconsistencies in the Company's peak forecast methodology as shown by the evidence in the record. When those errors are addressed, and a consistent methodology used, a steady trend appears in the weather normalized historical peak load values. The corrected methodology shows that six of the past seven winters have had weather-normalized peak loads within 190 MW of MW. This trend calls into question Alabama Power's forecast, as MW is MW less than the roughly 12,200 MW peaks that the Company forecasts for 2023 and 2024, and is line with the PDM model's forecast for 2023 and 2024. Tr. 1188:16-23; *see* J. Wilson Test. at Fig. JFW-1.

a. Inconsistent use of coincident temperature

The Company described its weather normalization methodology as relying on coincident temperature (i.e. temperature in the hour of peak). Tr. 269:17-23. The Company compares the coincident temperature to a "design temperature" of 16.59 degrees, which is considered indicative of the "typical minimum temperature" in the Alabama Power Service territory. Tr. 256:11-20, 258:12-23. If the coincident temperature exceeds the design value, the Company's weather normal calculation increases the peak load value. Tr. 260:17–261:1. For example, if the peak load to be weather normalized is 10,000 MW at a coincident temperature of 20.59 degrees (4 degrees above the design temperature), the Company would adjust the load upward by 641.32 MW (4 x 160.33 MW).[7] *See* Burke Rebuttal Test. 5:15-18 (providing the Company's equation). Conversely, if the peak load occurred at less than 16.59 degrees, the Company would adjust the load downward by 160.33 MW/degree. Tr. 261:2-7.

[7] This is the temperature response slope, which the Company developed to show how customers' demand for electricity responds to low temperatures. Tr. 252:1-9. It allows the Company to predict a load response for each degree of temperature difference.

The problem is that the Company did not consistently use a coincident temperature approach. Tr. 271:14-20. In its initial filing, the Company used the daily minimum temperature instead of the coincident temperature in several instances. Tr. 271:21–272:3. After these and other inconsistencies were revealed at the deposition of Ms. Burke in February 2020, but just days before the hearing, the Company made an errata filing in which Ms. Burke revised six of the 13 weather-normalized years used in the Company's winter peak load forecast. *See* Tr. 274:17–275:7. *Compare* Energy Ala./Gasp Hr'g Ex. 2 at 3 (Ms. Burke's corrected workpaper) *with* Energy Ala./Gasp Hr'g Ex. 3 at 3 (Ms. Burke's original workpaper). Ms. Burke's corrected calculations, which endeavored to consistently apply coincident temperature, yielded several weather-normalized values that were higher than those in the original figure. *Id.*

Furthermore, the Company's approach, even after corrections, continues to conflate the coincident temperature and minimum temperature approaches. The Company's design temperature of 16.59 degrees is based on the typical *minimum* temperature for Alabama Power's service territory. Burke Rebuttal Test. 4:20–5:2; Tr. 258:12-23. Thus, Ms. Burke's weather normalization approach involves taking a coincident temperature load value and adjusting it with reference to a minimum temperature, which is often colder than the coincident temperature. Had she made an apples-to-apples comparison, using daily minimum temperatures as the point of comparison to her design value, the resulting weather normalized values would have been lower.

b. Problems with using coincident temperatures to calculate weather normalized peak values

Even when consistently applied, the Company's reliance on coincident temperatures is problematic because it tends to inflate weather-normalized values, resulting higher peak load projections. As noted, Ms. Burke's corrected calculations produced several higher weather normalized values.

The problem is illustrated by another departure from the coincident temperature approach that Ms. Burke's errata filing did not correct. As Ms. Burke conceded at the hearing, she did not use a coincident temperature approach for one recent year, 2018. Ms. Burke instead used the average of two temperatures adjacent to peak, 16.75 degrees, which is "virtually equivalent" to the design temperature of 16.59 and should result in a weather normalized value that is very close the peak load. Tr. 270:2-12; Burke Rebuttal Test. 13:7-8. Indeed, by using an average, as opposed to the coincident temperature, Ms. Burke's weather-normalized peak demand (12,014 MW) was very close to the actual peak demand for the day (11,989 MW). Burke Rebuttal Test. 13:8-14. However, in this one instance, Ms. Burke's calculation was close to the actual peak demand only because she did not follow her own methodology. Had Ms. Burke followed the Company's stated approach and used the coincident temperature (19 degrees), the weather normalized value for 2018 would have been 362 MW higher. Tr. 271:3-13; Energy Ala./Gasp Hr'g. Ex. 2 at 3.

A more reliable approach would have been to use a different metric—such as daily minimum temperature—and apply it consistently. As Mr. Wilson explained, loads during cold weather are mainly influenced by temperatures in the hours preceding peak. J. Wilson Test. 17:8-12. The coincident temperature, which occurs during the hour of the peak load) is often higher than the minimum temperature for the day, which often occurs earlier, e.g., between 6:00 and 7:00 AM. *See, e.g.,* Tr. 270:2-12 (in 2018 the minimum temperature, during the 6:00 AM hour was 14.5 degrees, while the temperature during the 8:00 AM hour (the peak) was 19 degrees). Therefore, coincident temperature has less explanatory power than using a temperature prior to the peak load, such as the daily minimum temperature or the temperature in the preceding hour. *Id.* 17:10-12.

Mr. Wilson calculated the winter weather normalized historical peak loads using a minimum temperature approach. Unlike the Company's calculations, he found a consistent trend in winter weather normalized values, with six of the past seven summers within 190 MW of MW. Tr. 1188:16-23. This suggests that the Company's projected peak demand projection for 2023 and 2024 (12,200 MW) is substantially overstated.

c. Inconsistent application of the 25 degree cap

The Company's weather normalization analysis begins with looking at weekdays when temperatures fall below 25 degrees. Tr. 264:18-23. The 25 degree threshold functions as a cap; if a coincident temperature exceeds it, the Company uses 25 degrees. But the evidence shows the Company did not apply the cap in 2006 or 2013. Had it done so, the weather normalized calculation would have been about 1,000 MW less than the stated value of 11,338 MW for 2006, and 600 MW less than the stated weather normalized calculation of 11,531 MW for 2013. *See* Tr. 279:21–281:13. In both instances, the Company's failure to apply the cap resulted in weather normal values hundreds of megawatts higher than they would have been under a consistent approach.

d. Issues with the second-day cold weather approach

Alabama Power typically calculates its winter weather normalized value by using the actual peak load date. But for some of the years covered by its analysis, the Company weather normalized multiple dates instead of just the peak load date. Ms. Burke justified this deviation by stating that the Company is looking at the cumulative nature of cold weather. Burke Rebuttal Test. 10:14-17. However, this approach was not cumulative in nature, because the Company still used a single hour and temperature to calculate its weather normal value. Instead, this approach allowed the Company to shop around and cherry-pick the highest weather normalized value.

For example, on January 8, 2015, the (actual) peak load was 12,398 MW and the coincident temperature was 11 degrees. Energy Ala./Gasp Hr'g Ex. 2, at 3. On January 9, 2015, the peak load was a lower 11,094 MW and the coincident temperature was a warmer 26.85 degrees. *Id.* Even though the actual load was lower and the temperature was higher, the weather normalized calculation was higher for January 9, 2015, so Ms. Burke chose it as the winner. Tr. 275:13-16, 265:22–277:13.

2. Flawed adjustments to the peak load forecast

For the 2019 forecast, Alabama Power's PDM model results were lower than the Company's weather normalized peak loads. Tr. 286:1-6. While this discrepancy might have caused the Company to doubt the validity of its weather normalization methodology, the Company instead viewed it as calling into question the accuracy of its PDM model. Tr. 247:5-11, 286:1-6. To bring the PDM model results in line with the weather normalized values, Ms. Burke made several upward adjustments to the PDM forecast. Tr. 286:7–287:8. Collectively, these upward adjustments produced a roughly 700 MW increase in projected peak demand. *See* Ala. Power Co. Hr'g Ex. 18; Burke Dep. 109:18–110:4. Because these adjustments almost equal the capacity of the proposed Barry Unit 8, it is extremely important to determine whether they were warranted.

a. 349 MW Upward Adjustment to Winter Peak Loads

The Company adjusted its peak forecast by comparing the hourly results from the PDM model with actual hourly results for 2017 for all sectors other than industrial. Tr. 287:9-15. Based on this comparison, the Company adjusted the January (and thus the winter peak) forecast loads upward by 349 MW. Tr. 287:9-15, 288:7-10.

This adjustment appears arbitrary. It is based on a single year, 2017, and yields volatile results for other winter months. Tr. 287:9-15. For instance, while it suggests under-forecasting for January by 349 MW, it also suggests that the PDM model is over-forecasting November by 156 MW and December by 258 MW, and is under-forecasting February by only 56 MW. Ala. Power Co. Hr'g Ex. 18; Burke Dep. 105:21-23. Most telling, however, is the result for January 2018, which showed that the model is over-forecasting the winter peak by 314 MW. Tr. 288:11-23; *see* Energy Ala./Gasp Hr'g Ex. 21. Ms. Burke sought to discount these results as preliminary. Tr. 288:13-23. However, the Company has performed no analysis with the final January 2018 data to determine whether the final data would also suggest over-forecasting. Tr. 288:11–289:7.

This adjustment is based on an analysis that used all 744 January hours. J. Wilson Test. 23:7-8; *see* Energy Ala./Gasp Hr'g Ex. 21. When benchmarking is performed using only the 10% highest load hours, the adjustment for January turns negative, , meaning that the PDM is actually over-forecasting January, not under-forecasting it. J. Wilson Test. 23:9-14.

b. <u>Special 130 MW January Adjustment</u>

On top of the above 349 MW upward adjustment, the Company added another 130 MW to January loads (and thus to winter peak projections) based on Alabama Power's 2018 winter weather normalized peak value. Tr. 289:8-14. The primary calculation for the 130 MW increase is the 2018 winter weather normalized peak value minus the PDM's January peak. J. Wilson Test. 23:17-18. However, when a minimum temperature approach is used for calculating the 2018 winter weather normalized peak, the adjustment becomes a downward adjustment and reduces the peak forecast. *Id.* 23:19–24:3.

c. <u>204.4 MW Industrial Load Adjustment</u>

The Company further adjusted its PDM forecast by 140 MW in 2021 and 280 MW in 2022 and beyond. *See* Tr. 289:21–290:6. Ms. Burke learned of these additions through her industrial representatives, who are Alabama Power employees and who conduct customer surveys. Burke Dep. 111:9-16. Ms. Burke testified that she did not know whether these new loads were already reflected in the third-party econometric models (such as IHS Markit) that it uses to develop its forecasts. Tr. 290:13–291:13. If so, then these additions may already be counted in Alabama Power's energy forecast, and thus this adjustment would amount to double counting.

Furthermore, the Company's method of forecasting industrial energy sales may not lead to accurate forecasts, calling the industrial load adjustments into further question. The Company relies more heavily on the customer surveys for its near-term forecast, meaning two to three years into the future. Tr. 293:20-23. For the customer surveys, the Company surveyed 250 of more than 6,000 industrial customers, focusing on the larger customers. Tr. 295:4-7.

The Company has previously tested the accuracy of these surveys and admits that "some [industrial representatives] provide results that are more accurate than others." Burke Dep. 125:7-8. For instance, the Company has found that the surveys often fail to account for large fluctuations in a customer's load. Tr. 294:1-18; Burke Dep. 125:13-20. In addition, the customer surveys did not ask about customers' plans to improve energy efficiency or whether they planned to switch fuels for some processes (i.e., plans that would decrease a customers' electricity usage). J. Wilson Test. 30:1-6.

d. Itron Model Verification of Peak Load Forecast

In its rebuttal testimony, Alabama Power asserts that it verified its adjusted peak load forecast using an Itron forecast model. Tr. 242:18-20. However, the Company performed this alternate peak demand forecast as part of its peak demand forecast for 2020, not for the 2019 peak forecast used in the 2019 IRP and filed as part of the Company's Petition. Tr. 291:14-17, 292:1-3.

The record lacks sufficient information to determine the reasonableness of the alternative Itron forecast. The extent of Itron's involvement was providing the model and the framework. Alabama Power provided all of the data that went into the model. Tr. 291:21-23. Furthermore, Itron never reviewed Alabama Power's final forecast. Tr. 292:4-6.

B. Problems with Alabama Power's Target Reserve Margin

Southern Company Services (SCS), a subsidiary of Southern Company, performs a reserve margin study for the Southern Company system every three years, with the most recent having been performed in 2018.[8] Tr. 65:9-12. The study occurs as part of the coordinated planning activities among the Southern Company retail operating companies. Tr. 124:5-15. Mr. Jeffrey Weathers, the Resource Planning Manager for SCS since 2016, oversaw the development of the 2018 RM Study, which was conducted by two employees in his department. Tr. 66:14–67:3. Neither Mr. Weathers nor those two employees were involved in the 2015 Reserve Margin Study. Tr. 67:4-9. The study results in a recommended target reserve margin (TRM), which the Company then uses for reliability planning. Tr. 68:16-19.

The 2018 Reserve Margin Study was the first to recommend the use of seasonal planning, which means using separate TRMs for summer and winter. Tr. 69:5-8. The study recommended a 16.25% summer TRM and a 26% winter TRM. Tr. 69:19–70:4. Prior reserve margin studies recommended a single, year-round TRM, which has increased over time. *See* Tr. 68:20–69:8.

[8] There is no requirement of the Commission that the studies only be performed on a three-year basis. That is simply the Company's practice. Tr. 123:7-10. Mr. Weathers testified that the study can be completed in a matter of months. Tr. 124:16-19. Unless an earlier date is ordered by the Commission, the Company will perform its next reserve mragin study in 2021, refreshing the data, reassessing resource adequacy, and determining the appropriate level of TRM going forward. Tr. 122:20-123:4.

The 2012 study recommended a year round TRM of 15%, while the 2015 study recommended increasing the TRM to 17%. *Id.*

While the 2018 Reserve Margin Study recommended an appropriate level of reserves for both summer and winter, it did not specify how Alabama Power should meet that reserve level or what specific resources should be added to its system. *See* Tr. 118:13–119:11. Reserve margin studies do not prescribe a certain type of generation to meet a recommended TRM. *Id.* Their purpose is to determine the appropriate level of reserves needed to maintain reliability, not how a utility will meet those reserves. *Id.*

There are typically two approaches to reserve margin planning. One is to identify a reserve margin that meets a physical reliability standard. To determine this standard, Southern Company uses a one day in ten year reliability standard, also known as the 0.1 loss of load expectation (LOLE), and determined that the winter TRM is 25.25%. Tr. 206:11-17. This is the most common industry practice. Tr. 206:18-23. The other approach is to calculate the reserve margin in a way that balances the risk-adjusted costs and benefits of supplying reliability, which SCS does by calculating the Economic Optimum Reserve Margin (EORM). Tr. 207:1-9. SCS determined that the risk-adjusted winter TRM is 26%. Tr. 72:6-11.

After the RM study was conducted in 2018, Alabama Power retained Mr. Kevin Carden, the Director of Astrapé Consulting, LLC, to perform due diligence on the 2018 Reserve Margin Study with respect to conformance to industry standards, best practices, accuracy and thoroughness. Tr. 187:17-22. Astrapé Consulting specializes in resource adequacy planning for the electric industry, and is the licensor of SERVM, the software that SCS developed and continues to use for its RM studies. Tr. 184:4-11, 198:13-19. Mr. Carden has close ties to Southern Company, having previously worked for SCS as a reliability engineer before starting

Astrapé in 2005. Tr. 197:10-15. While working for SCS, Mr. Carden performed just one reserve margin study using SERVM. Tr. 197:16-23. In late 2005, Astrapé put in a bid to Southern Company to become the licensor of SERVM. Tr. 198:9-12. Three months after Mr. Carden left SCS, Astrapé's bid was approved. Tr. 198:13-16.

For the 2018 Reserve Margin Study, SCS used Astrapé's SERVM software. Tr. 199:23–200:3. Astrapé provided a few inputs to the study—the scarcity price curve and the load and generator assumptions for neighboring utilities. Tr. 204:4-9. Otherwise, SCS staff performed the 2018 RM study. Tr. 205:4-7.

The main focus of Mr. Carden's analysis was on the reliability inputs and assumptions in the 2018 RM study. Tr. 187:23–188:5. He looked at the magnitude of resources required to maintain system reliability, but did not attempt to identify different resource mixes and technologies to meet the need. Tr. 196:9-17. In reviewing the 2018 Reserve Margin Study, Mr. Carden's key question was whether "[SCS] adequately represented the weather related and economic forecast area related to load variability," and whether they accurately captured generation performance risks and market support. Tr. 185:8-17.

1. <u>The RM Study's Reliability Analysis</u>

As part of its 2018 Reserve Margin Study, SCS conducted a reliability analysis to determine the reserve margin level required to meet the 0.1 LOLE. Tr. 179:7-23. SCS determined that the LOLE level for the Southern Company system is 25.25%. Tr. 180:10-14. One of the key drivers of this approach is weather-related load uncertainty. Tr. 207:10-13. SCS attempts to account for weather-related load uncertainty by using inputs and assumptions that take extreme temperatures into account. However, its assumptions based on extreme temperatures that have not been seen in decades likely overstated winter reliability risk, and by extension, the recommended winter target reserve margin.

a. Historical Weather Data

The RM Study uses 54 years of weather data (1962-2015) to develop a synthetic load curve. Tr. 207:14-17. SCS used this weather history to determine load response and reserve requirements if such historical temperatures and weather patterns were to occur again in the future. Tr. 60:9-18. As Mr. Weathers testified, SCS used 54 years of data because "that was how much weather data that [it] ha[d] able to use." Tr. 61:20-22.

The data set includes many instances of extremely cold temperatures that have either not been seen or seen only rarely in the past several decades. For example, there were 232 hours with temperatures under 13 degrees, but only 13 of those hours occurred since 1997. Similarly, there were 98 hours below 9 degrees, but such low temperatures have not been recorded since 1997, over 20 years ago. The data set includes 50 hours below 6 degrees, but there has been no such temperature since 1985, over 30 years ago. J. Wilson Test. 55:1-17. In the first half of the 54 years (1962-1988), the temperature fell below 10 degrees eight times and below five degrees six times. Tr. 78:5-23. But in the second half of the 54 years (1989-2015), the temperature fell below 10 degrees just three times and never dropped below five degrees. Tr. 79:1-11. In the last twenty years, the temperature has dropped below 10 degrees once, during the 2014 polar vortex. Tr. 80:13-16.

Astrapé's general recommendation is that the maximum amount of data that is available should be used. Tr. 210:18-20. The RM Study data set begins at 1962. The years 1962 and 1963 were unusually cold. If more data is indeed better, as Mr. Carden claimed, the Company should have included data prior to 1962, which Mr. Wilson confirmed is available. Tr. 1201:6-10.

Looking at the 15 years prior to 1962, temperatures were relatively mild, save for one year. Tr. 1200:16-20. If those 15 years prior to 1962 had been included in the data set, the reserve margin would have been much lower. Tr. 1200:20-22.

Or the Company could have focused on more recent data. In other reserve margin studies that it performs, Astrapé creates weather load shapes with data only going back to 1980 because public data sources for most of his clients only goes back that far. Tr. 209:3-12. Mr. Carden performed a sensitivity analysis that determined the LOLE for each possible data set (i.e., excluding years since 1980, excluding years since 1981, etc.). Tr. 209:13-210:2. He determined that depending on the year selected, the reserve margin ranged from 25.25% to as low as 22%, illustrating the impact that a chosen data set can have on the overall LOLE. Tr. 210:23-211:9.

b. Historical Weather Data's Impact on Load

How loads react to extreme temperatures is a critical assumption in a reserve margin study. Carden Dep. 31:18-21. In the 2018 RM study, for the most extreme synthetic load profile, SCS determined that loads could reach as high as 22% above the forecast winter peak. Tr. 207:20–208:1. For comparison, during the Polar Vortex in 2014, when the Southern Company system reached its highest ever winter load, the system load was only 7.7% above the forecast winter peak. J. Wilson Test. 48:3-8, Figures JFW-7 and JFW-8; Weathers Rebuttal Test. 12:17-18. Alabama Power's system load was only 3% above its 2023 winter peak forecast during that event. J. Wilson Test. 49:7-9.

This extreme load assumption was based on the minimum system temperature since 1962, which was –3 degrees in 1985. Tr. 208:2-9. This extreme temperature occurred just once in the entire 54-year data set, and has not been experienced at all in the last 35 years. Tr. 208:10-19.

To determine the load for extreme winter temperatures, SCS selected data from only one month of one year (January 2014, the Polar Vortex month) and calculated how load would change based on a MW/degree basis. J. Wilson Test. 53:1-4. For each degree of temperature drop, the formula adds a fixed 406.6 MW to the peak load. *Id.* at 53:4-17. This is known as the peak load adjustment factor (PLAF). *Id.*

SCS then applied the PLAF to the extreme cold temperatures that occurred between 1962 and 1985 (which, again, have been experienced only rarely or not at all since) to determine what load would be if those temperatures occurred now. Accordingly, the model forecasted higher loads, thus producing the 22% above peak value that is used in the RM Study. *See* Weathers Rebuttal Test. 13:3-5. In addition to other flaws in the PLAF approach,[9] assuming that loads will reach 22% above the forecast peak (based on temperatures not experienced in over 30 years) results in an unreasonably inflated winter target reserve margin.

To make matters worse, SCS then applied an economic load forecast uncertainty assumption to its synthetic load profile. The economic load forecast assumption is intended to reflect the additional uncertainty about the forecast's accuracy. Tr. 214:18–215:4. If the economy grows faster than expected, there is a risk of under-forecasting the peak load. *Id.* Using U.S. GDP load growth and errors from historical forecasts, SCS assumed that loads could be greater than the forecast level. Ala. Power Co. Hr'g Ex. 1, at 10-11 (Table I.3. Load Forecast

[9] For instance, one of the major flaws of the the peak load adjustment factor is that it uses a fixed 406.6 MW/degree adjustment, therefore reflecting constant and continuous load growth as temperatures drop. Weathers Rebuttal Test. 13:14-15. However, such a linear relationship between extreme temperatures and load is not reliable because once temperatures drop to extremes, customers have turned on everything that they can to stay warm. J. Wilson Test. 55:21–56:1. Mr. Carden asserted that load response strongly correlates with temperature in the Company's service territory, in part because of the high percentage of customers with heat pumps. Carden Rebuttal Test. 6:16-20, 7:3-7. While heat pumps require supplemental heating devices under 32 degrees, *id.* at 6:18-20, these devices are either on or off, and therefore likely do not add load at a constant rate in relation to temperature, Carden Dep. 51:20-22. In addition, in the most extreme cold, some entities like schools and offices will remain closed or open late, which would further reduce the impact of extreme temperature on load. J. Wilson Test. 56:2-5. Mr. Carden did not do any analysis of whether closures or delayed openings would impact the load in extreme temperatures. Tr. 214:13-17.

Error) [hereinafter 2018 RMS]; J. Wilson Test. 44:11-45:3. SCS then applied this load forecast uncertainty assumption to its synthetic load shapes. Thus, SCS applied this to the highest assumed winter peak load, which as discussed above, is already 22% higher than the forecast winter peak. J. Wilson Test. 51:11-52:3.

c. Power Plant Outage Assumptions

In extreme temperatures, traditional power plants, such as gas units, can suffer from higher than normal forced outage rates. 2018 RMS at 21-22. Because of their concerns about winter reliability, Alabama Power and the Southern system have undertaken "winterization enhancements" to improve power plant performance during extreme temperatures. *Id.*; Weathers Rebuttal Test. 9:14–10:1. To reflect these measures, the 2018 Reserve Margin Study assumed improvement in the historical outage trend of about two percent. Weathers Dep. 116:13-22.

But even with these assumed improvements, Weathers Dep. 116:13-22, the 2018 Reserve Margin Study adopted an exponential assumption for cold weather outages in which outage rates under extreme cold rise more than above normal outage rates. J. Wilson Test. 60:19-21; *see also* Weathers Dep. 116:10-13 (stating that the base level of outages is about If instead a linear trend line is plotted for the same historical outage rates, the result is lower outage rates at colder temperatures. J. Wilson Test. 63:3-4. Both Mr. Weathers and Mr. Carden conceded that a linear trend line results in a better correlation to the actual historical data. Weathers Rebuttal Test. 10:14-18 (calling the linear curve fit "slightly greater"); Carden Rebuttal Test. 17:8-9 ("The curve fit may be better with linear regression when analyzing only temperatures below 16 degrees . . . .").

According to Energy Alabama/Gasp expert Mr. Wilson, the RM Study's use of an exponential assumption leads to overstating the impact of extreme cold on power plant outage rates by about 2% at the coldest temperatures. J. Wilson Test. 63:17-19. The recommended reserve margin is based upon the highest load events, which are driven by the coldest temperatures; thus, overstating the outage rates at the coldest temperatures by 2% would overstate the reserve margin by a similar amount. *Id.* 63:22–64:2.

2. The RM Study's Economic Analysis

Also as part of its 2018 Reserve Margin Study, SCS determined the economic optimum reserve margin (EORM), which is the reserve margin that is lowest cost on an expected cost basis. Tr. 70:14-21. SCS determined the EORM for the winter to be 22.5%. Tr. 71:2-8. But SCS also conducted a risk analysis, which evaluated the cost to customers of increasing reliability over the EORM levels. Tr. 70:21–71:1. This risk-adjusted EORM evaluation increased the RM another 3.5%, up to 26%. Tr. 72:6-11.

a. Value of Lost Load

One input to the EORM analysis (but not the reliability analysis) is the Value of Lost Load (VOLL), also called the cost of expected unserved energy. Tr. 84:8-14. In simplest terms, VOLL considers the cost to customers if the Company is not able to serve all of its load. Tr. 84:15–85:3.

To determine the VOLL, SCS hired a separate company to conduct a survey in 2011. Tr. 85:11-14; Energy Ala./Gasp Hr'g Ex. 33. The survey did not include any Alabama Power customers, only Georgia Power and Mississippi Power customers. Tr. 85:15-22. In addition, the survey was conducted prior to the Company's concerns about winter reliability and its adoption of seasonal planning. The survey asked participants about only one winter outage scenario, a one-hour, no warning scenario even though the data showed that VOLL decreases when customers receive warnings. Tr. 91:23–92:2, 94:4-7.

The values used in the study are times higher than the analogous parameter used in the Texas wholesale market design, which uses $9,000/MWh. The reserve margin study includes a sensitivity analysis that used a more reasonable /MWh for the cost of an outage. 2018 RMS at 57. Using this VOLL lowers the winter EORM reserve margin by two percentage points, from 22.5% level to 20.5%. *Id.*; Tr. 95:13-23.

b. Risk-adjusted EORM

The reserve margin study recommends using a risk-adjusted EORM, which increases the EORM by 3.5%, from 22.5% to 26%. 2018 RMS at viii; Tr. 72:6-11. It does so under the assumption that Alabama Power customers are willing to incur higher costs over the long-term to reduce the magnitude of high costs under the most unfortunate scenarios. 2018 RMS at vii-viii; Tr. 72:11–73:7. But this added reliability comes with a price—using the risk-adjusted EORM results in additional costs borne by Southern Company customers. Tr. 75:7-10. Mr. Weathers testified that the actual expected increase in cost for the risk adjustment is roughly $4.00 per customer per year,[10] and that for those $4.00, customers will receive roughly double the reliability. Tr. 75:16-22.

The question is whether customers need that doubled reliability. SCS conducted the risk-adjusted EORM because costs could be higher than expected in the EORM evaluation. Tr. 73:8-14. But the opposite could also be true, making the risk-adjusted EORM unneeded. Costs could be lower than expected if, for example, load did not grow as quickly as expected. Tr. 73:20-22. This would not be particularly surprising considering that in the last ten years, loads have not grown as quickly as they did prior to the recession in 2008-2009. *See* Tr. 73:23-74:3. Alabama Power's peak load forecasts since 2007 have generally been too high when compared to recent

[10] As Mr. Weathers stated, this $4 amount is just an estimate: "[t]he specific cost would be situational, depending on resources that are used, resources that are deployed, all those type of things." Weathers Dep. 101:3-6.

weather normal peaks. J. Wilson Test. 10:12-15. Costs could also be lower if winter temperatures are warmer than expected, as occurred this past winter, which turned out to be mild. Tr. 74:4-7.

C. Combined Effect of Unreasonable Load Forecast and Reserve Margin Assumptions

As the above discussion illustrates, the Company's projected capacity needs rest on a number of unreasonable and questionable assumptions. As a result of flawed upward adjustments to the load forecast, the projected peak value for 2023 (12,209 MW), 2019 IRP at 21, is exaggerated by almost 700 MW (comparable in size to the proposed Barry Unit 8). When the peak demand model forecast is used without adjustments, as recommended by Mr. Wilson, APC's 2023 peak forecast drops from 12,209 MW to MW. J. Wilson Test. 66:12-15.

In addition, the Company has significantly overstated its winter target reserve margin. Energy Alabama/GASP expert James Wilson suggests that more appropriate assumptions would result in a 20% winter target reserve margin. *Id.* at 66:3-11. If a 20% winter target reserve margin is used in tandem with an unadjusted peak forecast, the Company's 2023 needs are 1,400 MW lower than what the Company projects. *Id.* at 66:12-15.

AIEC shares many of the concerns raised by Energy Alabama/Gasp. AIEC witness Pollock expressed a high degree of skepticism about the results suggesting that Southern Company requires a 26% TRM in winter months. Tr. 970:10-15. Mr. Pollock noted that most utilities' regional transmission organizations have lower planning reserve margins, with the largest at 20% and most in the teens. Tr. 971:1-11; AIEC Hr'g Exs. 3-4. While the Company countered that the Tennessee Valley Authority and PowerSouth Cooperative each have target reserve margins of 25%, this is a function of isolated planning. Both TVA and Southern Company are part of the same reliability planning region—the SERC Southeast Region. A 2018 study by SERC[11] concluded that if the region as a whole were to engage in integrated planning, rather than on an individual utility basis, the range of reserve margins would be 13 to 20%. Tr. 1012:6-18. According to the North American Electric Reliability Corporation (NERC),[12] most reliability regions plan a reference reserve margin of 20% or less. Pollock Direct Test. 17:4-5; AIEC Hr'g Ex. 4. As a result, Mr. Pollock concluded that it would be premature for the Commission to adopt the 26% winter TRM without further analysis by the Commission and collaboration among interested parties. Pollock Direct Test. 4:14-16. Mr. Pollock further recommended the Commission deny the proposed capacity additions until capacity is needed. *Id.* at 4:18.

II. <u>The Reasonableness of the Company's Proposed Resource Additions</u>

Having now addressed issues related to the question of need, the Commission turns to the reasonableness of the Company's chosen resource portfolio. The overriding consideration here is the cost-effectiveness, which the Company agrees is synonymous with "least-cost." Tr. 322:10-21. Related considerations include overall risks to captive customers and whether there are less risky alternatives to the Company's preferred approach.

In determining the "least-cost" alternative available to the Company, the Company appears to have engaged in an iterative (rather than integrated) process for determining the

[11] SERC stands for the Southern Electric Reliability Corporation. Its mission is to reduce risks to the reliability and security of the electric grid (also known as the bulk power system) for today and the future. *See About SERC*, SERC Reliability Corp., https://www.serc1.org/about-serc (last visited May 1, 2020). SERC performs this work under Federal Energy Regulatory Commission (FERC) approved delegation agreements with the North American Electric Reliability Corporation (NERC). *Id*.

[12] The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by FERC and governmental authorities in Canada. *See About NERC*, North Am. Elec. Reliability Corp., https://www.nerc.com/AboutNERC/Pages/default.aspx (last visited May 1, 2020).

portfolio of projects for selection. The genesis of the Barry Unit 8 proposal was in 2016, when a vendor approached SCS with a fixed price turnkey proposal. Tr. 578:22–579:4. At that time, the proposal did not correspond to any particular capacity deficit on the Southern system generally or on the Alabama Power system in particular. Tr. 579:18–580:1. In late 2017, the Company had selected the Barry Steam Plant as the site for a new gas unit. Tr. 591:8-10. The Company then went to market in January of 2018 for turnkey options to build this new gas plant. Tr. 583:21–584:1. The final turnkey proposals from that solicitation were submitted to SCS in August of 2018. Tr. 584:2-5. In the fall of that same year, the Company issued separate Capacity and Renewable RFPs. Kelley Direct Test. 16:6-13. In November of 2018, the initial award letter was issued for the gas combined cycle turnkey option at Barry. Bush Direct Test. 16:21-22. These three separate processes—the turnkey project solicitation, the Capacity RFP and the Renewable RFP—eventually lead to the "short-list" of projects used the Alabama Power to make-up its Petition.

A. Company has capacity available on short-term basis through the IIC

As noted, the Company asserts an immediate capacity need, which included the now past 2019-2020 winter season. The Company emerged from this past winter without a reliability event in part because the winter turned out to be mild, but also because it was able to share capacity with the other retail operating companies. Tr. 56:19–57:1, 364:13–365:15.

Alabama Power participates in a contract between the operating companies called the Intercompany Interchange Contract (IIC), which is an operating agreement allowing each of the companies to pool resources and dispatch as one system. Tr. 53:15-22. The pool currently includes the three retail operating companies—Alabama Power, Georgia Power, and Mississippi

Power—as well as Southern Power Company and former Southern Company subsidiary Gulf Power.[13] Tr. 365:21–366:11.

One of the purposes of the pool is to share temporary surplus to meet temporary deficits. Tr. 367:18-23. Together, the retail operating companies currently have approximately 45 gigawatts (GW) of capacity. Tr. 588:22–89:2. The IIC is an operating agreement that accounts for such capacity-sharing after the fact. Tr. 368:8-20. Sharing can occur in part because the operating companies within Southern Company peak at different times of day. Tr. 115:20–117:4. For example, Georgia Power peaks at a different time than Alabama Power, creating opportunities for the Company to buy excess power from Georgia Power. In addition, Georgia Power remains a summer peaking utility, meaning that its peak needs do not coincide with Alabama Power's winter reliability events. Tr. 116:10–118:12. In addition, these sharing agreements allow the operating companies to save customers money. Tr. 117:7-16.

The Company considers the IIC an operating agreement, not a planning document, and asserts that reliance on surplus capacity made available through the pool "cannot be the long-term solution to our winter reliability need." Kelley Rebuttal Test. 8:9-10. However, on cross-examination, the Company acknowledged that the IIC does not prohibit the Company from relying on surplus capacity for up to three consecutive years, just as it was able to do this past winter. Tr. 371:23–372:3. Indeed, just as the retail operating companies engage in "coordinated planning" on an ongoing basis, the IIC provides for "coordinated system operations" to reap the benefits that coordinated planning may yield. 2019 IRP at 6-7. Mr. Kelley testified that "the IIC lowers total production cost and enhances system reliability, which benefits all of the operating companies." Kelley Direct Test. at 5:1-2. Nevertheless, in his economic evaluation on the

[13] Gulf Power is now owned by NextEra. Negotiations are underway for Gulf Power to exit the pool sometime over the next several years. Tr. 366:12-22.

Company's proposal, Mr. Looney did not review, nor did Alabama Power ask him to review, whether there may be existing resources on the Southern Company system to meet the Company's claimed needs on a temporary basis. Tr. 708:13-19, 710:3-9.

In addition to capacity surpluses available under the IIC, Alabama Power may purchase capacity from companies or entities that are not in the Southern system. Tr. 54:11-17. Neighboring regions outside the Southern system may peak in different hours than the Company. Tr. 113:17–114:5. If a neighboring region peaks at a different time, that means their maximum load for the day is at a different time. Tr. 114:6-13. In such instances, the Company would be able to purchase excess power from them. Tr. 115:5-8.

While the existence of neighboring surpluses, whether within or outside of the IIC, may not satisfy the Company's long-term needs, they do tend to undermine the Company's assertions of an immediate, "emergency"[14] need for 2,400 MW of additional capacity. At the very least, the potential availability of capacity from neighboring regions, and the Company's failure to evaluate such availability to satisfy near-term needs, calls into question whether it is prudent for the Commission to approve the entirety of the Company's request. As the Company testified, it is already evaluating its options for next winter. Tr. 57:18-20. Given the surplus capacity potentially available to it, the Company has not adduced substantial evidence as would justify, for example, immediate approval and "early start" under the Hog Bayou PPA.

B. The Company's proposal is over-reliant on natural gas.

As the proposed solution to winter reliability needs, the Company's Petition is heavily reliant on gas generation. Approximately 80% of the capacity submitted for approval consists of gas-fired combined cycle generation. This over-emphasis on a single fossil resource gives rise to

[14] *See* Tr. 190:22–191:4.

two distinct problems. First, gas generation suffers from some of the same winter reliability issues that the Company cites as factors driving its winter capacity needs. As a result, and as Mr. Rábago testified, the Petition actually exacerbates winter reliability concerns: it "triggers the need for even larger reserve margins to cover the inadequacies and vulnerabilities of the incremental resources." Rábago Test. 9:12-14.

Second, the Company's overwhelming emphasis on fossil resources exposes customers to undue, long-term carbon risk. This risk is especially acute in the case of Barry Unit 8, a new self-build project that the Company expects to be in service through 2063. Tr. 658:13-16. The Company's Petition in general, and Barry Unit 8 in particular, stand at odds with Southern Company's goal of "low to no" carbon by 2050. Tr. 408:4-10. Yet the Company would have its customers assume all of the climate risk associated with these resources, including the risk that these assets could become stranded before the end of their useful lives. *See, e.g.*, Rábago Test. 11:2-4.

1. <u>Natural gas reliability concerns</u>

The Company's 2015 Reserve Margin Study identified five factors as driving its emerging winter reliability needs. Energy Ala./Gasp Hr'g Ex. 1, at v-vi. Two of those drivers—increased unit outages due to cold weather and increased risk of fuel delivery disruption due to winter conditions—are virtually unique to fossil-based resources and to natural gas in particular. *See, e.g.*, Tr. 149:6-9. The Company reiterated these same factors in its 2018 Reserve Margin Study, 2018 RMS at 40, A-4, while simultaneously advancing its capacity need by 15 years in its 2019 IRP.

When temperatures get very cold, the Company tends to have more unplanned outages, which reduces the capacity available to meet load. Tr. 148:20-22. Those units are generally fossil generation resources. Tr. 453:19-21. On occasion over the past decade, more than 10% of the system's fossil capacity has been in a forced outage rate concurrently. Tr. 453:14-21. As the Company concedes, a gas burning plant can have a forced outage in cold weather due to equipment freezing, even if it has sufficient fuel. Tr. 149:6-9.

But having sufficient fuel is the other weather-related risk inherent to gas-fired resources. As early as 2009, Southern Company first identified that there were possible scheduling restrictions on the gas pipelines related to relying on non-firm or interruptible gas supply. Tr. 99:17–100:1-8. Pipelines limit supply during peak and extreme cold conditions to firm contracts. Tr. 131:21–132:7. While the Company purports to address this risk through its fuel policy, which mandates firm fuel procurement for combined cycle units, the Company concedes it may not procure firm transportation for its combustion turbines because those units are not expected to be used in all hours of the day. Tr. 103:15–104:11. Hence, for the very sorts of units the Company expects to be operating during winter peak—which typically occurs between 6:00 and 8:00 in the morning[15]—the Company still faces fuel-related winter reliability risk. Tr. 104:10-11. And even firm transportation is excused during a force majeure event, which could include a weather event that damages a natural gas pipeline. Tr. 107:23–108:6.

While the Company insists that the proposal would further diversify its resource mix, the evidence shows it would not. Under the proposal the Company's resource mix in 2024 would consist of about 60% fossil resources (coal and natural gas), roughly the same percentage as currently, and the very types of resources prone to weather-related forced outages. Tr. 454:23–455:7.

[15] Tr. 112:2-3.

A related risk inherent to natural gas is fuel price volatility. For its natural gas fuel price projections, the Company relied on Charles River and Associates, which provided the Company with low, medium and high gas scenarios. Tr. 437:20–438:1. However, for the economic analysis of its chosen portfolio, the Company opted not to run a high gas scenario. Tr. 413:23. As a result, the Commission does not know the fuel price risk that customers would bear over the next several decades. Alabama Power expects its customers to pay for all of Barry Unit 8's fuel costs, along with all other operational costs, over its useful life. Tr. 658:17-19, 659:23–660:8.

The Company acknowledges that historically natural gas prices have been volatile. Tr. 830:14-17. Furthermore, while natural gas prices are currently at historic lows, the Company is aware that, nationally, 68 GW of gas-fired power plant capacity have announced for operation by 2025. Tr. 624:11-15. However, the Company has not analyzed what will happen to natural gas prices if all of that proposed generation is built. Tr. 624:16-19. The Company acknowledges that customers bear the burden of the high-price risk scenario as they are generally expected to cover the costs of service. Tr. 804:14-20; *see* Baker Dep. 26:3-14. For Barry Unit 8, the Company expects the fuel cost over the life of the unit to compare in magnitude to its in-service capital costs. Tr. 805:14-17. As Mr. Bush stated in his cross examination, "it's not unreasonable to think that operating a fuel could be more, depending on the scenario, than the cost of actual in-service cost." Tr. 659:19-22.

2. Carbon regulation risk

The Company does not dispute the reality of the climate crisis, and the accompanying need for utilities to rein in their carbon emissions. Tr. 621:8-11. The Company acknowledges the carbon reduction commitment of its parent, Southern Company, which is a 50% reduction in carbon dioxide emissions by 2030 (compared to a 2007 baseline), and low to no carbon dioxide emissions by 2050. Tr. 408:4-10. A unit like the proposed Barry Unit 8 will emit carbon every hour that it is burning gas; nevertheless, the Company performed no direct analysis of Barry Unit 8's impact on Southern Company's climate goals. Tr. 621:12-15. The Company's carbon risk analysis was limited to assuming just two future carbon price scenarios: a zero dollar per ton reflective of current reality and a $20 per ton price. Tr. 760:23–761:4.

The Company asserts that Barry Unit 8 will contribute to lowering carbon emissions because its relative efficiency will allow the Company to run less efficient units less frequently. Tr. 621:15-16. However, the Company has no plans to retire those less efficient units when Barry Unit 8 comes online because it says it needs all of them to meet its capacity requirements. Tr. 618:11-16. And even if Barry Unit 8 contributes to lowering carbon emissions in the near term, the fact remains that the Company proposes to operate the unit through 2063, well past Southern Company's "low to no" deadline of 2050. The Company attempts to reconcile this apparent conflict by suggesting that Barry Unit 8 could burn hydrogen or be equipped with carbon capture and sequestration (CCS). Tr. 403:19, 406:15-10. The Company has not, however, undertaken to analyze either option. Tr. 403:23–404:2, 407:6. As a result, there is no information before the Commission showing how much it could cost customers to pursue an option such as retrofitting Barry Unit 8 with CCS technology. Tr. 622:10-16; Bush Dep. 80:12-23, 81:5-8.

The threat of carbon regulation coupled with the ongoing price declines of carbon-free resources like solar and battery storage creates a risk that resources like Barry Unit 8 could become "stranded assets" before the end of their useful lives. Yet the Company here has performed no analysis of stranded asset risk. Tr. 432:13-16. And the Company proposes no mechanism for protecting customers from stranded asset risk, even though it has done so before, for two existing units at the Plant Barry site.

As part of the certification of two other combined cycle units at Plant Barry—Units 6 and 7—the Company agreed that its shareholders would assume the stranded asset risk associated with those units. Tr. 429:14-20. The Company recommends no such condition here because it views the circumstances as different. When Barry Units 6 and 7 were certified, in the late 90s, the Alabama Legislature was considering retail restructuring and stranded asset legislation. Tr. 430:11-23. With no such legislation being considered currently, the Company evidently does not feel compelled to offer this protection for its customers even though among the circumstances making the current proposal different is the increased threat of carbon regulation, which could drastically increase the operating costs for Barry Unit 8.

The Company does not believe there is any stranded asset risk associated with its proposal because the added units will be more efficient than many older units. Tr. 431:4-8. Of course, the same was true of Barry Units 6 and 7 when those units were certified, but the Commission still ordered protective measures for ratepayers. Despite the Company's confidence that Barry Unit 8 will not become a stranded asset over its forty-year life, the Company is unwilling to expose its shareholders to this supposedly non-existent risk. Tr. 617:7-8. As proposed, the Company's shareholders will profit from Barry 8's construction as a self-build, Tr. 889:14–890:4, but the Company's customers will bear all the risk. The Company acknowledges, however, that it is for the Commission to decide whether such a condition should accompany any grant of certification in this proceeding. Tr. 616:16-17.

C. <u>Solar BESS is the least cost alternative for meeting the Company's claimed capacity needs</u>.

Under Mr. Looney's economic evaluation of the proposal, the five solar BESS projects were the least-cost resources. Tr. 764:10-13. These projects provided energy and capacity benefits across all seasons. Tr. 783:17-21. As the Company acknowledges, the capacity afforded by the battery component of the projects will allow the Company to increase the flexibility of its system and help ensure reliability during peak periods. Tr. 801:7-12.

Mr. Looney's economic analysis compared the resources identified through the Company's solicitations to determine which ones would make up the most cost-effective portfolio on a net present value (NPV) basis. Tr. 767:9-13. NPV is a way of taking a long stream of values and reducing it to one present value that accounts for the time value of money. Tr. 764:17-22. In other words, it allows for comparison of one value to another in terms of today's buying power. *Id.* Mr. Looney's team was given the solar BESS projects by Alabama Power. Tr. 778:19–779:1.

As shown on Mr. Looney's Exhibit MBL-1 (Ala. Power Co. Hr'g Ex. 37), a negative value indicates that the values quantified by the company were greater than the costs and is "a good thing in this evaluation." Tr. 765:11-13, 766:11-13. Three of the solar BESS projects had negative values, meaning that, on average, these projects are likely to produce net savings for customers. Tr. 765:16-21 As a whole, the solar BESS projects in the Petition will put downward pressure on overall system costs, thereby benefiting customers. Tr. 766:14-19.

In contrast, the three gas proposals showed positive values, putting them at the bottom of the overall ranking. As Mr. Rábago testified, the weighted average NPV for the nearly 1,900 MW of proposed gas capacity is $322 per kW, whereas the weighted average NPV for the five solar BESS is *minus* $14 per kW. Rabago Test. 8:5-9. This demonstrates the "vastly superior economic and other characteristics [of solar BESS] compared to gas-fired resources." *Id.* at 22:1-2. The Central Alabama PPA was the last ranked resource, with a positive average NPV that is an order of magnitude higher than the first ranked solar BESS project. Tr. 767:14–768:1. If gas prices rise, Mr. Looney testified that the five solar BESS projects will have even more value compared to the other resources proposed in the Petition. Tr. 816:17-21

The solar BESS projects offer practical benefits as well. Solar generating systems are not adversely impacted by weather; in fact, they are more efficient when temperatures are lower. Rábago Test. 22:5-6. Mr. Weathers testified that he was not aware of any incidents of a forced outage of a solar PV facility in winter; he agreed that "solar is not prone to cold weather outages to the extent natural gas plants are." Tr. 151:10-18. And neither solar nor battery storage is impacted by gas deliverability or affordability. Rábago Test. at 22:7-8. The smaller size of these systems, and their geographic dispersion across the Company's service territory, diversifies operating risks. *Id.* at 22:8-10. In sum, as Mr. Rábago testified, "solar plus storage resources meet the demand for energy and capacity at lower cost and in a way that does not drive higher winter reserve margin requirements." *Id.* at 22:10-12.

Given the array of benefits provided by the solar BESS proposals, it is unclear why these projects make up just 400 MW of the 2,400 MW proposed for approval. The Company evaluated, but ultimately excluded another 560 MW of such projects due to a decline in their "capacity equivalence." Tr. 782:22–783:9. The Company used a metric known as Incremental Capacity Equivalence, or ICE, to assess the reliability contribution of the solar BESS projects. Tr. 758:16-19. The Company found that the 400 MW of BESS projects provided high capacity equivalence, meeting between 85% and 92% of the reliability that would be afforded by a dual-fuel combustion turbine. Tr. 785:9-12. In fact, the Company found that 500 MW of BESS projects—i.e. 100 MW more than it's proposing for approval here—had an ICE factor exceeding 90%. Tr. 787:1-4; 792:21-22 A larger tranche, totaling 750 MW, exhibited a diminished ICE factor but still delivered a capacity equivalence of almost 80%. Tr. 792:8-10. However, due the slight drop in ICE factor to below the 85% threshold, the Company excluded these additional projects from consideration. Moreover, the Company did not compare the cost of the 560 MW of solar BESS projects that it excluded from consideration with the high gas cost scenario. Tr. 505:17-21.

The 85% threshold chosen by Mr. Looney as a cut-off point appears to be somewhat arbitrary. *See* Tr. 786-87. Furthermore, the Company's analysis was limited to two-hour duration batteries, which Mr. Looney testified "our system has a limited appetite for." Tr. 784:12-14. While the Company received some bids for four- and eight-hour batteries in response to its Capacity RFP, it found that these projects were not cost competitive with the majority of the other resources. Tr. 780:7-17. However, Mr. Looney acknowledged that battery and solar prices have declined meaningfully in recent years, and will continue to do so. Tr. 779:20–780:3. As Mr. Looney testified, "over the last several years, every renewable solicitation tends to produce lower prices than the one before it." Tr. 773:19-22.

The Company plans to issue another Renewable RFP this fall pursuant to the authority granted in Docket 32382, which could well yield competitive prices for longer duration solar plus battery proposals. Tr. 348:20-22, 773:10-13. However, that docket limits eligible project sizes to just 80 MW, which prevents the Company from realizing the economies of scale that tend to benefit larger projects. Tr. 352:10-19. Mr. Rábago recommended that the Company immediately conduct a solicitation for additional solar plus battery storage in order to take advantage of superior economics of solar generation and the improving economics of storage technologies. Rábago Test. 29:9-11.

In addition, the ICE factor is simply a measure of reliability benefit; it does not assess energy benefits. Mr. Looney's analysis shows that the solar BESS projects will provide a significant reduction in energy cost for customers. Tr. 819:9-12. The solar component of these proposals provides an energy benefit because solar has no fuel costs. Tr. 812:21-22. While the Company's proposal is designed to meet a capacity need, the energy benefits of its chosen course are directly relevant to the ultimate costs borne by customers. Indeed, the Company considers Barry Unit 8 beneficial in large measure due to the energy savings it will provide. Tr. 797:5-8. Yet, despite acknowledging the significant fuel savings potential of solar resources (whether or not paired with storage), the Company has not performed any study of the optimal amount of solar that could be added to its system. Tr. 347:20–348:3. The Company currently has just 92 MW of solar on its system. Tr. 356:17-20.

Finally, adding more renewable resources like solar will also serve the broader public interest. The Company acknowledges that a number of major companies are interested in obtaining more of their energy from solar. Tr. 499:4-17. The Company agrees that adding more power from renewables can position the State of Alabama to better compete with other states for new business, and that solar can support local economic development through new jobs and increased tax revenues to cities and counties. Tr. 502:7-11, 504:1-5.

D. The Company failed to seriously consider demand-side options.

The Company's proposal is heavily weighted toward supply-side measures. It includes just 200 MW of demand-side and distributed energy resources, which have yet to be defined. Tr. 463:13-14. The demand-side component appears to be some combination of gap-filler and afterthought. The Company formulated it only after deciding to pursue Barry Unit 8 and the other supply-side measures when those measures did not yield sufficient capacity to match the identified need. Tr. 470:17-22.

The Company's approach to demand-side measures appears inconsistent with the stated aim of its IRP process, which is to identify an optimum combination of demand-side and supply-side resources to meet demand and energy needs in a reliable and cost-effective manner. Kelley Direct Test. 7:6-9. Indeed, that is what it means for the plan to be "integrated." Tr. 317:2-12. Demand-side options can provide capacity "as well as supply-side options." Tr. 317:10-12. The Company claims it evaluated demand-side measures on a consistent basis with supply-side options. 2019 IRP at 15. Mr. Kelley testified that this means letting both demand- and supply-side options have at least an equal shot at meeting the demonstrated need.[16] Tr. 468:12-16. However, the record shows that the Company last performed a comprehensive assessment of demand-side options in 2014. Tr. 397:15–398:2. The Company has not updated that study, and its Capacity RFP did not solicit demand-side resources. Tr. 469:2-4. Indeed, as noted, the Company does not yet even know what demand-side measures it may pursue. Mr. Kelley testified that the Company is waiting for the Commission to allow it to plan for winter reliability before it can move ahead in earnest with those programs. Tr. 394:5-11. But this lack of prior Commission approval did not similarly hinder the Company in developing its suite of supply-side proposals.

The Commission has, in any event, long urged the Company to "investigate and actively pursue viable demand side management programs." Order at 3, *Ala. Power Co. Petition for Certificate of Pub. Convenience & Necessity*, Docket 21887, 1992 WL 12150657 (Ala. P.S.C. Jan. 1992). This was an explicit directive accompanying the Commission's grant of approval for the Company to construct a combustion turbine at its Greene County site in 1992. Demand-side measures reduce expected peak load and thereby become embedded in the Company's load

[16] The Company additionally considers energy efficiency, a type of demand-side measure, to be a "priority resource," having made a filing to that effect with this Commission in docket 31045. Petition to Intervene and Comments of Ala. Power Co. at 7, *Consideration of Sections 532 & 1307 of the Energy Independence & Security Act of 2007*, Docket 31045 (Ala. P.S.C. Apr. 6, 2009). However, Mr. Kelley testified that he was unaware of that filing and did not know what it meant for energy efficiency to be a priority resource. Tr. 465:22–466:13.

forecast. 2019 IRP at A2-2. In this way, they help avoid the need for new, more expensive supply-side capacity.

The record shows that the Company has failed to pursue demand-side measures that could have avoided or helped reduce the capacity need claimed here. For example, Looney admitted that his team never "evaluate[d] whether a combination of solar plus batter projects and demand side measures, like distributed resources, would be a lower cost option as compared to gas generators . . . ." Tr. 822:9-13. Over the past decade, as winter reliability concerns became apparent, the Company pursued only supply-side solutions. It took steps to winterize its fleet and thus lower forced outage rates, while bringing some fossil units at Plant Barry back into service and upgrading others. Tr. 455:13–456:11. But the Company did not seek to alter or eliminate any of its declining block rates, which afford lower electricity prices at higher levels of consumption. Tr. 456:12-18. Apparently, the Company is considering this option only now and only in the event the Petition is approved. Tr. 888:10-16. Nor did the Company eliminate any of its programs incentivizing adoption of electric heating, even though such programs increase winter load. Tr. 457:4–458:12. Indeed, the Company continues to offer financing to customers who want to purchase heat pumps. Tr. 225:15-17.

Nor did the Company develop and deploy any programs seeking to harness smart thermostat technology to shift or shave residential customer load—a particularly apt demand-side measure given that the winter peak tends to occur during a narrow two-hour window within a select few months. Tr. 442:1-8. The Company only recently instituted such a program, known as Power Pause, as a pilot limited to Company employees. Tr. 473:11–474:4; 2019 IRP at A2-6. In its 2016 IRP, the Company listed a smart thermostat program among its residential energy efficiency offerings, which Mr. Kelley acknowledged could be used to reduce peak energy use.

Tr. 472:23–473:5. However, it appears the Company has eliminated this program, as it does not appear in the updated list of residential offerings contained in the 2019 IRP. *See* 2019 IRP at A2-8, A2-9. While it lasted, the smart thermostat program was tied to the purchase of a heat pump, which would, of course, add to winter load. Tr. 474:20-21.

Another pilot put in place only just last year is a residential water heater pilot, which Mr. Kelley described as an opportunity to reduce load during winter mornings. Tr. 473:13-17; 2019 IRP at A2-6. The goal of this 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 electric demand without adversely impacting the availability of hot water for those customers." 2019 IRP at A2-6. While this is certainly a laudable initiative, it is unclear why the Company did not seek to institute such a pilot years ago, after winter reliability concerns first became apparent.

The Company's consideration of demand-side options appears deficient in two other crucial respects. First, the Company considers the ratepayer impact measure (RIM) test as the only valid test of cost-effectiveness of demand-side proposals. Tr. 479:20–481:5. As Mr. Rábago testified, "[t]his approach unreasonably constrains program adoption based on the biased view that DSM programs that increase rates for non-participant customers in the short term, but are still cost effective in reducing costs for all customers over the life of the measure, should not be adopted." Rábago Test. 26:10-13. Mr. Rábago recommends that the Company use the Utility Cost Test and Total Resource Cost test to screen and select demand side resources because those tests allow evaluation of the full resource value of DSM measures in reducing or avoiding utility costs. *Id.* at 27:2-5.

Second, in developing its DSM programs, the Company puts no particular emphasis on low-income programs. Tr. 396:12-15. Mr. Kelley testified that he was not even aware of the U.S.

Department of Energy's low-income weatherization grant program. Tr. 443:20–444:4. This is a major failing because Alabama has high rates of poverty, and low-income Alabamians struggle to pay their electricity bills. *See* Energy Ala./Gasp Hr'g Exs. 7, 8.

Alabama Power's annual energy efficiency spending as a percentage of revenues is less than one-tenth of one percent. Howat Test. 16:17-19. According to the non-profit, non-partisan American Council for an Energy Efficient Economy (ACEEE), Alabama as a whole consistently ranks in the bottom fifth of states in terms of energy efficiency performance. Rábago Test. 24:10-11. In ACEEE's 2017 Utility Energy Efficiency Scorecard, Alabama Power ranked in last place among 51 utilities evaluated (based on 2015 data). *Id.* at 24:15-17.

Despite abundant potential for energy savings, Alabama Power's 2019 IRP projects only minor increases in DSM efforts over the next twenty years. Indeed, even with its new-found attention to winter peaks, the Company projects only two increases in its 600-hour interruptible program—a 135 MW increase in 2021 and again in 2022—but no other resource deferral growth due to any other DSM program between 2019 and 2038. 2019 IRP at A2-3. For passive DSM programs, the Company projects only 104 MW in increased winter and summer peak reduction between 2019 and 2038, with none of it occurring in the residential sector. *Id.* at A2-7.

E. **The proposal is not in the public interest because it will exacerbate energy burden in Alabama.**

As would be expected for a capacity increase of this magnitude, the Company's proposal will prove costly for its customers. A $1.1 billion price tag discussed at the hearing (and in some news reports) is simply the capital cost of the proposal. Tr. 382:21-22. The figure does not include multi-decadal operation and maintenance costs that the Company will incur at Barry Unit 8 and the other proposed gas units. Tr. 383:3-8. The Company considers the total proposal cost confidential. Tr. 855:3-7. Of course, the proposal's total life-cycle costs to customers will depend on such factors as fuel costs and carbon pricing.

The costs of the proposal will be recovered through rates. Tr. 855:12-15. As a result, ratepayers bear the risks associated with the petition. Tr. 858:14-22. In 2024 the proposal will cost residential customers approximately $95 million and will add approximately $4 to the monthly bill of the "typical residential customer," which it defines as someone using 1,000 kWh per month. Tr. 880:9-10, 852:3-8. However, the Company concedes that the average usage of its residential customers is closer to 1,200 kWh per month. Tr. 867:16-17. If the Company had used average usage, the estimated bill impact would be 40 to 50 cents higher each month. Tr. 869:7-11. This means that in 2024 average residential customers will pay more than $50 extra per year. For other retail customers, the company estimates a rate increase of 2%. Tr. 871:9-10.

The Company did not look beyond 2024 for its bill impacts calculations. Tr. 879:1-2. The Company did not perform a full life-cycle analysis of bill impacts, Tr. 879:14-17, nor did it conduct any bill impact analysis specific to low-income customers. Tr. 871:22–872:4.

Achieving a lowest cost portfolio for any proposed capacity addition is especially important in Alabama. Poverty rates in Alabama remain high, with almost a quarter of the state's population living at or below 150% of the federal poverty level (FPL), and another 10.5% living at or below 75% of the FPL. Howat Test. 9:18-20. At the same time, electricity usage and expenditures in Alabama are extremely high. In 2018, Alabama ranked 48th among the 51 U.S. jurisdictions for residential electricity usage and 49th for electricity expenditures. *Id.* at 8:16-19; *see* Energy Ala./Gasp Hr'g Ex. 8.

As a result, many Alabama households suffer from high electricity burdens for Alabama households—defined as the percentage of household income consumed each month by electric bills. Energy Alabama/Gasp witness John Howat found that an Alabama household living at 150% of the FPL bears an electricity burden fully three times higher than a household with an annual income of $75,000. Howat Test. at 9:3-5. For an Alabama household at 75% of the FPL, the electricity burden is nearly six times the national average. *Id.* at 9:12-13.

The consequences of such high home electricity burden can be devastating. Many households experiencing home energy affordability challenges report receiving disconnection notices, keeping indoor temperatures at unsafe levels, or foregoing other necessities to pay for energy service. *Id.* at 10:9-13. Lower-income households are more likely to be late in making utility payments, and therefore to have late payment fees, collection charges, and in the event of disconnection, reconnection charges assessed against them. *Id.* at 11:11-14. For these households, such added costs can add substantially to the total cost of retaining access to basic, necessary electricity service. *Id.* at 11:16-17.

To help alleviate electricity burden in Alabama, Mr. Howat recommended that the Company implement robust, effective energy-efficiency programs. *Id.* at 15:20-21. Such programs would generate substantial bill savings while improving comfort, safety and health for low-income customers. *Id.* at 15:21-22. Mr. Howat also recommended that the Company collect and make publicly available various data points needed to gauge the state of low-income and general home energy security in its service territory. This would include such information as total billed usage; number and dollar value of unpaid accounts 60-90 days after bill issuance; total number of accounts charged late fees and the total dollar value of those fees; number of service disconnections for non-payment and the average length of those disconnections; and the number and dollar value of accounts written off as uncollectible. *Id.* at 19-20. These types of information have long been collected and reported in states like Ohio, Illinois, Pennsylvania and Iowa. *Id.* at 21-24.

<u>FINDINGS AND CONCLUSIONS</u>

After full consideration of the evidence presented and information made available to it, the Commission **FINDS** that the proposed certificate of convenience and necessity should be granted in part and denied in part.

On the issue of need, the Commission **FINDS** that the Company's 2018 RM study substantially overstates what is necessary to satisfy reliability or economic objectives; that winter risk and reserve margins are especially overstated due to assumptions that exaggerate the likely future frequency and magnitude of extreme winter temperatures and peak loads; that the Company's highest winter peaks are overstated by at least five percent, which directly affects the reserve margin; and that winter power plant outage rates are overstated by approximately 2 percent.

The Commission **FURTHER FINDS** that the Company's weather normalization approach inflates the weather normalized historical peak values by using an inconsistent, flawed approach.

The Commission **FURTHER FINDS** that the Company has overstated its peak load forecast by applying flawed upward adjustments to its PDM forecast.

The Commission **FURTHER FINDS** that using the Company's unadjusted PDM forecast, and a more reasonable 20% reserve margin, the Company's 2023 deficit is overstated by roughly 1,400 MW.

Regarding the reasonableness of the Company's chosen portfolio, the Commission **FINDS** that solar BESS are the least cost resources, with vastly superior economics to the proposed gas resources. In addition, the Commission **FINDS** that the Company should seek additional solar BESS, as they are the least cost resources for consumers. Furthermore, the Commission **FINDS** that the Company should have designated specific proposals for 200 MW of DSM and distributed energy resources.

Otherwise, the Commission **FINDS** that the Company's proposal depends too heavily on fossil generation resources that are inherently subject to two of the very risk factors (forced outages and fuel delivery constraints) that the Company cites as driving its winter reliability concerns.

The Commission **FURTHER FINDS** that the Company's proposal will not reasonably mitigate carbon price risk and is inconsistent with Southern Company's stated carbon reduction goals.

The Commission **NOTES** that utility commissions in Indiana and Minnesota have recently denied natural gas capacity proposals based on many of the same issues identified in this case.[17]

The Commission **FURTHER FINDS** that the Company's proposal will unreasonably raise residential electric bills by requiring customers to pay for more resources than are needed to maintain system reliability.

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[17] *See* Order of Commission, *Verified Petition of S. Ind. Gas & Electric Co.*, Cause No. 45052, (Ind. Util. Reg. Comm'n Apr. 24, 2019), *available at* https://iurc.portal.in.gov/legal-case-details/?id=bbf15412-0a17-e811-811d-1458d04eaba0 (denying request for certificate of public convenience and necessity to construct 850 MW combined cycle plant where utility screened out multiple less expensive alternatives and failed to account for material risks); Order Denying Petition and Requiring Supplemental Modeling, *In the Matter of a Petition by N. States Power Co. d/b/a Xcel Energy*, Docket No. IP-6949, E-002/PA-18-702, (Minn. P.U.C. Dec. 18, 2019), https://www.edockets.state mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E0971A6F-0000-C530-A454-070880095CFD}&documentTitle=201912-158444-02 (denying Xcel's request to purchase 720 MW natural gas combined cycle plant as inconsistent with public interests where potential costs to ratepayers were too high and potential benefits too uncertain). Xcel subsequently consummated purchase of the facility through an unregulated subsidiary, which had the effect of insulating its customers from the costs and risks identified by the Minnesota Public Utilities Commission. Mike Hughlett, *Regulators clear way for Xcel Energy's $650 million Mankato power plant deal*, Star Tribune (Jan. 17, 2020), https://www.startribune.com/regulators-approve-xcel-energy-s-650-million-mankato-power-plant-deal/567045422/.

The Commission **FURTHER FINDS** that electricity usage and bills for residential customers in Alabama are among highest in U.S.; that low-income Alabamians carry extraordinarily high home electricity burdens; that high electric bills in Alabama threaten home energy security and severely impact lower-income households.

The Commission **FURTHER FINDS** that increased spending on cost-effective energy efficiency can reduce low-income electricity burdens but that the Company's spending is much lower than national average.

The Commission **FURTHER FINDS** Company is not collecting the sufficient data points required to gauge the state of low-income and general residential home energy security in its service territory

IT IS, THEREFORE, ORDERED BY THE COMMISSION, that the September 6, 2019 Petition of Alabama Power is hereby denied in part and granted in part.

IT IS FURTHER ORDERED BY THE COMMISSION that the Company's proposals to construct and acquire new gas-fired generation, specifically Barry Unit 8, Hog Bayou Energy Center, and Central Alabama Generating Station generation projects are hereby denied.

IT IS FURTHER ORDERED BY THE COMMISSION that the Company's proposal to move forward with the proposed power purchase agreements for solar BESS resources is hereby approved.

IT IS FURTHER ORDERED BY THE COMMISSION that the Company immediately conduct a solicitation for additional solar and solar BESS in order to take advantage of the superior economics of solar generation and the steadily improving economics of storage technologies.

IT IS FURTHER ORDERED BY THE COMMISSION that the Company develop and file, within 180 days of the effective date of this Order, a plan for identifying and procuring all cost-effective DSM and distributed energy resources that pass a total resource cost test, with a priority on measures that address summer and winter peak demand.

IT IS FURTHER ORDERED BY THE COMMISSION that the Company file, within 60 days of the effective date of this Order, a full documentation of its weather normalization methodology. In doing so, the Company should consider developing a more sophisticated methodology for weather normalization that makes use of additional relevant information, such as temperature over multiple hours, wind speeds, and humidity.

IT IS FURTHER ORDERED BY THE COMMISSION that, within 180 days of effective date of this Order, the Company correct the errors and inconsistencies in its weather normalization methodology, including by using an approach that takes into account the hours preceding the peak load hour, such as a minimum temperature approach.

IT IS FURTHER ORDERED BY THE COMMISSION that the Company develop and document, within 60 days of the effective date of this Order, a detailed methodology for evaluating any anticipated large change in load (additions or losses), and for determining whether, and how much, of the anticipated load change should be reflected as an external adjustment to the load forecasts.

IT IS FURTHER ORDERED BY THE COMMISSION that the Company correct its peak load forecast by removing the flawed upward adjustments that inflated the 2019 peak load forecast. The Company shall file a corrected and updated peak load forecast within 60 days of the effective date of this Order.

IT IS FURTHER ORDERED BY THE COMMISSION that the Company correct the flawed inputs and assumptions in the 2018 Reserve Margin Study that lead to substantial overstatement of the winter TRM. The Company shall file a corrected and updated Reserve Margin Study with the Commission within 180 days of the effective date of this Order.

IT IS FURTHER ORDERED BY THE COMMISSION that the Company, within 180 days of the effective date of this Order, file and make available to the public the customer usage, billing, and arrearage information, for both general residential and low income residential customers, as recommended in the testimony of Energy Alabama/Gasp witness John Howat.

IT IS FURTHER ORDERED BY THE COMMISSION that jurisdiction is retained over this matter to make such further orders as deemed necessary or appropriate under the circumstances.

IT IS FURTHER ORDERED BY THE COMMISSION that this Order shall be effective as of the date hereof.

DONE at Montgomery, Alabama, this ___ day of _____, 2020

Respectfully submitted this 1st day of May, 2020.

Keith Johnston

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CERTIFICATE OF SERVICE

I hereby certify that on May 1, 2020, I served the foregoing *Brief of Energy Alabama and Gasp in the form of a Proposed Order* via electronic mail to the parties below:

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