January 27, 2020

Rebuttal Testimony of Alabama Power Company

Docket No. 32953

Volume 1

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Volume 2

1. Jeffrey B. Weathers (and rebuttal exhibit JBW-1)

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BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF JEFFREY B. WEATHERS
ON BEHALF OF ALABAMA POWER COMPANY

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

A. My name is Jeffrey B. Weathers. I am the Manager of Resource Planning for Southern Company Services, Inc. ("SCS"). My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q. HAVE YOU PREVIOUSLY PRESENTED DIRECT TESTIMONY ON BEHALF OF ALABAMA POWER IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this Rebuttal Testimony is to respond to the testimony of various intervenors filed in Docket No. 32953 commenting on the Direct Testimony that I have submitted in this proceeding. I will not attempt to address every issue raised, so the absence of any specific rebuttal to each and every aspect of an intervenor's testimony addressing my Direct Testimony should not be construed as acceptance of such position.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In recent years, Alabama Power Company ("Alabama Power" or "Company") has experienced a significant shift in reliability risk from the summer to the winter season. To address these reliability risks, the Company has adopted seasonal planning, with separate Summer and Winter Target Reserve Margins. Doing so recognizes the Company's current operational environment and continues the Company's practice of planning for reliable and cost-effective service for customers. The Company needs to use a winter-specific Target Reserve Margin to effectuate seasonal planning and facilitate coordinated planning with the other Southern Company retail operating companies—all of which affords many benefits, both direct and indirect, to Alabama Power's customers.

Contrary to testimony filed by intervenor witnesses, Mr. Jeffry Pollock on behalf of Alabama Industrial Energy Consumers, as well as Messrs. Karl Rábago and James Wilson for Energy Alabama/Gasp, the Company's processes and computational procedures for the Target Reserve Margin are centered upon proven methods consistently applied by the Company and across the industry. These processes and procedures are described in my Direct Testimony and detailed in the Company's 2018 Reserve Margin Study ("Reserve Margin Study" or "Study").[1] The Reserve Margin Study appropriately recognizes the reality that winter weather and extreme cold present unique challenges to the availability and capability of the Company's generation resources to meet customer demand and develops an adequate margin for reasonably foreseeable contingencies. So too, the Study appropriately recognizes the vital importance of reliable electricity supply to customer homes and businesses and is intended to preserve the Company's capability to meet its power supply obligations in all seasons.

[1] *See* Exhibit JBW-1.

In general, intervenor witnesses raise various observations and criticisms about assumptions in the Reserve Margin Study and contend that the Company's Winter Target Reserve Margin is too high. In this Rebuttal Testimony, I will explain how these criticisms are incorrect and would, if adopted, expose the Company and its customers to undue risks. The reserve margin recommendations of these intervenor witnesses would impair the Company's ability to provide reliable service to its customers.

In this Rebuttal Testimony, I primarily focus on reserve margin-related opinions expressed by Mr. Wilson, as well as the portions of Mr. Pollock's and Mr. Rábago's testimonies raising concerns about elements of the Reserve Margin Study. Alabama Power's witness Ms. Burke sponsors Rebuttal Testimony that specifically addresses Mr. Wilson's critiques of the Company's load forecast. In addition, Mr. Carden, Director of Astrapé Consulting, confirms that the Company's Reserve Margin Study was prepared in accordance with industry practice and that the Winter Target Reserve Margin adopted by the Company is reasonable.

RELIABILITY AND SEASONAL PLANNING

Q. PLEASE EXPLAIN WHY THE COMPANY HAS ADOPTED SEASONAL PLANNING.

A. Operational experience and forecasted conditions indicate a significant shift in reliability risk from the summer season to the winter season. As a result, the Company's historical summer-based capacity planning approach requires transition to a seasonal approach that considers both the summer and the winter. Seasonal planning provides greater visibility into the system conditions and capacity needs corresponding to these seasons and avoids limiting reliability decisions to a single season.

Q. WHAT ARE THE DRIVING RISKS THAT CAUSED THE COMPANY TO ADOPT SEASONAL PLANNING?

A. As I discussed in my Direct Testimony, the Reserve Margin Study identified six factors driving increased winter reliability risks: (1) the narrowing difference between summer and winter weather-normal peak loads; (2) higher volatility of winter peak demands relative to summer peak demands; (3) cold weather-related unit outages; (4) penetration of solar resources; (5) increased reliance on natural gas; and (6) market purchase availability in extreme weather conditions. The first five drivers were first discussed in the Company's 2015 Reserve Margin Study. The 2018 Study confirmed the persistence of these five drivers and also reflected the need to consider the sixth driver (market purchase availability).

Q. HAS ANY INTERVENOR WITNESS ARGUED THAT THE COMPANY SHOULD NOT HAVE ADOPTED SEASONAL PLANNING OR SHOULD NOT USE A SEPARATE WINTER TARGET RESERVE MARGIN?

A. No. Based on my review of testimony filed by intervenors in this proceeding, it does not appear that anyone is challenging the appropriateness of seasonal planning or the corresponding use of a Winter Target Reserve Margin for long-term planning. In fact, Mr. Pollock recommended the adoption of seasonal planning in light of Alabama Power having become a winter-peaking system.[2] Mr. Wilson stated that it is important to evaluate

[2] *See* Pollock Testimony, pages 15 & 34.

resource adequacy during all times of the year,[3] and Mr. Rábago agreed that the Company's identified winter drivers justify higher winter reserve margins.[4] Given this testimony, the questions raised by intervenors focus on the level of the winter reserve margin and/or suggest deferral of action in favor of further study.

Q. CAN THE COMPANY IMPLEMENT SEASONAL PLANNING WITHOUT THE ADOPTION OF A SPECIFIC TARGET RESERVE MARGIN FOR THE WINTER?

A. No. It is not possible for the Company to implement and act on seasonal planning without a specified Winter Target Reserve Margin. Reliability would be undermined were the Company simply to defer action until some future date and continue to rely on a reserve margin predicated largely on summer reliability.

Q. PLEASE SUMMARIZE INTERVENORS' SPECIFIC CONCERNS WITH THE COMPANY'S 25.25 PERCENT WINTER TARGET RESERVE MARGIN.

A. Intervenors generally contend that the Company's diversified 25.25 percent level and the Southern system's overall Winter Target Reserve Margin of 26 percent are higher than other utilities. Intervenors also raise various technical objections to the models and methodologies used to derive such margins. These technical objections include: (1) the risk adjustment to the Economic Optimum Reserve Margin ("EORM"); (2) the information used to determine the Value of Lost Load ("VOLL"); (3) the cold weather outage adjustment; (4) the assessment of loads at extreme temperatures; and (5) the use of 54 years of weather data. My testimony that follows refutes intervenors' claims on these matters.

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[3] *See* J. Wilson Testimony, page 34.

[4] *See* Rábago Testimony, page 15.

RISK ADJUSTMENT TO EORM

Q. WHY DOES THE COMPANY PERFORM RISK ANALYSIS?

A. As explained in the Reserve Margin Study, the EORM is based on the "expected" case in the model. In scenarios in which load grows faster than expected, temperatures are higher than expected, or unit performance is poorer than expected, the cost exposure can be much higher than the expected case.[5] A risk-adjusted EORM and the addition of a corresponding measure of capacity reserves provides customers with protection against the occurrence of such events (and the cost impacts associated with them) and at a substantial value relative to the cost of such reserves.

Q. CAN YOU ELABORATE?

A. Yes. The Reserve Margin Study includes a risk adjustment to the EORM through application of a Value at Risk ("VaR") analysis in order to benefit customers by reducing the risk of higher cost outcomes. The Southern system's Winter Target Reserve Margin of 26 percent (adjusted to 25.25 percent for Alabama Power) equates to an 80th percentile of risk, which means that at this level only 20 percent of the highest cost outcomes in the probabilistic analysis are not addressed with reserves. Risk mitigation to this 80 percent level is highly cost effective, yielding a nearly 2:1 benefit-to-cost ratio.[6] Additionally, the amount of Expected Unserved Energy at the 80 percent VaR is less than half of that at the EORM, meaning the level of reliability is doubled for relatively little incremental cost. The VaR adjustment, therefore, clearly benefits customers.

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[5] *See* Exhibit JBW-1, pages 44-49.

[6] *See id.*, page 48.

Q. IS IT PRUDENT TO ELIMINATE THE RISK ADJUSTMENT, AS MR. WILSON SUGGESTS?

A. No. Using the EORM without any adjustment for risk would not be prudent in my opinion. Mr. Wilson claims, without evidence, that the Company's customers are risk neutral. He predicates this claim on the theory that the higher cost of purchased imports, which would be borne by the Company and its customers while benefiting *other utilities and their customers*, will incentivize new capacity construction by merchant generators. The Company's Reserve Margin Study, however, focuses on the costs and reliability of electric service for *the Company's customers*. The Company cannot responsibly plan its system around the prospect of merchant generators making wholesale sales during emergencies and those sales incentivizing the construction of generation facilities in other states.[7] Finally, it is important to remember that extreme cold weather events tend to last for multiple days and impact an entire region, straining the electric grid in a large geographic area and not just within a single utility's footprint. In sum, Mr. Wilson fails to appreciate the challenges of mitigating an inadequate reserve margin through reliance on external sources, and the likelihood of more frequent outages such dependence would cause.

[7] In fact, merchant generators have other means available to them for maximizing revenues apart from making wholesale sales in scarcity situations. For example, a generator may conclude that it is more profitable to sell its gas supply in the daily market rather than using that gas to fuel its facility in support of a sale in the wholesale energy market.

VALUE OF LOST LOAD

Q. INTERVENORS ALSO CRITICIZE THE COMPANY'S VOLL. ARE THOSE CRITICISMS VALID?

A. No. The Company's VOLL reflects the costs that customers assign to an outage. The costs were determined using the results of a 2011 survey[8] of customers in Southern's service territory, with updated weighting by customer class and an escalation of the costs to the study year.[9] Mr. Pollock criticizes the Company for using outage costs that assume no warning is given to customers prior to a curtailment, which he characterizes as a worst-case scenario.[10] The Company selected the values it did, however, because they correspond to the circumstances most likely to give rise to such a reliability event—i.e., conditions that it did not forecast. Use of outage costs associated with warning presumes that every event will afford the system operators advanced insight into the nature of the event and how it will affect customers—which is unlikely. Accordingly, the Company properly reflected costs associated with the absence of any warning.[11] In addition, the Reserve Margin Study includes a discussion of efforts to test the responsiveness of the Target Reserve Margin to changes in the VOLL. One of the evaluations drew from a data source compiling the results of customer surveys similar to the Southern survey and performed by utilities around the country. That source estimated VOLL at a value higher than that used in the Study.[12]

Q. IS IT REASONABLE TO RELY ON ONLY RESIDENTIAL CUSTOMER VALUATION, AS MR. WILSON SUGGESTS?

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[8] *See* Exhibit JFW-25.

[9] *See* Exhibit JBW-1, pages 32-33.

[10] *See* Pollock Testimony, page 22.

A. No. Focusing on the residential class ignores the outage costs to the Company's commercial and industrial classes, whose service needs cannot be disregarded and who likewise face consequences were a load shedding event to occur.[13]

<u>COLD WEATHER OUTAGES</u>

Q. DID INTERVENORS QUESTION THE COMPANY'S ANALYSIS OF UNIT OUTAGES IN COLD WEATHER?

A. Yes. Both Mr. Pollock and Mr. Wilson argue against the Company's analysis of unit outages in cold weather, with Mr. Pollock going so far as to suggest that the Company erred in relying on actual experience.

Q. HOW DO YOU RESPOND TO MR. POLLOCK'S CONCERN THAT INDUSTRY WINTERIZATION IMPROVEMENTS MAY NOT BE SUFFICIENTLY REFLECTED IN THE RESERVE MARGIN STUDY?

A. As discussed by Mr. Kelley in his Rebuttal Testimony, the Company and the Southern system, as part of their ongoing attention to winter reliability, have taken operational and maintenance actions to alleviate the concerns related to winter reliability risks. The benefits of these initiatives are reflected in the data used to prepare the Reserve Margin Study.[14] The Study likewise modeled an improvement in the ability of the system to endure

[11] Mr. Wilson points to an inapposite measure (the wholesale market price cap in the centrally administered energy market of Electric Reliability Council of Texas ("ERCOT")) as evidence that the VOLL used by the Company is too high. Mr. Carden explains why reliance on the ERCOT value is misplaced.

[12] *Compare* Exhibit JBW-1, page 33 *with id*., pages 57-58.

[13] *See* Exhibit JBW-1, page 33.

[14] *See* Direct Testimony of Jeffery B. Weathers ("Weathers Direct"), p. 8; *see also* Exhibit JBW-1, pages 21-22 and A-7 to A-9.

cold weather events, with assumed winterization enhancements in effect.[15] Thus, Mr. Pollock is wrong to say that the Company's Study does not fully account for improved winterization efforts.

Q. WHY DOES MR. WILSON CONTEND GENERATOR OUTAGE RATES ARE OVERSTATED IN THE STUDY?

A. The Reserve Margin Study modeled incremental unit outages at extremely cold temperatures based on a trend of actual historical data. The relationship between historical temperatures and generation unit outages was modeled to predict future outages at extremely cold temperatures. While the Company used an exponential curve fit, Mr. Wilson claims a linear curve fit produces greater correlation for temperatures below 16°F, and that the difference on generating unit outage rates is about 2 percent at the lowest temperatures.[16]

Q. DID THE COMPANY CONSIDER USING A LINEAR CURVE FIT?

A. Yes, the Company considered using a linear regression. However, the Company selected an exponential regression based on actual experience and understanding of the engineering design and capabilities of its generation facilities.[17] Specifically, generator performance begins to degrade at an exponential rate once temperatures reach extreme cold. Thus, slightly greater linear correlation did not justify its use in the Study.

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[15] *See* Exhibit JBW-1, page 21. Specifically, the Reserve Margin Study assumed EFOR improves by 2 percentage points.

[16] *See* J. Wilson Testimony, page 63.

[17] This view is reinforced by research reported by PJM on the effects of wind chill on forced outages. *See Capacity Performance*, Slide 7, PJM (attached as Reb. Ex. JBW-1).

Further, an examination of Mr. Wilson's Figure JFW-13 reveals that a linear regression results in a higher cold weather outage rate for all but the most extreme temperatures. Conversely, for all temperatures down to 3°F, the Company's exponential regression results in lower outage rates.[18] In fact, there are only four weather years (1963, 1966, 1982 and 1985) in which the Company's regression results in higher outages than Mr. Wilson's regression. This comparison shows that the Company's modeling approach is not materially different than what Mr. Wilson would employ. If anything, the Company's approach yields the same or slightly lower Target Reserve Margin than would have been necessary to achieve the same level of reliability with the use of a linear regression. Mr. Carden explains this further in his Rebuttal Testimony.

Q. MR. RÁBAGO AND SIERRA CLUB'S MS. WILSON CRITICIZE THE COMPANY FOR INCLUDING GAS RESOURCES IN THE PORTFOLIO, CITING WINTER RELIABILITY RISKS. DID THE COMPANY PROPERLY CONSIDER THESE RISKS IN ITS ANALYSIS?

A. Yes. The winter reliability risks intervenor witnesses reference have been properly considered in the Reserve Margin Study[19] by modeling the impact of cold weather on existing and additional gas units. I do not expect the impact of these risks to be exacerbated by the gas resources included in the Company's portfolio. As explained in the Study,[20] the gas delivery risk for combined cycles such as the ones included in the portfolio is largely mitigated through compliance with the Southern Company Fuel Policy, which includes

[18] *See* J. Wilson Testimony, Figure JFW-13 on page 62.

[19] *See* Exhibit JBW-1, pages 21-22, 30-31, A-7-A9, & A-11-A-14.

[20] *See id.,* page A-14.

requirements for procurement of firm gas transportation. The required level of firm transportation provides considerable benefits to system reliability, including in cold weather conditions. The small number of instances where firm transportation for combined cycles may not be sufficient to supply all of the unit's generation (e.g., extended operation at full pressure, as opposed to base mode) are accounted for in the Target Reserve Margin. Indeed, except on the rare occurrence of a force majeure event, the contracted firm transportation gas capacity will be available to supply the needs of the facility. Finally, I should note that gas combined cycles such as the ones in this proposal are dispatchable in all hours of the day and provide a reliable, flexible supply of generation on cold winter mornings. The same level of flexibility cannot be achieved with the renewable generation resources Mr. Rábago and Ms. Wilson suggest the Company should add to replace the proposed gas resources.[21]

LOADS AT EXTREME TEMPERATURES

Q. WHY DOES THE STUDY MODEL LOADS AT EXTREME WINTER TEMPERATURES GREATER THAN LOADS ACTUALLY EXPERIENCED ON THE SYSTEM?

A. The study is simply capturing load response to lower temperatures. The system's all-time winter peak occurred during the Polar Vortex of 2014.[22] However, temperatures during the Polar Vortex averaged approximately 10 degrees across the Southern system. As shown in Figure I.1 of the Reserve Margin Study, our system has experienced temperatures

[21] *See* Rábago Testimony, page 29; *see also* R. Wilson Testimony, page 31; *cf*. Detsky Testimony, page 4.

[22] *See* J. Wilson Testimony, pages 48-49.

colder than observed during the Polar Vortex, including in the early 1980s.[23] Since the 1980s, customer count and winter demand have grown. The modeled loads reflect this growth and the stronger winter response experienced in recent years. Accordingly, the model forecasts higher loads in response to the extreme temperatures that have occurred historically.

Q. HOW DOES THE COMPANY CALCULATE LOADS FOR EXTREME TEMPERATURES?

A. In order to determine what the load would be if the weather from each of the 54 historical years occurred again, the Company uses a sophisticated neural net modeling approach. This model takes the historical relationship between temperature and load and predicts a future load for a given temperature profile. For temperatures with few data points, the Company applies a linear regression using a Peak Load Adjustment Factor ("PLAF"), based on proximate temperatures for which sufficient data exist, which enhances the modeling for such temperatures. This modeling reflects the continued growth in load as temperatures reach extremely cold levels. Mr. Wilson challenges the model's conclusions that load levels increase as temperatures drop, but the Company's historical load data refutes Mr. Wilson's generalized hypothesis. Ms. Burke discusses this point more fully in her Rebuttal Testimony.

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[23] *See* Exhibit JBW-1, page 3.

WEATHER HISTORY

Q. WHY DOES THE COMPANY USE 54 YEARS OF WEATHER HISTORY DATA IN THE RESERVE MARGIN STUDY?

A. We believe that historical extreme temperatures can reoccur in the future. The Company includes *all* of the available weather data in order to have the *most robust* set of weather conditions to evaluate. Both Mr. Wilson and Mr. Pollock seem to suggest that, for whatever reason, the system will not experience similar weather conditions ever again.

Q. DOES THE RESERVE MARGIN STUDY OVER-EMPHASIZE INFREQUENT COLD WEATHER EVENTS?

A. No. The Reserve Margin Study is a probabilistic analysis. Consequently, extreme cold events such as those experienced in the 1980s are included in the Study, but they are not over-emphasized. Rather, they are properly weighted based on historic frequency of occurrence. Temperatures that occurred infrequently were assigned very low probabilities in the Study, while temperatures that occurred more frequently in the historical data set were assigned higher probabilities. It would improperly bias the data set to ignore extremely cold events on the assumption that such temperatures cannot occur again, as suggested by Mr. Wilson and Mr. Pollock. This is unsound from a modeling standpoint and would lead to diminished system reliability. The prospect for load shedding is at its greatest in these most extreme weather events, and without these events in the model, load shedding would occur during less extreme and more frequently occurring events. Accordingly, it is to customers' benefit that the Company consider data from all available weather years.

TARGET RESERVE MARGIN RECOMMENDATION

Q. DID ANY INTERVENORS PROPOSE ALTERNATIVES TO THE COMPANY'S TARGET RESERVE MARGIN?

A. Yes. Mr. Wilson supports a 20 percent winter reserve margin.[24] Mr. Rábago raises the prospect of a 17 percent margin, which reflects an average of several selected utilities.[25]

Q. DO EITHER OF THESE PROPOSALS HAVE MERIT?

A. No.

Q. WHAT IS THE BASIS FOR MR. WILSON'S NUMBER?

A. Mr. Wilson predicates his 20 percent value on his claims that Company loads in coldest conditions are overstated by 5 percent in the Reserve Margin Study and that the unit outage rates are overstated by 2 percent.[26] Adding these two numbers together, he arrives at a 7 percent downward adjustment of the Company's Winter Target Reserve Margin, and then rounds up to 20 percent.[27]

Mr. Wilson's 5 percent component is based on his arguments regarding the Company's assessment of loads at extremely cold temperatures and its use of 54 years of weather data. As I demonstrated above, these claims are without merit.[28] Similarly, the 2

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[24] *See* J. Wilson Testimony, page 66.

[25] *See* Rábago Testimony, page 15. I would note that one could infer from Mr. Pollock's testimony various reserve margins ranging from 13 percent to 20.5 percent, depending on his different resource recommendations. Mr. Pollock does not, however, provide any analysis supporting a particular reserve margin. As for his other criticisms, those are addressed in the rebuttal testimonies of other Company witnesses.

[26] To be clear, it does not appear that Mr. Wilson performed a reserve margin study to develop the 20 percent value. No such study was provided in response to the Company's request for his workpapers.

[27] *See* J. Wilson Testimony, page 66.

[28] Mr. Wilson also contends that load forecast uncertainty contributes to this 5 percent number; however, Mr. Carden explains the errors of this assertion in his Rebuttal Testimony.

percent component arises from his preferred use of a linear regression, rather than exponential, for unit outages in extremely cold conditions. As I discussed above, the Company's use of the exponential regression reflects actual experience and understanding of the engineering design and capabilities of its generation facilities, and does not increase the Target Reserve Margin. If anything, Mr. Wilson's approach results in a neutral or slightly upward impact to the reserve margin.

Q. IS MR. WILSON'S MATH A PROPER WAY TO DEVELOP A WINTER TARGET RESERVE MARGIN?

A. No. The Target Reserve Margin is not simply the reserve margin required for the load corresponding to the coldest temperatures in the study. The Reserve Margin Study presents the results of a probabilistic analysis of over 700,000 production cost simulations, which weights the conditions at the coldest temperatures with temperatures from every other year in the 54-year weather history.[29] Furthermore, the Target Reserve Margin is not simply the EORM resulting from the analysis. It considers risk to customers through the VaR assessment, and it considers reliability through the comparison to the 1:10 LOLE metric (which is discussed in my Direct Testimony and the Reserve Margin Study). For all of these reasons, it is wrong to assume, as Mr. Wilson does, that a change to peak load, or to the resources available at peak load, equates to an arithmetic, one-for-one change to the Target Reserve Margin.

[29] *See, e.g.,* Exhibit JBW-1, page 34.

Q. WHAT IS YOUR ASSESSMENT OF MR. RÁBAGO'S 17 PERCENT FIGURE, WHICH HE PREDICATES ON THE AVERAGE WINTER TARGET RESERVE MARGIN OF SEVERAL UTILITIES?

A. Like Mr. Wilson's number, Mr. Rábago's figure is meaningless for purposes of this proceeding. Mr. Rábago took a straight average of the winter target reserve margins that are publicly available for other utilities in the Southeast. Seven of the twelve utilities in the table are in the state of Florida, which as Mr. Kelley observes in his testimony exhibits different system conditions. To this end, the Company's Reserve Margin Study is a comprehensive system-specific evaluation based on its own customers, their energy and reliability needs, and the resources that are available to serve those customers. Accordingly, the Reserve Margin Study is far superior to Mr. Rábago's simple averaging technique, which fails to account for the considerations described above in any meaningful way.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF JEFFREY B. WEATHERS ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA)

COUNTY OF SHELBY)

Jeffrey B. Weathers, being first duly sworn, deposes and says that he has read the foregoing prepared testimony and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Jeffrey Weathers

Jeffrey Weathers

Subscribed and sworn to before me
this 27th day of January, 2020.

Esther Howard Brandenburg

Notary Public

ESTHER T. HOWARD
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 05-12-2020

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Rebuttal Testimony for Jeffrey B. Weathers

Reb. Ex. JBW-1

Capacity Performance

Education and Dialogue Session

August 12, 2014

January 2014 Polar Vortex and Winter Storm

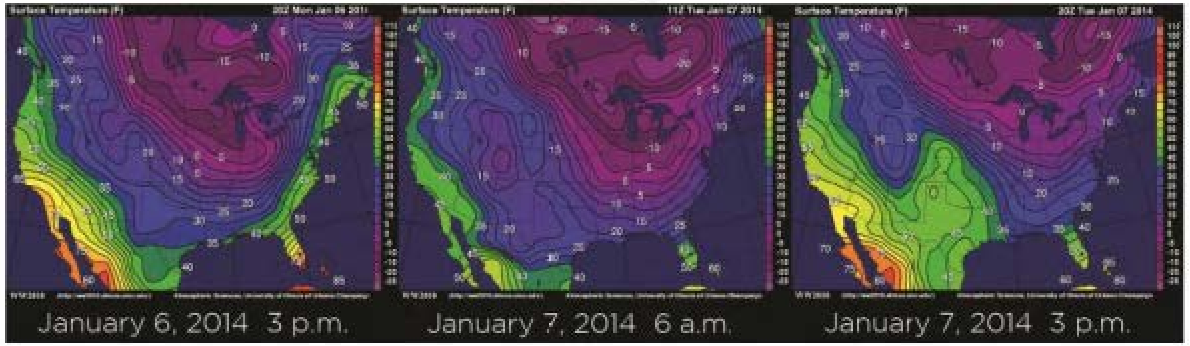
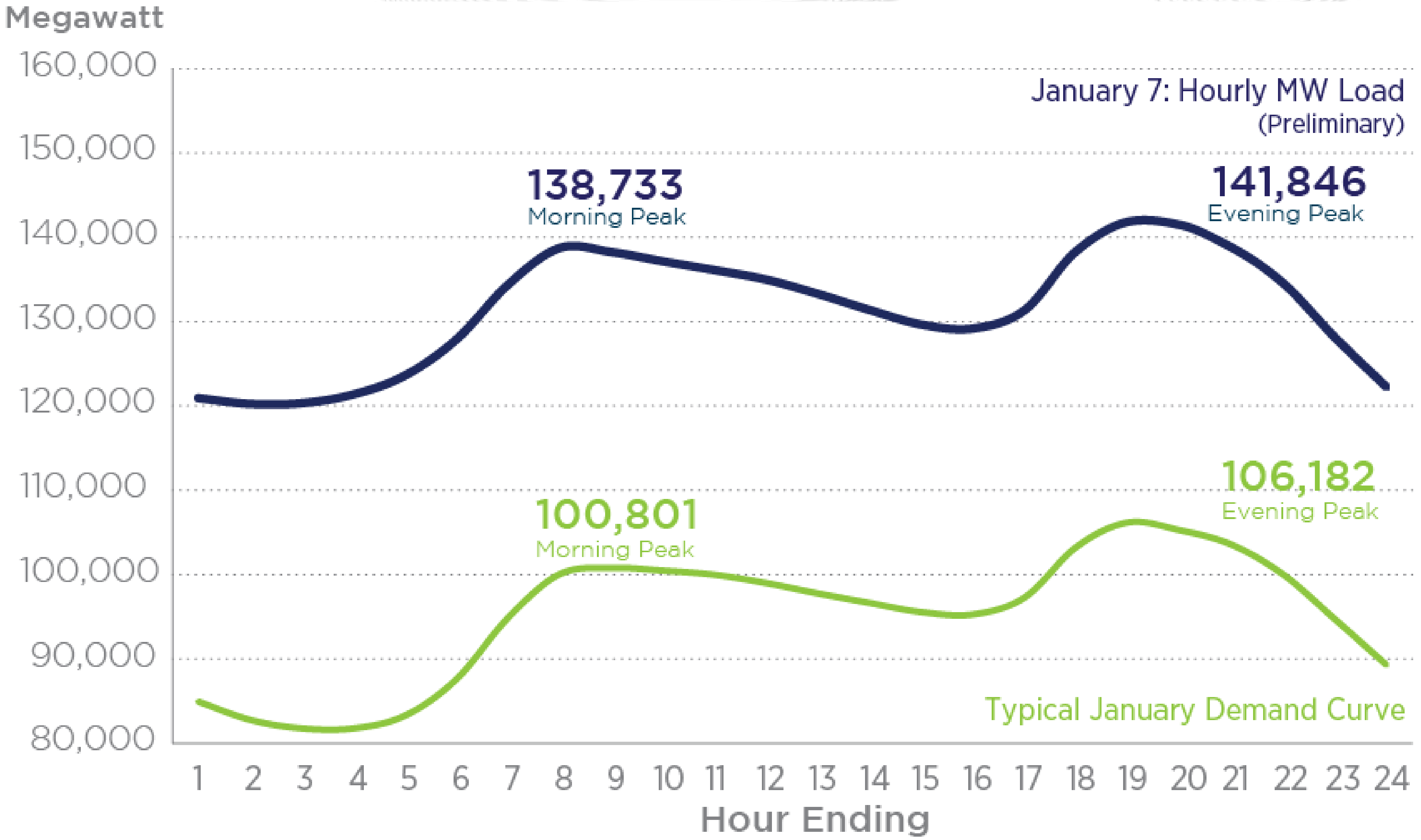
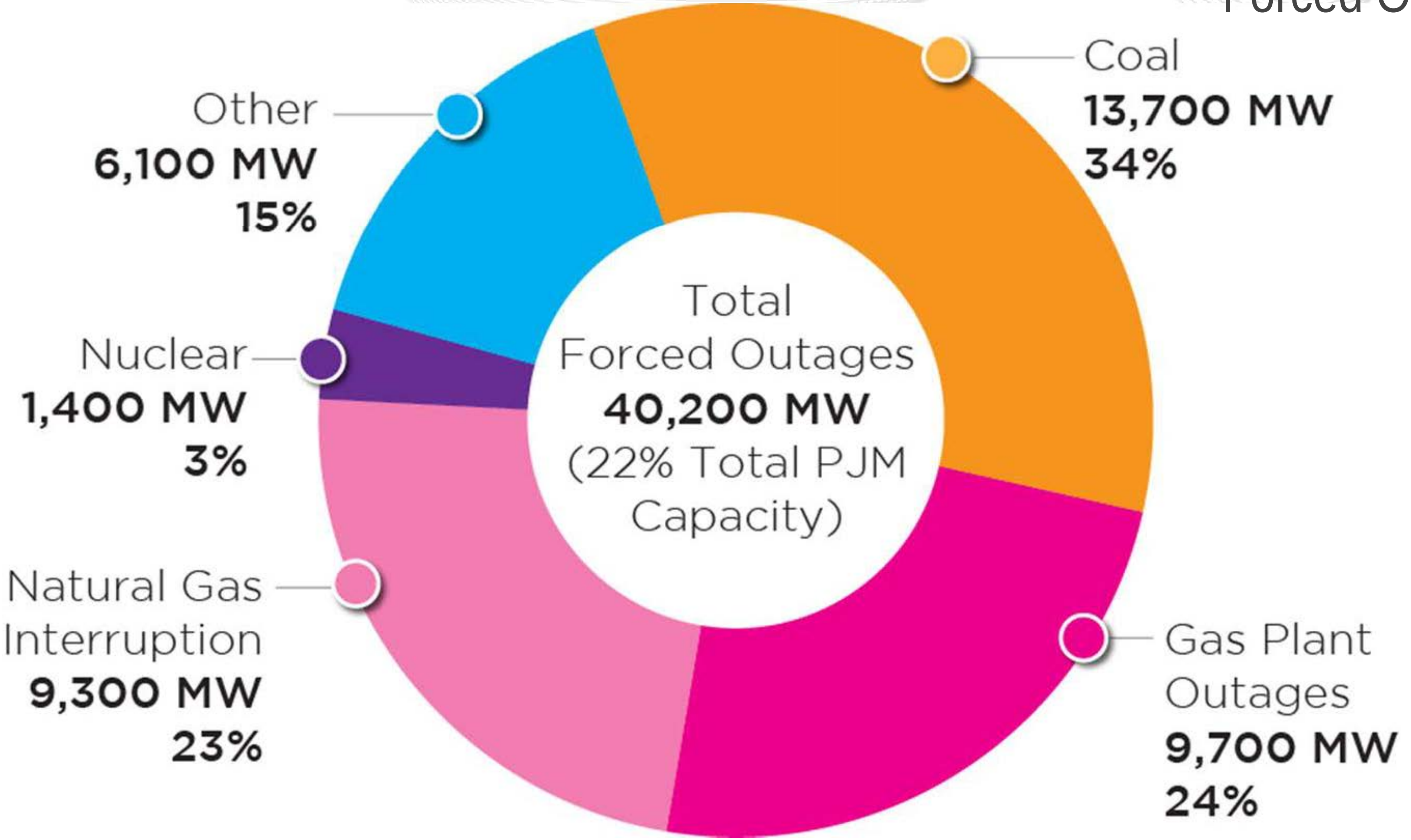


Figure 2: January 2014 Minimum Temperatures: Columbus, Philadelphia, Chicago and Richmond

January 7 – Peak Load vs. Typical Load

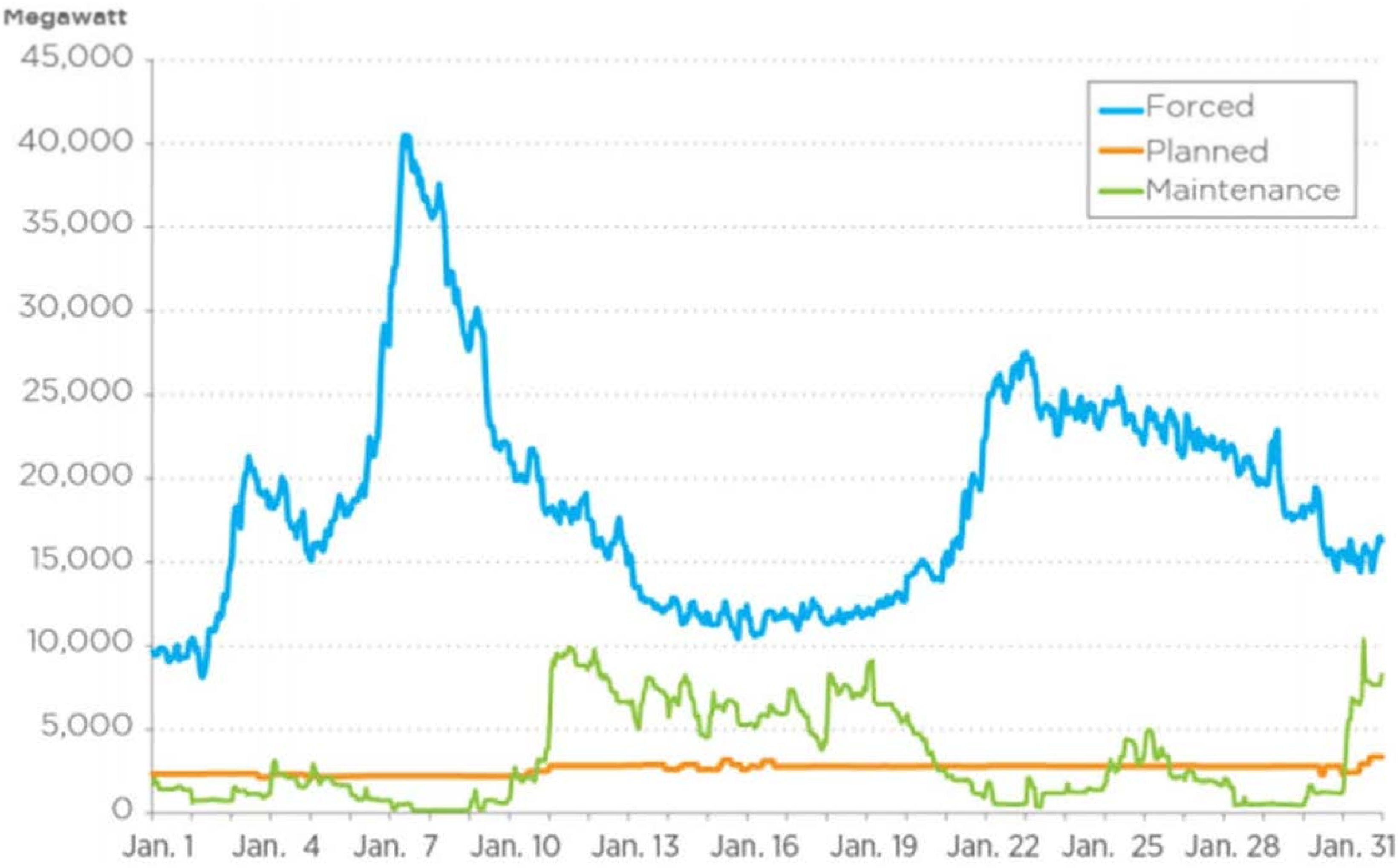


Jan. 7 Evening Peak, 7:00 p.m. Forced Outages



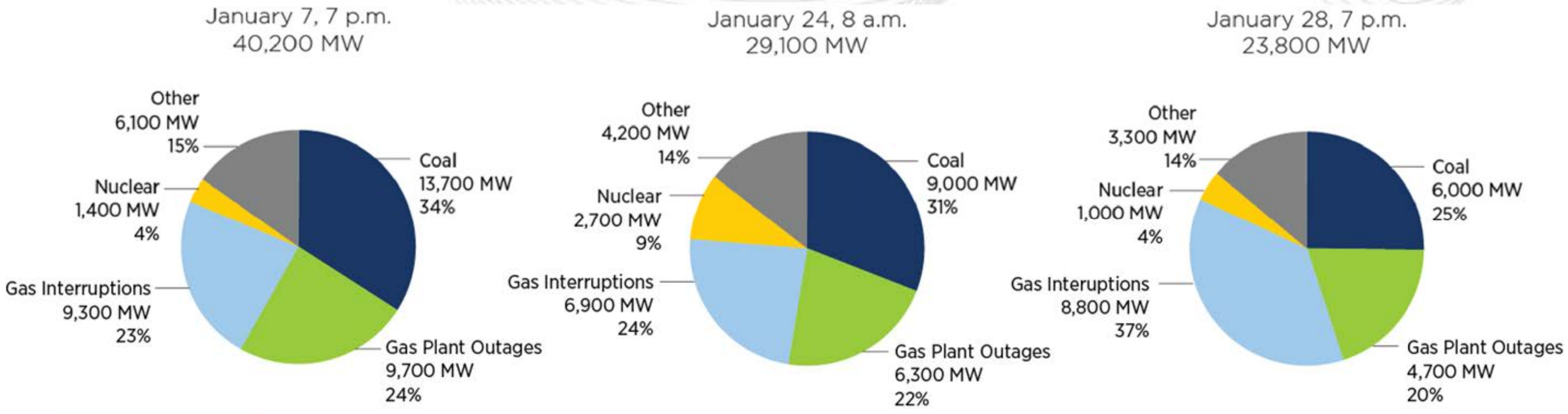
Increased Generation Outage Rates

Figure 4: Generator Outages – January 2014



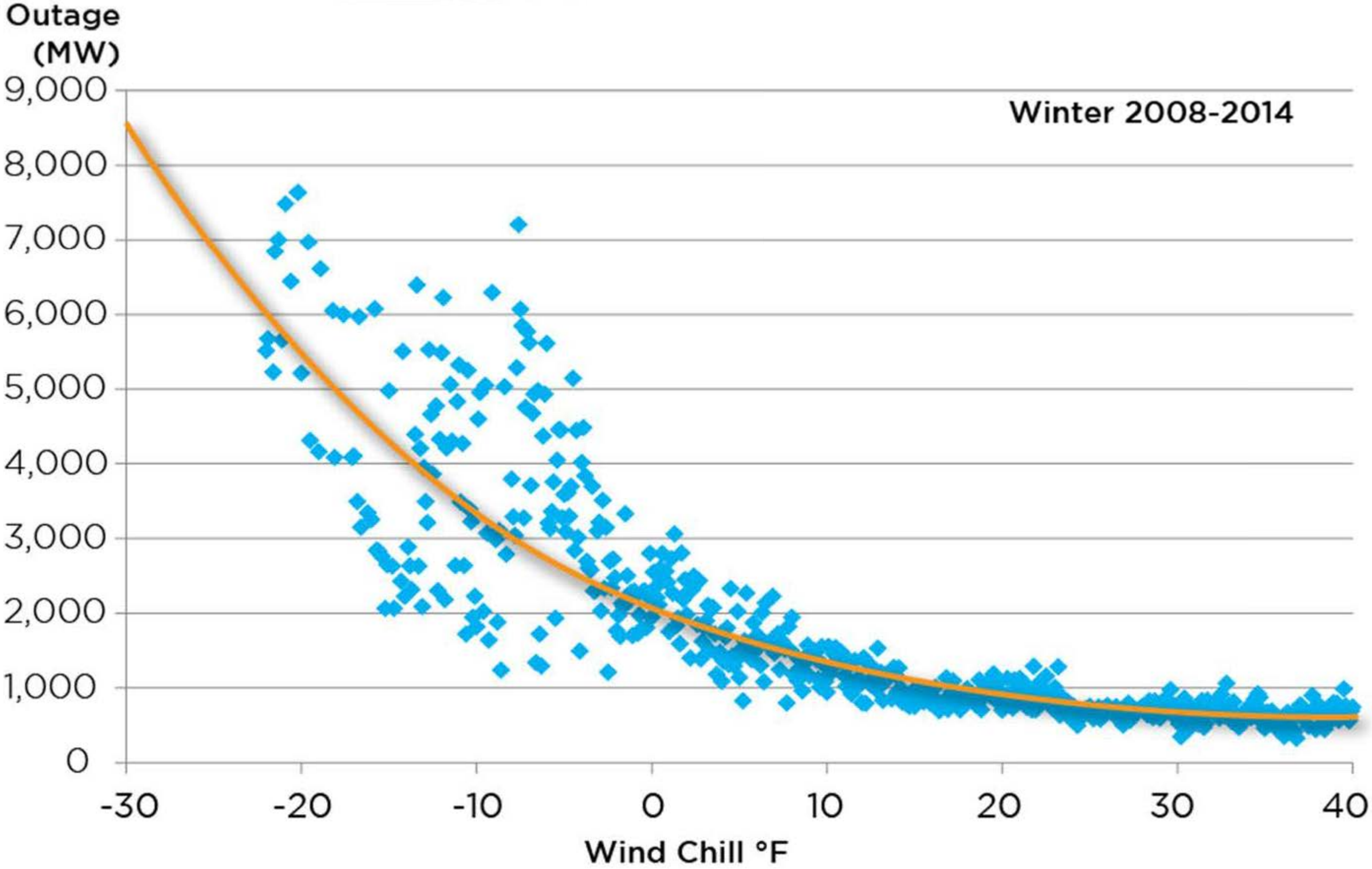
Increased Generation Outage Rates

Figure 5: Forced Outages



Coldest low/high temp of the three days	January 7		January 24		January 28	
	Low	High	Low	High	Low	High
Philadelphia	4	13	8	19	12	21
Richmond	10	22	11	25	14	27
Pittsburgh	-9	4	0	19	-8	7
Columbus	-7	11	0	22	-11	6
Cleveland	-11	4	-1	21	-9	7
Lexington	-4	11	-5	24	2	12
Chicago	-12	3	-6	28	-11	3

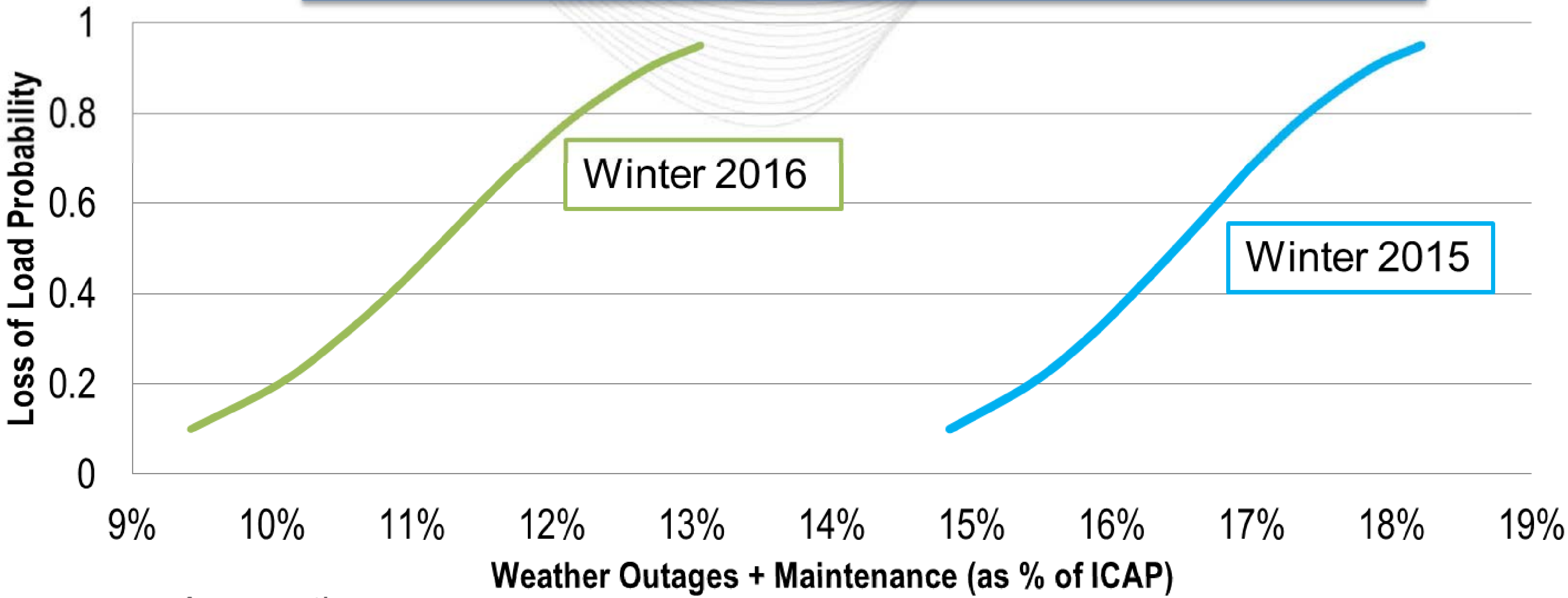
Wind Chill vs. Forced Outage – Western PJM



Cold Weather Induced Equipment Issues

- Frozen equipment
- Fuel Issues
  - Frozen fuel
  - Delivery issues
- Emissions equipment
- Consumables impacts
- Secondary processes
- Units not frequently operated

Loss of Load Probability on Peak Winter Day



Assumptions:

PJM is at a 90/10 winter load level

No DR is implemented

Emergency assistance is only from RPM committed external units

Fuel Security and Reliability

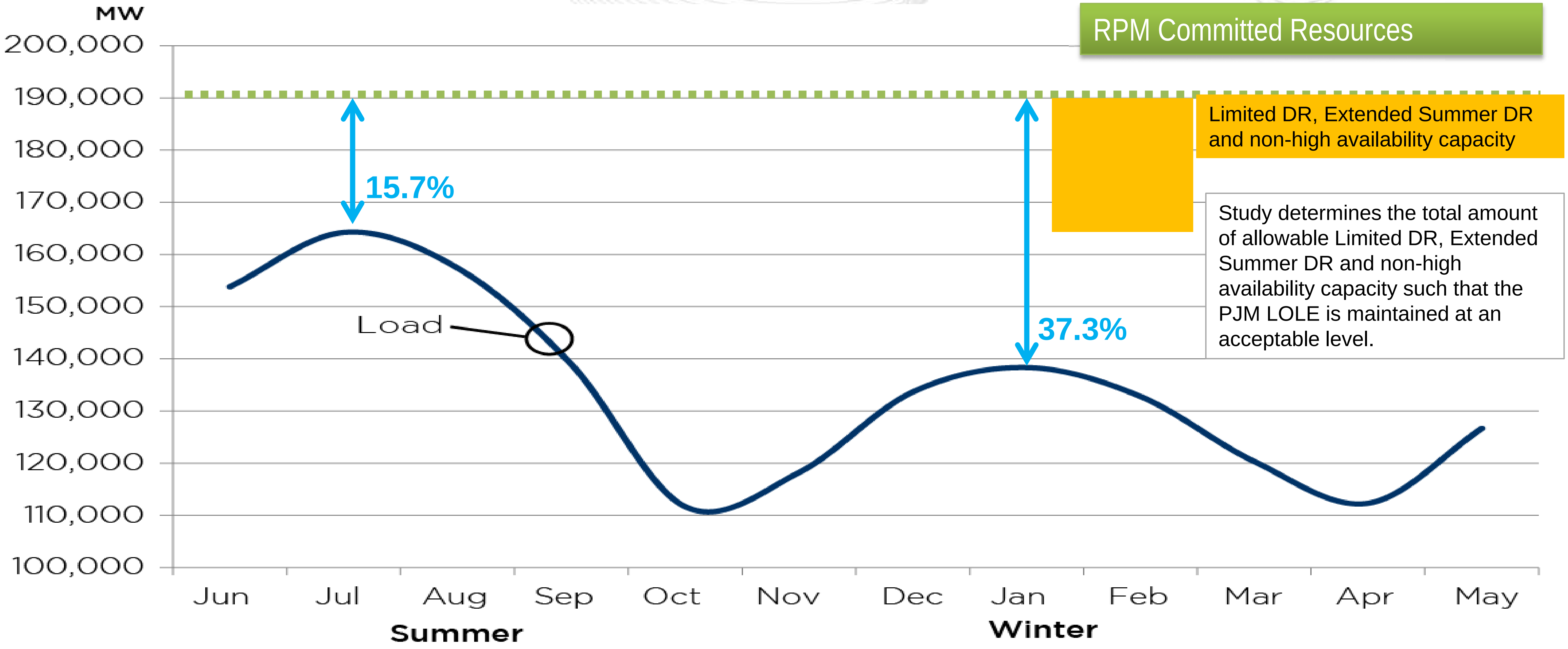
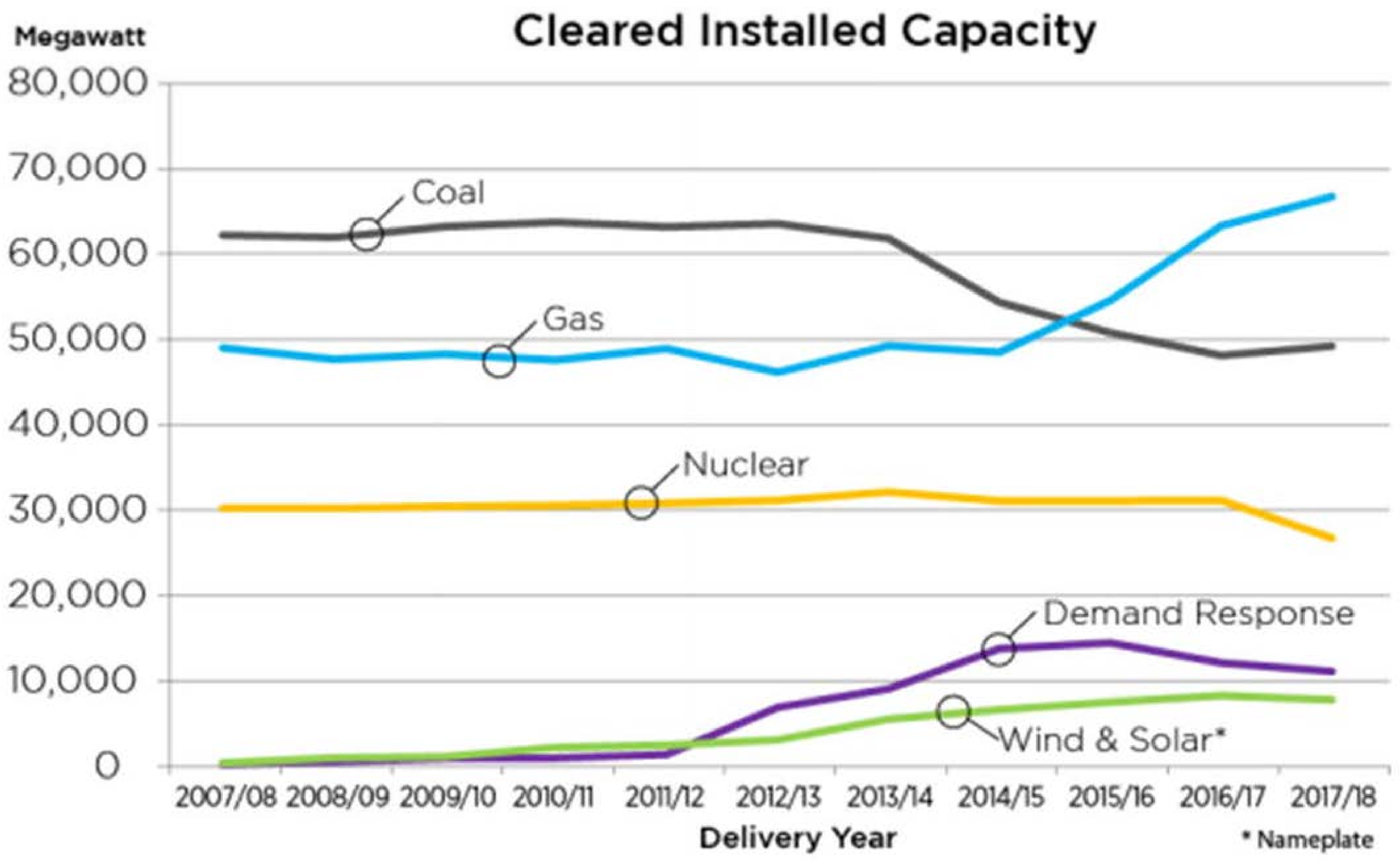
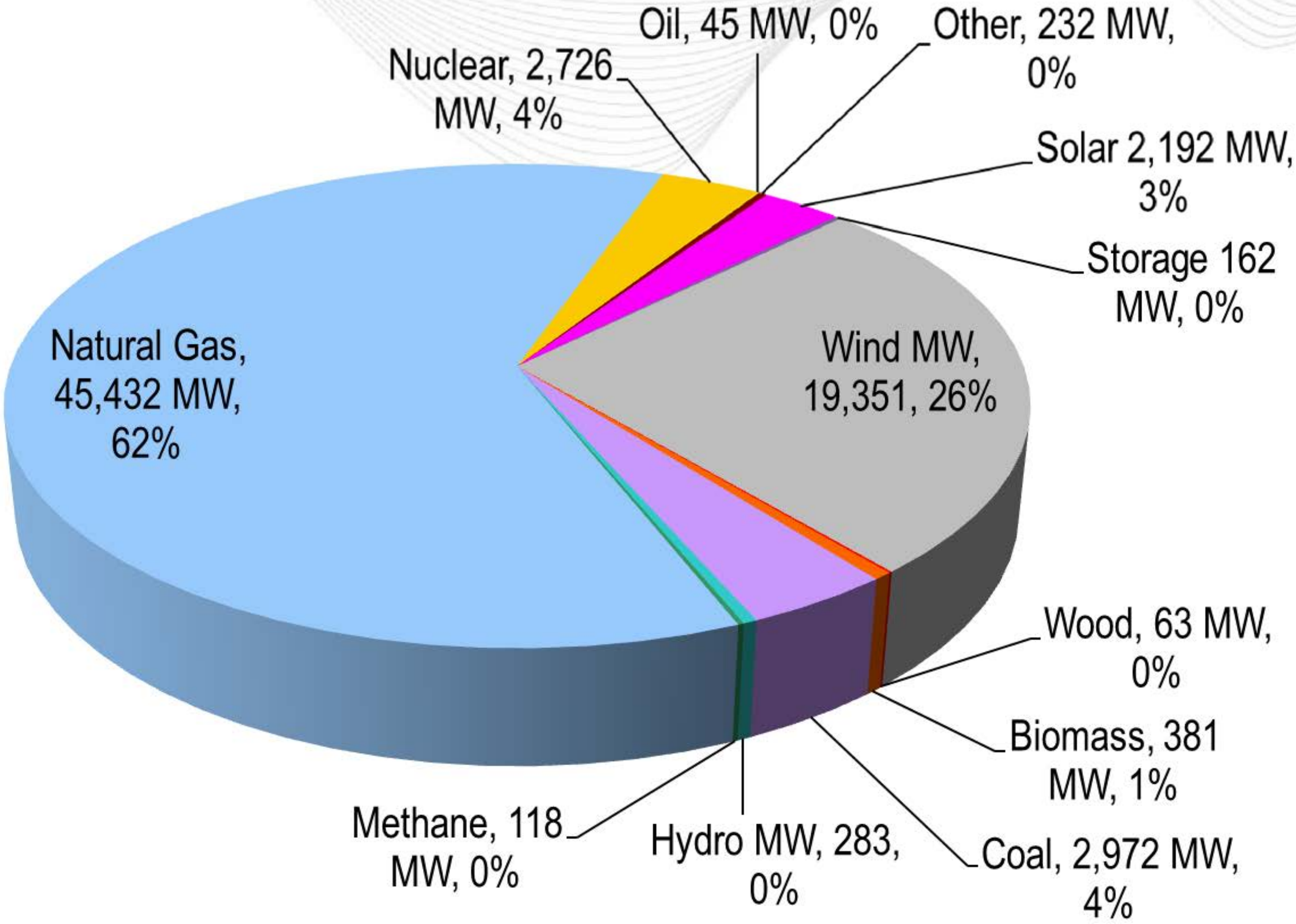


Figure 10: Cleared Installed Capacity



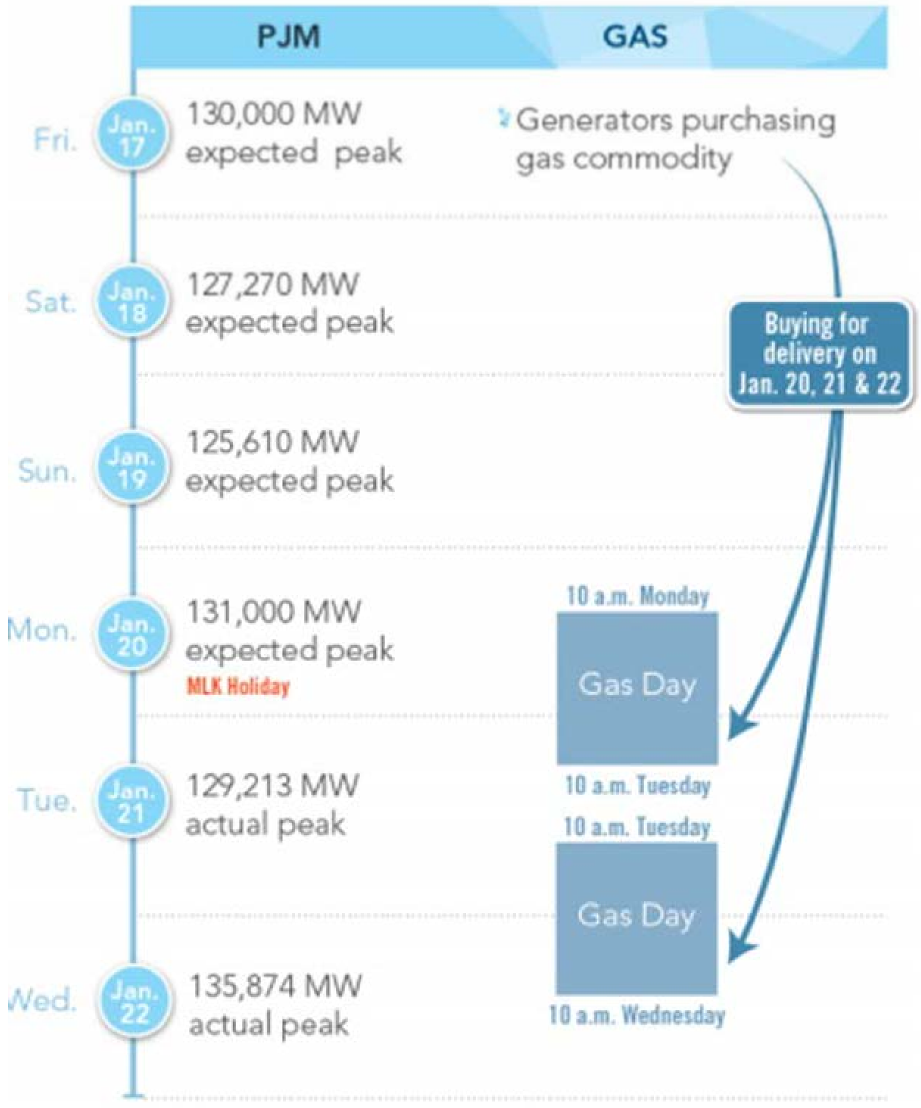
PJM Queued Generation (Nameplate Energy) – Active and Under Construction



As of 03/2013

- Fuel availability is within the generation owner's control
- Penalties for capacity resource unavailability during peaks are insufficient
- Incentives created by insufficient peak period penalties
- Current PJM capacity market rules do not allow full reflection of costs for low probability, high reliability events
- Current PJM energy market rules either do not allow full reflection of costs for low probability, high reliability impact events, or bias decisions away from more reliable solutions
- Overarching direct and indirect incentives for enhancing availability and market implications

- Transportation Issues:
  - Timing of Gas Day and Electricity Day
  - Operational Flow Orders
  - Connections behind LDC city gate
- Commodity Market Issues:
  - Timing of commodity purchases with respect to electricity commitments
  - Weekday vs. weekend


PJM
GAS
Fri.
Jan. 17
130,000 MW
expected peak
Generators purchasing gas commodity
Sat.
Jan. 18
127,270 MW
expected peak
Buying for delivery on Jan. 20, 21 & 22
Sun.
Jan. 19
125,610 MW
expected peak
Mon.
Jan. 20
131,000 MW
expected peak
MLK Holiday
10 a.m. Monday
Gas Day
10 a.m. Tuesday
Tue.
Jan. 21
129,213 MW
actual peak
10 a.m. Tuesday
Gas Day
10 a.m. Wednesday
Wed.
Jan. 22
135,874 MW
actual peak

Reduced and Restricted Availability Generation and Demand Resources

- Fuel procurement restrictions; primarily natural gas.
- Environmental limitations that limit the total run hours for a generation resource.
- A lack of compensation for resource flexibility
- A shift in the supply curve has rendered resources designed to be base load into the role of peaking resources.
- Reductions in staff at some generation sites to minimize costs
- Increase of Demand Response (DR) as a capacity resource

Increasing Amount of Inflexible Resource Offer Parameters

- Some generation resource owners have chosen to decrease staffing at sites
- Business rule changes in 2012 that allowed unit owners to manage startup and notification times in excess of 24 hours
  - During recent summer days has exceeded 5,000 MW
- Limited run hours due to environmental restrictions

- Performance Incentives / Penalties
- Operational Availability and Flexibility
- Fuel Security

- Energy Storage Participation in RPM (PC)
- QTU Credit (MIC)
- Cold Weather Resource Performance Improvement – long term aspects (OC)
- Gas Unit Commitment Coordination – long term aspects (OC)
- Unit Market Offers (MIC)
- Gas / Electric Coordination

- 13,700 MW coal out on January 7 with 13,000 out because they had no natural gas to start. Why weren't these units already on?
- Figure 5 is confusing. Pie charts have different days than table and are not in chronological order, or is the middle chart supposed to be January 24?
- "PJM data show that generator outage rates can be expected to increase during cold weather conditions." Would be good to discuss the basis for this conclusion. More than just three days of data? Need an explanation of Figure 6.
- "The end result is that with a greater shift toward gas-fired resources there is no incentive for generators to sign up for Firm Transportation and expand available pipeline capacity, and then greater uncertainty of which resources will be available based on the ability to secure bundled commodity and transportation on a short-term basis." Is it a good assumption that signing up for firm transport will incent construction of new gas pipeline capability? Thought you needed a longer commitment.

- What is Short-term spot firm transportation?
- LOLP (Should we consider an LSE's peak load obligations as well)
- Need more explanation of unnumbered figure (7?) on page 16 and discussion on how a 15% outage rate in winter translates to a 10% LOLP
- Are figures 7, 8 and 9 all based on the PJM LOLP study? How do these figures tie together?
- "Performance data from January, 2014, clearly indicate that, under extreme winter conditions, the amount of unavailable generation can exceed 20 percent of the total generation fleet." But is it usual to expect that high a level of outages? Thought this was unusual. During "normal" weather, outages much less. So do we plan for LOLP based on extreme or normal?
- Perhaps I read too quickly, but the only thing I saw that made me think about redefining capacity was the "lack of compensation for resource flexibility."

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF MARIA J. BURKE
ON BEHALF OF ALABAMA POWER COMPANY

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

A. My name is Maria Burke. I am the Forecasting Manager for Alabama Power Company ("Alabama Power" or the "Company"). My business address is 600 18th Street North, Birmingham, Alabama 35203.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I graduated from Auburn University in August 1986 with a Bachelor of Science degree in Chemical Engineering, and completed my Masters in Business Administration from Samford University in 2001. In 1986, I began my career with the Southern Company at a research facility in Wilsonville, Alabama as a process engineer, and then as an environmental engineer.

I continued my environmental permitting work with Southern Electric International in 1990, helping to develop independent power projects both domestically and internationally. I joined the System Planning Department of Southern Company Services, Inc. ("SCS") in November 1992 and spent the next six years in various engineering and supervisory positions. I was involved in supply-side bid evaluation from December 1996 through March 2000. After working for three years in SCS Transmission and a short time in SCS Engineering as the Scrubber Program Manager, I moved to Alabama Power as the Forecasting Manager, where I have been since 2005.

Q. WHAT ARE YOUR CURRENT JOB DUTIES AND RESPONSIBILITIES?

A. As Forecasting Manager, I have direct responsibility for the development of Alabama Power's demand, energy, customer and revenue forecasts. I am part of the Company's Forecasting and Resource Planning group, which is under the direction of John B. Kelley.

Q. HAVE YOU PREVIOUSLY PRESENTED DIRECT TESTIMONY ON BEHALF OF ALABAMA POWER IN THIS PROCEEDING?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address claims raised by various intervenors, particularly Mr. Wilson and Mr. Howat on behalf of Energy Alabama/Gasp, Inc. While I have made every effort to be comprehensive in my responses to these claims, the absence of any specific rebuttal to each and every aspect of an intervenor's testimony on a given issue should not be construed as acceptance of such position.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. As detailed in the testimony of other Company witnesses, Alabama Power has evolved from a summer-peaking utility to a winter-peaking utility. The load forecast is a critical component in the Company's 2019 Integrated Resource Plan ("IRP") and its determination of the amount and timing of needed resources, as reflected in the Company's petition in this proceeding. My team and I have worked diligently to ensure that we adapt the analytical approach Alabama Power used to prepare the load forecast to accommodate this shift, thereby positioning the Company to continue to provide reliable service to our customers in the winter months. Our analytically rigorous process produced B2019 peak forecast results that are reasonable and reliable. As further verification, we later compared the B2019 peak forecast results against those derived through the application of a newer model, finding them to be quite consistent.

My rebuttal testimony also explains the errors underlying Mr. Wilson's criticisms of the Company's process, criticisms that I find indicative of a fundamental misunderstanding of peak load forecasting by a utility obligated to provide reliable service to customers. Specifically, I address his arguments regarding the Company's weather normal calculation of historical peaks, the adjustments to the Company's Peak Demand Model ("PDM") and the industrial energy forecasting process. Mr. Wilson's testimony makes clear that he would prefer a lower peak demand forecast, and his arguments appear designed to chip away at our methods until he reaches his desired outcome. But Mr. Wilson's result-driven approach is contrary to a fundamental principle of load forecasting; we allow the data inputs and analysis to drive our results, and not the other way around.

Finally, my rebuttal testimony discusses the typical energy consumption patterns of residential customers in the state of Alabama. Alabama residents consume a larger amount of electricity than residential consumers in other states. However, when all forms of energy are considered, Alabama's total residential energy consumption is among the lowest in the nation.

WEATHER NORMALIZATION PROCESS

Q. MR. WILSON CLAIMS THAT THE WEATHER NORMALIZATION PROCESS USED BY THE COMPANY EXHIBITS "ERRORS AND INCONSISTENCIES." IS HIS STATEMENT ACCURATE?

A. No. Mr. Wilson mischaracterizes the Company's weather normalization process. He also makes several erroneous statements regarding practices that he claims the Company should have utilized.

Q. WHY DOES THE COMPANY UTILIZE WEATHER NORMALIZATION OF SUMMER AND WINTER PEAKS?

A. The Company uses weather normalization to enhance its understanding of seasonal peak loads. Weather normalized historical peaks do not, however, serve as the driver for the forecast of peak demand. Instead, the peak demand forecast properly is calculated "bottom up" using the energy forecasts developed by class and by industrial segment.

Q. HOW DID THE COMPANY UNDERTAKE TO WEATHER NORMALIZE WINTER PEAK DEMANDS?

A. The first step involved the determination of how our customers' demand for electricity responds to low temperatures, focusing specifically on temperature-sensitive load that includes residential, commercial and wholesale customers. To do this, we gathered the daily peaks on weekdays in which the temperature was at or below 25 degrees. We also captured the effects of cold build-up by examining data for the following weekday. Then we applied a temperature response slope of [redacted] per degree to determine what the identified daily peaks would have been if the system had experienced a temperature of [redacted][1] which reflects the typical minimum temperature expected in Alabama Power's service territory in the winter.

Q. HOW DID YOU DERIVE THE TEMPERATURE RESPONSE SLOPE?

A. We developed a regression model by plotting a set of system hourly loads, less industrial loads, against the coincident hourly Alabama Power service area weighted temperatures. The loads used were those occurring on weekdays, during the hours of 6 AM through 8 AM, at temperatures at or below 25 degrees. Industrial loads were excluded from this calculation because our data and experience have shown that electricity consumption by the industrial class is not weather sensitive. This resulted in the referenced temperature response slope of [redacted] per degree. I would emphasize that this slope showed a correlation of greater than 75 percent at temperatures below 25 degrees. We then used the [redacted] per degree slope as the weather factor to weather normalize our winter peak load. This factor, which can be referred to as the coincident or weather adjustment factor, tells us that for every degree that the cold weather temperature drops below 25 degrees, the demand should increase by approximately [redacted]. In formulaic terms, it can be stated as follows:

Coincident Adjustment Factor = [redacted]

Q. WHAT IS THE SIGNIFICANCE OF A 75 PERCENT CORRELATION FACTOR?

A. A correlation factor measures the statistical relationship between an independent and a dependent variable; in this case, temperature and load. The higher the factor, the more

[1] All degree references in this testimony are in Fahrenheit.

direct the correlation. A correlation of 75 percent indicates a strong linear relationship between temperature and Alabama Power's weather-sensitive load.

Q. DOES MR. WILSON CRITICIZE THIS [redacted] PER DEGREE ADJUSTMENT FACTOR?

A. Yes. First, he expresses consternation over the Company's use of data only from the years 2010, 2014 and 2015. The reason for this is straightforward and consistent with proper evaluative techniques. Specifically, these years provided me with sufficient information to analyze the behavior of system loads in response to cold temperatures. The other years did not contain enough data points from which I could develop a reliable data set. Nonetheless, as the analyses of the three years all yielded consistent results, I find the [redacted] temperature response slope to be well supported using the data from these years.

Mr. Wilson also claims that it "is questionable that a parameter based on non-industrial loads was applied to adjust all loads . . . ."[2] However, as a matter of simple math, the weather adjustment was not "applied" to the industrial class load, which as I previously stated, is not weather sensitive. The weather normalized peak load forecast is the sum of the industrial, residential and commercial loads, *plus* the weather adjustment that reflects only the response of weather-sensitive load to changes in temperature. Because this coincident adjustment is additive in nature, it has no effect on the industrial loads. This can be proven as follows:

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[2] J. Wilson Testimony, page 18, lines 11-12.

Equation 1:

Weather-Adjusted Peak = Coincident Peak – Coincident Adjustment Factor

Equation 2:

Coincident Peak = Coincident Peak Contribution from Weather-Sensitive Classes + Coincident Peak Contribution from Non-Weather-Sensitive Classes

Substituting Equation 2 Into Equation 1 Yields Equation 3:

Weather-Adjusted Peak = Coincident Peak Contribution from Weather-Sensitive Classes + Coincident Peak Contribution from Non-Weather-Sensitive Classes – Coincident Adjustment Factor

Q. MR. WILSON ALSO CLAIMS THAT THE IMPACT OF INCREMENTAL COLD ON LOAD IS REDUCED AT VERY LOW TEMPERATURES. DOES THE COMPANY'S ACTUAL EXPERIENCE CONFIRM HIS ASSUMPTIONS?

A. No. As evidenced by my Rebuttal Exhibits MJB-1 and MJB-2, the temperature response slope does not change at the low end of the temperature graph. This means that customer response conditions in Alabama Power's service territory continued to grow at a steady rate in response to cold temperatures. As both graphs clearly indicate, the current winter relationship for Alabama Power customers remains linear even at the lowest temperature points.

Q. HOW DO ALABAMA POWER'S WEATHER NORMALIZATION PRACTICES ALIGN WITH THE METHODS OF INDUSTRY PEERS DESCRIBED IN THE ITRON STUDY THAT MR. WILSON REFERENCES?

A. Very well. Alabama Power uses standard industry approaches for weather normalizing historical peak data. Mr. Wilson cites the Itron study to support the proposition that utility peak demand forecasting methods generally show a year-over-year linear trend. This is not the case, however, and there is nothing in Alabama Power's forecasting approach that is inconsistent with the Itron study. For whatever reason, Mr. Wilson misrepresents the Itron study.

Q. HOW DID MR. WILSON MISREPRESENT THE ITRON SURVEY?

A. The Itron study compiles responses to a thirty-question survey of 135 utilities across North America regarding only their weather normalization practices – not the results or the presence or absence of historical trends arising from the utilization of those practices. Moreover, the survey primarily focused on energy weather normalization, with little emphasis on normalization practices for system peak demands. In fact, only seventy-four of the 135 respondents reported that they perform weather normalization of their system peak. Further, the survey question related to peak demand inquired about the kind of weather used to normalize historical peaks—not whether utilities' historical peaks follow a trendline.[3]

In introducing the Itron study, Mr. Wilson claims that "[i]f an effective approach to weather-normalization approach is applied, the weather-normalized past peaks should reflect and reveal trends due only to trends in economic and demographic drivers."[4] There are two problems with this statement. First, his positioning of the statement in proximity

[3] The Itron survey is attached as Reb. Ex. MJB-3.

[4] *Id.*, page 13, lines 4-6.

to the discussion of the Itron study creates the implication that his opinion is also a conclusion of the survey, which it is not. Second, his statement suggests that there will be smooth trends in the non-weather load impacts, which in our experience is not the case.

Q. WHY IS MR. WILSON INCORRECT TO EXPECT ALABAMA POWER'S HISTORICAL WEATHER NORMAL PEAK DEMANDS TO FOLLOW A TRENDLINE?

A. There are several reasons why this is so. For example, Alabama Power's wholesale loads fluctuate, as contractual demands end or wholesale customers elect to meet their needs through resources other than the Company. Also, the industrial class load is volatile, a fact that Mr. Wilson appears to appreciate.[5] These customers, which comprise 40 percent of Alabama Power's retail energy sales, are heavily dependent on regional, national and global economics. Moreover, industrial customers may choose to operate at full production capacity in one hour, but reduce their production the next, for reasons such as an emergency maintenance requirement or an operational parameter change. Such operational fluctuations can occur quickly and significantly alter peak demand, further disrupting any "trend" that might be drawn from historic behavior.

Q. MR. WILSON ASSERTS THAT ALABAMA POWER HAS "DEVIATED FROM ITS USE OF MINIMUM TEMPERATURES" BY SUBSTITUTING CONTEMPORANEOUS TEMPERATURES. IS HIS STATEMENT ACCURATE?

[5] *Id.*, page 28, lines 4-5 ("Industrial sales are more variable, primarily due to higher sensitivity to economic conditions.").

A. No. Alabama Power's weather normalization calculation is not based on minimum temperatures; rather, it is typically based on temperatures coinciding with peak load. The Company provided Mr. Wilson the appropriate concurrent temperature for each peak in our workpapers.[6] While it is often true that the minimum temperature occurs at the same hour as the winter peak demand, this is not always the case. Relying on the minimum temperature regardless of the coincidence, as Mr. Wilson advocates, would bias the observation of weather normalized winter loads downward. Further, from a technical standpoint, if Mr. Wilson really had concerns regarding Alabama Power's use of coincident—not minimum—temperatures, one would expect him to use the data provided in discovery to develop his own temperature response slope and not to use the Company's [redacted] factor.

Q. DOES MR. WILSON OFFER ANY OTHER CRITICISMS OF THE COMPANY'S WEATHER NORMALIZATION METHODS?

A. Yes. Mr. Wilson also states that the Company "does not recognize the impact of cumulative cold weather."[7] This is not true. As I described earlier, Alabama Power's quantification of the peak response on the second day of a cold weather front, or what I termed cold weather build-up, allows us to evaluate the cumulative impact of several consecutive days of cold temperatures. On the first day of a cold weather event, homes and buildings may still retain heat from temperatures prior to the event. However, by the second day, this residual effect

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[6] *See* Ex. JFW-8. As reflected in these workpapers, the Company did use an average of temperatures adjacent to the peak hour for 2018, which had the effect of dampening (i.e., lowering) the weather-adjusted peak. The decision to employ a more conservative adjustment was based on the conclusion that an application of the temperature response slope to the temperature reported for the coincident peak would not have been representative of the load's response to a rapid change in temperature.

[7] J. Wilson Testimony, page 17, lines 19-20.

has diminished, and actual electricity demand may register just as strong as the first day, even if outdoor temperatures are somewhat milder. Hence the importance of testing the weather normal magnitude of this second day of the weather event.

Q. WHAT IS YOUR REACTION TO MR. WILSON'S ALTERNATIVE APPROACHES TO WEATHER NORMALIZATION?

A. I find each of them to be a poor substitute. His varying approaches all yield correlation coefficients below 50 percent, with only one above 35 percent.[8] The reason for this lack of correlation is that his analysis is inclusive of all loads and fails to exclude the non-weather-sensitive industrial class. In contrast, and as I discussed earlier, Alabama Power's approach results in a much greater correlation (75 percent) by excluding the industrial class, and thus is a much more accurate approach.

PEAK DEMAND MODEL ADJUSTMENTS

Q. MR. WILSON RECOMMENDS THAT THE OUTPUT OF THE PEAK DEMAND MODEL FORECAST BE USED WITHOUT ANY ADJUSTMENTS. WERE THESE ADJUSTMENTS APPROPRIATE?

A. Yes. The Peak Demand Model ("PDM") is a univariate tool that was developed to forecast system peaks. The term "univariate" means the tool is designed to respond to a single variable, in this case temperature. The PDM does a good job of forecasting summer coincident peak demands because summer temperatures (and customer behavior in response to those temperatures) are relatively stable from hour to hour. However, in the

[8] *Id.*, page 20, Table JFW-1

winter, customer usage in the early morning hours can be quite volatile and temperatures can change rapidly. As a result, developing the appropriate load shape response equations in the PDM model for the winter is more challenging. In recognition of this issue, and in preparation for the B2019 forecasting cycle, Alabama Power identified appropriate modifications to improve PDM's performance in capturing winter peak demand in the Company's service territory. Predictably, Mr. Wilson disagrees with all of them, concluding that none are warranted.

Q. WHAT MODIFICATIONS WERE REQUIRED TO ADDRESS THE ISSUE?

A. We made three modifications: a monthly benchmark adjustment; a January-specific adjustment based on observed conditions in 2018; and an adjustment to reflect known industrial class load additions on the horizon.

Q. PLEASE DESCRIBE THE MONTHLY BENCHMARK ADJUSTMENT.

A. This adjustment benchmarks the output of the PDM against known loads and concurrent temperatures on our system. Specifically, we compared our 2017 actual hourly peak demand and actual hourly temperatures with the hourly modeled results from PDM for the weather-sensitive classes. Differentials were determined for each month, with [redacted] reflecting the value for the peak month of January.[9] The addition of this benchmark adjustment to the results of the PDM model made them more reflective of our specific winter-related issues and, consequently, more representative of our winter peak period.

[9] Benchmark adjustments were determined for every month; however, the [redacted] adjustment reflects that determined for January, the peak system month.

Q. WITH THIS ADJUSTMENT PERFORMED, WHY DID YOU NEED TO MAKE FURTHER MODIFICATIONS?

A. This adjustment, on its own, did not resolve all issues related to the development of the B2019 forecast, a fact evident to us through an application of known system conditions for January 2018.

Q. PLEASE EXPLAIN.

A. On January 18, 2018, the system experienced an actual peak under conditions virtually equivalent to the design temperature of [redacted], which I discussed earlier. The actual peak demand was [redacted]. The weather normalized peak demand was [redacted]. The Company then estimated the expected peak load for 2019, accounting for expected class-specific load changes and losses, which yielded an expected weather normal 2019 peak demand of [redacted]. PDM, however, only projected a peak demand of [redacted]. With the additional benchmark adjustment of [redacted], the modified PDM projection for January still fell short of our weather normal expectation by [redacted].

Q. DOES MR. WILSON HAVE ANY COMMENTS ON THE COMPANY'S [redacted] JANUARY ADJUSTMENT?

A. Yes. Although he does not refute the January adjustment in principle, he contends that the Company miscalculated the January 2018 peak value upon which the calculation is based, claiming it used the "wrong temperature measure."[10] Were I to use Mr. Wilson's approach, however, I would not capture the actual peak experienced by the Company. Accordingly, his argument is without merit.

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[10] J. Wilson Testimony, page 23, line 20 through page 24, line 1.

Q. ANOTHER CLAIM OF MR. WILSON IS THAT THE COMPANY "DOUBLE COUNTED" A FURNACE ADJUSTMENT. IS HIS ASSERTION CORRECT?

A. No. I have reviewed my underlying analysis and have confirmed that the forecasted winter peak value for January 2019 only reflects a single [redacted] furnace adjustment.[11] Specifically, the January 2019 peak value ([redacted]) is the sum of the unadjusted PDM output ([redacted]), plus the benchmark adder ([redacted]), plus the January-only adjustment ([redacted]). As the January-only adjustment includes the furnace, the separate [redacted] furnace adjustment was properly applied only to the remaining eleven months of the year.[12]

Q. DID MR. WILSON HAVE ANY ADDITIONAL CRITIQUES OF THE COMPANY'S PDM MODEL ADJUSTMENTS?

A. Yes. Mr. Wilson also questioned two adders applied to the peak demand, one in 2021 and a second in 2022. These additions reflect the expected arrival of two new industrial loads, one in mid-2020 and a second in mid-2021. The adders were necessary in order for the PDM results to accurately account for the new load.

Q. DID THE COMPANY TAKE ADDITIONAL STEPS TO VALIDATE ITS FORECAST?

A. Yes. While we had a high degree of confidence in our PDM-adjusted results, we decided to pursue a new modeling framework. In furtherance of these efforts, we contacted Itron,

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[11] Perhaps the confusion is traceable to his Exhibit JFW-2, which includes a table that erroneously shows the specific furnace adjustment in January. Attached as Reb. Ex. MJB-4 is a table that provides corrected information in this regard.

[12] *See* JFW-10, Row 21.

a well-regarded industry consultant whose work Mr. Wilson referenced in his testimony, to help us develop a tool that would better capture the impact of multiple variables, in addition to temperature, that drive hourly peak demand. Upon completion, we calibrated the tool using our B2019 energy projections. As shown below, use of the Itron tool validated our PDM-adjusted results.

[redacted]

Q. CAN YOU ADDRESS MR. WILSON'S ASSERTION THAT ALABAMA POWER HAS HISTORICALLY OVERFORECASTED ITS PEAK?

A. Yes. Mr. Wilson bases this assertion on his Figure JFW-2, which includes peak demand forecasts from B2007, B2010, B2013, B2016 and B2019.[13] Alabama Power's load forecasts rely in large part on third-party economic forecasts. It should come as no surprise

[13] *See* J. Wilson Testimony, page 11.

to anyone that the B2007 forecast, compiled in 2006, did not anticipate the magnitude of the economic downturn resulting from the Great Recession that struck in 2008.

After the Great Recession, these economic forecasts consistently underestimated recovery time for the state of Alabama and thus overestimated employment growth for our state. Despite recurring projections of optimistic economic growth, Alabama did not reach its pre-recession employment numbers until mid-2018. Nevertheless, Alabama Power has managed to achieve a high degree of forecast accuracy, as demonstrated in the table below. To the extent the forecast has deviated from actual load, Alabama Power has both over-forecasted *and under-forecasted* peak loads.

[redacted]

<u>INDUSTRIAL ENERGY FORECAST</u>

Q. EXPLAIN HOW ALABAMA POWER DEVELOPS ITS INDUSTRIAL LOAD FORECAST.

A. Alabama Power's monthly industrial energy forecast relies on three sources of industrial information: first, near-term survey data drawing directly from existing large customers' operational expectations; second, near-term equipment estimates associated with new customers; and third, monthly econometric regression models developed by segment for the longer term. Through the survey process, the Company collects specific information about its customers' anticipated facility expansions, long-term maintenance and modernization plans and other courses impactful to expected electricity needs.

Q. IS MR. WILSON CRITICAL OF THE COMPANY'S USE OF SURVEYS AS PART OF THE DEVELOPMENT OF THE INDUSTRIAL LOAD FORECAST?

A. Yes. Mr. Wilson questions the Company's use of customer surveys, but his concerns strike me as superficial. The surveys provide us critical insight into specific customer business and operational plans that are not captured in third-party economic data. As noted above, these interviews reveal details such as facility expansions, equipment modifications, efficiency measures and other actions that influence load forecasts—details that are not included in the data Mr. Wilson would have the Company employ. Aside from giving the Company insight into customer-specific operational plans, the surveys also allow Alabama Power to continue to cultivate and support its relationships with industrial customers, further promoting economic development in the state of Alabama.

Q. WHY DOES ALABAMA POWER USE BOTH ECONOMETRIC AND SURVEY DATA IN INDUSTRIAL FORECASTING?

A. Industrial sales represent more than 40 percent of Alabama Power's retail sales and, as noted earlier, are not highly temperature sensitive. Relative to residential and commercial sales, industrial hourly demand can be quite volatile, as customer composition changes, as product demand and manufacturing schedules ebb and flow, as maintenance occurs and as individual customers make plans to grow and expand their businesses. In fact, in his testimony, Mr. Wilson acknowledges that "industrial sales are more variable."[14] Given the complexity inherent in forecasting industrial load, the significant amount of such industrial load and the importance of our industrial customers to the economic health of our state, the Company makes every effort to ensure that this forecast is as accurate as possible. We believe that layering econometric analysis and survey results enables us to better assess our industrial customers' future needs.

Q. DO THE ECONOMETRIC REGRESSION AND SURVEY RESULTS EVER DIFFER?

A. Yes. One example is our military installations, which are included in Alabama Power's industrial customer class. Alabama has been through several rounds of military Base Re-Alignment and Closures, which economic forecasts historically have had difficulty capturing. At one time, the economics showed declines due to national reductions in government spending, but our surveys reflected growth because Alabama installations were chosen to continue programs previously housed at other locations slated for closure. Our surveys gave us the ability to better quantify the energy expectations of our military customers, who were in a position to provide more information than economic forecasts.

Q. WHAT IS MR. WILSON'S PRINCIPAL CRITICISM OF THE COMPANY'S INDUSTRIAL LOAD FORECAST?

A. First, it should be noted that Mr. Wilson rejects the B2019 forecast but embraces the B2018 forecast—which is lower—as "more reasonable," although both forecasts use the same

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[14] *Id.*, page 28, line 4.

methodology.[15] This is yet another instance of Mr. Wilson appearing to select those elements of Alabama Power's forecasting methodology that support his narrative of lower peak demand forecasts.

Mr. Wilson attacks the data underlying the variables used in the econometric industrial load forecast. He strongly advocates for the use of "available, highly relevant" yearly industrial production data supplied by IHS Markit.[16] However, these data provide annual variables, while Alabama Power's monthly forecast requires monthly equations. In addition, our experience with such granular data has proven that they do not yield more accurate forecasts. Thus, the utilization of these same economic variables, but on a national level instead of a state level, provides reasonable econometric modeling results.

Q. BASED ON YOUR EXPERIENCE AS FORECASTING MANAGER, DO YOU HAVE ANY FINAL OBSERVATIONS REGARDING OTHER INTERVENOR TESTIMONY?

A. I find a number of suggestions in the testimony of Energy Alabama/Gasp witness Mr. Howat regarding residential energy use to be misleading.

Q. CAN YOU EXPLAIN?

A. Mr. Howat dedicates much of his testimony to the notion of "home energy security", with a focus on the impact of higher than average electricity bills on residential consumers in the state of Alabama. Electricity bills are driven by two components, the <u>price</u> of electricity and the <u>amount</u> of electricity used by the customer. Mr. Howat confirms that residential

[15] *Id.*, page 6, line 17.

[16] *Id.*, page 30, line 13.

electricity prices in the state of Alabama are relatively modest, ranking 25th out of the 51 jurisdictions reviewed.[17] As he points out, this leaves high customer usage in Alabama as the driver of the higher than average electricity bills.[18] He provides data showing that in 2018, residential customer electricity usage in Alabama ranked 48th among the 51 jurisdictions represented.[19] Mr. Howat concludes that this higher than average electricity usage represents a lack of energy efficiency and creates a financial burden for Alabamians that threatens their home energy security.[20]

Q. IS THIS A FAIR CONCLUSION?

A. No. It is misleading to draw such a conclusion regarding home energy security, or efficient choices respecting energy use, solely on the basis of electricity usage. Residential customers use energy for many purposes, including home cooling and heating, water heating, lighting, cooking and powering other common household appliances. Many of these purposes can be accomplished through a variety of energy sources — not only electricity, but also natural gas, propane or oil. Moreover, while one customer may choose to use electricity for all household energy needs, another customer may use natural gas for home heating, water heating and cooking needs, leaving only the remaining load to be supplied by electricity. A customer's choice regarding the energy source used for each purpose is driven by many variables and differs significantly from state to state and region to region. Obviously, the resulting electricity usage will be different in virtually every

[17] Howat Testimony, page 8, lines 13-14.

[18] *Id.*, page 8, lines 18-20.

[19] *Id.*, page 8, lines 16-18.

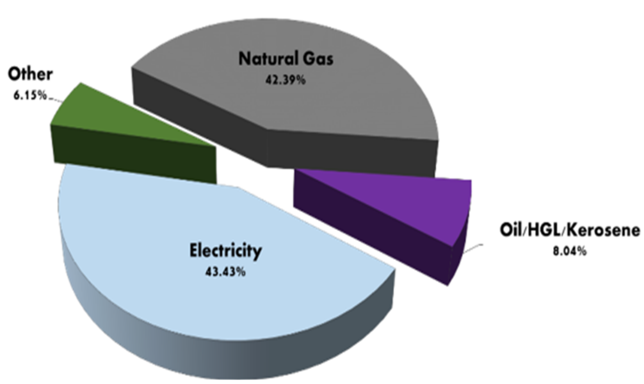
[20] *Id.*, page 8, lines 18-20. *See also id.*, page 4, lines 9-17 & page 15, lines 20-21.

location. Comparing only electricity usage — instead of the total household energy usage — is an incomplete analysis of the factors impacting both energy efficiency and the financial burden associated with a residential customer's home energy security.

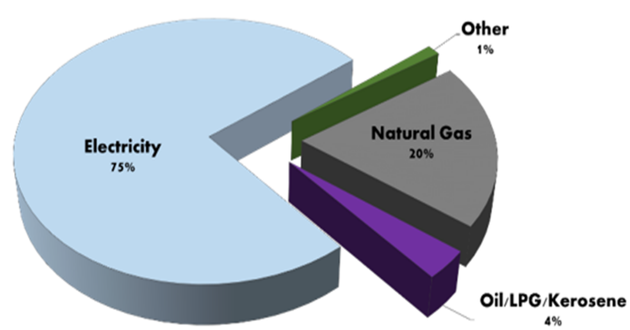
Q. CAN YOU DESCRIBE THE TYPICAL ENERGY CONSUMPTION PRACTICES OF ALABAMA RESIDENTS?

A. In Alabama, customers typically choose electricity as the energy source for more of their household needs, as compared to consumers in other states. For example, many customers in Alabama choose to use an electric heat pump to heat their homes because it is more efficient and cost-effective than other heating options. Put simply, customers in Alabama find that electricity is the best value for meeting many of their household energy needs. According to data gathered by the U.S. Energy Information Administration ("EIA") (depicted in the charts below), approximately 43 percent of nationwide household energy consumption comprises electricity. In contrast, 75 percent of household energy consumption in Alabama is provided by electricity.[21]

National

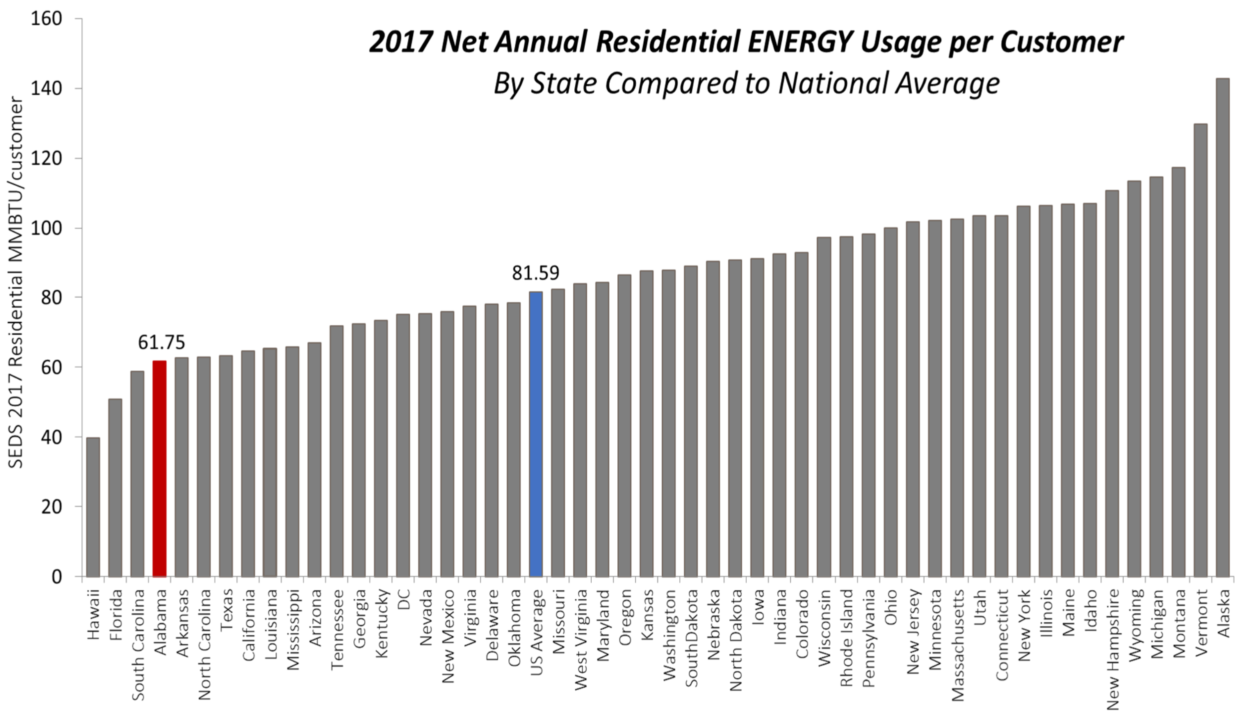


Alabama



[21] *See* U.S. Energy Info. Admin., *Residential Sector Energy Consumption Estimates, 2017*, https://www.eia.gov/state/seds/sep_sum/html/sum_btu_res.html (attached as Reb. Ex. MJB-5).

Accordingly, a fair comparison of energy consumption practices of residential customers across the nation requires consideration of all forms of energy consumed in the household – not just electricity, as Mr. Howat has done. When all forms of energy are considered, Alabama's residential household energy consumption per customer <u>is among the lowest in the country</u>.[22] Specifically, EIA source data for 2017 depicted in the chart below shows that Alabama ranks fourth lowest in total energy consumption per residential customer.



Mr. Howat's focus on electricity usage in isolation makes it appear that Alabama's residential customers are not energy efficient. This is not the case, as evidenced by the data depicted above. To the contrary, Alabama energy consumers simply choose to use

---

[22] *Id. See also* U.S. Energy Info. Admin, *Electric Sales, Revenue, and Average Price*, 2017 Table 1, https://www.eia.gov/electricity/sales_revenue_price (former data set divided by latter data set).

one energy source (electricity) more frequently than others, but their total energy usage (on a per customer basis) is lower than most consumers across the country.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF MARIA J. BURKE
ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA)

COUNTY OF SHELBY)

Maria J. Burke, being first duly sworn, deposes and says that she has read the foregoing prepared testimony and that the matters and things set forth therein are true and correct to the best of her knowledge, information and belief.

Maria J. Burke

Maria Burke

Subscribed and sworn to before me
this 27 day of January, 2020.

Esther Howard Brandenburg

Notary Public

ESTHER T. HOWARD
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 05-12-2020

Rebuttal Testimony for Maria J. Burke

Reb. Ex. MJB-1

CONFIDENTIAL

NOT INTENDED FOR PUBLIC DISCLOSURE

Rebuttal Testimony for Maria J. Burke

Reb. Ex. MJB-2

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Rebuttal Testimony for Maria J. Burke

Reb. Ex. MJB-3

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2013 Weather Normalization Survey

Itron, Inc.
11236 El Camino Real
San Diego, CA 92130-2650
858-724-2620

March 2014

2013 Weather Normalization Survey

Weather normalization is the process of reconstructing historical energy consumption assuming that normal weather occurred instead of actual weather. The process contains two key assumptions. First, a model is used to identify the weather response and calculate the difference between energy consumption under normal and actual weather conditions. Second, normal weather is defined and constructed to represent typical weather conditions.

In November 2013, Itron conducted a survey of North American energy forecasters to understand and document the current practices in weather normalization. The survey asked three types of questions. The first set of questions was used to identify the respondents and the application of their weather normalization process. The second set of questions was asked to gain insights into their modeling assumptions. The final set of questions was asked to understand their definition of normal weather.

Identification Questions

Questions 1 through 8

The Survey includes responses from 135 companies across North America. These companies are separated into categories based on a self-reporting question and company identification. Figure 1 and

Figure 2 show the relative size of each category.

Figure 1: Survey Respondents

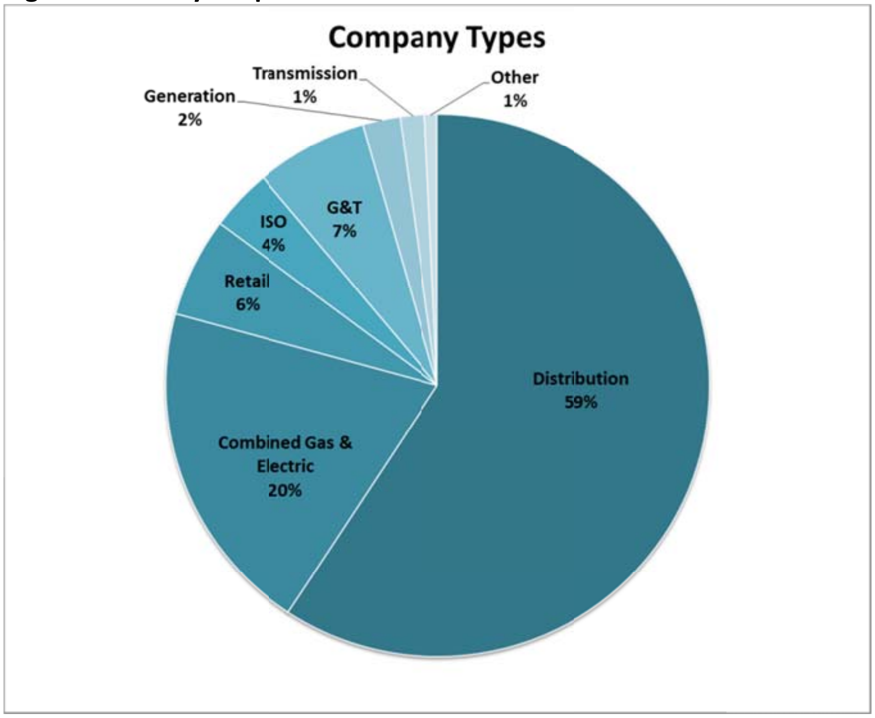


Figure 2: Survey Respondents by Size and Classification

Company Classification	Responses	Annual Energy (GWh)
Distribution	80	1,757,893
Combined Gas & Electric	27	764,094
Retail	8	212,505
ISO	5	1,355,781
G&T	9	104,096
Generation	3	308,982
Transmission	2	251,337
Other	1	NA

Category Definitions

The categories used are defined as follows.

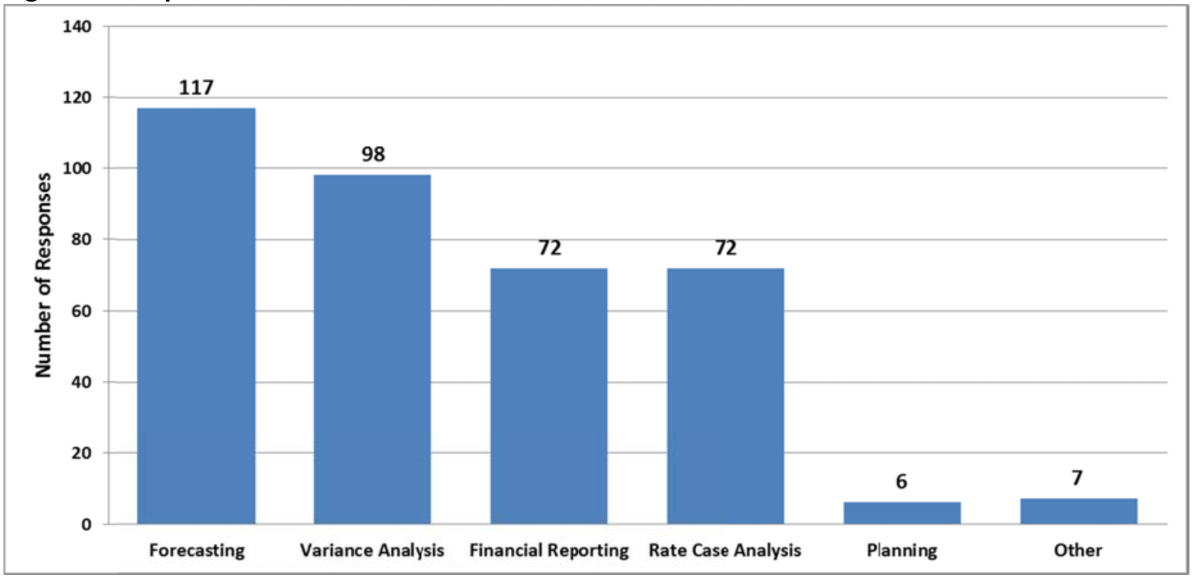
- **Distribution**. Distribution companies include both gas and electric companies that deliver service to an end-use customer. While these companies may include transmission and generation components, these components are not necessary for including a company into this category. Within this category, seven (7) respondents are gas only companies.
- **Combined Gas & Electric**. These companies include both natural gas and electric distribution systems.
- **Retail**. Retail companies are non-regulated electric or gas companies serving either retail or wholesale customers.
- **ISO**. Independent System Operators (ISOs) are regional organizations responsible for dispatching the electric grid and moving electricity throughout a region.
- **G&T**. Generation and Transmission (G&T) companies maintain generation and transmission functions, but do not deliver energy to the end-use customer. Instead, these companies deliver energy at the wholesale level.
- **Generation**. Generation companies own power plants and do not deliver energy to end-use customers.
- **Transmission**. The primary business of a transmission company is to transmit energy from generators to wholesale customers.
- **Other**. The Other category includes companies that do not fit the definitions provided in the previous categories, but still perform a weather normalization function.

The Distribution and Combined Gas & Electric categories represent final deliveries to end-use customers. These companies account for approximately 55% of all electricity sold in the United States and Canada.

Weather Normalization Purposes

The 135 companies reported multiple uses for weather normalization as shown in Figure 3. While forecasting is the most common application, variance analysis, financial reporting, and rate cases are also extremely common.

Figure 3: Purpose of Weather Normalization



Category Definitions. The categories presented in Figure 3 are defined below.

- **Forecasting**. Forecasting applies normal weather to a model in a future time horizon.
- **Variance Analysis**. Variance analysis applies the weather normalization process to a historical time frame to understand differences between an original forecast and actual results.
- **Financial Reporting**. Financial reporting uses weather normalization to understand and project sales for budget analysis.
- **Rate Case Analysis**. Rate case analysis uses weather normalization for setting rates in a regulatory environment.
- **Planning**. Planning includes applications in price forecasting, distribution planning, and transmission planning.
- **Other**. Other includes responses that do not fit the previously defined categories, as well as companies that do not perform any weather normalization process.

Model Questions

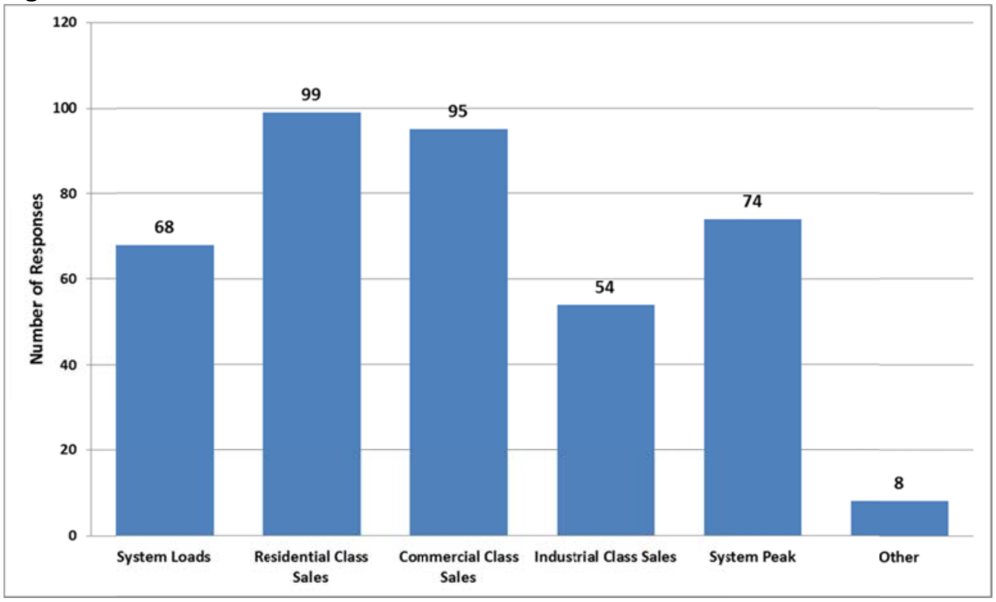
Questions 9 through 22

The first assumption in weather normalization is the model used to identify the historical weather response and calculate the impact of normal weather compared to actual weather. The model questions are used to identify the classes being normalized, the frequency of the model estimation process, and the weather drivers included in the model.

Weather Normalization Classes

Figure 4 shows that the most common class for weather normalization is the residential class (99 responses), closely followed by the commercial class (95 responses). These two classes tend to be highly weather responsive and contribute to the majority of a system's weather response. System peaks and total system loads are weather normalized by 74 and 68 respondents, respectively. Only 54 respondents normalize the industrial class. The other class includes responses for government, irrigation, wholesale, and farm classes.

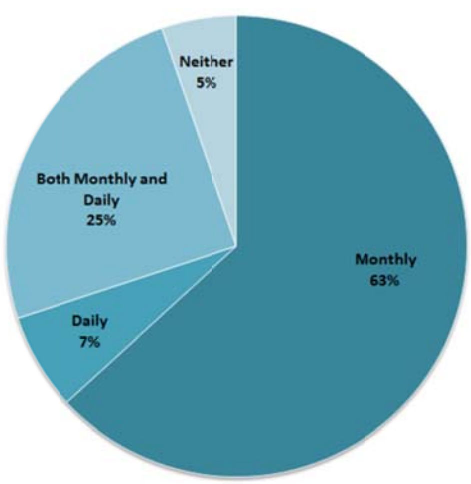
Figure 4: Weather Normalization Classes



Data Frequency

Data frequency indicates the periodicity of the weather normalization models. Typically, daily data are used in daily models and monthly data are used in monthly models. Figure 5 shows the results from 132 respondents to this question. In these results, 63% use monthly data and 7% use daily data. Respondents that use both monthly and daily data indicate a mix of model periodicities and applications. The neither response includes respondents who do not perform weather normalization at the monthly or daily level.

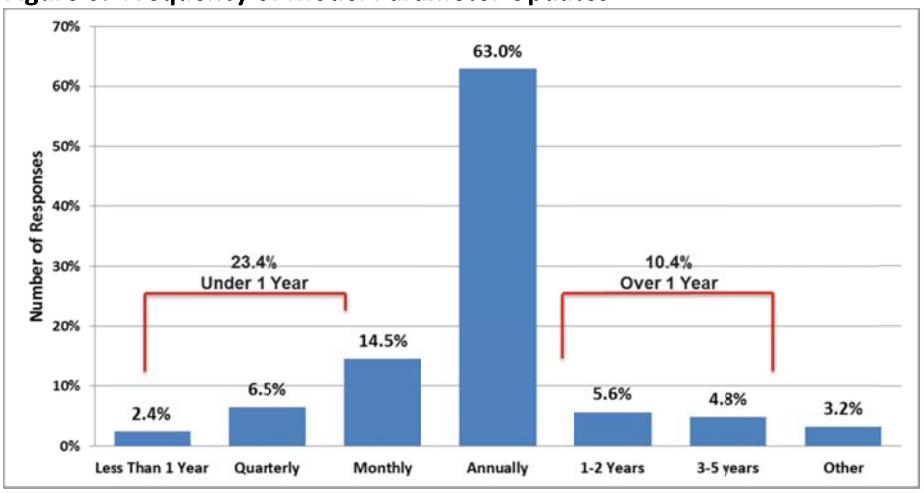
Figure 5: Data Frequency of the Model



Frequency of Model Parameter Updates

Weather Normalization models are periodically refreshed to capture changes in weather responses. Figure 6 shows that 63%, or 124 responses to this question, refresh their model every year. 23.4% of respondents refresh their models multiple times during the year, and 10.4% of respondents refresh their models every one to five years. Only 3.2% of respondents indicate that models are refreshed on an "as needed" basis.

Figure 6: Frequency of Model Parameter Updates



Model Descriptions

Because a model is used to obtain the weather response of energy consumption, a series of questions were asked to understand the weather variables used in the model. The compiled results identify categories of weather variables for each class. The variable categories are defined in Figure 7 and

Figure 8. The remainder of this section describes the models used for the system, residential, commercial, and industrial classes.

Figure 7: Heating Variable Category Definitions

Heating Variable Category	Description
HDD	Model includes heating degree day (HDD) and/or HDD spline variables. No other weather variables are used.
Interactions	Model interacts HDD or HDD splines with another variable. Model may include HDD or HDD spline variables separately.
Other	Model includes additional weather variables beyond HDD or HDD splines. However, no interactions with HDD or HDD splines are included.
HDD/Int/Oth	Model includes HDD or HDD splines, interactions, and additional weather variables.
None	Model is not used to normalize for cold weather.

Figure 8: Cooling Variable Category Definitions

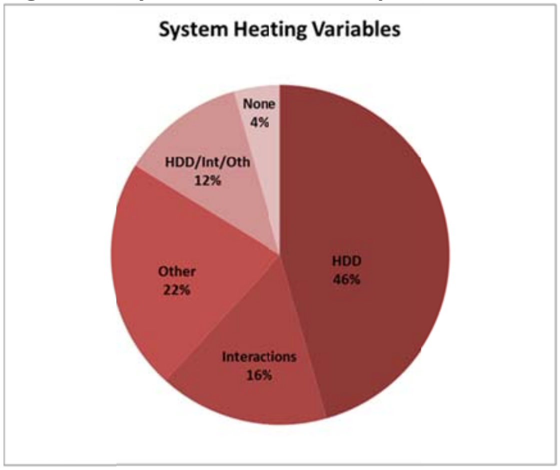
Cooling Variable Category	Description
CDD	Model includes cooling degree day (CDD) and/or CDD spline variables. No other weather variables are used.
Interactions	Model interacts CDD or CDD splines with another variable. Model may include CDD or CDD spline variables separately.
Other	Model includes additional weather variables beyond CDD or CDD splines. However, no interactions with CDD or CDD splines are included.
CDD/Int/Oth	Model includes CDD or CDD splines, interactions, and additional weather variables.
THI	Model uses THI (temperature-humidity index) instead of CDD and may include interactions and additional weather variables.
None	Model is not used to normalize for hot weather.

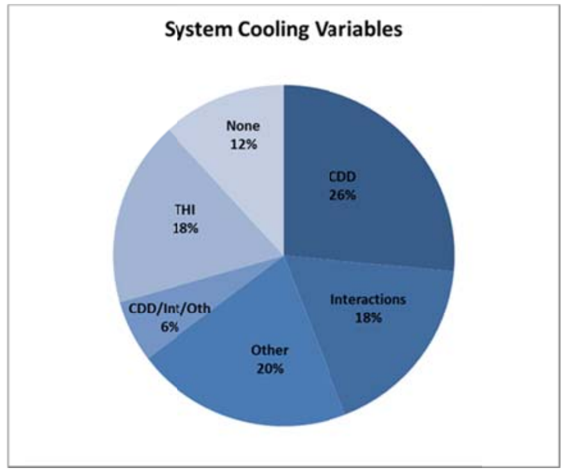
System Model Description

The weather variables used to capture the heating and cooling effects in a system model are shown in Figure 9. These responses are based on the definitions from Figure 7 and

Figure 8. Of the 68 respondents normalizing system loads, most utilities use only HDD for heating (46%) and CDD for cooling (26%).

Figure 9: System Model Description





Additional variables are used in some system models. 22% of respondents use them to capture the heating effect, and 20% of the respondents use them to capture the cooling effect. The variables listed by respondents are shown in

Figure 10 with the number of responses shown in parenthesis.

Figure 10: System Other Variables

Other Heating Variables	Other Cooling Variables
Wind (6) Cloud Cover (5) Lag Weather (3) Dew Point/Humidity (2) Effective Temperature (1) High/Low Temperature Spread(1) Precipitation (1)	Dew Point/Humidity (8) Wind (5) Cloud Cover (4) High Temperature (3) Precipitation (3) High/Low Temperature Spread (1) Lag Weather (1)

Interactive variables allow for the heating and cooling response to change under specific conditions. 16% of the responses use interactions in the heating effect, and 18% of the responses use interactions for the cooing effect. The interacted variables listed by respondents are shown in Figure 11 with the number of responses shown in parenthesis. The primary interaction is daytypes, which includes daily, monthly, and seasonal binary variables.

Figure 11: System Interactive Variables

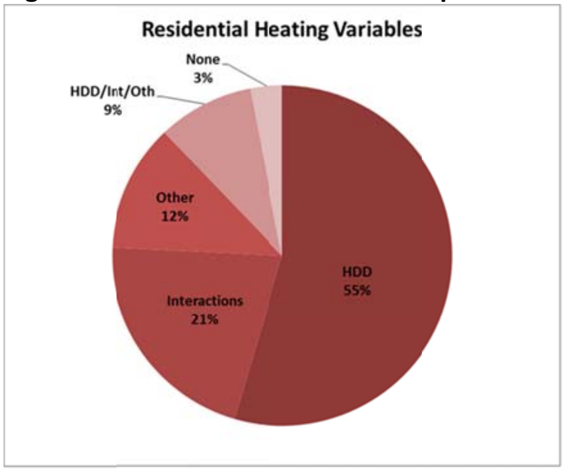
Heating Interactions	Cooling Interactions
Daytypes (9) End Use Trend (2) Economic Trend (1) Lag Temperatures (1) Deviations from Normal (1) Peak Temperature (1)	Daytypes (11) End Use Trend (3) Economic Trend (1) Hours of Light (1) Peak Temperature (1)

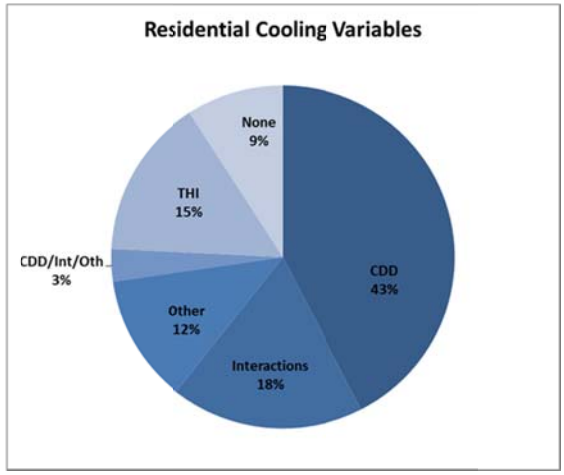
Residential Model Description

The weather variables used to capture the heating and cooling effects in a residential model are shown in Figure 12. These responses are based on the definitions from Figure 7 and

Figure 8. Of the 99 respondents normalizing residential consumption, most utilities use only HDD for heating (55%) and CDD for cooling (43%).

Figure 12: Residential Model Description





Other variables are used by 12% of respondents to capture both heating and cooling responses. The variables listed by respondents are shown in Figure 13 with the number of responses shown in parenthesis. Among other variables used, wind, cloud cover and dew point/humidity are the most common.

Figure 13: Residential Other Variables

Other Heating Variables	Other Cooling Variables
Wind (5)	Dew Point/Humidity (5)
Cloud Cover (5)	Wind (4)
Heating Degree Hour (3)	Cooling Degree Hour (2)
Lag Weather (2)	Lag Weather (2)
Dew Point/Humidity (2)	Precipitation (2)
High/Low Temperature Spread(1)	Cloud Cover (1)
Precipitation (1)	High/Low Temperature Spread (1)

Interactive variables are used by 21% of respondents for heating and 18% for cooling effects. The dominant interaction is with daytype binary variables as shown in Figure 14.

Figure 14: Residential Interactive Variables

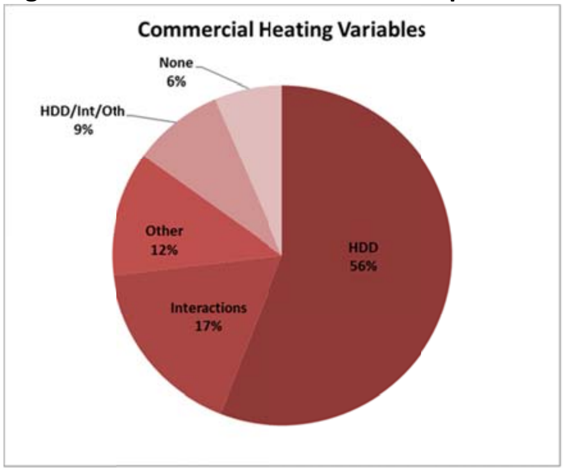
Heating Interactions	Cooling Interactions
Daytypes (12)	Daytypes (14)
End Use Trend (6)	End Use Trend (4)
Economic Trend (2)	Economic Trend (3)
Customer Counts (2)	Daylight Hours (1)
Daylight Hours (1)	Customer Counts (1)

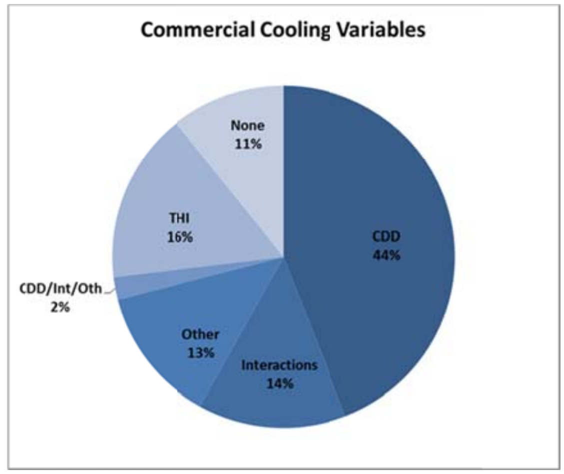
Commercial Model Description

The weather variables used to capture the heating and cooling effects in the commercial model are shown in Figure 15. These responses are based on the definitions from Figure 7 and

Figure 8. Of the 95 respondents normalizing commercial consumption, most utilities use only HDD for heating (56%) and CDD for cooling (44%).

Figure 15: Commercial Model Description





Some respondents use other variables to capture both heating and cooling responses. The variables listed by these respondents are shown in Figure 16 with the number of responses shown in parenthesis. Among other variables used, wind, cloud cover and dew point/humidity are the most common.

Figure 16: Commercial Other Variables

Other Heating Variables	Other Cooling Variables
Wind (7) Cloud Cover (5) Dew Point/Humidity (3) Heating Degree Hour (1) High/Low Temperature Spread(1) Lag Weather (1) Precipitation (1)	Wind (4) Dew Point/Humidity (4) Precipitation (2) Cloud Cover (1) Cooling Degree Hour (1) Daylight Hours (1) High/Low Temperature Spread (1) Lag Weather (1)

The interactive variables used in the commercial models are shown in Figure 17. As with the residential and system models, the main category of interactions is the daytype variable.

Figure 17: Commercial Interactive Variables

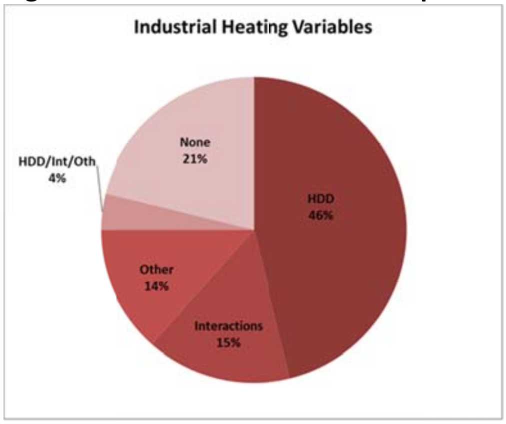
Heating Interactions	Cooling Interactions
Daytypes (11) Economic Trend (2) End Use Trend (1) Customer Counts (1) Daylight Hours (1)	Daytypes (12) Economic Trend (2) Customer Counts (2) End Use Trend (1) Day Light Hours (1)

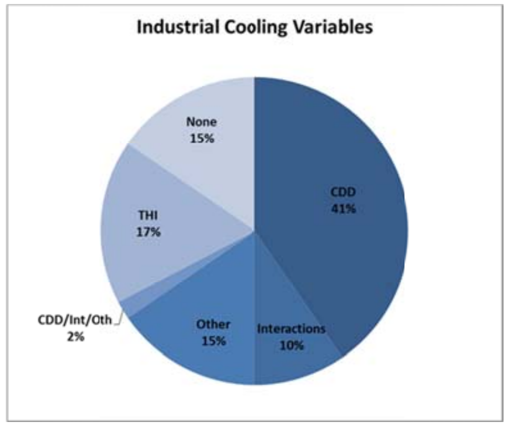
Industrial Model Description

The weather variables used to capture the heating and cooling effects in the industrial model are shown in Figure 18. The responses are based on the definitions from Figure 7 and

Figure 8. Of the 54 respondents normalizing Industrial consumption, most utilities use only HDD for heating (46%) and CDD for cooling (41%).

Figure 18: Industrial Model Description





The other interactive variables used by some respondents to capture both heating and cooling responses are shown in Figure 19 and Figure 20. In both categories, a low number of respondents reported specific other and interactive variables.

Figure 19: Industrial Other Variables

Other Heating Variables	Other Cooling Variables
Wind (3) Cloud Cover (3) Dew Point/Humidity (1)	Wind (2) Dew Point/Humidity (2) Precipitation (1) Cloud Cover (1)

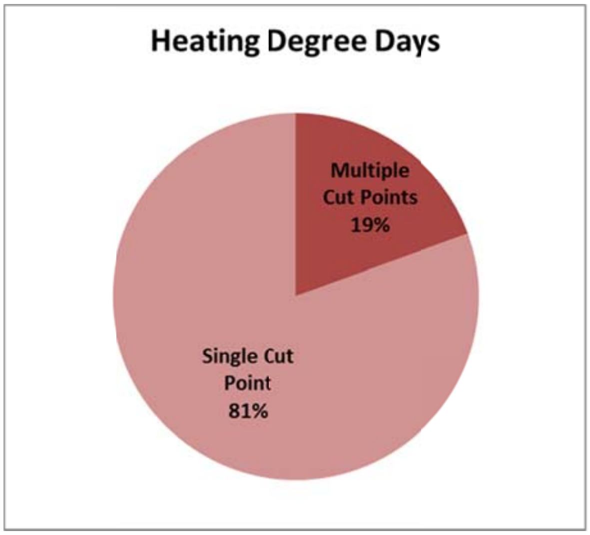
Figure 20: Industrial Interactive Variables

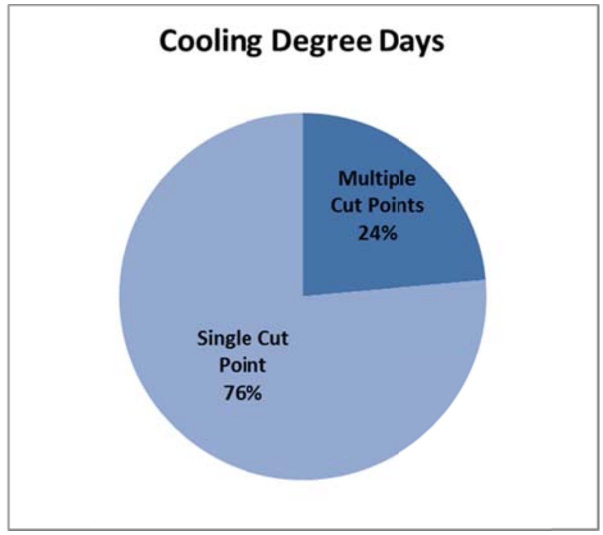
Heating Interactions	Cooling Interactions
Daytypes (4) Economic Trend (1)	Daytypes (4) Economic Trend (1)

Temperature Cut Points

HDD and CDD are calculated as the difference between the actual temperature and a temperature reference point. Regression models use these variables to capture the non-linear heating and cooling response. A single cut point variable is used when assuming a linear response from the temperature reference point. Multiple cut point variables are used when assuming a changing linear response from the temperature reference point. Figure 21 shows the percentage of respondents that use single versus multiple cut points to capture the heating and cooling response.

Figure 21: Heating and Cooling Degree Day Cut Points


Heating Degree Days
Multiple Cut Points 19%
Single Cut Point 81%


Cooling Degree Days
Multiple Cut Points 24%
Single Cut Point 76%

Temperature Humidity Index Calculation

A Temperature Humidity Index (THI) is used to combine temperature and humidity into a single numerical value that captures the effects of moisture in the air. Recently, utilities have reported a wide variety of mathematical calculations to capture this effect. This survey allowed for respondents to define their index calculations.

Of the 13 responses to this question, four distinct equations were provided. These four equations capture the interaction between dry bulb temperatures (T) and moisture in the form of dew point (DP) or relative humidity (RH). The equations are shown below.

$$\text{Index} = 0.55 * T + 0.20 * DP + 17.50$$

$$\text{Index} = T - (0.55 - 0.55*RH/100) * (T - 58)$$

$$\begin{aligned}\text{Index} = {} & -42.379 + ((2.04901523*T) + (10.14333127*RH)) \\ & - (0.22475541*T*RH) - (0.00683783 * (T^2)) \\ & - (0.05481717 * (RH^2)) + (0.00122874 * (T^2) * RH) \\ & + (0.00085282 * T * (RH^2)) \\ & - (0.00000199 * (T^2) * (RH^2))\end{aligned}$$

$$\begin{aligned}\text{Index} = {} & 16.923 + ((1.85212 * 10^{-1}) * T) + (5.37941 * RH) - ((1.00254 * 10^{-1}) * T * RH) \\ & + ((9.41695 * 10^{-3}) * T^2) + ((7.28898 * 10^{-3}) * RH^2) + ((3.45372 \times 10^{-4}) * T^2 * RH) \\ & - ((8.14971 * 10^{-4}) * T * RH^2) + ((1.02102 * 10^{-5}) * T^2 * RH^2) - ((3.8646 * 10^{-5}) * T^3) \\ & + ((2.91583 * 10^{-5}) * RH^3) + ((1.42721 * 10^{-6}) * T^3 * RH) + ((1.97483 * 10^{-7}) * T * RH^3) \\ & - ((2.18429 * 10^{-8}) * T^3 * RH^2) + ((8.43296 * 10^{-10}) * T^2 * RH^3) \\ & - ((4.81975 * 10^{-11}) * T^3 * RH^3)\end{aligned}$$

Normal Weather Questions

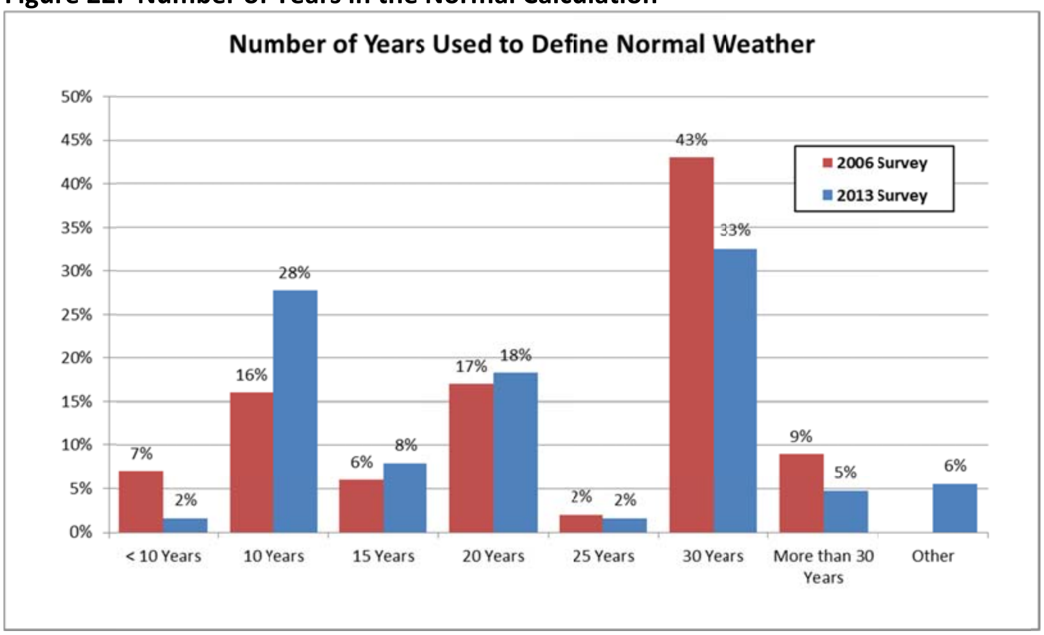
Questions 23 through 30

The second assumption in weather normalization is the definition of normal weather. Normal weather represents an expected weather condition and is typically represented by an average. Multiple factors can impact the average calculation including the number and range of years. This survey asked a series of questions to understand the common practices in calculating the averages. In 2006, Itron conducted a similar weather normalization survey. Several of the topics show comparative results with the 2006 survey.

Number of Years in the Normal Calculation

Figure 22 shows the number of years used to calculate normal weather compared to the 2006 survey responses. In 2013, 33% of the 126 respondents define weather based on 30 years of historical weather data. This response compares to 43% using 30 year averages from the 106 responses in the 2006 survey. The largest changes between 2006 and 2013 are reduction in the percent using 30 years and the increase in percentage using 10 years.

Figure 22: Number of Years in the Normal Calculation



Changing the Number of Years

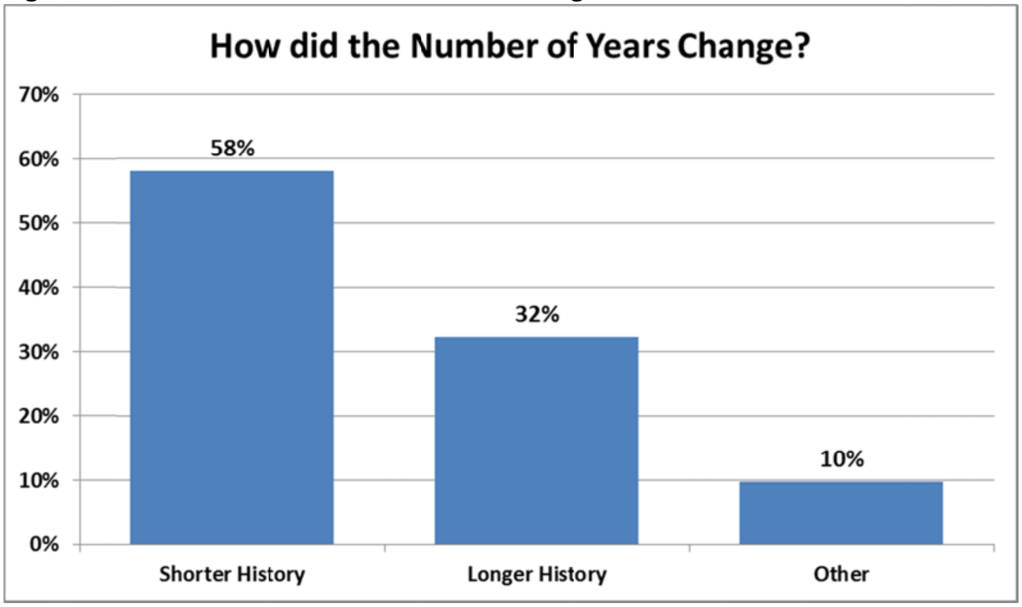
Changing the number of years used in the normal weather calculation has been a common technique for handling climate change. In 2006, 25% of survey respondents indicated that they had changed the number of years recently. In 2013, the same question was asked with 32% indicating a recent change. These results are shown in Figure 23.

Figure 23: Recent Changes to the Number of Years

Update Frequency	2013 Survey	2006 Survey
Responses	125	115
Changed Recently	32%	25%
Has Not Changed	68%	75%

Figure 24 shows the results of a follow-up question asking how the number of years has changed. Of the respondents who have changed recently, 58% use fewer years while 32% use more years than previously used. The other responses indicated changes that use multiple definitions for normal weather depending on the purpose of the weather normalization process.

Figure 24: How the Number of Years Has Changed



Frequency of Normal Calculations Update

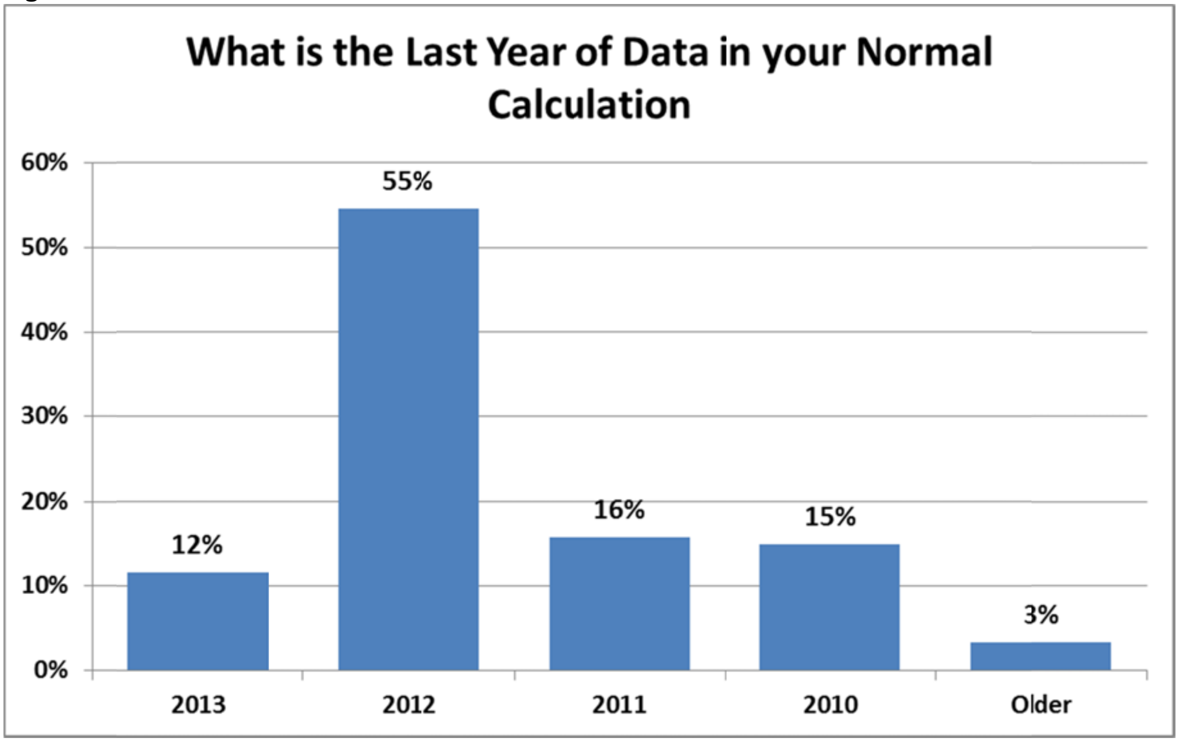
Each year, the availability of new weather data creates the opportunity to recalculate normal weather. Figure 25 shows that 81% of respondents update their normal weather each year compared to 69% from the 2006 Survey.

Figure 26 displays the last year of data included in the normal calculation. In this figure, 83% of the respondents include data from 2011, 2012, and 2013 in their calculation.

Figure 25: Update Normal Weather Annually

Update Frequency	2013 Survey	2006 Survey
Responses	124	114
Update Annually	81%	69%
Do Not Update Annually	19%	31%

Figure 26: Last Year of Normal Calculation Period



Oversight of Regulators

Because normal weather can impact forecasts, planning studies, and rates, regulatory entities may be involved in overseeing the normal weather calculation. Figure 27 shows the number of respondents whose normal weather calculation is overseen a regulatory entity. The percentage is similar to the responses obtained in the 2006 survey.

Figure 27: Normal Weather Calculation Specified by Regulators

Update Frequency	2013 Survey	2006 Survey
Responses	123	166
Regulatory Oversight	16%	13%
No Regulatory Oversight	84%	87%

Climate Change

While many utilities manage climate change effects by changing the number of years used in the normal weather calculation, the survey requested information about climate change adjustment beyond changing the number of years.

Figure 28 shows that 9% of respondents use a method for climate change beyond controlling the number of years

Figure 28: Account for Climate Change

Update Frequency	2013 Survey
Responses	124
Account for Climate Change	9%
Do Not Account for Climate Change	91%

Normal Peak Weather

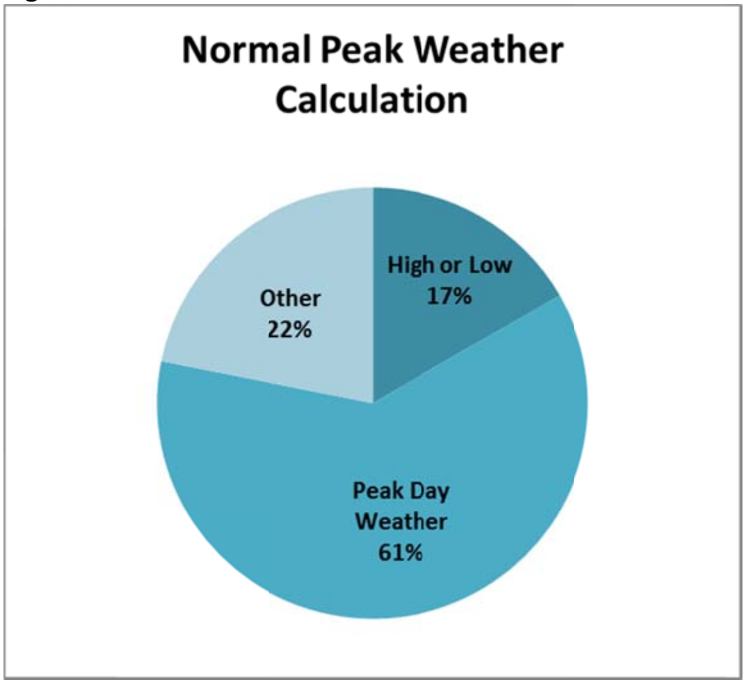
Normal peak weather is used to normalize peak weather events. Two types of normal calculations are typically used in the normal peak weather calculation. These calculations are defined below.

- **Peak Day Weather.** Peak day weather is defined as the weather conditions on the peak day only. After identifying these days, the temperatures (or HDD and CDD values) are averaged across these historical events.
- **High or Low.** High or low weather is defined by identifying the highest and lowest historic temperatures in a month and averaging across these events regardless of when the monthly peak event occurred. The High and Low weather may have occurred on a weekend and did not cause the highest load event in the month.

Figure 29 shows the results from 96 responses to this question. In this figure, 61% of respondents use the peak day weather approach. The other responses include different methods reported by respondents. These methods are listed below with the number of respondents include in parenthesis.

- Temperature on Peak Hour (4)
- High Temperature Variations such as THI or a heat index (3)
- Rank and Average (3)
- Load Factor Method (2)
- Current and Preceding Day (1)
- Probability Distribution (1)
- Cold Snap Duration (1)
- Other (6)

Figure 29: Normal Peak Weather



Summary

In November 2013, Itron conducted this survey of North American energy forecasters to understand and document their current weather normalization practices. The weather normalization process includes two key assumptions – a model and normal weather. This survey captures the characteristics of the current models and normal weather definitions used by 135 companies.

While the process of each company contains variations based on their customer base and needs, a few common characteristics are observed through this survey. These characteristics are summarized below.

- **Classes**. Most companies normalize the residential and commercial classes. These classes tend to be the most weather sensitive and represent the majority of impacts due to weather.

- **Weather Variables**. When normalizing a class, most models are driven by HDD and CDD variables. However, several responses show a significant interest in other weather variables such as wind speed, cloud cover, dew point, and humidity. Additionally, interactions with daytype variables are also common because they capture heating and cooling response variations based on weekdays, months, and seasons.

- **HDD and CDD Definition**. When defining HDD and CDD, most companies use a single HDD and CDD cut point to capture the non-linear weather-consumption responses.

- **Normal Weather Calculation**. The normal weather calculation is still dominated by 30 year averages, but there is a transition to using shorter averages.

- **Normal Weather Updates**. Most companies update the normal weather calculation each year to remain current with the latest weather information

Weather normalization continues to be a major task for companies as seen by the strong response to the well-defined applications in forecasting, variance analysis, financial reporting, and rate cases.

Rebuttal Testimony for Maria J. Burke

Reb. Ex. MJB-4

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Rebuttal Testimony for Maria J. Burke

Reb. Ex. MJB-5

Reb. Ex. MJB-5

Table C5. Residential Sector Energy Consumption Estimates, 2017
(Trillion Btu)

State	Coal [a]	Natural Gas [b]	Petroleum: Distillate Fuel Oil	Petroleum: HGL [c]	Petroleum: Kerosene	Petroleum: Total	Biomass: Wood [d]	Geothermal	Solar [e]	Electricity Retail Sales	Net Energy [f]	Electrical System Energy Losses [g]	Total [f]
Alabama	0.0	27.2	0.1	4.8	(s)	4.8	1.5	0.1	0.1	103.0	136.7	186.8	323.5
Alaska	0.0	20.0	7.8	0.4	(s)	8.2	5.5	0.1	(s)	7.0	40.8	12.3	53.1
Arizona	0.0	34.3	(s)	3.9	(s)	3.9	3.1	0.1	14.8	116.9	173.1	228.3	401.4
Arkansas	0.0	26.1	(s)	2.9	(s)	3.0	4.4	0.8	0.1	58.1	92.5	109.6	202.1
California	0.0	446.3	0.4	22.1	0.3	22.8	20.1	0.3	78.4	307.5	875.5	540.1	1,415.5
Colorado	0.0	125.6	0.2	10.3	(s)	10.5	10.8	0.3	3.2	63.5	212.4	130.9	343.3
Connecticut	0.0	49.8	45.0	9.0	(s)	54.1	5.7	(s)	3.1	42.2	154.9	75.0	229.9
Delaware	0.0	10.4	1.8	2.3	(s)	4.1	0.6	0.4	0.6	15.9	32.0	27.7	59.7
Dist. of Col.	0.0	12.4	0.1	(s)	0.0	0.1	(s)	(s)	0.2	8.2	20.9	17.5	38.4
Florida	0.0	15.4	0.1	6.3	(s)	6.3	0.2	8.0	29.2	414.4	473.5	702.4	1,176.0
Georgia	0.0	114.4	0.1	7.0	(s)	7.1	2.5	0.3	0.5	186.9	311.5	354.5	666.0
Hawaii	0.0	0.6	(s)	0.6	0.0	0.6	(s)	0.0	7.6	9.0	17.2	16.8	34.0
Idaho	0.0	30.1	0.7	4.2	(s)	4.9	12.7	0.1	0.1	29.8	77.8	56.7	134.5
Illinois	0.0	388.8	0.4	18.1	0.1	18.6	4.6	2.0	1.5	149.2	559.9	331.8	891.6
Indiana	0.0	128.9	0.9	10.8	0.1	11.8	10.3	3.8	0.3	107.7	262.1	235.7	497.8
Iowa	0.0	63.7	1.0	14.6	(s)	15.6	4.2	0.5	0.3	46.8	125.4	95.2	220.6
Kansas	0.0	56.3	(s)	6.1	(s)	6.1	3.0	0.3	0.1	44.4	110.2	95.3	205.5
Kentucky	0.0	45.2	0.5	4.5	0.1	5.1	7.6	1.9	0.2	84.9	144.8	187.1	332.0
Louisiana	0.0	29.7	(s)	1.7	(s)	1.7	0.4	0.9	1.9	100.8	135.4	177.0	312.4
Maine	0.0	2.8	31.5	6.6	1.3	39.3	17.1	0.1	0.4	15.8	75.6	24.0	99.6
Maryland	0.0	79.4	10.4	6.3	0.1	16.9	4.8	0.6	4.7	89.0	195.1	191.2	386.3
Massachusetts	0.0	124.8	70.7	8.1	0.2	79.0	8.4	0.1	5.3	66.0	283.6	125.9	409.5
Michigan	0.0	312.8	2.5	34.9	0.1	37.4	30.1	4.3	0.8	112.5	498.0	226.8	724.8
Minnesota	0.0	127.7	3.6	25.0	0.1	28.6	14.0	1.1	0.5	73.6	245.5	140.4	385.9
Mississippi	0.0	19.1	(s)	4.8	(s)	4.8	0.8	0.2	(s)	59.5	84.5	93.8	178.3
Missouri	0.0	87.3	0.1	12.1	(s)	12.2	14.5	0.4	0.9	112.8	228.1	242.5	470.6
Montana	0.0	22.4	0.4	7.2	(s)	7.6	10.9	0.1	0.1	17.8	59.0	36.6	95.6
Nebraska	0.0	36.1	0.1	4.6	(s)	4.7	1.8	0.5	0.1	33.0	76.0	70.2	146.2
Nevada	0.0	42.5	0.2	2.2	(s)	2.4	1.9	0.3	3.7	44.1	95.1	69.7	164.8
New Hampshire	0.0	7.6	23.7	9.6	0.4	33.8	11.3	(s)	0.6	15.2	68.4	31.5	99.8
New Jersey	0.0	230.8	18.7	4.3	(s)	23.1	2.4	0.5	8.1	94.7	359.6	176.5	536.0
New Mexico	0.0	31.2	(s)	4.0	(s)	4.0	7.9	0.1	1.4	22.2	66.8	45.2	112.0
New York	0.0	446.5	83.6	21.9	2.3	107.7	28.8	0.4	8.1	167.5	759.1	295.6	1,054.7
North Carolina	0.0	62.1	4.0	14.2	0.7	18.9	7.6	1.0	0.9	191.5	282.0	367.4	649.4
North Dakota	0.0	11.9	0.8	5.2	(s)	6.0	0.6	0.5	(s)	16.5	34.5	34.6	69.1
Ohio	0.0	277.6	7.7	17.2	0.2	25.1	18.2	2.6	0.5	169.9	493.8	344.9	838.7
Oklahoma	0.0	53.2	(s)	7.0	(s)	7.0	2.6	(s)	0.1	74.5	137.5	136.4	273.8
Oregon	0.0	51.2	2.0	2.2	0.1	4.3	22.5	0.4	2.2	68.5	149.0	115.2	264.2
Pennsylvania	0.0	228.2	71.2	17.7	0.9	89.8	28.1	1.3	2.2	176.5	526.2	344.3	870.6
Rhode Island	0.0	19.0	10.3	1.2	(s)	11.6	1.4	0.1	0.3	10.3	42.6	13.9	56.5
South Carolina	0.0	25.4	0.5	4.1	0.1	4.6	1.3	0.6	0.9	99.7	132.5	218.3	350.9
South Dakota	0.0	12.8	0.4	4.0	(s)	4.4	1.6	0.6	(s)	15.9	35.3	31.6	66.9
Tennessee	0.0	58.9	0.2	5.4	0.2	5.8	5.4	0.2	0.2	134.1	204.7	292.1	496.8
Texas	0.0	168.8	(s)	16.0	(s)	16.0	1.6	1.6	3.8	492.2	683.9	956.7	1,640.6
Utah	0.0	69.6	0.1	2.5	(s)	2.6	3.2	0.1	2.1	32.5	110.0	64.7	174.7
Vermont	0.0	3.6	10.3	6.4	0.3	17.0	12.4	(s)	0.7	6.9	40.7	2.6	43.3
Virginia	0.0	81.1	8.9	9.9	0.4	19.1	11.0	0.8	0.9	150.1	263.1	290.7	553.8
Washington	0.0	98.3	4.8	8.8	(s)	13.6	26.3	0.4	1.0	127.2	266.8	237.3	504.1
West Virginia	0.0	24.3	1.2	2.0	0.1	3.2	8.3	(s)	0.1	36.1	72.0	71.8	143.8
Wisconsin	0.0	136.3	4.1	22.3	(s)	26.4	24.7	0.6	0.5	72.4	260.9	153.1	414.0
Wyoming	0.0	13.3	0.1	3.5	(s)	3.6	4.2	0.1	(s)	9.5	30.7	20.5	51.2
United States	0.0	4,591.8	431.3	430.7	8.4	870.4	433.0	39.6	193.4	4,703.9	10,817.1	9,046.9	19,864.0

[a] Data are not collected and are assumed to be zero.

[b] Natural gas as it is consumed; includes supplemental gaseous fuels that are commingled with natural gas.

[c] Hydrocarbon gas liquids, assumed to be propane only.

[d] Wood and wood-derived fuels.

[e] Solar thermal and photovoltaic energy. Includes solar thermal energy consumed as heat by the commercial and industrial sectors.

[f] Adjusted for the double-counting of supplemental gaseous fuels, which are included in both natural gas and the other fossil fuels from which they are mostly derived, but should be counted only once in net energy and total.

[g] Incurred in the generation, transmission, and distribution of electricity plus plant use and unaccounted for electrical system energy losses.

Where shown, (s) = Value less than 0.05 trillion Btu.

Note: Totals may not equal sum of components due to independent rounding.

Web Page: All data are available at https://www.eia.gov/state/seds/seds-data-complete.php.

Sources: Data sources, estimation procedures, and assumptions are described in the Technical Notes.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF MICHAEL A. BUSH
ON BEHALF OF ALABAMA POWER COMPANY

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

A. My name is Michael A. Bush. I am the Manager of Generation Planning and Development for Southern Company Services ("SCS"). My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q. HAVE YOU PREVIOUSLY PRESENTED DIRECT TESTIMONY ON BEHALF OF ALABAMA POWER IN THIS PROCEEDING?

A. Yes. As I previously testified, Alabama Power, by and through SCS acting as its agent, has entered into a turnkey Agreement for Engineering, Procurement and Construction ("EPC Agreement") of new combined cycle generating capacity at Alabama Power's Barry Steam Plant ("Barry Unit 8"). The construction and delivery of Barry Unit 8 pursuant to the EPC Agreement is predicated on the Company's receipt of a certificate of convenience and necessity from the Alabama Public Service Commission ("Commission"). If authorized, and upon completion, Barry Unit 8 will provide approximately 726 MW of winter-rated capacity (increasing to approximately 743 MW of winter-rated capacity under a subsequent uprate), with an expected useful life of 40 years.

My Direct Testimony provided details regarding Barry Unit 8. Specifically, I presented: a high-level technical overview of Barry Unit 8, including its fundamental design parameters and operating characteristics; an overview of the manner by which Barry Unit 8 would be constructed and placed into service, if approved by the Commission, including details around the EPC Agreement; and an explanation of the process that ultimately gave rise to the execution of the EPC Agreement.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The primary purpose of my Rebuttal Testimony is to respond to various intervenors in this proceeding whose sponsored witnesses offer opinions regarding my Direct Testimony. I do not attempt to address every issue raised in intervenor testimony that might bear in some way on my testimony, however, and the absence of any rebuttal to a specific comment should not be construed as an acceptance or endorsement of it.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Contrary to testimony filed by intervenor witnesses—chiefly Sierra Club's Ms. Wilson and Mr. Detsky and Energy Alabama/Gasp witness Mr. Rábago—Barry Unit 8 is expected to be a reliable and valuable resource for Alabama Power and its customers throughout its 40-year useful life. In this Rebuttal Testimony, I will explain how the arguments of these witnesses lack merit and are predicated on flawed and biased analyses.

Q. WHAT IS THE GENERAL POSITION OF THE INTERVENOR WITNESSES?

A. The noted witnesses raise various observations and criticisms about Barry Unit 8, primarily because it is a new fossil-fueled generating unit. In summary, they claim that Barry Unit 8 and the other fossil-fueled resources for which the Company seeks a certificate are unnecessary and more expensive—in terms of long-run future costs (including stranded costs)—than clean energy portfolios that only include renewables, storage, energy efficiency and demand-side management.

Q. DO YOU AGREE WITH THE WITNESSES THAT FOSSIL-FIRED GENERATION PRESENTS RISKS SUCH THAT UTILITIES SHOULD MOVE AWAY ENTIRELY FROM CONSTRUCTING NEW FOSSIL GENERATION, SUCH AS BARRY UNIT 8?

A. No. I believe the country's electricity supply will continue to source from a diverse resource mix, including fossil-fired generation, that provides both reliable and cost-effective service. There is an ongoing transition in how electricity is produced in the United States, with a shift away from coal-fired resources due to environmental regulations and persistently low natural gas prices. And I expect the industry will continue to see transition as technologies evolve and the costs, capabilities and scalability of those technologies improve.

As intervenors' witnesses recognize, however, gas-fired power plants will continue to play an increasing role in the country's electricity generation during this transition. In fact, each of the witnesses rely on a report by the Rocky Mountain Institute ("RMI") that identified 68 gigawatts of gas-fired power plant capacity announced for operation by 2025 across multiple jurisdictions and power markets—including 63 combined cycle plants.[1] I believe these figures are a testament to the industry's confidence that natural gas-fired generation will remain a reliable, resilient and economic generating option for meeting customers' electricity needs for decades to come.

[1] Ex. RW-10, page 20. Neither the capacity reference nor the number of combined cycles includes Barry Unit 8.

Q. ARE THERE OTHER EXAMPLES OF INTERVENOR WITNESSES OFFERING INFORMATION THAT SUPPORTS THE COMPANY'S DECISION TO SEEK AUTHORIZATION FOR THE CONSTRUCTION OF BARRY UNIT 8?

A. There are. Mr. Detsky references the U.S. Energy Information Administration ("EIA") 2019 Annual Energy Outlook ("AEO") to support the sweeping claim that "solar and wind generation are the most cost-effective resources available."[2] An examination of the 2019 reference case in the AEO (which represents EIA's best assessment of how the U.S. and world energy markets will operate through 2050) reveals EIA's conclusion that natural gas-fired generation will continue to grow steadily and remain the dominant fuel in the electric power sector through 2050.[3] Given this, Mr. Detsky's reference to the AEO is misleading and could result in conclusions being drawn that are different than those set forth in the actual report. For example, the section of the AEO cited by Mr. Detsky to support the above-quoted statement actually is titled: "Combined-cycle and solar photovoltaic are the most economically attractive generating technologies when considering the overall cost to build and operate a plant and the value of the plant to the power system."[4] My interpretation of the data shown supports the title statement and indicates that advanced combined cycle technologies, like Barry Unit 8, are in most instances more cost effective than solar generation and wind generation in meeting a system reliability need when evaluated appropriately.

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[2] Detsky Testimony, page 10, lines 2-3.

[3] *See* Ex. MDD-5, pages 21-22, 28, 91-92 & 95.

[4] *See id.*, pages 99-100.

Ms. Wilson's testimony provides a similar illustration. In her testimony, she responds to the question "Is there evidence that utilities are choosing other resource additions over gas units?" by citing the decision by Florida Power & Light ("FP&L") to build the Manatee Energy Storage Center, a 409 MW storage system that will replace two existing gas units.[5] What she neglects to mention is that FP&L recently completed the Okeechobee Clean Energy Center, an approximately 1,700 MW combined cycle plant,[6] and has plans to bring online in 2022 the Dania Beach Clean Energy Center, an approximately 1,160 MW combined cycle plant.[7] So while it is true that FP&L is adding 409 MW of "other resources", it is also adding nearly 3,000 MW of gas-fired resources.

Q. YOU MENTIONED THE NEED TO EVALUATE RESOURCES APPROPRIATELY. WHAT DO YOU MEAN BY THIS STATEMENT?

A. Ms. Wilson, Mr. Detsky and Mr. Rábago all reference a study developed by RMI that uses a method known as Levelized Cost of Energy ("LCOE") as a basis for undertaking resource cost comparisons. As also discussed in Mr. Looney's testimony, this metric is not appropriate for final resource decisions. LCOE only considers costs. Because it does not consider the benefits that an asset may provide, it fails to present a complete picture of the overall value of a plant to the power system. The electric system is very dynamic, and the timing of costs and benefits is an important component of ensuring a cost-effective, reliable and safe electric system. The Lazard report included by Mr. Detsky even acknowledges

[5] R. Wilson Testimony, page 24, lines 6-11.

[6] *See* Florida Power & Light Co., *Powering the Needs of Florida's Growing Population and Economy*, *available at* https://www.fpl.com/rfp/okeechobee-fact-sheet.pdf (attached as Reb. Ex. MAB-1).

[7] *See* Florida Power & Light Co., *Modernizing FPL's Power Generation Facility in Dania Beach*, *available at* https://www.fpl.com/landing/pdf/dania-beach-fact.pdf (attached as Reb. Ex. MAB-2).

that LCOE results do not capture factors such as capacity value and transmission costs.[8] Moreover, the LCOE methodology ignores other important characteristics of an asset, such as its ability to provide firm capacity and be committed and dispatched continuously over an extended period of time. LCOE also is an inadequate tool when evaluating resources with differing useful lives. In my experience, the LCOE is more appropriately used as a screening tool.

Q. IS THERE INFORMATION IN INTERVENORS' TESTIMONY THAT VALIDATES YOUR CONCLUSION REGARDING THE APPROPRIATE USE OF LCOE?

A. Yes. A source document for the AEO report emphasizes that "direct comparison of LCOE across technologies [is] problematic and misleading as a method to assess the economic competitiveness of various generation alternatives."[9] The RMI report acknowledges a similar deficiency in the context of systems with very high penetrations of renewable generation, when it states:

> This analysis does not comprehensively assess gas plants' role in a dramatically different grid, such as one with a very high share (i.e., > 50 percent) of renewable generation. For investors, policymakers, and system operators considering resources for a reliable, very low carbon grid (typically in years after 2035), we recommend holistic **models that account for the different needs of a system with high wind and solar penetrations**.[10]

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[8] Ex. MDD-4, pages 1 & 19.

[9] *See* U.S. Energy Info. Admin., *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019*, page 3, *available at* https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf (attached as Reb. Ex. MAB-3).

[10] Ex. RW-10, page 30 (emphasis in original). On a related point, the report separately notes that "some regional constraints (not considered in our model) can favor new gas-fired capacity." *See id.* page 48. This acknowledgment further emphasizes the need for a holistic, system-specific analysis, as opposed to reliance on a generic tool.

This observation is true for any system that seeks to provide reliable electric service to its customers. Specifically, holistic modeling that accounts for the various and changing needs of a system is necessary to ensure that a system can respond reliably and cost effectively to customer demand and other system control-related events (such as the intermittency of renewable generation), whenever and however they occur. Thus, as with the observed hypothetical system referenced in the block quote above, the LCOE is inadequate for resource selection on Alabama Power's system given the inherent limitations of that approach.

Q. WHAT RISKS DO INTERVENORS TRY TO ASSOCIATE WITH THE PROPOSED PORTFOLIO?

A. Ms. Wilson, Mr. Detsky and Mr. Rábago claim the portfolio presents the following risks: 1) an over-reliance on natural gas generation in the state of Alabama; 2) a circular, winter reliability risk caused by natural gas generation; 3) climate risk; and 4) stranded cost risk. Messrs. Kelley, Weathers and Looney refute the first three of these alleged risks in their Rebuttal Testimonies. As I explain below, the assertions regarding "stranded costs" are likewise without merit and provide no legitimate basis for denying the petition.

Q. MS. WILSON, MR. DETSKY AND MR. RÁBAGO ALL CLAIM THAT BARRY UNIT 8 AND THE OTHER GAS RESOURCES PRESENT SIGNIFICANT "STRANDED COST" RISK. PLEASE EXPLAIN YOUR UNDERSTANDING OF THEIR ARGUMENTS.

A. In the context of intervenors' arguments, stranded cost risk is the risk that, prior to the end of an asset's expected useful life, the asset will no longer have value compared to other alternatives. The economic stranding of a long-lived asset relative to other available resources is a legitimate concern, but one that applies to any resource addition. In my opinion, the intervenor witnesses' fixation here is misplaced.

Q. HOW DO INTERVENORS REACH THEIR CONCLUSIONS REGARDING STRANDED COSTS?

A. The witnesses rely on a recent study by RMI entitled "The Growing Market for Clean Energy Portfolios", which expresses concerns regarding the cost-effectiveness of natural gas-fired resources compared to a so-called clean energy portfolio. To be clear, however, this study does not support a conclusion that Barry Unit 8 will be stranded. Rather, it simply concludes, using the inadequate LCOE technique I discussed earlier, that gas-fired units such as (but not including) Barry Unit 8 will become uneconomic by 2035, based on the assumption that the clean energy portfolio will be cheaper. Leaving aside the merits of that belief, the mere fact that the portfolio might have a lower LCOE than gas-fired generation does not immediately lead to the stranding of an asset.

Q. DID MS. WILSON, MR. DETSKY OR MR. RÁBAGO PARTICIPATE IN THE DEVELOPMENT OF THE RMI STUDY?

A. Not to my knowledge.

Q. WHAT IS RMI?

A. According to the report, RMI is a non-profit entity focused on transforming global energy use to create a clean, prosperous and secure low-carbon future by accelerating the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables.

Q. ARE YOU FAMILIAR WITH RMI'S STUDY?

A. I have reviewed the study report and its findings, along with summary information provided by Ms. Wilson from an analysis she performed using an RMI tool.

Q. DO YOU AGREE WITH THE CONCLUSIONS OFFERED BY INTERVENORS ON THE BASIS OF THAT STUDY AND THE RMI TOOL?

A. No. Based on my review, I conclude that the report presents a biased view regarding stranded asset risk, one that presumably is intended to deter future investment in gas-fired generation. Through my review, I also identified several major flaws in both the tool and Ms. Wilson's analysis as it relates to adding a unit like Barry Unit 8 to the Alabama Power system.

Q. HOW WOULD YOU DESCRIBE THE METHODOLOGY UTILIZED BY RMI FOR THE STUDY?

A. The foundation of the RMI resource comparison of the costs of gas plants and clean energy portfolios is LCOE, which I discussed earlier. RMI limited the clean energy portfolio ("CEP") to a combination of wind, solar, storage, demand-side management and energy efficiency. Further, the model attempted to require the CEP to match or exceed the "grid services" of the gas plant. The model required the CEP to produce at least as much energy as the gas plant each month. It also required the CEP to match or exceed the gas plant's seasonally adjusted nameplate capacity during a region's top 50 hours of peak net load in a year. The study uses data from a variety of sources to parameterize the CEP model.

Q. CAN THE CEP EVALUATED BY MS. WILSON MATCH OR EXCEED THE GRID SERVICES OF A FACILITY SUCH AS BARRY UNIT 8?

A. No. The minimal dispatchability of the CEP, as compared to a facility like Barry Unit 8, renders equivalency impossible.

Q. WHAT DID YOUR REVIEW OF THE STUDY'S INPUT ASSUMPTIONS REVEAL ABOUT THE DATA USED IN RMI'S CEP MODEL?

A. The study relies on a variety of sources that were outlined on page 52 of the report's Technical Appendix. While there are some assumptions that strike me as reasonable, other assumptions are predicated on studies and reports that are dated or that seem to lack confidence in the ultimate results. For example, state-level demand response potential derives from a 2009 FERC report. For energy efficiency costs, RMI relies on a Lawrence Berkeley National Laboratory report that includes a disclaimer stating that, while the document is believed to contain correct information, none of the involved parties assumes legal responsibility for the accuracy, completeness, or usefulness of any information disclosed in it.[11]

Q. WHAT WERE THE MAJOR FLAWS THAT YOU IDENTIFIED IN YOUR REVIEW OF THE STUDY?

A. The first major flaw in the study is the assumption that almost half of the "capacity" in the CEP comes from demand response and energy efficiency. This is an aggressive assumption when one requires the program to satisfy the appropriate cost-effectiveness measure, as described in Mr. Kelley's testimony. RMI states in the report that if demand management resources are ignored, the CEP is only competitive with 25 percent of proposed gas plant capacity studied.

[11] *See* Lawrence Berkeley Nat'l Lab., *The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs*, page ii, *available at* https://eta-publications.lbl.gov/sites/default/files/lbnl-6595e.pdf (attached as Reb. Ex. MAB-4).

A second significant flaw of the study involves RMI's assumptions as to the cost recovery periods afforded the gas resource under study and the CEP. For the gas resource, RMI adjusts the timing for recovery of the capital expenditures to an assumed 20-year life. In reality, the expected useful life of Barry Unit 8 is 40 years. Worse though is the treatment RMI affords CEP resources. Like the gas resource, RMI assumes a 20-year life for the CEP resources. But for CEP resources whose lives exceed 20 years, RMI does not condense the full life cycle costs into a 20-year recovery period. Rather, it appears RMI annualizes the resource's capital investment over its full life, and then takes the present value of the resource's first 20 years of cash flows. The remaining capital investment associated with the period following year 20 appears to be ignored. Thus, RMI's methodologies result in an unjustified cost advantage to the CEP portfolio, while simultaneously disadvantaging the gas resource.

Another significant flaw of the study is its assertion that the CEP provides the same grid services as a gas plant because the CEP was modeled as producing at least as much monthly energy and supplying the same output during the top 50 hours of peak net load in a year. As I discussed above, the CEP's inability to dispatch as a total portfolio precludes a conclusion that comparable grid services will be achieved. Moreover, the 50-hour requirement only captures a fraction of the year,[12] and comes nowhere close to yielding the reliability value or complete set of grid services that a fully dispatchable gas plant will provide throughout the entire day, across all days in the year. Further, the study

[12] In addition, Ms. Wilson appears to have utilized the top 50 load hours in RMI's "Southeast" region, which captured only the states of Florida, Kentucky, Louisiana and South Carolina. It does not appear that any of these hours are winter hours.

ignores the importance of unit commitment and dispatchability from the standpoint of reliability and cost optimization—features that are particularly valuable attributes of Barry Unit 8 given its high efficiency and its location on the system.

Q. DID YOU FIND ANY OTHER ISSUES WHEN REVIEWING THE ANALYSIS PERFORMED BY MS. WILSON?

A. Yes. Ms. Wilson has failed to demonstrate that a CEP can economically provide the reliability contribution that the Company requires. In reviewing her analysis, it appears the "top" 50 hours she evaluated all occur during the summer months of June, July, or August. While it is important to deliver low-cost, reliable energy all times of the day and all periods of the year, the purpose of Alabama Power's proposed portfolio is to address winter capacity needs. Her proposed CEP will not be able to meet the winter needs of the Company, if for no other reason than its dependence on a significant amount of solar energy that will not be available at the time of a winter peak.

The CEP MW values Ms. Wilson would use in lieu of Barry Unit 8 (a 743 MW resource) range from 2,446 MW to 2,602 MW, with the solar component between 1,051 MW and 1,193 MW. Alabama Power's maximum peak demand over the past ten years occurred in January, between 6 a.m. and 8 a.m. During this time of day, there is very little solar energy (if any) available to meet the peak. Her base case analysis, however, relies on energy from approximately 750 MW of solar to meet the "top" 50 hours during the summer. The available irradiance between 6 a.m. and 8 a.m. on any given January morning would come nowhere near this 750 MW contribution, resulting in a severely deficient CEP portfolio. This not only highlights flaws in her analysis, but also shows why the LCOE should not be used to make resource decisions.

Q. ARE THERE FURTHER AREAS OF CONCERN YOU IDENTIFIED IN MS. WILSON'S ANALYSIS?

A. Yes. Ms. Wilson appears to assume that Barry Unit 8 would dispatch exactly the same in all scenarios.[13] While Barry Unit 8 will provide significant energy value, it would not operate precisely the same in every case. For example, under her high gas price scenario, Barry Unit 8 would be expected to dispatch less than it would in a low gas price environment. The capability of a gas resource like Barry Unit 8 to respond to fuel price signals is one of the many nuanced benefits of having a dispatchable resource, benefits that an LCOE analysis cannot capture. Ms. Wilson also appears to have assumed the cost of Barry Unit 8 in 2019 real dollars.[14] This assumption overstates the net present cost of Barry Unit 8 relative to the costs shown for the CEP resources.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE LCOE RESULTS PRESENTED IN FIGURE 1 OF MS. WILSON'S TESTIMONY?

A. Yes. While I believe the RMI study is flawed, Ms. Wilson appears to deviate from the RMI methodology in order to generate her results. While Ms. Wilson stated she used the RMI tool to perform the evaluation, my review of her workpapers revealed the application of different assumptions than those documented in the study, specifically when assigning a value for the excess energy produced by her CEP.

While the RMI study repeatedly states that it used a value of $15/MWh for excess energy, Ms. Wilson's workpapers indicate at least one evaluation using an assumed value

[13] *See* Reb. Ex. MAB-5. For example, her spreadsheet Attachment H RMI_Outputs_20191202_0933.xls states that she assumed a 75 percent capacity factor in all scenarios (the fuel used is identical in all scenarios as well).

[14] *See id*. Her spreadsheet Attachment F CONFIDENTIAL Resource Cost.xls shows the cost of the BAU unit (I believe a reference to Barry Unit 8) and it indicates it as being in 2019 dollars.

for excess CEP energy of $20/MWh.[15] While I disagree that $15/MWh is a correct assumption and likely overstates the value of excess energy over the period of the evaluation, an increase to $20/MWh (33 percent) would seem to be nothing more than an effort to bias the analysis in favor of the CEP. However, even with the $20/MWh assumption, the RMI model still produced results showing Barry Unit 8 to be more economic than the CEP in three of the five scenarios, and essentially equal in a fourth. If the RMI assumption of $15/MWh were used, Barry Unit 8 would be more economic in four of her five scenarios.

To achieve the results presented in Figure 1 of her testimony, Ms. Wilson moved even further away from RMI's approach for valuing the excess energy of a CEP by implicitly assigning a market value to every MWh produced by the portfolio. She did so not by identifying a market value for each hour of the excess energy, but rather through the mere inclusion of the excess energy in the LCOE calculation. The validity of this approach for the purposes of this analysis is questionable, if for no other reason than it wrongly assumes that the energy will always have a market value greater than the cost.[16] And in reviewing the RMI report, I cannot find the use of a comparable assumption. I would emphasize that by offering these observations and comparisons, I am in no way endorsing the RMI model or Ms. Wilson's application of it. I am simply pointing out that Ms. Wilson deviated from the RMI methodology to reach her conclusions regarding the economics of her CEP relative to Barry Unit 8.

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[15] *See id.*; *see also e.g.*, Ex. RW-10, pages 22, 24, 26, 56.

[16] Given the renewable-heavy composition of the CEP, some production inevitably will occur during hours when the system does not need it or cannot accommodate it, forcing operators to dispose of the energy at low or even negative cost (sometimes referred to as "dump energy").

Q. WHAT ARE YOUR OVERARCHING CONCLUSIONS REGARDING THE RMI STUDY?

A. Considering the analytical flaws described above, coupled with the issues in its application by Ms. Wilson, I find the RMI tool and Ms. Wilson's use of it to be without meaningful value to this proceeding. In my opinion, neither supports a conclusion that Alabama Power's proposed gas-fired resources should be rejected, in whole or part. The diverse portfolio of gas-fired and renewable-based generation resources, as identified through the Company's comprehensive evaluative processes, can and will reliably and cost-effectively serve Alabama Power's customers for the duration of those assets' lives.

Q. DO YOU BELIEVE THAT THE GAS RESOURCES IN THE PROPOSED PORTFOLIO PRESENT STRANDED COST RISKS THAT SHOULD PRECLUDE THEM FROM BEING APPROVED BY THE COMMISSION?

A. No. As I pointed out earlier, stranded cost risk is applicable to any resource additions considered by the Company. It is not limited to just gas resources, as intervenors would seem to believe. While recognizing that the risk is not the same for each resource, this and other risks were assessed and considered in the Company's decision.

The proposed gas units all have different useful lives. The Hog Bayou PPA has a term of 19 years. Central Alabama has a remaining useful life of 23 years. Barry Unit 8 has an assumed useful life of 40 years. I consider it unlikely for any of these resources to become stranded assets during those periods. Upon completion, Barry Unit 8 would be the most efficient, flexible and cost-effective fossil-fueled unit on the Southern system. For Barry Unit 8 to become a stranded asset, conditions would have to exist where fossil-fueled generation is no longer a part of the Company's fleet of supply-side resources. I do not foresee such a development during the life of Barry Unit 8.

Q. DOES BARRY UNIT 8 HAVE THE ABILITY TO ADAPT TO A MORE CARBON CONSTRAINED ENVIRONMENT?

A. If authorized, and upon completion, Barry Unit 8 would be among the most efficient advanced combined cycle generating units in the world. Correspondingly, it would have one of the lowest CO_2 emission profiles of any combined cycle plant in operation. Beyond this, Barry Unit 8 is a candidate for future innovations that would enhance its ability to adapt to carbon pressures. For example, MHPS is in the early stages of developing a scalable J-Class gas turbine capable of being powered by a hydrogen fuel mix. Recall that Barry Unit 8 is a J-Class turbine. Thus, if this design were to be successfully developed, and if system economics warranted, it could be an option for the facility in the future. I would also note that Alabama Power completed a demonstration in 2014 of the carbon sequestration capabilities in the region near Plant Barry. Thus, if at some point in the future carbon capture technologies became a viable option for a combined cycle facility like Barry Unit 8, there is reason to believe the area could accommodate sequestration.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF MICHAEL A. BUSH
ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA)

COUNTY OF SHELBY)

Michael A. Bush, being first duly sworn, deposes and says that he has read the foregoing prepared testimony and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Michael Bush

Michael Bush

Subscribed and sworn to before me
this 27th day of January, 2020.

Esther Howard Brandenburg
Notary Public

ESTHER T. HOWARD
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 05-12-2020

8350756.1

Rebuttal Testimony for Michael A. Bush

Reb. Ex. MAB-1

Powering the needs of Florida's growing population and economy

At Florida Power & Light Company, we invest continuously in our infrastructure to ensure we can deliver a reliable supply of affordable, clean energy to our customers – 24 hours every day – now and in the future.

Powering Florida

We serve our customers using a variety of resources, including energy efficiency, wholesale electricity purchased from non-FPL power generators and FPL's fleet of power-generation facilities fueled by natural gas, solar, nuclear and other sources.

To ensure we can continue to meet our customers' energy needs, we conduct annual, in-depth planning. As part of our annual 10-year outlook filed with the Florida Public Service Commission (PSC) in 2014, we projected a need for more than 1,000 megawatts of additional firm power generation beginning in 2019 – and more in the years that follow.

Our estimated need for power took into account substantial energy conservation and FPL's three new universal (large-scale) solar plants, which were completed in late 2016.

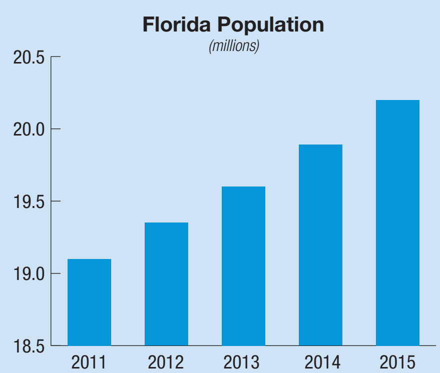
Why more power is needed

There are several reasons why additional power is needed:

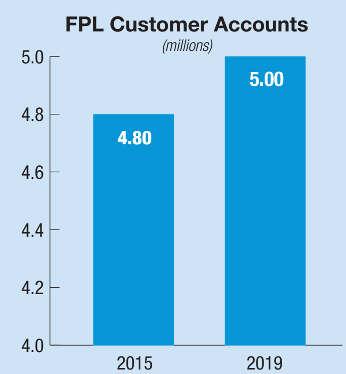
- **Growing population** – FPL serves approximately 4.9 million customer accounts in the state, a number expected to increase by 2019 to 5 million accounts serving approximately 10 million people. Florida's population is now the third largest in the nation, adding more than 300,000 people annually in recent years.
- **Expanding economy** – Population growth and increased business activity are major drivers of the state's strong economic growth.
- **Plant retirements** – As we retire older, inefficient power plants, customers benefit from our investments in high-efficiency clean energy centers fueled by natural gas, solar and nuclear – saving our customers money on fuel costs while reducing air emissions.

Florida's population and economy are growing

FPL is building firm new power-generation facilities to meet the energy needs of Florida's growing population and expanding economy. We also continue to retire older, inefficient power plants and make smart investments in new clean energy facilities – saving customers money on fuel costs and reducing air emissions.



Source: U.S. Census Bureau



How we're meeting Florida's growing energy needs

We're always working to identify the most cost-effective options for meeting our customers' power needs. In 2015, FPL issued a Request for Proposals (RFP) to solicit bids from non-FPL energy providers for firm power generation starting in 2019. Firm generation – the backbone of a reliable electric system – means that electricity is available to our customers at any time of day or night.

Simultaneously, we developed initial plans for the FPL Okeechobee Clean Energy Center, a highly efficient power-generating facility fueled by clean, U.S.-produced natural gas and located on FPL-owned property in northeast Okeechobee County. As a result of the RFP process, FPL's planned facility was selected as the best, most cost-effective option to serve our customers.

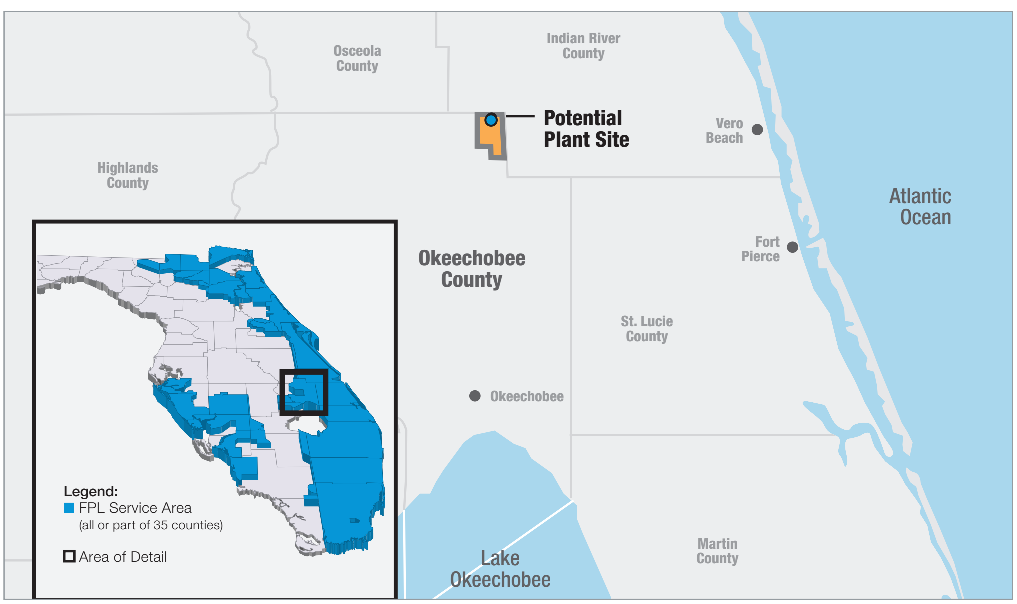
A comprehensive review and licensing process, which was completed in 2016, involved the Florida Public Service Commission, Florida Department of Environmental Protection and numerous other state, county, regional and federal agencies.

Proposed power facility

The FPL Okeechobee Clean Energy Center will be one of the cleanest, most efficient of its kind in the world. It will have a generating capacity of approximately 1,700 megawatts – enough to deliver power around-the-clock to more than 300,000 homes starting in June 2019. Developing a facility that size is the most cost-effective option for our customers compared to building a smaller plant – and then having to construct another facility soon after.

FPL's estimated $1.2 billion investment is producing more than 300 good-paying jobs, on average, during the two-year construction schedule – as many as 650 during peak work times. FPL's engineering, procurement and construction contractor, Zachry Group, is responsible for hiring the workforce to build the facility.

Based on similar projects FPL has developed, *construction* activities alone are expected to have an overall economic benefit to the region of more than $500 million. In addition, plant *operations* are projected to produce $238 million in new tax revenues to Okeechobee County, the school district, the regional water management district and other taxing authorities from 2020 to 2049 – an average of nearly $8 million annually.



FPL's new clean energy center is located on FPL-owned property in northeast Okeechobee County.

Current schedule

The FPL Okeechobee Clean Energy Center has completed a comprehensive review and permitting process by the Florida Department of Environmental Protection and a number of other state, county, regional and federal agencies.

That process, which included opportunities for public input, was completed in 2016.

Project construction began in early 2017 and is expected to take nearly two years to complete. The new facility is expected to begin generating power for customers in June 2019.

Questions?

You may submit questions or comments via email to: **AffordableCleanEnergy@FPL.com**

See our website

FPL.com/AffordableCleanEnergy

Rebuttal Testimony for Michael A. Bush

Reb. Ex. MAB-2

Reb. Ex. MAB-2

FPL

FPL.com/DaniaBeachEnergy

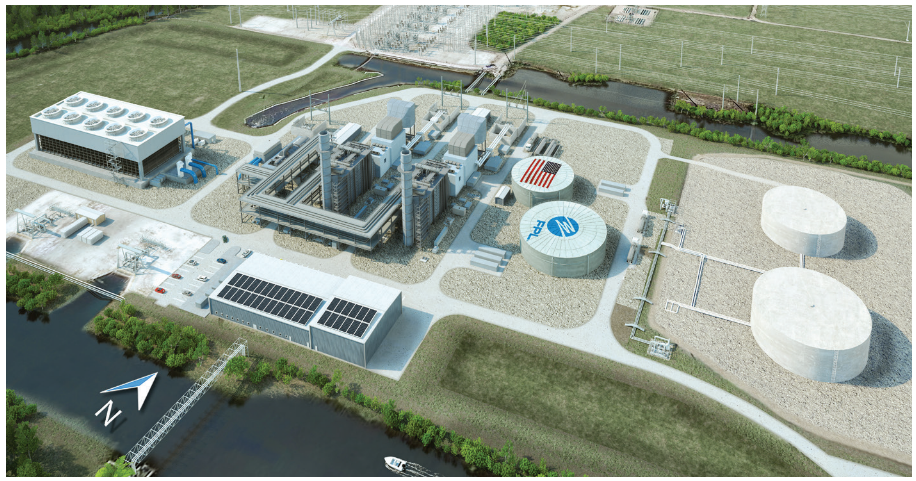
Modernizing FPL's power generation facility in Dania Beach

Projected to be the cleanest, most efficient power plant of its kind in the world, FPL's future Dania Beach Clean Energy Center will produce $337 million in estimated net savings for our customers along with substantial economic and environmental benefits for Broward County and all of Florida.

Clean, efficient energy for Southeast Florida

At FPL, we remain committed to delivering clean, reliable energy while keeping our customers' typical monthly bills among the lowest in the nation. We continue to invest in advanced power generation technology to modernize our energy system – replacing older, outdated power plants with highly efficient facilities that produce more energy with less fuel and substantially lower emissions.

As part of the ongoing modernization of our fleet of power-generating plants, we are proposing to build and operate the FPL Dania Beach Clean Energy Center in Broward County. The facility, which will be fueled by U.S.-produced natural gas, will replace the existing, aging power-generating units on the site. Plans call for the current plant to be dismantled starting in 2018.



The future FPL Dania Beach Clean Energy Center.

Improvements over the existing plant

Compared with the continued operation of our current facility – located on property west of the Fort Lauderdale airport – our planned clean energy center will:

» Produce $337 million in projected net cost savings for FPL customers
» Reduce primary air emissions by 70 percent
» Generate more power – while reducing FPL's overall use of natural gas
» Produce jobs and new tax revenue for Broward County

The modern new facility will be able to generate approximately 1,160 megawatts of energy – about 280 megawatts more than the existing plant. That's enough energy to power about 250,000 typical homes around the clock.

Economic benefits for Broward County

FPL's planned $888 million investment will generate substantial economic benefits for the Broward County area, including:

» Estimated $297 million in tax revenue for the county, the school district, Children's Services Council and other local taxing authorities
» Approximately 300 good-paying jobs, on average, during construction – as many as 650 during peak work times
» Significant economic benefits to the area from the purchase of local goods and services

Estimated $297 million in tax revenue

for Broward County, school district, Children's Services Council and other taxing authorities*

During its first full year of operation, the new FPL plant is expected to generate $13.47 million in tax revenue - more than double the $5.96 million in local taxes paid by the current plant in 2016.

$13.47 million
Future plant
First-year tax (2023)

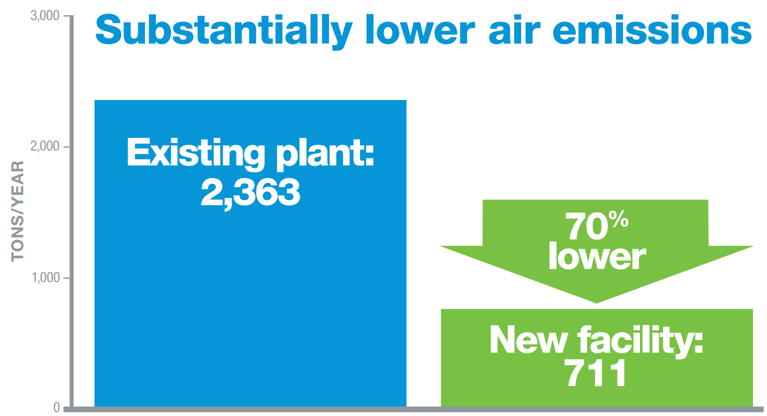
$5.96 million
Existing plant
(Units 4 & 5) 2016 tax

* Estimated total covers projected 40-year operating life of proposed new FPL facility

P100002539

Environmental improvements

The FPL Dania Beach Clean Energy Center will be one of the cleanest, most efficient power-generating facilities of its kind in the world. Compared with continued operation of the existing plant, the new facility will substantially cut air emissions and reduce FPL's overall use of natural gas.



Includes primary emissions: nitrogen oxide (NOx), carbon monoxide (CO), sulfur dioxide (SO2), particulates (10 & 2.5) and volatile organic compounds (VOC)

The new clean energy center is part of FPL's ongoing strategy to modernize its power generation system with facilities fueled by U.S.-produced natural gas and solar. Since 2001, these investments have prevented more than 120 million tons of carbon emissions, enabled FPL to shut down coal-burning power plants and reduced our use of foreign oil from more than 40 million barrels per year to less than 1 million.

Our current power plant on the site is also an important refuge for manatees during cold weather (as many as 947 have been documented in one day). The modern new facility will preserve this important warm-water refuge for this iconic species.

The proposed new power generation center will undergo detailed analyses by county, state and federal government agencies to ensure it fully complies with all environmental requirements, including air, water and wildlife.

An ideal location

Our Dania Beach property is the location of FPL's first power plant (1927), and it has been the site of power generation ever since. The current generating units (4 & 5) were last updated nearly a quarter-century ago, and some of their major components have operated since the 1950s.

The new modernized facility is expected to produce $337 million in estimated savings for our customers and improve service reliability in Southeast Florida. The new energy center will incorporate key components of the existing infrastructure. That means no new offsite power transmission lines, no new natural gas pipeline and no new electric substations are needed.

The planned facility will have a sleek, modern appearance similar to the FPL Port Everglades Clean Energy Center, which opened in 2016. It will also lower day-to-day operating costs – saving our customers money – and require less equipment than the existing plant, including 50 percent fewer: steam turbines and generators, power turbines and stacks.

The Broward County location is also important because it is situated in the critical Southeast Florida area, where more power generation is needed to keep pace with increasing energy use and the growing economy.

What's ahead

Experts with the Florida Department of Environmental Protection and numerous other county, state and federal government agencies continue to evaluate the proposed facility to ensure it complies with all regulatory requirements.

The review and permitting process is typically takes 14-16 months. Should the clean energy center receive all needed approvals, we would begin to dismantle the current plant in 2018. After construction, commercial operation is expected to begin in June 2022.

We're committed to sharing information and maintaining an open dialogue with the local community throughout the development of the FPL Dania Beach Clean Energy Center. Additional information is available at **FPL.com/DaniaBeachEnergy.** Feel free to contact us via email at **Dania-Beach-Energy@FPL.com** should you have questions or comments about our plans, or call us at 888-763-4282.

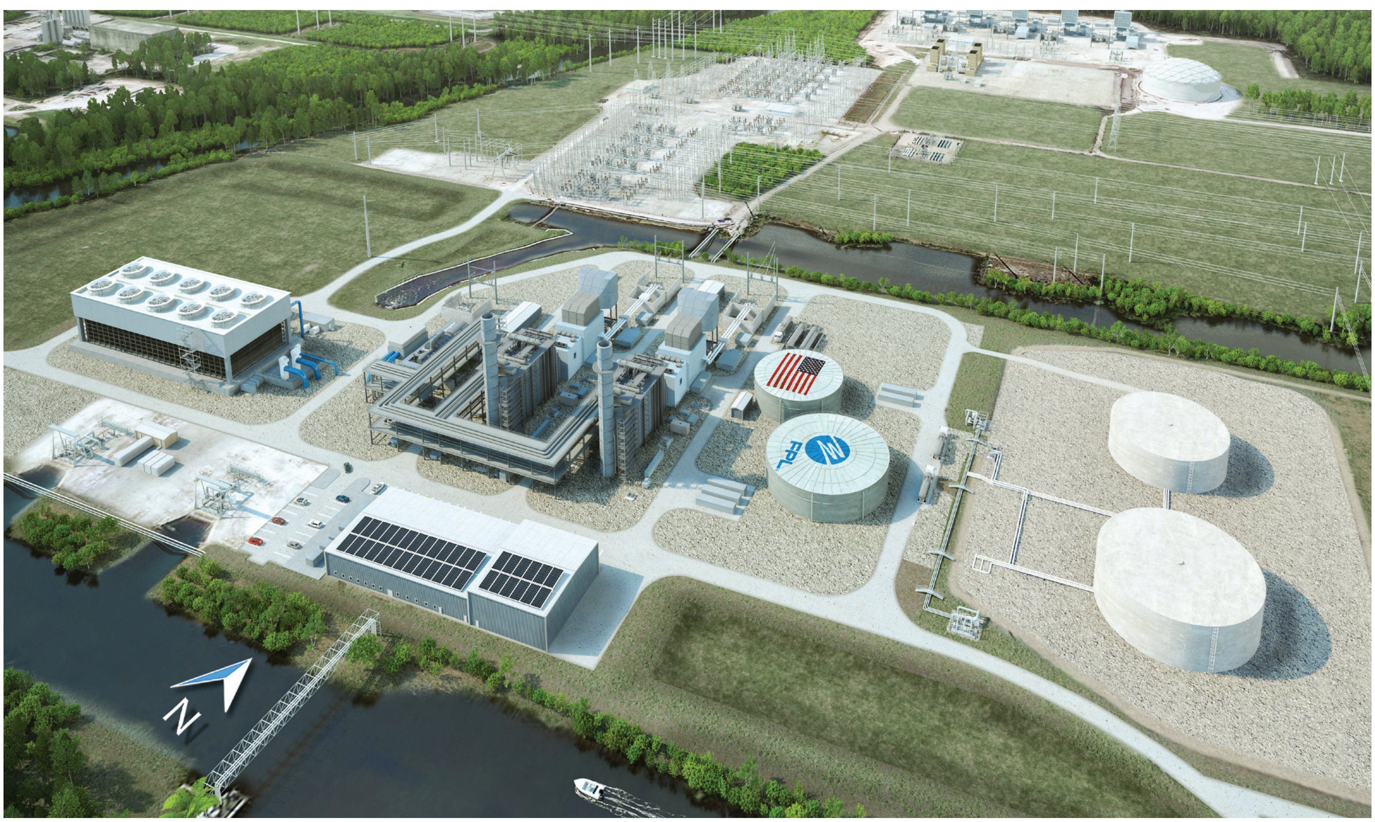
"FPL's new energy facility, much like the recent modernization of its Port Everglades plant, will produce major benefits that will ripple through the Broward County economy for decades to come."

Bob Swindell, President and CEO, Greater Fort Lauderdale Alliance

Current FPL Power Plant in Dania Beach

Rendering of existing plant.

Future FPL Dania Beach Clean Energy Center



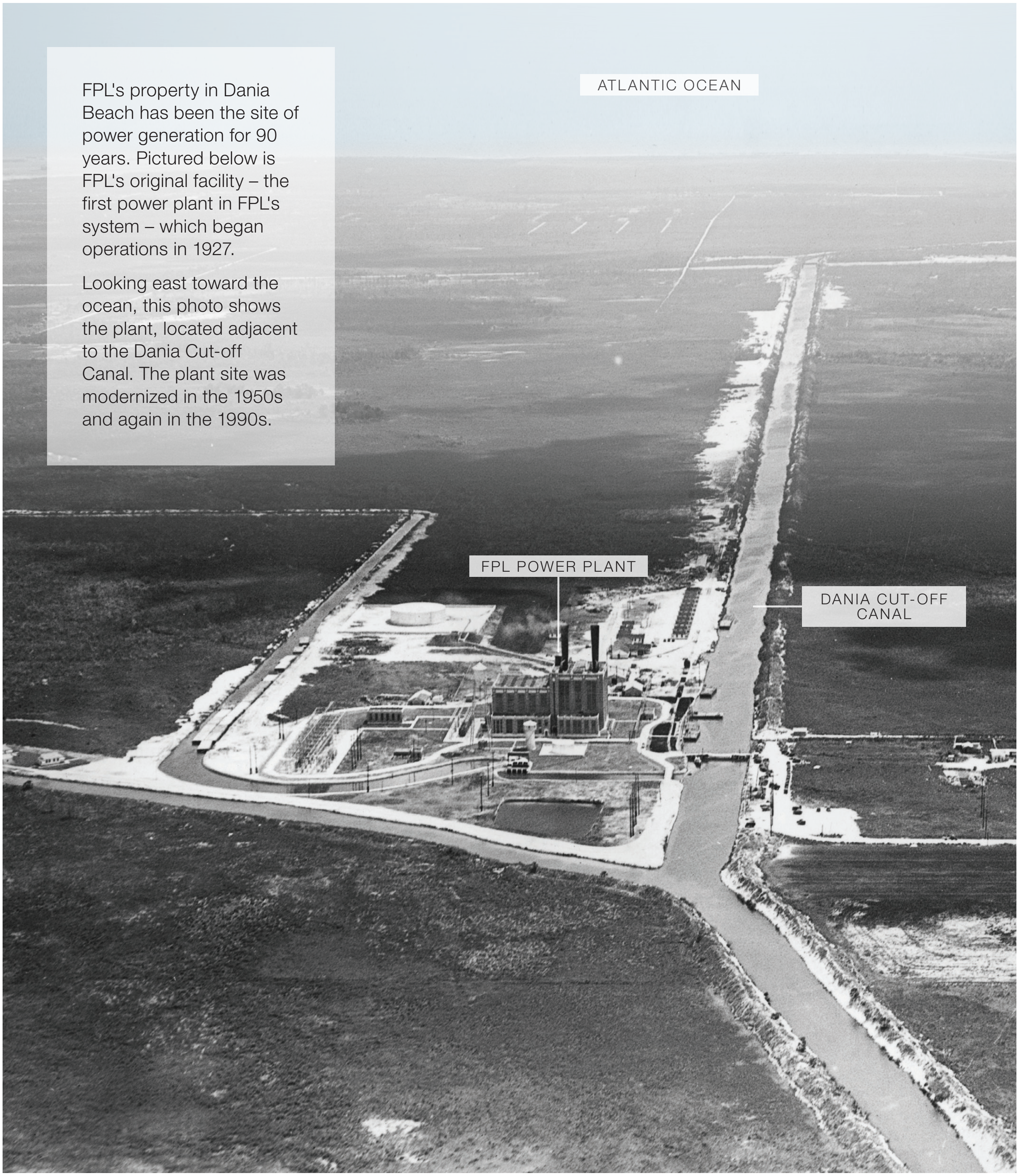
Conceptual rendering of proposed facility. Subject to final engineering.

Reb. Ex. MAB-2

FPL's first power plant: Dania Beach, 1927

FPL's property in Dania Beach has been the site of power generation for 90 years. Pictured below is FPL's original facility – the first power plant in FPL's system – which began operations in 1927.

Looking east toward the ocean, this photo shows the plant, located adjacent to the Dania Cut-off Canal. The plant site was modernized in the 1950s and again in the 1990s.



Rebuttal Testimony for Michael A. Bush

Reb. Ex. MAB-3

Independent Statistics & Analysis
U.S. Energy Information Administration

February 2019

Levelized Cost and Levelized Avoided Cost of New Generation Resources in the *Annual Energy Outlook 2019*

This paper presents average values of levelized costs and levelized avoided costs for electric generating technologies entering service in 2021, 2023,[1] and 2040 as represented in the National Energy Modeling System (NEMS) for the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2019* (AEO2019) Reference case.[2] Both values estimate the factors contributing to the capacity expansion decisions modeled, which also consider policy, technology, and geographic characteristics that are not easily captured in a single metric.

The costs for electric generating facilities entering service in 2023 are presented in the body of the report, with those for 2021[3] and 2040 included in Appendices A and B, respectively. Both a capacity-weighted average based on projected capacity additions and a simple average (unweighted) of the regional values across the 22 U.S. supply regions of the NEMS electricity market module (EMM) are provided, together with the range of regional values.

Levelized Cost of Electricity

Levelized cost of electricity (LCOE) represents the average revenue per unit of electricity generated that would be required to recover the costs of building and operating a generating plant during an assumed financial life and duty cycle.[4] LCOE is often cited as a convenient summary measure of the overall competiveness of different generating technologies.

Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.[5] The importance of each of these factors varies across the technologies. For technologies with no fuel costs and relatively small variable O&M costs, such as solar and wind electric generating technologies, LCOE changes nearly in proportion to the estimated capital cost of the technology. For technologies with significant fuel cost, both fuel cost and capital cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax credits (see text box on page 2), can also affect the calculation of LCOE. As with any projection, these factors are uncertain because their values can vary regionally and temporally as technologies evolve and as fuel prices change.

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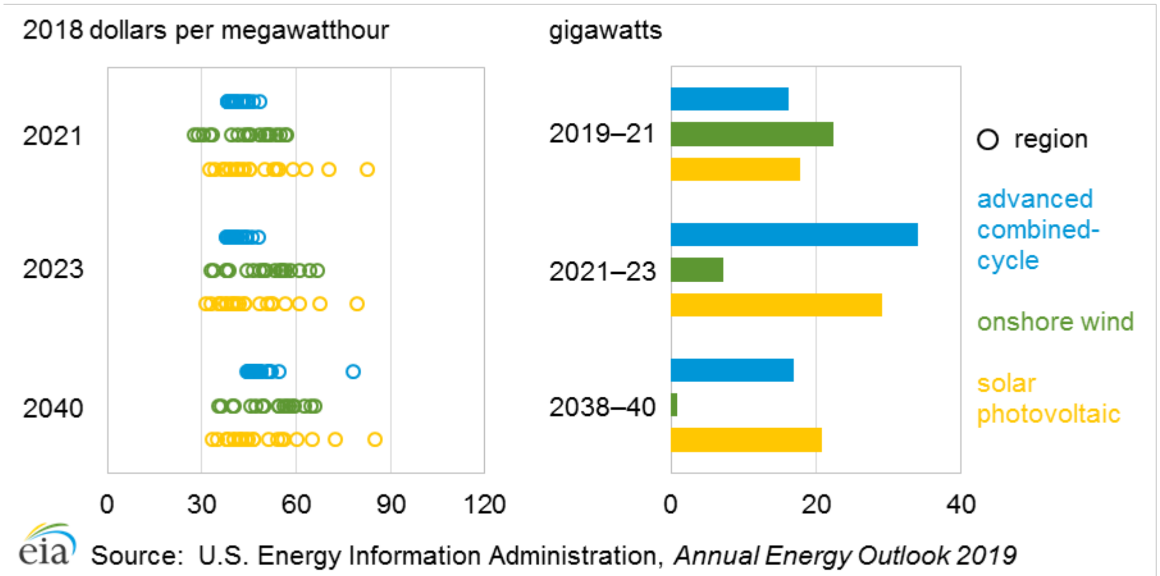
[1] Given the long lead-time and licensing requirements for some technologies, the first feasible year that all technologies are available is 2023.
[2] AEO2019 are available online (http://www.eia.gov/outlooks/aeo/).
[3] Appendix A shows LCOE and LACE for the subset of technologies available to be built in 2021.
[4] Duty cycle refers to the typical utilization or dispatch of a plant to serve base, intermediate, or peak load. Wind, solar, or other intermittently available resources are not dispatched and do not necessarily follow a duty cycle based on load conditions.
[5] The specific assumptions for each of these factors are given in the *Assumptions to the Annual Energy Outlook*, available online (http://www.eia.gov/outlooks/aeo/assumptions/).

Levelized Avoided Cost of Electricity

LCOE does not capture all of the factors that contribute to actual investment decisions, making the direct comparison of LCOE across technologies problematic and misleading as a method to assess the economic competitiveness of various generation alternatives. As illustrated by Figure 1 below, on average, wind LCOE is shown to be the same or lower than solar photovoltaic (PV) LCOE in 2021, with more wind generating capacity expected to be installed than solar PV. Wind LCOE continues to be about the same or lower than solar PV LCOE on average in 2040, but EIA projects much more solar PV capacity to be installed than wind during that time.

Figure 1. Levelized cost of electricity (with applicable tax subsidies) by region and total incremental capacity additions for selected generating technologies entering into service in 2021, 2023, and 2040



Comparing two different technologies using LCOE alone evaluates only the cost to build and operate a plant and not the value of the plant's output to the grid. EIA believes an assessment of economic competitiveness between generation technologies can be gained by considering the avoided cost: a measure of what it would cost to generate the electricity that would be displaced by a new generation project. Avoided cost provides a proxy measure for potential revenues from sales of electricity generated from a candidate project. It may be summed over a project's financial life and converted to a level annualized value that is divided by average annual output of the project to develop its *levelized* avoided cost of electricity (LACE).[6] Using LACE and LCOE together gives a more intuitive indication of economic competitiveness for each technology than either metric separately when several technologies are available to meet load. If several technologies are available to meet load, a LACE-to-LCOE ratio (or value-cost ratio) may be calculated for each technology to determine which project provides the most value relative to its cost. Projects with a value-cost ratio greater than one (i.e., LACE is greater than

[6] Further discussion of the levelized avoided cost concept and its use in assessing economic competitiveness can be found online: http://www.eia.gov/renewable/workshop/gencosts/.

Rebuttal Testimony for Michael A. Bush

Reb. Ex. MAB-4

Reb. Ex. MAB-4

LBNL-6595E

Ernest Orlando Lawrence Berkeley National Laboratory

The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs

Megan A. Billingsley, Ian M. Hoffman, Elizabeth Stuart, Steven R. Schiller, Charles A. Goldman, Kristina LaCommare

Environmental Energy Technologies Division

March 2014

The work described in this report was funded by the National Electricity Delivery Division of the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Reb. Ex. MAB-4

LBNL-6595E

The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs

Prepared for the
U.S. Department of Energy
National Electricity Delivery Division of the Office of Electricity Delivery and Energy Reliability

Principal Authors

Megan A. Billingsley, Ian M. Hoffman, Elizabeth Stuart, Steven R. Schiller, Charles A. Goldman, Kristina LaCommare

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Disclaimer

Rebuttal Testimony for Michael A. Bush

Reb. Ex. MAB-5

Case	Scenario	Data ScenInfo Outcompete Year	Data ScenInfo Energy (GWh/y)	Data ScenInfo CEP Energy (GWh/y)	Data ScenInfo Energy (Discounted GWh)	Data ScenInfo Fuel (mmBtu/y)
Barry8	Base	2035	3,542	4,526	33,754	22,124,399
Barry8	HighDSM	2023	3,542	4,352	33,754	22,124,399
Barry8	Carbon10	2032	3,542	4,526	33,754	22,124,399
Barry8	Carbon20	2029	3,542	4,526	33,754	22,124,399
Barry8	HighGasPr	2023	3,542	4,526	33,754	22,124,399

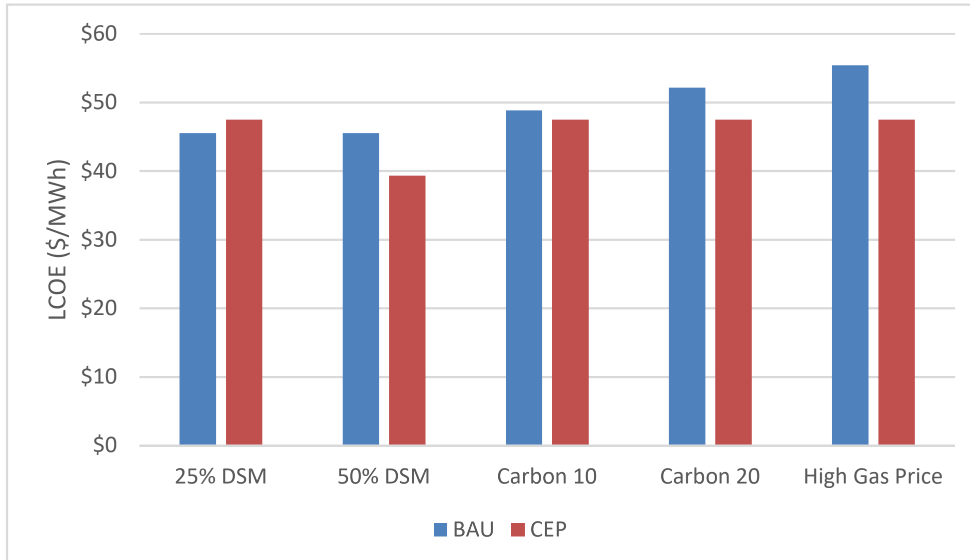
25% DSM
50% DSM
Carbon 10
Carbon 20
High Gas Price

The shaded cells are required

Region	Type	Resource	CapEx_value	CapEx_year	FOM_value	FOM_year	VOM_value	VOM_year	HR_value	Life_value	Learning_rate	Incentive	Degradation_value
Units			$/MW	$ year	$/MW-y	$ year	$/MWh	$ year	btu/kWh	years	% CapEx decline per year		MWh/cycle
Generic	BAU	NGCC	[redacted]	2019	[redacted]	2019	[redacted]	2019	[redacted]	20			
Generic	BAU	NGCT	875,000	2017	5,000	2017	7.35	2017	8902	20			
Generic	BAU	COL											
Generic	RE	Solar_Fixed	1,020,837	2019	12,617	2019				30	0.019672	ITC	
Generic	RE	Solar_Tracking	1,145,720	2019	13,587	2019				30	0.020	ITC	
Generic	RE	Solar_AC	0	2017	0	2017				30	0.019672	ITC	
Generic	RE	Wind	1,643,000	2019	44,912	2019				20	0.018	PTC	
Generic	RE	Wind_Offshore	4,404,000	2019	125,000	2019				20	0.026647	PTC	
Generic	ES	Storage_DC	198,000	2019	0	2019				20	0.057		0.000323178
Generic	ES	Storage_AC	648,000	2019	36,000	2019				20	0.057		
Generic	Tx	Default	77,693	2017	2,903	2017							
Generic	EE	Ind_Total	1,781,356	2012						12			
Generic	EE	Res_Refrigerator	1,525,352	2012						9			
Generic	EE	Res_Water_Heating	5,140,973	2012						12			
Generic	EE	Res_Space_Cooling	1,701,586	2012						15			
Generic	EE	Res_Space_Heating	1,701,586	2012						15			
Generic	EE	Res_Lighting	489,017	2012						7			
Generic	EE	Com_Cooking	1,468,849	2012						12			
Generic	EE	Com_Refrigeration	1,468,849	2012						12			
Generic	EE	Com_Water_Heating	1,468,849	2012						12			
Generic	EE	Com_Space_Cooling	2,326,485	2012						13			
Generic	EE	Com_Space_Heating	2,326,485	2012						13			
Generic	EE	Com_Lighting	734,425	2012						12			
Generic	DR	Ind_Total	99,361	2016	1,500	2016	35.00	2017		20			
Generic	DR	Res_Total	80,458	2016	1,215	2016	35.00	2017		20			
Generic	DR	Com_Total	65,413	2016	988	2016	35.00	2017		20			

Case	Scenario	Cost CEP LCOE	Cost CEP True LCOE	Cost CEP Net LCOE	Cost BAU LCOE	Cost CEP Net Capacity	Cost BAU Capacity
Barry8	Base	$60.69	$47.49	$55.13	$45.54	$275.88	$227.87
Barry8	HighDSM	$48.34	$39.34	$43.76	$45.54	$219.01	$227.87
Barry8	Carbon10	$60.69	$47.49	$55.13	$48.85	$275.88	$244.46
Barry8	Carbon20	$60.69	$47.49	$55.13	$52.17	$275.88	$261.05
Barry8	HighGasPrice	$60.69	$47.49	$55.13	$55.42	$275.88	$277.34

25% DSM
50% DSM
Carbon 10
Carbon 20
High Gas Price



BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF M. BRANDON LOONEY
ON BEHALF OF ALABAMA POWER COMPANY

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

A. My name is M. Brandon Looney. I am the Manager of Reliability and Resource Procurement for Southern Company Services Inc. ("SCS"). My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q. HAVE YOU PREVIOUSLY PRESENTED DIRECT TESTIMONY ON BEHALF OF ALABAMA POWER IN THIS PROCEEDING?

A. Yes. As I previously testified, my department worked with Alabama Power personnel to develop the economic analyses supporting the resource portfolio in Alabama Power's petition. I described the process and assumptions used and the results yielded by the analyses.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this Rebuttal Testimony is to respond to the testimony of various intervenor witnesses who direct opinions and criticism at the matters described in my Direct Testimony. I will not attempt to address every issue raised by intervenors, so the absence of any specific rebuttal to each and every aspect of that testimony should not be construed as acceptance of a position.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In general, the intervenor witnesses raise various criticisms of the methods, assumptions and tools utilized by the Company to perform its economic evaluation of candidate resources, even insinuating that the analysis was designed to favor gas resources over renewables. Through my Rebuttal Testimony, I will address these criticisms by demonstrating why the Company's analysis was fair and sound and the utilization of Strategist was appropriate and consistent with industry practice. I will also refute certain criticisms of the gas resources in the petitioned portfolio, specifically Central Alabama's utilization, and explain the application of a carbon price imposed on the portfolio. I will discuss the fallacy of the assertion that it would be more economic for the Company to pursue additional Solar BESS projects (above and beyond the proposed 400 MW in the Petition) instead of the gas resources. Finally, I will explain why a Levelized Cost of Energy ("LCOE") comparison is an inferior methodology for evaluating resource decisions compared to the method undertaken by the Company.

Q. SIERRA CLUB'S WITNESS MR. DETSKY CRITICIZES ALABAMA POWER'S USE OF STRATEGIST, BOTH IN CONNECTION WITH THE COMPANY'S INTEGRATED RESOURCE PLAN ("IRP") AS WELL AS IN THE EVALUATION OF RESPONSES TO THE REQUESTS FOR PROPOSALS ("RFPS"). ARE HIS CRITICISMS VALID?

A. No. SCS has extensive experience with Strategist, having performed countless simulations using the model. It is a robust model that can be employed to perform different types of analyses. In his Rebuttal Testimony, Mr. Kelley explains how Strategist was used as part of the development of the IRP, choosing from generic candidate technologies to identify a benchmark plan. Mr. Kelley also presents the reasons why certain types of resource technologies were excluded from Strategist's development of the benchmark plan, which served as the indicative basis from which Alabama Power could pursue the most appropriate course to meet system reliability needs. In contrast, my group used Strategist to evaluate the economics of the resource proposals received in response to the capacity RFP and the Barry Unit 8 turnkey project proposal relative to the benchmark plan.[1] The use of Strategist to develop the IRP benchmark plan and the use of Strategist to evaluate competing proposals are two distinct applications of the model that, contrary to Mr. Detsky's opinion,[2] are entirely consistent with accepted industry practice.

Q. WHY DID YOU NOT EVALUATE THE SOLAR BESS PROPOSALS USING STRATEGIST?

A. The Solar BESS projects present challenges for the standard modeling capabilities of Strategist, as they pair two resources, one of which is non-dispatchable (the solar component) and one of which is dispatchable (the BESS component). Historically, and in this analysis. we evaluate non-dispatchable renewable resources outside of Strategist, so we can be confident that the full value of the resource, over its life, is accurately captured. In my opinion, our approach was superior to adapting Strategist to accommodate the unique aspects of the Solar BESS proposals. In that regard, I would note that, although criticizing

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[1] Direct Testimony of M. Brandon Looney, page 3, line 16 through page 8, line 12.

[2] *See* Detksy Testimony, page 5, lines 1-2.

Alabama Power for the approach it used,[3] Mr. Detsky acknowledges Strategist modeling limitations elsewhere in his testimony when he offers observations regarding the methodology employed by Public Service Company of Colorado ("PSCo").[4] It is also worth noting that the Solar BESS projects, on average, proved to be the most cost-effective options in our evaluation.

Further, the Strategist output should not be the sole basis for a resource decision, as it is not designed to take into account all factors influencing the overall value of a proposal. While Strategist will yield production cost results based on deterministic inputs, it cannot resolve all competing contingencies of a dynamic nature, such as those surrounding transmission and fuel transportation. Although Alabama Power conducted an initial economic evaluation of the Solar BESS proposals through its Forecasting and Resource Planning group, the final evaluation of all the proposals encompassed both the proposals analyzed directly by my team using Strategist, as well as the Solar BESS proposals. Thus, Mr. Detsky is wrong when he testifies that the Company did not evaluate the Solar BESS proposals in conjunction with those involving natural gas-fired resources as part of the ultimate identification of a complete, cost-effective resource portfolio.[5]

Q. MR. DETSKY STATES THAT YOUR USE OF STRATEGIST DID NOT INCLUDE AN EVALUATION OF THE PROPOSED RESOURCE PORTFOLIO AS A WHOLE, LEAVING OPEN THE QUESTION OF WHETHER THE PORTFOLIO

[3] *See id.*, page 18, lines 6-10.

[4] *See id.*, page 32, lines 16-19.

[5] *Cf. id.*, page 18, lines 9-11.

REPRESENTS THE OPTIMAL SOLUTION FOR MEETING ALABAMA POWER'S NEEDS. DO YOU HAVE A RESPONSE TO THIS OPINION?

A. Yes. As I have explained both here and in my Direct Testimony, each proposal was examined individually to determine its relative economics against a reference system case based on the indicative benchmark resources. Strategist itself was not used to directly rank or select resources. Rather, we used Strategist to determine the production cost savings associated with traditional dispatchable resources. Forecasting and Resource Planning undertook its analysis to identify the production cost savings of the Solar BESS proposals. The production cost savings then were combined with other costs and benefits to determine an overall ranking of the resources including portfolio considerations concerning transmission and fuel transportation. This evaluative process accounted for all of the unique costs and benefits of each resource, and provided us with the least-cost, optimal combination of resources to meet Alabama Power's capacity needs. I do not agree with Mr. Detsky's opinion that Strategist could somehow have identified an alternative combination of higher-cost and lower-cost proposals that would render the Company's portfolio sub-optimal. The optimal portfolio of resources is that which has been proposed, reflecting the lowest individual incremental cost to customers.

Q. DID YOUR ANALYSIS SKEW THE COMPANY'S RESULTS IN FAVOR OF GAS UNITS OVER RENEWABLE OPTIONS, AS MR. DETSKY CLAIMS?

A. No.

Q. WHY IS MR. DETSKY'S CLAIM INCORRECT?

A. Mr. Detsky makes several assertions regarding our analysis of renewable options that are incorrect and/or misleading. First, he claims that Alabama Power inflated PPA prices by adding an unnecessary "equity cost adder", but neglects to mention that this cost was not applied to any of the renewable PPA options.[6] Mr. Detsky also claims that the exclusion of renewables in the development of the IRP benchmark plan (which he calls the "base case") is an "egregious example of the Company's putting its thumb on the scale."[7] As Mr. Kelley explains, however, the absence of renewables in the IRP benchmark plan did not preclude their consideration as a potential resource or diminish the value of renewables in the overall evaluation. This is demonstrated by the selection of the five Solar BESS projects for inclusion in the portfolio.

Contrary to Mr. Detsky's view, the Company's evaluation in no way disadvantaged renewable and storage options. I have already explained the reasoning behind the methodology employed, and how it is consistent with industry practice. I would also note that PSCo's approach (which Mr. Detsky appears to endorse) included the calculation of an Effective Load Carrying Capability ("ELCC"), which is analogous to our use of Incremental Capacity Equivalence ("ICE") Factors. We assigned an 85 percent ICE Factor for these particular 2-hour duration batteries, as compared to the 55 percent ELCC utilized by PSCo for such batteries. In that respect, our evaluation afforded the BESS component of the Solar BESS proposals more value than the process utilized by PSCo.

Q. DO THE RESULTS OF YOUR EVALUATION SUPPORT A CONCLUSION THAT ADDITIONAL SOLAR BESS PROJECTS COULD MEET ALABAMA POWER'S

[6] *See also* Rebuttal Testimony of Christine Baker, page 7, line 8 through page 8, line 8.

[7] Detsky Testimony, page 5, lines 15-16.

FULL CAPACITY NEED OR REPLACE ANY OF THE OTHER SELECTED RESOURCES?

A. No. The Solar BESS projects selected by the Company provide excellent value for customers; however, these projects include short duration, 2-hour batteries that will serve a specific reliability function in the Company's generating fleet. The Company has determined that a certain amount of short duration energy storage can provide a very high capacity equivalence. This determination led to the 85 percent ICE Factor used in our evaluation of the limited amount of Solar BESS projects. The Company's analysis further indicates that the ICE Factor for short duration batteries sharply falls after approximately 500 MW of penetration. Beyond that amount, a battery of much longer duration is required in order to provide comparable capacity equivalence. This conclusion is consistent with Table KLS-1 reproduced in Mr. Detsky's testimony, which indicates that a 6-hour duration battery would be needed to provide an 85 percent capacity equivalence. Our initial resource evaluations found that longer duration batteries (i.e., 6-hour to 8-hour) were not cost competitive with the resources ultimately selected by the Company.

Q. IS THE EQUITY COST INCLUDED IN YOUR ANALYSIS FOR CERTAIN PPAS AN APPROPRIATE COST TO CONSIDER IN THE EVALUATION?

A. Yes. As stated previously, our intent was to include all of the costs and benefits of each resource option in our evaluation in order to determine which resource options represented the least cost solution for customers. Ms. Baker's Rebuttal Testimony discusses more fully the basis for this cost component. Further, Mr. Detsky is incorrect in his representation that the PPA terms, particularly a provision related to variable interest entities, mitigate equity cost risk. The two issues are unrelated.

Q. DO THE RESULTS OF YOUR EVALUATION INDICATE THAT CENTRAL ALABAMA IS PROJECTED TO BE A LOW UTILIZATION RESOURCE, AS SUGGESTED BY MR. DETSKY?

A. No. Mr. Detsky makes several statements regarding the projected utilization of the Central Alabama facility that demonstrate a misunderstanding of our evaluation. Mr. Detsky refers to testimony by Sierra Club's witness Ms. Wilson for the proposition that Central Alabama is expected to run only about 35 percent of the time. This level of operation is not consistent with our evaluation. While the expected capacity factor of Central Alabama varies based on fuel price and carbon price assumptions, the near-term capacity factors are projected to remain well above 50 percent in both the moderate and low gas cases.

Q. WHAT DOES THE REFERENCED CAPACITY CREDIT REPRESENT?

A. Mr. Detsky also claims that Exhibit MBL-1 shows a "weak capacity credit" for Central Alabama, which he claims demonstrates the plant is "inefficient and may not be able to meet the capacity need for which it is being procured."[8] Mr. Detsky's claim in this regard shows that he does not understand the credit or the purpose behind it. The credit in question represents the value of various resources to the extent they become available for use by Alabama Power to serve the needs of its retail customers before the winter of 2023-2024 (hence the title "Pre Dec 2023 Capacity Credit"). Central Alabama has a lower credit because the existing wholesale contract associated with the output from the facility does not expire until mid-2023. Thus, Central Alabama does not provide as much "early" capacity value to Alabama Power customers as do some of the other resources in the

[8] *See* Detsky Testimony, page 28, lines 11-14.

portfolio, such as the Hog Bayou PPA that would provide capacity value to customers beginning in 2020. In short, Mr. Detsky is wrong in his assertion that this value represents a resource efficiency measure or an indication of the facility's ability to provide reliable capacity.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING CERTAIN INVERVENOR TESTIMONY INVOLVING THE USE OF LCOE FOR EVALUATION PURPOSES?

A. Yes. I strongly disagree with the apparent belief of these witnesses that LCOE is an appropriate metric upon which to predicate a resource decision. LCOE is a useful metric for generically comparing different resource types, and is often used for screening purposes. It is not, however, an appropriate basis for final resource decisions. LCOE does not address resource adequacy and thus does not evaluate the impacts on reliability of different resources. LCOE also generally presumes that all energy has the same value and that time of delivery is not important. Such an assumption is particularly problematic when comparing dispatchable resources with non-dispatchable or energy limited resources. A simple example in this regard is a comparison of a solar generator with a combustion turbine ("CT"). The solar generator could very well have a lower LCOE than the CT; however, it cannot deliver energy absent sunlight, regardless of cost. Our evaluation is intended to capture for each resource the specific costs, the total production cost impact, and the reliability contribution, such that a comparative ranking is established that reflects the complete value of each resource. Mr. Bush also discusses the limitations of the LCOE approach in his Rebuttal Testimony.

Q. DID THE COMPANY CONSIDER CO_2 EMISSIONS AS PART OF ITS EVALUATION OF THE PROPOSED RESOURCE PORTFOLIO?

A. Yes. Each resource option was evaluated under four scenarios, two of which included a \$20 carbon price. The \$20 carbon price scenarios reflect an assumed price for CO_2 emissions that begins in 2026 at \$20 per metric ton, and then escalates annually at a rate above inflation. This price does not represent any one specific approach to regulating CO_2 emissions, but instead serves as a proxy for potential carbon legislation or regulation. I would also note that Ms. Wilson's employer, Synapse Energy Economics, Inc., developed several CO_2 Price Trajectories in a 2016 publication, and our \$20 scenario falls within the range between its Low and Mid price trajectories.[9] Additionally, Synapse conducted analysis in 2018 considering six carbon price scenarios, ranging from \$0 to \$100 per short ton by 2050.[10] With escalation, our \$20 price reaches a level slightly above the middle of this range.

Q. MS. WILSON ASSERTS THAT THE PROPOSED GAS UNITS WOULD CAUSE DAMAGE BASED ON A SOCIAL COST OF CARBON, AS DETERMINED BY THE FEDERAL INTERAGENCY WORKING GROUP ON THE SOCIAL COST OF GREENHOUSE GASES ("IWG"). ARE YOU FAMILIAR WITH THE IWG?

A. Yes, somewhat. The IWG was convened in 2009 under the Obama Administration in order to determine how to monetize the net effects of CO_2 emissions for use in regulatory

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[9] Synapse Energy Economics, *Spring 2016 National Carbon Dioxide Price Forecast, available at* https://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf (attached as Reb. Ex. MBL-1).

[10] Synapse Energy Economics, Synapse Energy Economics, *The Price of Emissions Reduction: Carbon Price Pathways Through 2050*, https://www.synapse-energy.com/about-us/blog/price-emissions-reduction-carbon-price-pathways-through-2050 (attached as Reb. Ex. MBL-2).

analyses. In 2017, President Trump issued Executive Order 13783, which among other things disbanded the IWG and withdrew the Social Cost of Carbon documentation as no longer representative of government policy.

Q. IN YOUR OPINION, SHOULD THE COMPANY HAVE REFLECTED A "SOCIAL COST" OF CARBON IN ITS ANALYSIS, AS MS. WILSON SUGGESTS?

A. No. Our evaluation accounts for known and quantifiable costs and benefits that directly impact the Company's cost to serve its customers. As mentioned above, we considered the impact of potential greenhouse gas regulation or policy that would create a direct cost on emissions. By including these scenarios, the Company validated the robustness of the proposed portfolio in the event laws and regulations impacting the cost of carbon emissions were to change.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF M. BRANDON LOONEY
ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA)

COUNTY OF SHELBY)

M. Brandon Looney, being first duly sworn, deposes and says that he has read the foregoing prepared testimony and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Brandon Looney

Subscribed and sworn to before me
this 27th day of January, 2020.

Esther Howard Brandenburg
Notary Public

ESTHER T. HOWARD
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 05-12-2020

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Rebuttal Testimony for M. Brandon Looney

Reb. Ex. MBL-1

Spring 2016 National Carbon Dioxide Price Forecast

Updated March 16, 2016

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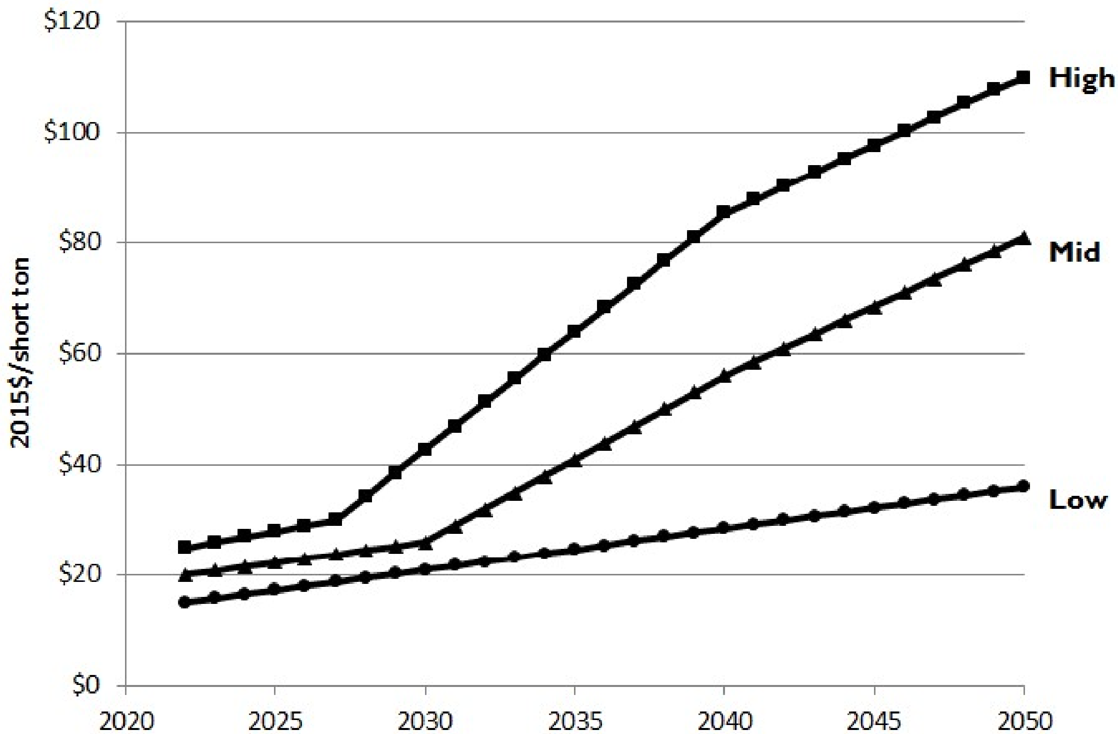
cooperation. As a result, we provide a single national-level CO_2 price and do not attempt to provide state-level forecasts. Figure 1 and Table 1 present Synapse's forecasts over the 2022-2050 period.[3]

Figure 1: Synapse 2016 CO_2 national price forecasts



Source: Synapse Energy Economics, Inc. 2016.

[3] Figure 12 compares Synapse's 2016 and 2015 CO_2 price forecasts. These forecasts do not differ substantially. Two key differences are a tighter range of prices in 2020 resulting from greater policy certainty, and higher 2015 forecasts for the Mid and High cases, resulting from the indicated stringency of the Clean Power Plan. The 2015 forecast was the first Synapse forecast to extend to 2050.

Table 1: Synapse 2016 CO_2 price forecasts (2015 dollars per short ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$0.00	$0.00	$0.00
2021	$0.00	$0.00	$0.00
2022	$15.00	$20.00	$25.00
2023	$15.75	$20.75	$26.00
2024	$16.50	$21.50	$27.00
2025	$17.25	$22.25	$28.00
2026	$18.00	$23.00	$29.00
2027	$18.75	$23.75	$30.00
2028	$19.50	$24.50	$34.25
2029	$20.25	$25.25	$38.50
2030	$21.00	$26.00	$42.75
2031	$21.75	$29.00	$47.00
2032	$22.50	$32.00	$51.25
2033	$23.25	$35.00	$55.50
2034	$24.00	$38.00	$59.75
2035	$24.75	$41.00	$64.00
2036	$25.50	$44.00	$68.25
2037	$26.25	$47.00	$72.50
2038	$27.00	$50.00	$76.75
2039	$27.75	$53.00	$81.00
2040	$28.50	$56.00	$85.25
2041	$29.25	$58.50	$87.75
2042	$30.00	$61.00	$90.25
2043	$30.75	$63.50	$92.75
2044	$31.50	$66.00	$95.25
2045	$32.25	$68.50	$97.75
2046	$33.00	$71.00	$100.25
2047	$33.75	$73.50	$102.75
2048	$34.50	$76.00	$105.25
2049	$35.25	$78.50	$107.75
2050	$36.00	$81.00	$110.00
Levelized 2022-2050	$23.02	$38.13	$55.27

Note: Levelized price based on a discount rate of 5 percent.

Based on analyses of the sources described in this report, and relying on our own judgment and experience, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2022 to 2050. In these forecasts, the Clean Power Plan together with other existing and proposed federal regulatory measures place economic pressure on CO_2-emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. In any state other than the

RGGI region and California, we assume a zero carbon price through 2019. Beginning in 2022, we expect Clean Power Plan compliance will put economic pressure on carbon-emitting power plants throughout the United States. We assume smooth allowance trading among large groups of states. The Clean Power Plan is followed later by a more stringent federal policy in the Mid and High cases. The CO_2 prices presented here are forecasts of "effective" prices of CO_2 which may or may not take the form of market-based allowances (see Section 3 for a discussion of different types of CO_2 prices).

- The **Low case** forecasts a CO_2 price that begins in 2022 at $15 per ton.[4] It increases to $21 in 2030 and $36 in 2050, representing a $23 per ton levelized price over the period 2022-2050. This forecast represents a scenario in which Clean Power Plan compliance is relatively easy, and a similar level of stringency is assumed after 2030. Low case prices are also representative of the incremental cost to produce electricity with natural gas as compared to coal, as indicated in the Energy Information Administration's 2015 Annual Energy Outlook.

- The **Mid case** forecasts a CO_2 price that begins in 2020 at $20 per ton. It increases to $26 in 2030 and $81 in 2050, representing a $38 per ton levelized price over the period 2022-2050. This forecast represents a scenario in which federal policies are implemented with challenging but reasonably achievable goals. Clean Power Plan compliance is achieved and science-based climate targets mandate at least an 80 percent reduction in electric section emissions from 2005 levels by 2050.

- The **High case** forecasts a CO_2 price that begins in 2022 at $25 per ton. It increases to approximately $43 in 2030 and $110 in 2050, representing a $55 per ton levelized price over the period 2022-2050. This forecast is consistent with a stringent level of Clean Power Plan targets that recognizes that achieving science-based emissions goals by 2050 will be difficult. In recognition of this difficulty, implementation of standards more aggressive than the Clean Power Plan may begin as early as 2027. New regulations may mandate that electric-sector emissions are reduced to 90 percent or more below 2005 levels by 2050, in recognition of lower-cost emission reduction measures expected to be available in this sector. Other factors that may increase the cost of achieving emissions goals include: greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass, and carbon capture and sequestration; and more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters).

Synapse' price forecasts are presented for planning purposes, so that a reasonable range of emissions costs can be used to investigate the likely costs of alternative resource plans. We expect an actual CO_2 price incurred by utilities in all states to fall somewhere between the low and high estimates throughout the forecast period.

In Figure 2, the Synapse forecasts are compared to a summary of the other evidence presented in this report, including the federal CO_2 price for rulemakings; existing Clean Power Plan studies; and utility reference, low , and high scenarios (see Section 4 through 6 for a discussion of these studies). In

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[4] "Tons" refer to short tons throughout this report.

Rebuttal Testimony for M. Brandon Looney

Reb. Ex. MBL-2

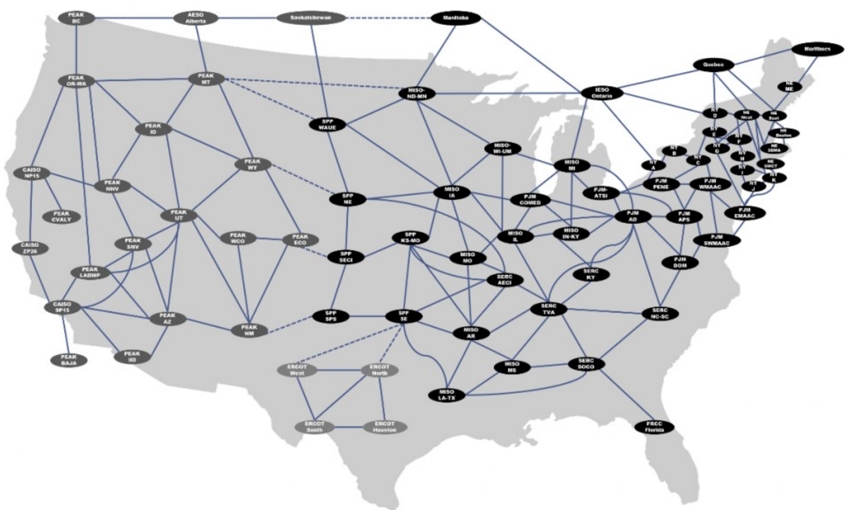
The Price of Emissions Reduction: Carbon Price Pathways through 2050

The October 2018 Intergovernmental Panel on Climate Change (IPCC) special report on climate change highlights the importance of averting catastrophic climate change. Centrally, it finds that global carbon dioxide (CO_2) emissions must reach net zero by 2050 in order to limit global warming to 1.5°C. With the United States' announced withdrawal from the 2015 Paris Climate Accord, the future of its commitment to reduce emissions 80 percent from 1990 levels is in peril. The United States continues to release approximately 20 percent of the world's carbon emissions. Accordingly, CO_2 prices are back in the news, as they represent one way to curb CO_2 emissions and put the United States back on a track to mitigating climate change.

The electric sector is the second-largest source of U.S. CO_2 emissions. There have been many proposals to price CO_2 emissions in the electric sector, most recently the Americans for Carbon Dividends campaign. In light of this, Synapse used the EnCompass model to explore how potential nationwide CO_2 prices would affect generation resource mix and CO_2 emissions in the electric sector.

Within the EnCompass model, we use a detailed, nationwide database to find least-cost optimal solutions to questions of system build-out and dispatch. The EnCompass model considers individual power plant cost and operational parameters, regional electricity sales, and environmental programs. EnCompass can solve both long-term capacity expansion problems and short-term system dispatch problems. For example, we can use EnCompass to analyze long-term national scenarios through 2050 or to investigate hourly generation patterns in a high-renewable system. In this analysis, we used the Horizons Energy National Database, which includes unit-level data across the 76 North American areas shown below.

Figure 1. Modeled areas and links in the EnCompass National Database

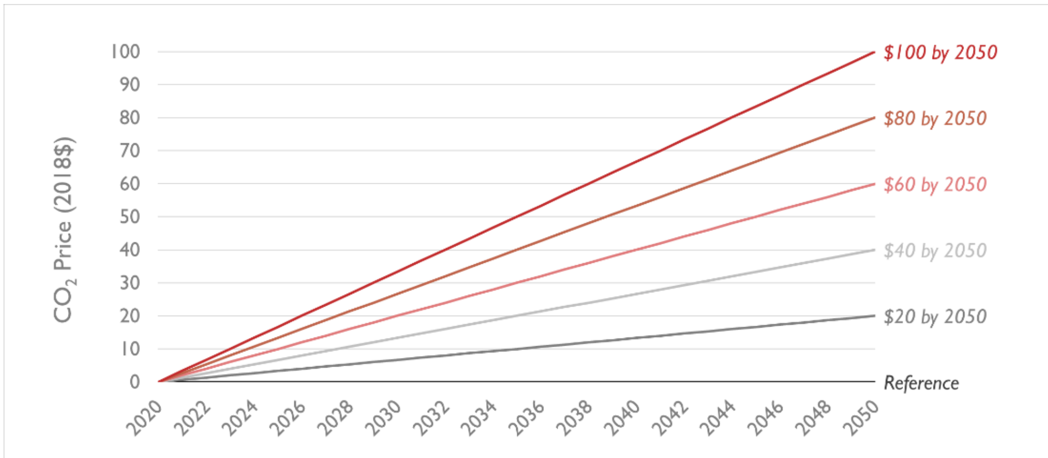


For this exploratory analysis, we used the following parameters:

- **Analysis Period:** 2020-2050, 24 hours a day, one on- and off-peak day per month
- **Performance:** Detailed capacity expansion, basic hourly dispatch simulation
- **Load:** NERC Long-Term Reliability Assessment forecasts and steady state-level energy efficiency implementation
- **Generic Power Plant Options:** State-level prices for new solar, wind, battery, combined cycle, gas turbine, and internal combustion units
- **CO_2 Revenues:** No revenue recycling

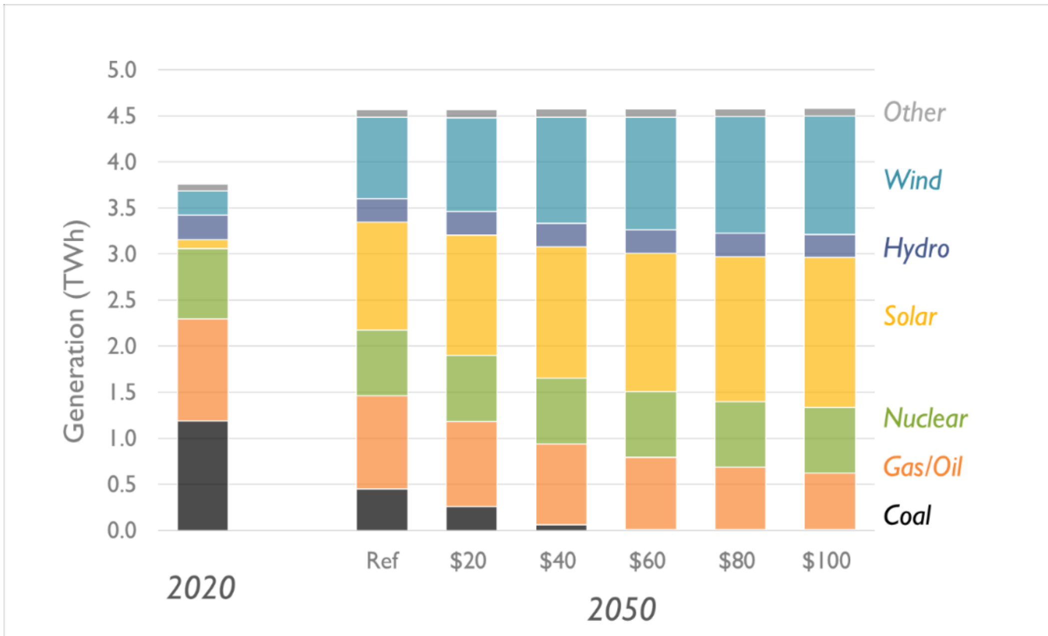
We modeled six scenarios with different linear CO_2 price projections through 2050, shown in Figure 2.

Figure 2. Modeled CO_2 price trajectories



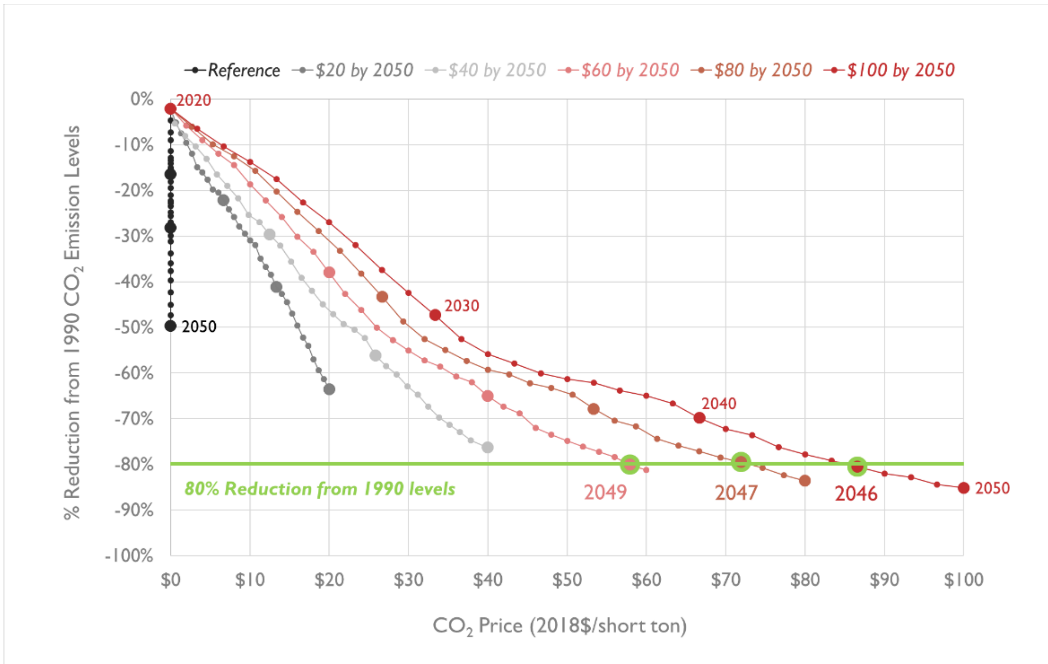
By 2050, our Reference case (featuring no carbon price) sees 36 percent less fossil generation and 278 percent more renewable generation (2 TWh) compared to estimated 2020 levels. This represents a 331 percent increase in U.S. renewable capacity, driven purely by reasonable renewable cost assumptions, even without a CO_2 price. In our highest-price case, at $100 per short ton, renewable generation is 423 percent higher (3 TWh) than 2020 levels, requiring a 511 percent renewable capacity increase. Coal generation drops steadily across our scenarios—in line with higher and higher CO_2 prices—and is completely phased out by 2050 in every scenario featuring a CO_2 price above $60 per short ton. In our $100 by 2050 scenario, fossil generation in 2050 is 73 percent lower than 2020 levels.

Figure 3. Annual U.S. electricity generation by fuel type and scenario



As demonstrated in Figure 4, depending on the year modeled, the same CO_2 price can result in a different amount of CO_2 reductions. The Reference case reduces CO_2 emissions 50 percent by 2050 (relative to 1990 levels) even with no CO_2 price—considerable progress but not enough to meet the United States' Paris Accord goal. In our three highest-priced scenarios, emissions are reduced by 80 percent (relative to 1990 levels) before 2050, meeting the Paris Accord goal. In many scenarios, we observe a "flattening" in CO_2 emissions reductions from 2032 to 2039. This could indicate a point at which zero-emitting resources achieve parity and begin to be rapidly deployed even without CO_2 pricing.

Figure 4. CO_2 emissions reductions by CO_2 price, relative to 1990 levels



Topics for further exploration

- How would increased energy efficiency deployment or other demand-side reductions impact electricity generation and emissions?
- How sensitive is the model to renewable costs?
- How do changing renewable portfolio standard policies, which require utilities to procure an increasing amount of electricity from renewables over time, impact these results?
- Do regional CO_2 prices produce different results than a national price?
- Do lower-range carbon prices (from $0 to $20 per short ton) result in different trends versus these scenarios?
- Do other implementation strategies (e.g., constant carbon price, carbon price expiration) result in different capacity, generation, and emissions?
- How do CO_2 prices impact energy market prices?
- What is the impact of increasing electricity demand from electric vehicles or heat pumps alongside CO_2 prices?
- What would happen if collected revenues from CO_2 prices were recycled? Or distributed to consumers?

Got modeling questions? Let us know! Contact us at npeluso@synapse-energy.com and pknight@synapse-energy.com.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF CHRISTINE M. BAKER
ON BEHALF OF ALABAMA POWER COMPANY

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

A. My name is Christine Baker. I currently serve as the Director of Regulatory Pricing & Costing Services for Alabama Power Company ("Alabama Power" or "Company"). My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q. HAVE YOU PREVIOUSLY PRESENTED DIRECT TESTIMONY ON BEHALF OF ALABAMA POWER IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this Rebuttal Testimony is to respond to certain claims and arguments set forth in the testimony of Alabama Industrial Energy Consumers' witness Mr. Pollock. I do not attempt to address every issue raised in his testimony (or in the testimony of other intervenors' witnesses) that might possibly bear on my Direct Testimony, so the absence of any specific rebuttal should not be construed as acceptance of such position.

Q. IN YOUR DIRECT TESTIMONY, YOU STATED THAT THE EXPECTED NET PRESSURE ON RATES, ONCE ALL SUPPLY-SIDE RESOURCES ARE IN

SERVICE, IS APPROXIMATELY $4 PER MONTH FOR A TYPICAL RESIDENTIAL CUSTOMER.

A. That is correct.

Q. DID ANY OF THE INTERVENORS DISPUTE THIS ESTIMATE?

A. Yes. Mr. Pollock challenged the Company's projected rate pressures associated with cost recovery for the proposed portfolio of resources. I find his conclusions, however, to reflect a misunderstanding of the applicable rate mechanisms. Moreover, his testimony provides no meaningful basis to reject the Company's proposal or otherwise conclude that the Company's estimates are incorrect or unreasonable.

Q. WHAT CAUSES YOU TO CONCLUDE THIS?

A. First, Mr. Pollock builds his argument based on the assumption that any costs recovered through Rate CNP Parts A and B would be allocated to individual rates on an energy basis (i.e., kWh), rather than on a revenue basis as modeled by Alabama Power.[1] A cursory review of the Rate CNP tariff, which I included with my Direct Testimony, would have revealed that costs directed for recovery through the CNP Purchase Factor (i.e., Rate CNP Part B) are allocated to the respective rates according to the revenue allocation formula set forth in the tariff (as stated in my testimony).[2] Similarly, had Mr. Pollock reviewed Part A of the tariff (the CNP Plant Factor), he would have seen that cost recovery does not default to an energy allocation formula as he presumed, but rather requires the Commission to specify the applicable allocation formula in its order on certification. This point too was

[1] *See* Pollock Testimony, page 26, lines 6-14 & page 32, lines 7-8.

[2] *See* Direct Testimony of Christine Baker ("Baker Direct"), page 8, lines 10-12 & page 9, lines 10-14; *see also* Ex. CMB-1, page 5 (Rate CNP, Part B).

discussed in my Direct Testimony, with reference to the specific paragraph in Rate CNP regarding allocations.[3]

Q. IS IT REASONABLE TO BELIEVE THAT THE COMMISSION WOULD REJECT THE COMPANY'S REQUEST TO SPECIFY THE REVENUE ALLOCATION FORMULA FOR THE RATE CNP PART A PLANT FACTOR?

A. No. The Company's petition for certification is clearly based on a reliability need for capacity, and the associated costs to be recovered under Rate CNP Part A are capacity related. Hence it is appropriate to use the revenue allocation formula. In contrast, the energy allocation formula is generally considered more appropriate for costs incurred due primarily to energy benefits rather than capacity needs.

Q. DOES MR. POLLOCK MAKE OTHER CLAIMS THAT YOU FOUND TO BE INACCURATE OR MISLEADING?

A. Yes. Mr. Pollock claims that the Company's rate pressure calculations are entirely unsupported.[4] Mr. Pollock was provided with workpapers, however, that reflected the Company's calculation of the estimated retail rate impact of approximately 2 percent and the corresponding typical residential monthly bill impact of approximately $4.[5] Moreover, Mr. Pollock clearly reviewed these workpapers, as he references them as a source in Table 1 of his testimony.[6]

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[3] *See id.*, page 4, lines 6-11; *see also* Ex. CMB-1, pages 3-4 (Rate CNP, Part A).

[4] *See* Pollock Testimony, page 25, line 7.

[5] These workpapers have since been updated to reflect refinements to certain cost assumptions. These changes did not, however, materially impact my original estimates, as stated above. *See* Reb. Ex. CMB-1. *See also* Baker Direct, page 10, line 11.

[6] *See* Pollock Testimony, page 6.

In any case, Mr. Pollock states that retail base rates will increase by 5 percent.[7] In offering this inflated number, as compared to the approximately 2 percent rate impact presented by the Company, Mr. Pollock wholly ignores the substantial energy savings associated with the projects, as referenced in my Direct Testimony[8] and reflected in my workpapers. Further, in performing his calculation, Mr. Pollock chose to use base rate revenues as his denominator rather than total retail revenues, even though the latter is the customary metric employed by the Company when performing impact evaluations. As a reference, Rate RSE relies on total retail revenues (in the denominator) for purposes of determining the adjustment limitation prescribed by the tariff.[9]

Q. DO YOU AGREE WITH MR. POLLOCK'S OPINION THAT THE USE OF RATE CNP PARTS A AND B FOR COST RECOVERY OF CERTAIN ASPECTS OF THE PORTFOLIO IS UNNECESSARY GIVEN THE FORWARD-LOOKING DESIGN OF RATE RSE?[10]

A. No. The forward-looking design of Rate RSE has been in place for over a decade. During that time, Parts A and B of Rate CNP have continued to serve as viable tariff options, with modifications implemented (most recently in 2017) that reaffirmed them as appropriate mechanisms for the recovery of costs associated with resource additions to the Alabama Power electric system. Moreover, Rate CNP Parts A and B direct the recovery of specified costs associated with certificated resources <u>only after</u> the actual closing of an acquisition,

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[7] *See id.*, page 7, lines 1-2.

[8] *See* Baker Direct, page 10, lines 12-14.

[9] *See id.*, Ex. CMB-1, page 19 (Rate RSE, Adjustment Limitations).

[10] *See* Pollock Testimony, page 4, line 28 through page 5, line 1.

the commercial operation of a plant or the beginning of a power purchase agreement. The alternative, which Mr. Pollock appears to espouse,[11] could lead in certain cases to the recovery of new resource costs through Rate RSE in advance of a Commission decision regarding the issuance of a certificate. For example, the Hog Bayou PPA is scheduled to begin service to Alabama Power customers in 2020 if it is certificated.[12] Recovery of the associated non-fuel costs through Rate RSE, rather than Rate CNP Part B, would have required the inclusion of those costs in the annual Rate RSE filing submitted for rates effective January 1, 2020, and prior to a final decision regarding certification of the Hog Bayou PPA. As described in my testimony, the Rate CNP Part B Purchase Factor contemplates the timing of the issuance of a certificate and thus commencement of the agreement prior to initiating recovery of these costs.[13]

Q. WITH RATE CNP PART A BEING THE APPROVED MECHANISM TO INITIATE RECOVERY OF COSTS ASSOCIATED WITH AN ACQUISITION, WHY DOES ALABAMA POWER PROPOSE TO POSTPONE THE OPERATION OF THE CNP PLANT FACTOR?

A. As reflected in my Direct Testimony[14] and in the Company's petition, the entirety of the output of the Central Alabama plant is committed under a power sales agreement through mid-2023. The revenues from this agreement are expected to more than offset the acquisition costs during this time. Thus, postponing the operation of the Rate CNP Plant

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[11] *See* Pollock Testimony, page 29, lines 8-9 & page 31, lines 10-11.

[12] *See* Baker Direct, page 8, line 13.

[13] *See id.*, page 8, lines 13-18.

[14] *See id.*, page 5, lines 11-13.

Factor and flowing both the costs of the acquisition as well as revenues from the power sales agreement through the same mechanism, Rate RSE, will avoid an associated rate increase during this interim period. Instead, the offsetting revenues from the power sales agreement will place downward pressure on the rates of customers until the operation of the CNP Plant Factor.[15]

Q. MR. POLLOCK APPEARS CRITICAL OF THE PURCHASE PRICE AND THE RESULTING ACQUISITION ADJUSTMENT ASSOCIATED WITH CENTRAL ALABAMA. WHAT IS YOUR RESPONSE TO HIS CLAIMS?

A. Mr. Pollock's criticisms appear focused on the absence of "evidence" that the purchase price is reasonable and appropriate.[16] The Direct Testimony of Messrs. Kelley and Looney explain how the Company solicited proposals from the market and arrived at the decision to acquire Central Alabama as part of the cost-effective resources proposed for certification.

Q. DOES MR. POLLOCK OFFER ANY COMMENTS REGARDING THE RECOVERY OF CAPACITY RELATED COSTS ASSOCIATED WITH THE SOLAR BESS PAYMENTS?

A. Yes. Notwithstanding his view that these costs should be recovered through Rate RSE rather than Rate CNP Part B,[17] Mr. Pollock indicates that a separate mechanism could have merit, provided the costs are spread to all customers based on demand rather than energy.[18]

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[15] *See id.*, page 6, lines 1-8.

[16] *See* Pollock Testimony, page 28, lines 1-4.

[17] *See id.*, page 32, lines 20-22.

[18] *See id.*, page 32, lines 5-7.

Rate CNP Part B allocates costs using base rate revenues, which serves as a proxy for costs driven primarily by demand. Thus, by Mr. Pollock's own reasoning, Rate CNP Part B is an appropriate mechanism for cost recovery of the demand component of the Solar BESS projects.[19] Mr. Pollock alternatively suggests the potential recovery of the BESS costs through Rate ECR, but this is at odds with other parts of his testimony, as Rate ECR is allocated on an energy basis.[20]

Q. DID YOU FIND MR. POLLOCK'S DISCUSSION OF THE EQUITY COSTS ASSOCIATED WITH OPERATING LEASES TO BE CORRECT?

A. No. By way of background, beginning in 2019, the Financial Accounting Standards Board required companies to adopt new accounting standards for leases. Under these new accounting standards, operating leases (which encompass certain PPAs) are now recognized on the balance sheet as a liability along with a corresponding asset. The credit rating agencies consider this liability as debt in the capital structure of a company, thus impacting the ratios of debt to equity. As the credit rating agencies adjust the debt component of the Company's capital structure, it will become necessary for the Company to add equity to maintain its capital structure ratios sufficient to preserve its credit quality.[21]

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[19] As a point of clarification, Mr. Pollock's Table 4, at page 27, includes what appears to be a typographical error, as the energy component associated with the Solar BESS projects is 62 percent—not 72 percent as stated.

[20] *See* Pollock Testimony, page 5, lines 21-23 & page 32, line 22 through page 33, line 2. Mr. Pollock also points to the authorized recovery through Rate ECR of costs associated with the wind PPAs (Chisholm View and Buffalo Dunes) as being a basis for recovery of the BESS demand-related costs in Rate ECR. This statement neglects to observe that the Commission, by order dated February 14, 2017 in Docket Nos. 31653 and 31859, approved the recovery of all costs associated with the wind projects through Rate ECR because those PPAs were certificated on the basis of expected energy savings, and not for reliability reasons related to a need for additional capacity. In contrast, the Solar BESS projects—and particularly the capacity feature of the BESS component—are being pursued for certification based on a reliability need for additional capacity.

[21] The credit rating agencies could adjust the amount of this liability that impacts the capital structure downward (or to less than the full liability) based on qualitative considerations.

Equity added for this purpose will not be "imputed", as Mr. Pollock testifies,[22] but will be real and will have an actual cost. Consistent with this reality, Alabama Power included this equity cost in its economic evaluation of impacted PPAs, such as the Hog Bayou PPA.[23] As that cost arises from the obligations incurred under that agreement, the cost is properly recoverable. Given the nature of the cost and its relationship to the Company's capital structure, Alabama Power has requested the Commission confirm its recovery through Rate RSE.[24]

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[22] *See* Pollock Testimony, page 28, line 8.

[23] To be clear, evaluation of proposals involving Solar BESS or solar projects did not include an equity cost, as the costs of these proposals would not be reflected on the balance sheet as liabilities.

[24] *See* Baker Direct, page 8, lines 2-4.

PUBLIC VERSION

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF CHRISTINE M. BAKER ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA)

COUNTY OF SHELBY)

Christine M. Baker, being first duly sworn, deposes and says that she has read the foregoing prepared testimony and that the matters and things set forth therein are true and correct to the best of her knowledge, information and belief.

Christine Baker

Christine Baker

Subscribed and sworn to before me
this 27th day of January, 2020.

Esther Howard Brandenburg

Notary Public

ESTHER T. HOWARD
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 05-12-2020

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Rebuttal Testimony for Christine M. Baker

Reb. Ex. CMB-1

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