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January 27, 2020

Alabama Public Service Commission
RSA Union Building
100 North Union Street, Suite 950
Montgomery, Alabama 36104

Attention: Mr. Walter L. Thomas, Jr.
Secretary

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

Dear Secretary Thomas,

On behalf of Alabama Power Company, we are submitting for filing rebuttal testimony and exhibits in the above-captioned proceeding. As these materials include confidential and proprietary information, we are providing a version for public posting along with a non-public confidential version to be retained under seal. The filing has been served on intervenors in accordance with governing procedures.

If you have questions concerning any aspect of this filing, please contact the undersigned.

Very truly yours,

Dan H. McCrary

Dan H. McCrary

cc: Service list

January 27, 2020

Rebuttal Testimony of Alabama Power Company

Docket No. 32953

Volume 1

1. John B. Kelley (and rebuttal exhibit JBK-1)

2. Kevin D. Carden (and rebuttal exhibits KDC-1 – KDC-12)

Volume 2

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

2. Maria J. Burke (and rebuttal exhibits MJB -1 – MJB-5)

3. Michael A. Bush (and rebuttal exhibits MAB-1 – MAB-4)

4. M. Brandon Looney (and rebuttal exhibits MBL-1 – MBL-2)

5. Christine M. Baker (and rebuttal exhibit CMB-1)

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

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

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

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

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

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

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

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

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

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

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

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

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

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

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

Q. PLEASE SUMMARIZE THESE AREAS.

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

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

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

ALABAMA POWER'S CAPACITY NEED

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. WHAT IS THE IIC?

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

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

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

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

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

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

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

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

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

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

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

[9] *See* IIC Section 7.1.

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

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

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

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

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

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

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

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

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

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

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

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

[14] *See* Ala. Code § 37-1-49.

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

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

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

Q. PLEASE EXPLAIN.

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

Q. DOES THIS MEAN THAT GREENE COUNTY UNITS 1 AND 2 WOULD BE DERATED?

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

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

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

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

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

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

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

Q. IS THIS WHAT ALABAMA POWER EXPECTS TO HAPPEN?

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

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

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

RESOURCE IDENTIFICATION AND THE RFP PROCESS

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

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

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

A. The process the Company used to arrive at its proposed resource portfolio was fair and comprehensive. The Capacity RFP solicited capacity from wholesale market participants on a broad basis, with the key requirements being that the proposals encompassed dispatchable capacity that was connected to or deliverable at the border of the Southern electric system.[15] The Company also worked with original equipment manufacturers to explore the feasibility and cost-effectiveness of potential turnkey combined cycle power plants, as discussed by Mr. Bush. The Company also relied on its biennial Renewable RFP process.[16] In addition, Alabama Power explored potential DSOs and DER projects that might prove cost effective. The combined results of these initiatives were evaluated against the Benchmark Plan and across a wide range of scenarios covering varying price paths for natural gas and carbon dioxide. As a result of this evaluation, Alabama Power selected the resource portfolio proposed in this certification filing, which provides the lowest cost mix of resources to meet Alabama Power's stated reliability needs.

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

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

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

A. No. The Capacity RFP specifically solicited renewable projects, subject to dispatchability requirements. The Capacity RFP also allowed the market to submit solar proposals when

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

[16] Order Granting Approval of Petition of Alabama Power Company, APSC Docket No. 32382 (Sept. 16, 2015).

paired with energy storage or another type of generator providing capacity value. Thus, the market had multiple opportunities to propose renewable offerings for the Company to evaluate.

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

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

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

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

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

A. The Company is pursuing all of the Solar BESS projects that proved to be economically viable. The Company evaluated approximately 1,000 MW of Solar BESS projects; however, only 400 MW exhibited better economics than the other projects in the proposed portfolio. That said, these combined projects represent one of the largest announced Solar BESS deployments in the United States to date.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEMAND SIDE OPTIONS AND DISTRIBUTED ENERGY RESOURCES

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

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

Q. ARE THEIR CRITICISMS VALID?

A. No.

Q. PLEASE EXPLAIN.

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

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

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

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

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

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

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

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

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

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

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

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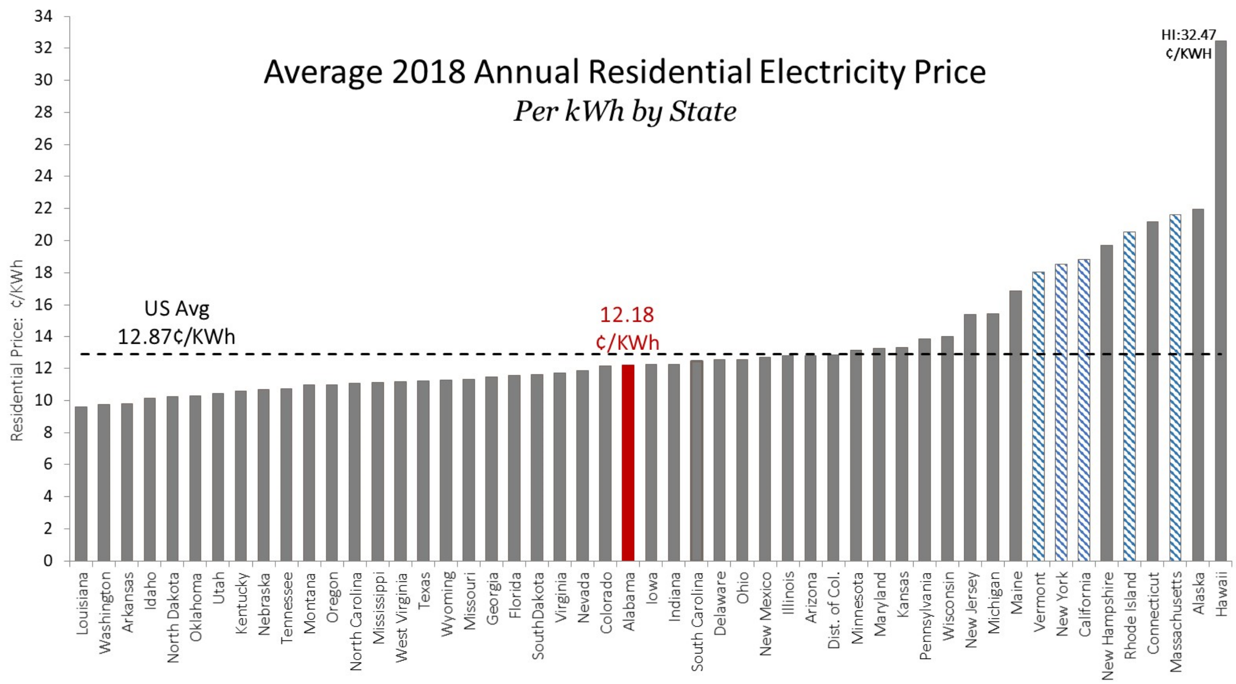
[23] ACEEE, *2017 Utility Energy Efficiency Scorecard*, page 18, *available at* https://aceee.org/research-report/u1707 ("*Utility Scorecard*").

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

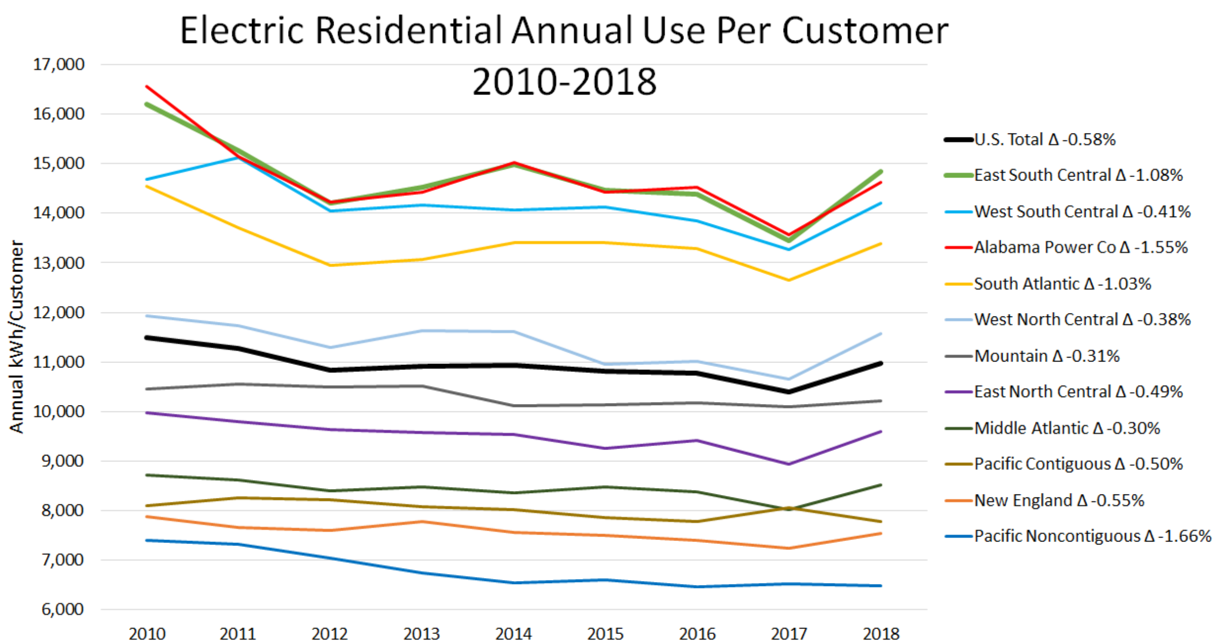


Q. IS AN INCREASED INVESTMENT OF CUSTOMER DOLLARS NECESSARY TO REALIZE ENERGY EFFICIENCY IMPROVEMENTS?

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

[24] *See generally* ACEEE, *2019 State Energy Efficiency Scorecard*, *available at* https://aceee.org/research-report/u1908.

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



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

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

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

Q. WHAT DO INTERVENORS ADVOCATE IN THIS AREA?

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

Q. DO YOU HAVE ANY ISSUES WITH THIS APPROACH?

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

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

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

Q. WHY DOES THE COMPANY USE THE RIM TEST?

A. The RIM test is the most appropriate measure for a DSM program because programs that "pass" the RIM test produce net benefits to *all customers* over the useful life of the program.

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

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

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

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[26] *See Utility Scorecard*.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

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

STATE OF ALABAMA)

COUNTY OF SHELBY)

John B. Kelley, 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.

John B. Kelley

John Kelley

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 John B. Kelley

Reb. Ex. JBK-1

Colorado 2017 All-Source Solicitation

To view information regarding the PSCo 2017 All-Source Solicitation and the RFPs comprising it, please ensure that you have Colorado selected within the state selector drop down in the upper left-hand corner of our website.

Have a question? Check out our FAQ

2017 Company Ownership RFP

This RFP seeks proposals which would lead to Company ownership of an existing or proposed/new generating facility, including fully-dispatchable, non-dispatchable and semi-dispatchable technologies.

Go to this RFP

2017 Dispatchable RFP

This RFP seeks proposals for fully-dispatchable generation resources (new or existing) under a power purchase agreement.

Go to this RFP

2017 Renewable Resources RFP

This RFP seeks proposals for non-dispatchable, renewable generation resources (new or existing) under a power purchase agreement.

Go to this RFP

2017 Semi-Dispatchable Renewable Capacity Resources RFP

This RFP seeks proposals for semi-dispatchable, renewable generation resources (new or existing) under a power purchase agreement.

Go to this RFP

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF KEVIN D. CARDEN
ON BEHALF OF ALABAMA POWER COMPANY

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

A. My name is Kevin D. Carden. I am the Director of Astrapé Consulting ("Astrapé"). My business address is 3000 Riverchase Galleria, Suite 575, Hoover, Alabama 35244.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE?

A. I hold a Bachelor of Science Degree in Industrial Engineering from the University of Alabama. Prior to starting Astrapé in 2005, I was employed by Southern Company Services, Inc. ("SCS") as a reliability engineer, where I performed resource adequacy studies for Alabama Power Company ("Alabama Power" or "Company"), Georgia Power Company, Mississippi Power Company, and Gulf Power Company. These companies operate their bulk transmission facilities as a single electric system, and along with Southern Power Company engage in joint commitment and centralized dispatch of their resources under the Southern Company System Intercompany Interchange Contract. I am an active participant in several industry groups concerned with resource adequacy and reliability, including the NERC Probabilistic Assessment Working Group and IEEE Loss of Load Expectation Working Group.

Q. WHAT ARE YOUR JOB DUTIES AND RESPONSIBLITIES AT ASTRAPÉ?

A. As the Director of Astrapé Consulting, I primarily manage the Strategic Energy and Risk Valuation Model ("SERVM") software for Astrapé and perform reliability studies, capacity valuation studies, and renewable integration studies using SERVM for clients across North America and internationally. SERVM was originally developed by SCS in the 1980s to assist with system reliability planning needs. Astrapé took over maintenance of the model in 2005 and began marketing the software to other entities across the country. In addition to providing resource adequacy analysis for many of the largest utilities in the nation, Astrapé has performed resource adequacy analysis for many of the structured markets in North America, including MISO, SPP, ERCOT, PJM, and AESO. Most of these entities rely on SERVM simulations for their resource adequacy assessments. I have also performed studies for FERC and the United States Department of Energy on the implications of market structure on electric system reliability.[1]

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to allegations and opinions of certain intervenor witnesses in this proceeding directed at the 2018 Reserve Margin Study ("RMS"), which serves as the analytical basis for the winter and summer target reserve margins incorporated in the process used by the Company to develop its 2019 Integrated Resource Plan ("IRP"). These allegations and opinions are offered primarily by Mr. Wilson on behalf of Energy Alabama/Gasp, but also in a less specific manner by Mr. Pollock on behalf of Alabama Industrial Energy Consumers.

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[1] My *curriculum vitae* is attached as Reb. Ex. KDC-1.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Mr. Weathers, testifying on behalf of Alabama Power, provided Direct Testimony concerning the Company's RMS and, importantly for this proceeding, the Company's decision to utilize a winter target reserve margin, given that winter reliability has become more constraining than summer reliability.

In this testimony, I will explain how the RMS, as sponsored by Mr. Weathers, was performed in accordance with industry best practices, that assumptions made by SCS were (and remain) appropriate, and that specific criticisms of the intervenors are inaccurate or based on faulty assumptions. I will then summarize why the target reserve margin recommended by the study achieves the desired reliability at a reasonable cost.

ASTRAPÉ INVOLVEMENT AND STUDY OVERVIEW

Q. DID ASTRAPÉ HAVE ANY ROLE IN THE DEVELOPMENT OF THE RMS?

A. Yes. Astrapé is the licensor of the SERVM model used to perform the simulations for the RMS, and in that capacity remains available throughout any study to provide technical modeling guidance. SCS also engaged Astrapé to develop load and generator assumptions for neighboring electric entities, which are inputs for the RMS. After completion of the RMS, Astrapé performed a review of the inputs and methods used in the study to confirm their appropriateness and technical accuracy.

Q. IN YOUR OPINION, WAS THE STUDY PERFORMED ACCORDING TO INDUSTRY BEST PRACTICES?

A. Yes, the RMS was performed in accordance with best practices in the industry. In reserve margin planning studies, two approaches are frequently employed: 1) identify a reserve margin that meets a physical reliability standard such as 0.1 (one event in ten years) Loss of Load Expectation ("LOLE"); and 2) calculate a reserve margin that balances the risk-adjusted costs and benefits of supplying reliability. While the method that assesses the reserve margin satisfying a 0.1 LOLE standard of reliability is the most common industry practice, the economic balancing method is often performed to evaluate risks and costs associated with planning to a specific physical reliability standard. The RMS undertaken by SCS employed both methods.

Q. WHAT ARE THE KEY DRIVERS OF RESERVE MARGIN STUDY RESULTS?

A. The key drivers of modeled system reliability include assumptions around weather-related load uncertainty, economic-related load uncertainty, generator performance uncertainty, and market purchase availability. The estimated Value of Lost Load ("VOLL") influences economic optimum reserve margin analysis. In the following sections of my testimony, I describe the methods employed to develop these inputs and address related concerns raised by intervenors.

WEATHER-RELATED LOAD UNCERTAINTY

Q. RESERVE MARGIN STUDIES MUST CONSIDER A WIDE RANGE OF WEATHER-RELATED LOAD UNCERTAINTY SCENARIOS. PLEASE DESCRIBE HOW THESE SCENARIOS ARE DEVELOPED.

A. In all resource adequacy studies that Astrapé performs, we develop synthetic load profiles for the modeled systems in a similar fashion to that employed by SCS. First, a relationship is developed between weather conditions and load based on current customers. This relationship may be defined by variables such as current temperature, prior temperatures, and time of day. The weights, coefficients, and underlying methods for defining the relationships may be different for various temperature splines and seasons. Ultimately, these relationships are applied to many years of historical weather data to produce a synthetic profile that represents the expected load conditions of the current customer base at the historical temperatures. These synthetic profiles then are scaled so that half of the profiles have seasonal peak demands higher than seasonal peak forecasts, and half have seasonal peak demands lower than seasonal peak forecasts. In this way, the median peak demand, or weather normal peak demand, is synchronized with the forecasted peak demand.

Q. IN THE MOST EXTREME WINTER SYNTHETIC SHAPE, SCS EXPECTS PEAK DEMAND 22 PERCENT ABOVE THE NORMAL WINTER PEAK. IN YOUR OPINION, IS THIS LEVEL OF VARIABILITY IN THE SYNTHETIC SHAPES REPRESENTATIVE OF FUTURE POTENTIAL LOAD VARIABILITY?

A. Yes. Normal peak winter demand[2] on the Southern system occurs on days when the minimum average system temperature is 14.5°F.[3] The minimum temperature experienced since 1962 is -3°F, which is a maximum variation of 17.5°F. Normal peak summer demand

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[2] Normal peak winter demand is defined as the demand level at which half of possible weather scenarios produce lower demand and the other half produce higher demand.

[3] This value is based on Astrapé's independent temperature analysis.

occurs on days when the maximum temperature is 95.9°F. The maximum temperature experienced since 1962 is 103°F, which is a maximum variation of 7.1°F. Coupling the higher winter load variation with the observed load response by temperature yields the relationships demonstrated in the RMS between winter and summer reserve margin requirements. Astrapé independently performed cold weather temperature and load regression analysis, which identified very similar relationships to those identified by SCS.

Q. DO YOU AGREE WITH MR. WILSON'S ASSERTION THAT LOAD UNCERTAINTY IS OVERSTATED IN THE RMS?

A. No. Establishing the relationship between load and weather conditions based on recent history is well supported and the extrapolation of that relationship to lower temperatures in the RMS is consistent with industry best practices.

Q. MR. WILSON MENTIONS THAT IN "THE PJM SYSTEM, REPRESENTING A COLDER CLIMATE, THE CHANCE OF A WINTER PEAK 10% OR MORE OVER THE FORECAST IS CONSIDERED TO BE ABOUT 2.5%." DOES THIS COMPARISON HAVE MERIT?

A. No. Mr. Wilson is comparing the Southern system to a very different region with fundamentally different weather and primary heating methods. Many customers in the Southern system use electric heat pumps for heating. This technology works well for temperatures above 32°F, but below this threshold, it must be supplemented, often with electric resistive heating, as shown in Figure 1.

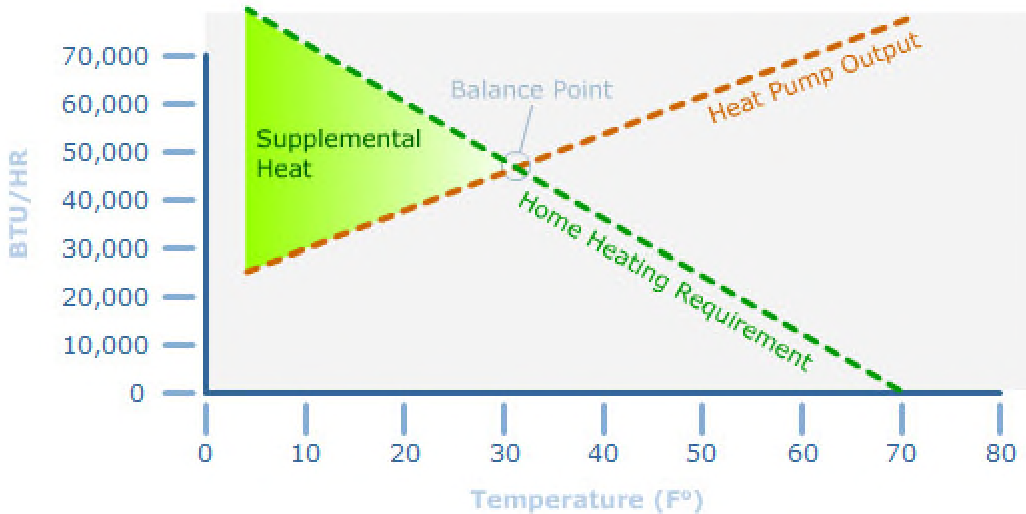

Figure 1. Balance Point for Heat Pumps[4]

Not surprisingly, because PJM encompasses a region with a colder climate, most customers there rely on natural gas and/or fuel oil for heating, and not electric heat pumps like customers do in the Southern system. This means that load response is not as strongly correlated with cold weather in PJM as it is in Southern. Figure 2 illustrates these differences in heating methods by climate.

[4] Source: "Air-Source Heat Pump or Air-to-Air Heat Pump", Penn State College of Earth and Mineral Sciences, https://www.e-education.psu.edu/egee102/node/2090 (attached as Reb. Ex. KDC-2).

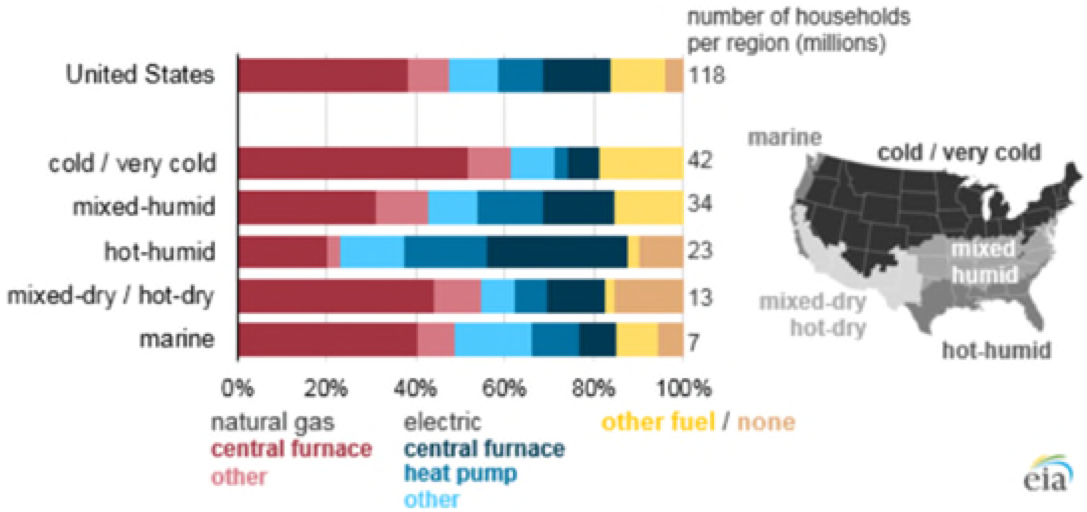

Figure 2. Main Heating Equipment Choice by Climate Region, 2015[5]

Q. ARE THERE ANY OTHER ASPECTS OF WEATHER IN THE SOUTHERN REGION THAT PRESENT UNIQUE CHALLENGES TO GENERATION ADEQUACY PLANNING?

A. Yes. Because summer and winter load peaks are comparable in magnitude on the Southern system, reliability events can occur in either or both seasons. In order to meet the annual 0.1 LOLE reliability standard, reserve margins must be high enough that individual season's LOLE is less than 0.1. In areas that are exclusively summer or winter peaking, reserve margins can be lower since all LOLE is expected in a single season. For reference, some Astrapé clients in developing countries require much higher reserve margins to meet

[5] Source: *An Examination of the US Residential Heating Market – Background, Behavior, Policy, and Prospective Companies*, University of Michigan School for Environment and Sustainability, page 20, https://deepblue.lib.umich.edu/bitstream/handle/2027.42/146738/An%20Examination%20of%20the%20US%20Residential%20Heating%20Market_338.pdf?sequence=1&isAllowed=y (attached as Reb. Ex. KDC-3).

0.1 LOLE because their peak loads can occur in any month. For example, the Economically Optimal Reserve Margin ("EORM") for Tenaga Nasional Berhad in Malaysia is 32 percent,[6] which is not sufficient to meet the 0.1 LOLE reserve margin standard.

Q. MR. WILSON SUGGESTS EXTREME COLD WEATHER EXPERIENCED IN THE COMPANY'S SERVICE AREA IN THE PAST, SUCH AS IN THE 1980S, SHOULD NOT BE CONSIDERED EVEN A LOW PROBABLITY TO HAPPEN AGAIN. DO YOU AGREE?

A. No. Statistical analysis is more robust with a larger sample size giving credence to SCS's practice of including all available weather data back to 1962. In the same way that engineers, actuaries, insurance companies, and farmers have to consider many years of data to understand risks of droughts, floods, hurricanes, and tornadoes, electric system planning requires a large sample size to understand the risk of low probability cold or hot temperature events. In my opinion, the historical record remains a reasonable approximation of future variation, and the very cold temperatures seen in the 1960s and 1980s could be experienced again in the Southeast. In other reserve margin studies that Astrapé performs, we create synthetic weather shapes with data going back to 1980 simply because most regions only have good temperature records back to that date. As SCS has access to earlier data, it is reasonable and appropriate to use it. In any case, Astrapé performed sensitivity analysis with the results of the RMS, excluding data for the years prior to 1980. The result was a higher indicated reserve margin.

[6] *See* https://apps.theedgemarkets.com/article/malakoff-falls-349-putrajaya-cancels-ipp-licence (attached as Reb. Ex. KDC-4).

Q. MR. WILSON STATES: "BASED ON THE ANALYSIS DOCUMENTED IN THIS TESTIMONY, I FIND THAT THE HIGHEST WINTER PEAKS, THAT ARE THE MAIN DRIVERS OF THE WINTER RESERVE MARGIN, ARE OVERSTATED BY AT LEAST FIVE PERCENT, AND THIS WILL DIRECTLY AFFECT THE RESERVE MARGIN". IS MR. WILSON CORRECT IN ASSERTING THAT AN OVERSTATEMENT OF LOAD UNCERTAINTY DIRECTLY AFFECTS THE RESERVE MARGIN?

A. No, Mr. Wilson's assertion is not correct. This is because the determination of a reserve margin that meets a 0.1 LOLE standard is *probabilistic*. Since not all modeled LOLE occurs in the asserted weather years, only the probability weighted contribution would affect the reserve margin. Some LOLE comes from moderately cold temperatures that were seen in recent history. The distribution of LOLE by season also demonstrates that a significant proportion of events occur in the summer. Thus, overstatement of the coldest winter loads, even if true, would not have a one-for-one effect on the reserve margin required to meet 0.1 LOLE.

Q. MR. WILSON CRITICIZES THE COMPANY'S COLD WEATHER LOAD MODELING ON THE BASIS OF ITS LACK OF "GOODNESS OF FIT". IS THERE ANY MERIT TO THESE CLAIMS?

A. I agree with Mr. Wilson that the correlations between various weather variables and loads exhibit low R^2 values. However, this does not demonstrate that the relationship between load and temperature is weak. On the contrary, performing regression on the relationship between load and temperature for the Southern system after averaging loads for discrete temperature levels shows R^2 values above 85 percent. This means while there is significant variability of the load at specific temperatures, load has a very predictable relationship to temperature on average.

Q. WHAT ARE THE IMPLICATIONS OF THE OBSERVED VARIATION IN LOAD RESPONSE?

A. Because load can be much higher or much lower than predicted by regression analysis, robust analysis should reflect these possibilities. To address this issue, Astrapé introduces random modifiers when performing cold weather modeling to capture the potential variation. This means that some days at specific temperatures will experience loads considerably higher than forecast by the load model and other days at the same temperature will have lower loads. Because the effects of extreme loads are asymmetric, the Company's exclusive use of a linear trend (without the addition of random modifiers) will tend to understate reliability risk, as it will not capture the occurrence of loads higher than those predicted by the average trend. Alternate methods that incorporate this effect result in a higher required reserve margin.

<u>ECONOMIC RELATED LOAD UNCERTAINTY</u>

Q. MR. WILSON STATES THAT MODELING FOUR YEARS OF ECONOMIC GROWTH-RELATED LOAD UNCERTAINTY DOES NOT REFLECT THE TEMPORAL RISK OF ELECTRIC SERVICE PROVIDERS TO PROCURE

ADDITIONAL CAPACITY, SUGGESTING THAT ONE YEAR OF UNCERTAINTY IS SUFFICIENT.[7] IS HE CORRECT IN THIS REGARD?

A. No, Mr. Wilson's suggestion is not reasonable. Mr. Wilson contends that one year of load growth uncertainty is adequate because responsive mitigation strategies can be adopted, such as accelerating development and construction of new resources, increasing demand response programs, or increasing short-term power purchases from adjacent power generating organizations—all within a one-year window. However, the modeling approach employed by SCS already includes neighboring utilities' loads and resources. New conventional resources generally cannot be planned, permitted, and constructed in less than 3 to 4 years, and this practical limitation applies in neighboring regions just as it applies to Southern. Thus, purchasing from other generation owners in the event of unexpected load growth would be limited to existing resources—resources that are already reflected in the model for purposes of potential short-term purchase opportunities. Simply put, no new resources will be available inside the development/construction window that the model doesn't already incorporate, so it would be counter-factual and imprudent to claim they represent additional mitigation opportunities.

The other mitigation strategy suggested by Mr. Wilson is to recruit new demand response customers. However, the Company already has a significant penetration of demand response customers and such resources have annual call limits. This means incremental demand response programs are likely to have declining marginal

[7] *See* J. Wilson Testimony, page 43, lines 6-21 & page 46, lines 1-6.

benefits. Incorporating additional demand response customers is something that should be done as a part of resource mix studies rather than reserve margin studies, and to my knowledge is perennially under consideration at the Company.

Q. IS THE FOUR-YEAR LOAD GROWTH UNCERTAINTY DISTRIBUTION USED IN THE RMS A REASONABLE REPRESENTATION OF THIS RISK?

A. Yes. Most forms of economic forecasting are cyclical in nature. Periods of under-forecasting economic growth are followed by periods of over-forecasting growth. While most companies have consistently over-forecast growth in the past decade, the underlying reasons have been addressed in current forecasts. Instead of expecting 2 percent load growth, many utilities now are projecting less than 1 percent, or even negative load growth, in the future. If energy efficiency trends in lighting, climate control, and computing reach physical limits, or if new technologies such as electric vehicles gain in popularity, there is a significant potential to under-forecast load growth in the future.

Q. DESCRIBE THE IMPACT OF ECONOMIC LOAD FORECAST ERROR.

A. Given the low probability of under-forecasting load growth, its impact is modest compared to other assumptions such as weather-related load uncertainty and generator performance risk. In studies for other clients, we have determined that using shorter horizon economic forecast error distributions reduces the target reserve margin by less than 1 percent.[8] Consistent with this finding, SCS's sensitivity in the RMS indicates that moving to a one-year load forecast error distribution would reduce Southern's EORM by only 0.5 percent.

[8] *See* "Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region", The Brattle Group, page 42, http://www.ercot.com/content/wcm/lists/143980/10.12.2018_ERCOT_MERM_Report_Final_Draft.pdf (attached as Reb. Ex. KDC-5).

GENERATOR PERFORMANCE RISK

Q. PLEASE DESCRIBE THE UNIT OUTAGE MODELING IN SERVM.

A. In order to capture generator performance risk, SERVM simulations randomly sample historical unit outage events. The modeled annual forced outage rates match historically observed rates, but random sampling produces individual iterations with differing amounts of available capacity (higher or lower) across the system. This technique is critical for reliability planning because most reliability events occur when a more-than-average amount of generation is offline.

Q. IN YOUR EXPERIENCE, HOW IS GENERATOR PERFORMANCE IMPACTED BY EXTREME WEATHER?

A. In resource adequacy studies that we perform around the world, there is a nearly ubiquitous relationship between increased risk of unforced outage and extreme temperatures. Specifically, cold weather, especially when wind-chill factors are taken into account, has a more marked effect on the likelihood of generator outages than does hot weather. This has been extensively documented in work by Murphy, Sowell, and Apt using historical performance data in PJM.[9]

Q. IS THIS PERFORMANCE IMPACT GENERALLY CAPTURED IN RELIABILITY MODELS?

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[9] *See* Sinnott Murphy, Fallaw Sowell & Jay Apt, *A time-dependent model of generator failures and recoveries captures correlated events and quantifies temperature dependence*, Applied Energy, https://www.sciencedirect.com/science/article/pii/S0306261919311870 ("Murphy, Sowell, and Apt") (attached as Reb. Ex. KDC-6).

A. Astrapé has been modeling higher likelihood of generator outages based on historical patterns in its reliability modeling for years. However, many in the industry continue to use tools that are unable to capture this effect.

Q. IN YOUR OPINION, DOES THE COMPANY'S RMS APPROPRIATELY MODEL THE PERFORMANCE IMPACT OF COLD WEATHER ON GENERATORS?

A. Yes. I believe the RMS appropriately estimates the potential reliability risk impact of increased outages during cold weather. If anything, it may understate this reliability risk, as suggested by anecdotal comparisons of actual and modeled unit performance during the 2014 Polar Vortex. Figure 3 below depicts in red the actual outages from January 7, 2014, along with the various modeled curves showing that during the peak load hours of that day, actual outages were higher than at least 99 percent of all modeled scenarios at those same temperatures.

[redacted]

Southern has implemented and therefore properly assumes cold weather hardening in developing unit outage distributions used in the RMS. I believe, however, that the Company may have overstated the ability of the system to perform during cold weather—which renders its resulting targets lower than they might otherwise be. Further, the data evaluated by Murphy, Sowell, and Apt indicates cold weather impacts of similar magnitude, but at a higher frequency,[10] as shown in Figure 4.

[10] *See* Reb. Ex. KDC-6, page 9.

[redacted]

Q. MR. WILSON ARGUES THAT THE RELATIONSHIP IDENTIFIED BY THE COMPANY WOULD BE MORE APPROPRIATELY MODELED AS LINEAR RATHER THAN AS AN EXPONENTIAL CURVE. DO YOU AGREE WITH HIS ASSESSMENT?

A. No. The curve fit may be better with linear regression when analyzing only temperatures below 16 degrees, but a broader view clearly shows an exponential relationship. Regardless, the projected effects at the coldest temperatures do not influence the 0.1 LOLE reserve margin because load is already high enough in those cases to create LOLE. Therefore, using the linear relationship as suggested by Mr. Wilson actually serves to create a need for a modestly higher reserve margin target—not a 2 percent lower reserve margin target as he claims.[11] Astrapé performed a sensitivity analysis using the RMS dataset in SERVM to analyze Mr. Wilson's proposed linear relationship. The LOLE curve as a function of reserve margin shifted toward worse reliability by up to 0.25 percent. This further confirms my opinion that the Company's RMS reaches a very reasonable target winter reserve margin.

<u>MARKET PURCHASE AVAILABILITY</u>

Q. WHAT IS THE INDUSTRY STANDARD WITH RESPECT TO MODELING NON-FIRM PURCHASE AVAILABILITY IN RESOURCE ADEQUACY STUDIES?

A. There is not a well-defined industry standard in this regard. However, most regions do assume that some non-firm purchases will be available during extreme periods. Non-firm import availability is subject to the load and resource balance of neighboring regions as well as import limitations into the study region. Often, regions impose a separate transmission import limit to reflect cautious assumptions around the availability of non-firm imports, rather than solely relying on the calculated availability of imports. In PJM, non-firm transmission import capacity provides the equivalent of 2,442 MW of installed capacity inside PJM, as compared to a system peak of over 150,000 MW.[12] This represents

[11] *See* J. Wilson Testimony, page 63, lines 12-19.

[12] *See 2019 PJM Reserve Requirement Study*, page 20, https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx (attached as Reb. Ex. KDC-7).

less than 2 percent of system peak. In the NYISO, non-firm imports provide capacity equivalent to 8.2 percent of system peak.[13]

Q. WHAT APPROACH DOES ASTRAPÉ EMPLOY WHEN MODELING NON-FIRM PURCHASES?

A. We believe neighbors have adequate capacity to achieve their stated reliability targets, and reflect this assumption in our model of short-term purchase opportunities. Excess capacity may be available for purchase if the price is sufficient to cover costs and the seller is willing to take the risk of committing its output to export. This means that any reliability support supplied by neighbors will come as a consequence of weather and generator outage diversity, from a willing seller, rather than assuming that a neighbor will carry additional capacity that it does not need to support the study region.

Q. DO YOU BELIEVE THE LEVEL OF NON-FIRM PURCHASES MODELED BY SOUTHERN APPROPRIATELY BALANCES THE SUPPORT IT SHOULD EXPECT TO RECEIVE?

A. Yes. In our review, we noted that Southern calibrated neighbor reliability in a similar fashion to the approach we use in our studies. We also compared the hourly modeled non-firm purchases during extreme weather to the historical purchases during similar events by season. We also noted the modeled purchases were generally equal to or higher than historical levels, even though neighboring reserve margins were in excess of planning targets in the historical period monitored. This suggests that Southern may have modeled

[13] *See Technical Study Report: New York Control Area Installed Capacity Requirement For the Period May 2019 to April 2020*, pages 18-19, http://www.nysrc.org/pdf/Reports/2019%20IRM%20Study%20Body-Final%20Report[6815].pdf (attached as Reb. Ex. KDC-8).

the market support too aggressively, but there is also a possibility that excess reserves may persist in the markets. It is my opinion the Company struck a reasonable balance and, yet again, made a modeling choice that fosters a lower winter season target than other reasonable choices would have produced.

VALUE OF LOST LOAD

Q. ARE THE VOLL FIGURES USED IN THE RMS APPROPRIATE?

A. Yes. The values for VOLL used in the RMS are based on a customer outage cost survey performed by Southern in 2011. That survey was performed by Freeman, Sullivan & Co.,[14] the leading firm at the time for outage cost surveys. The study was performed according to industry best practices and recognized some of the shifts in value placed on electric service reliability and customer usage patterns over prior decades. A similar trend toward higher VOLL has been recognized in numerous outage cost surveys, presumably due to the increasing importance of personal computing and other electronic devices.

Q. MR. WILSON REFERENCES THE ADMINISTRATIVE $9,000/MWH VOLL USED IN ENERGY AND ANCILLARY SERVICE PRICING IN ERCOT. DOES THIS REPRESENT THE LOAD-WEIGHTED VOLL FOR ERCOT CUSTOMERS?

A. No. London Economics, a consulting firm, was commissioned by ERCOT to determine VOLL. However, the firm expressly recognized that a true VOLL for a given load service

[14] *See* J. Wilson Ex. JFW-25.

area should be based on actual customer surveys targeting the area in question. London Economics provided only a literature review and disclaimed that its work product provided a true VOLL for the ERCOT region, stating "[a]rriving at an accurate VOLL estimate for ERCOT will require a comprehensive customer survey process."[15] A comprehensive customer survey is what Southern has used for its RMS. London Economics further stated in its report that "Load-weighted [VOLL] averages are often in the $30,000 - $40,000 per MWh range". The $9,000/MWh price cap used in ERCOT is primarily derived from workpapers commissioned from the Brattle Group by ERCOT in 2012, which note that the cap is not "based on an analysis of customers' VOLL or an analysis of the price cap needed to sustain investments."[16]

CLOSING SUMMARY

Q. GIVEN ALL THE DRIVERS OF RELIABILITY, DOES A COMPARISON OF RESERVE MARGINS ACROSS REGIONS PROVIDE ANY INSIGHT INTO WHETHER A ZONE IS EXPECTED TO BE RELIABLE?

A. No. Peak demand variability differs widely. Import capability and regional diversity vary widely. System mix and forced outage rates vary widely. Customer class breakdown varies widely. Each of these factors dictate that rigorous reliability analysis must be

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[15] *Estimating the Value of Lost Load*, London Economics, page 1, http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf (attached as Reb. Ex. KDC-9).

[16] *ERCOT Investment Incentives and Resource Adequacy*, The Brattle Group, page 77, http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/Brattle_ERCOT_Resource_Adequacy_Review_2012-06-01.pdf (attached as Reb. Ex. KDC-10).

performed to understand system reliability and to plan the system to the industry standard of 0.1 LOLE.

Q. IN YOUR OPINION, DO OTHER REGIONAL RELIABILITY STUDIES, WHICH SUGGEST THE ADEQUACY OF LOWER RESERVE MARGINS TO MEET THEIR STATED RELIABILITY TARGETS, FULLY QUANTIFY THE INHERENT RISKS?

A. No. Reliability studies produced by other entities often ignore critical reliability drivers such as correlations between forced outage rates and temperature. Further, calibration with history suggests that some modeling under-predicts reliability events since emergency conditions in 2014 and 2018 were not forecast given the reserve levels that were in place in those years. The 2016 Probabilistic Assessment required by NERC[17] predicts zero probability of reliability events for SERC-SE and MISO,[18] and yet in January 2018, MISO declared an "Energy Emergency", because the system lacked sufficient reserves to balance generation and load in the MISO South portion of the footprint. In addition, MISO, SERC, SPP, and TVA each experienced constrained bulk electrical systems.[19]

Q. IN YOUR OPINION, DOES THE RMS ADEQUATELY QUANTIFY RELIABILITY RISKS AND PRODUCE APPROPRIATE SEASONAL RESERVE MARGIN TARGETS?

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[17] *See 2016 Probabilistic Assessment*, NERC, pages 6 & 33, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016ProbA_Report_Final_March.pdf (attached as Reb. Ex. KDC-11).

[18] The report's forecasts were in terms of Loss of Load Hours ("LOLH"), which is a more stringent measurement of reliability as compared to LOLE.

[19] *See* The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018, FERC & NERC, pages 3, 6-7, https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf (attached as Reb. Ex. KDC-12).

A. Yes. The analytical approach employed by the Company was rigorous and did not bias assumptions affecting reliability. Further, as explained above, in several of the major categories of criticism, the Company's methods tended to push down the target winter reserve margin. If the Company was attempting to inject an upward bias into its methods, it would have made different choices than those it did make. Astrapé has always advocated for this type of paradigm, which models the system as it is expected to be and applies risk adjustments to the results as appropriate. The risk-adjusted economically optimal reserve margin proposed by the Company meets industry standard reliability targets and does not place an undue economic burden on customers. Measuring economic optimality with the proposed risk adjustment appropriately normalizes for the fixed nature of capital costs against the variable nature of reliability risks.

Q. WHAT ARE THE IMPLICATIONS OF ACCEPTING MR. WILSON'S RECOMMENDED RESERVE MARGIN TARGET OF 20 PERCENT?

A. As shown in Figure 5 of the RMS, LOLE would rise to one event every [redacted], which is [redacted] more frequent than the industry standard. Considering the reliability strain on the system in both 2014 and 2018 winters, when actual reserves were significantly higher than the winter target margin of 26 percent, and when temperatures proved milder than the extreme temperatures exhibited over the past 50 years, Mr. Wilson's recommendation would result in not only more frequent reliability problems than industry standard, but reliability events of larger magnitude.

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 KEVIN D. CARDEN
ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA)

COUNTY OF SHELBY)

Kevin D. Carden, 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.

Kevin Carden

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

Ryan Jones
Notary Public

RYAN JONES
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 07-25-2023

Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-1

Kevin Carden | Director, Astrapé Consulting, LLC

3000 Riverchase Galleria, Suite 575
Hoover, AL 35244
(205) 988-4404
kcarden@Astrapé.com

With a background in production cost simulations for risk analysis and reliability planning for power supply options, coupled with twenty years of diverse utility management experience, Mr. Carden possesses the technical background needed to successfully execute a wide range of resource adequacy studies. Under Kevin's leadership, Astrapé Consulting has provided consulting services to utilities nation-wide including the Southern Company, TVA, SCE, EON-US, PGE, SMUD, APS, CLECO, and LCRA. For the Southern Company, he led the redevelopment of SERVM, an industry leading Resource Planning tool which is currently managed and licensed by Astrapé. Additional responsibilities have included project financial analysis, RFP independent evaluation, target reserve margin studies, renewable capacity valuation, demand side management program development and contract management for many large capital projects. Kevin holds a B.S. in Industrial Engineering from the University of Alabama.

Experience

Modeling and design for assessment of power supply options
Intensive power modeling experience in multiple applications, including software design
Developed proprietary generation reliability and dispatch model for electric utilities
Demand forecasting, demand-side option management, and optimal reserve margin targets
Evaluation, procurement, and administration of long term power purchase contracts
Demand-side options pricing and evaluation
Bid preparation for power purchase RFPs
Managing Director, Astrapé Consulting, LLC
Generation Reliability Manager, Southern Company Services
Holds U.S. patent in Generation Reliability Modeling techniques (#7698233)

Major Clients

Southern California Edison	Portland General Electric Company	Southern Company Services
Georgia Power Company	SMUD	PPL
LCRA	Tennessee Valley Authority	Arizona Power Service
Santee Cooper	ERCOT	CPUC
MISO	Terna	Malaysia
Pacific Gas & Electric	Publics Service Company of New Mexico	

Industry Specialization

Contract Management	Electric Market Analysis	Reliability Planning
Demand Forecasting	New Generation Development	Resource Planning
Dispatch Modeling	Project Financial Analysis	Risk Assessment and Mitigation

Education

B.S. Industrial Engineering, The University of Alabama

Relevant Experience

Redevelopment of SERVM

Company Name: Southern Company Services - Resource Planning.
Mr. Carden has been responsible for the redevelopment, management, and use of a proprietary dispatch model used by the Southern Company for over two decades. This model is used primarily for reliability risk analysis and provides key insights into the value and need of capacity in both the short-term and long term. Kevin identified the need for the development of market modeling algorithms, new hydro logic, updated transmission modeling, economic dispatch criteria, reliability dispatch rules, and other key factors which contribute to reliability risks. Kevin wrote the majority of the logic for these additions based on his extended experience in resource planning. Using the model to run studies for the Southern Company, Kevin has recommended risk mitigation strategies that balance the cost of new capacity with the reliability benefits of those resources.

Resource Adequacy Assessments

Southern Company Services: Maintain SERVM for Southern Company and assist in all resource adequacy studies. All reserve margin studies have been filed with regulators. Performed Production Costs and LOLE Based Reserve Margin Study in 2007, 2010, 2013; Performed Interruptible Contract evaluation; Performed Various Other Resource Adequacy Assessments and Product Cost Studies.

Tennessee Valley Authority: Performed Various Reliability Planning Studies including Optimal Reserve Margin Analysis, Capacity Benefit Margin Analysis, and Demand Side Resource Evaluations using the Strategic Energy and Risk Valuation Model (SERVM) which is Astrapé Consulting's proprietary reliability planning software. Recommended a new planning target reserve margin for the TVA system and assisted in structuring new demand side option programs in 2010. Performed Production Costs and Resource Adequacy Studies in 2009, 2011, 2013, and 2015.

PPL - Louisville Gas & Electric and Kentucky Utilities: Performed Reliability Studies including Reserve Margin Analysis for its Integrated Resource Planning Process. This study included the probabilistic simulations regarding load uncertainty, generator performance, and weather uncertainty. Planning Reserve Margin to Company based on lowest cost and risk to customers. Reserve margin study was filed with Kentucky State Commission.

CLECO: Performed resource adequacy studies for CLECO to determine optimal reserve margin and assist in other resource adequacy decisions. Performed Production Costs and LOLE Based Reserve Margin Studies. Performed 2016 Reserve Margin Study.

Pacific Gas and Electric (PG&E): Performing flexibility Requirement Study 2015 – 2017. CES Study for Renewable Integration and Flexibility 2015 – 2016.

California Energy Systems for the 21st Century Project: Performed 2016 Flexibility Metrics and Standards Project. Developed new flexibility metrics such as EUE flex and LOLE flex which represent LOLE occurring due to system flexibility constraints and not capacity constraints.

Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-2

Published on *EGEE 102: Energy Conservation and Environmental Protection* (https://www.e-education.psu.edu/egee102)

Air-Source Heat Pump or Air-to-Air Heat Pump

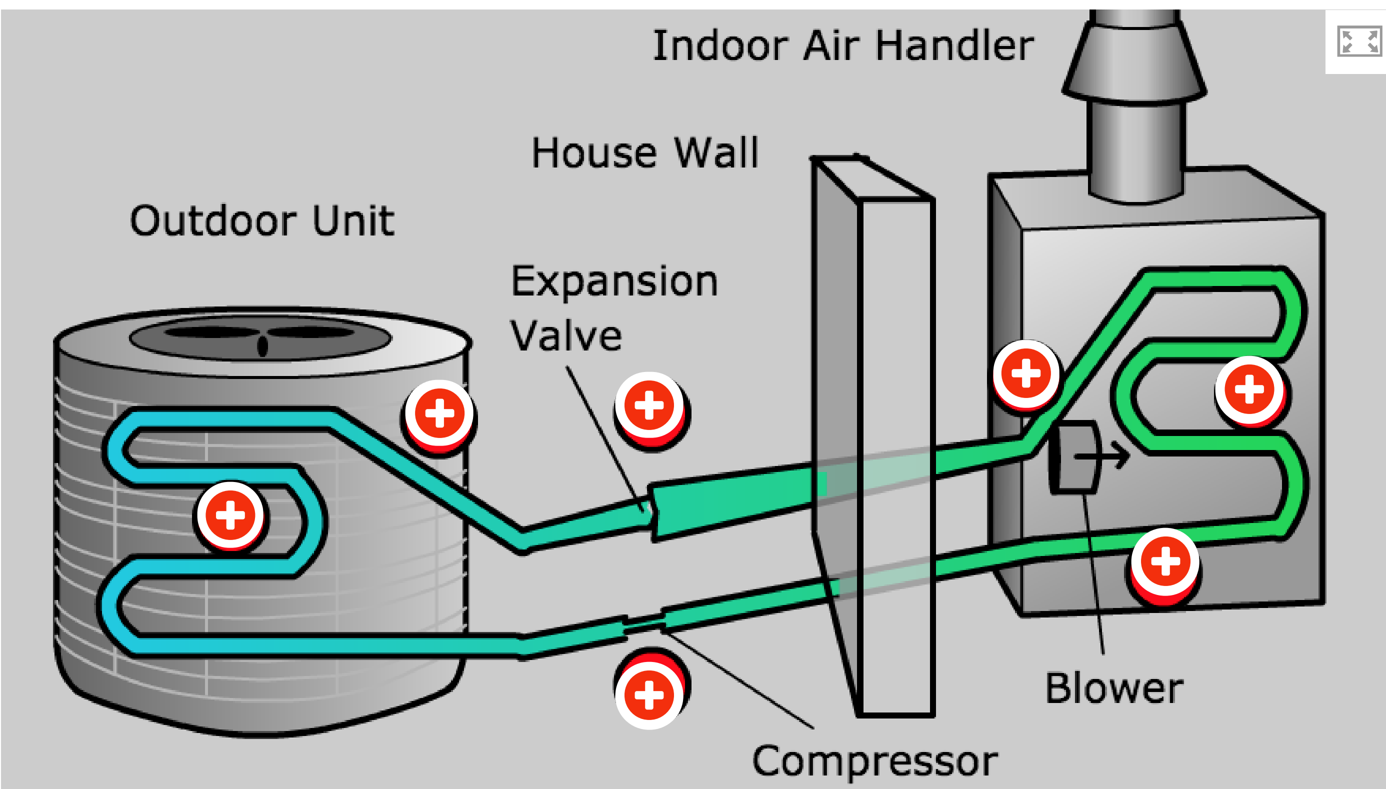
An air-source or air-to-air heat pump can provide both heating and cooling.

- In the winter, a heat pump extracts heat from outside air and delivers it indoors.
- On hot summer days, it works in reverse, extracting heat from room air and pumping it outdoors to cool the house.

Nearly all air-source and air-to-air heat pumps are powered by electricity. They have an outdoor compressor/ condenser unit that is connected with refrigerant-filled tubing to an indoor air handler. As the refrigerant moves through the tubing of the system, it completes a basic refrigeration cycle, warming or cooling the coils inside the air handler. The blower pulls in room air, circulates it across the coils, and pushes the air through ductwork back into rooms.

When extra heat is needed on particularly cold days, supplemental electric-resistance elements kick on inside the air handler to add warmth to the air that is passing through.

Instructions: Click on the hot spots below to find out how the heating cycle of an air-source heat pump works:



In the winter, a heat pump extracts heat from outside air and delivers it indoors. In the summer, the heat pump extracts heat from room air and pumps it outdoors to cool the house.

Instructions: Observe the heating and cooling cycles of a heat pump.

Heating Cycle

Cooling Cycle

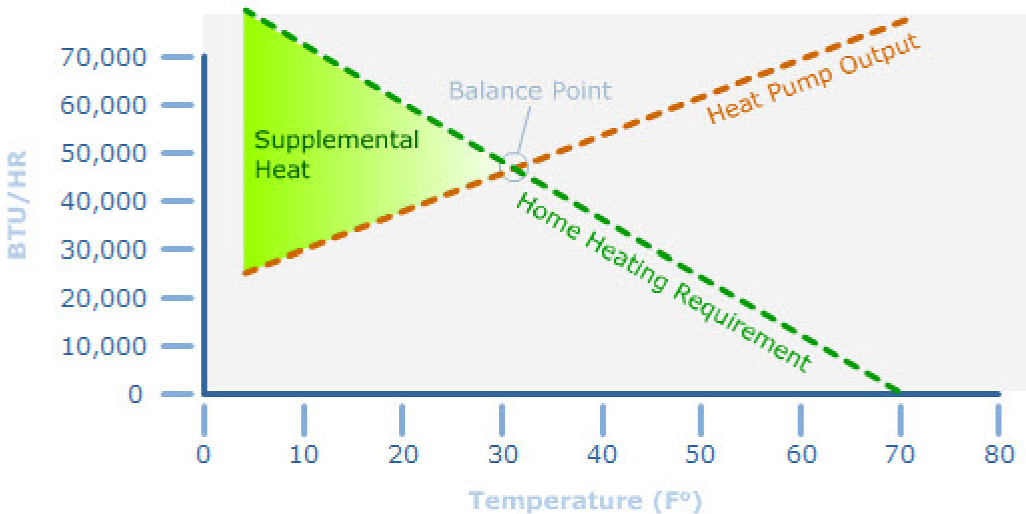
The Balance Point

As we have learned, air-source and air-to-air heat pumps work by extracting heat from the outside air. These heat pumps require a backup system to supplement their heating ability when the outdoor temperature gets below a certain temperature.

As the outdoor temperature drops, the heating requirement of the house increases and the output of the heat pump decreases. At some point, the temperature of the home's heating requirement and the heat pump output match. This temperature is called the **balance point** and usually falls between 30-45 degrees Fahrenheit. For any temperatures below the balance point, supplemental heat will be required.

To locate the balance point, the heating requirement (BTUs/h) of the house and the heat pump output (BTUs/h) are plotted against the changes in outside temperature. The place where the home heating requirement and heat pump output lines cross is the balance point.

Take a look at the graph of the Balance Point.



Balance Point Graph

Efficiency of a Heat Pump

Efficiency of a heat pump is measured using a term **Coefficient of Performance** (**COP**), and it is the ratio of the useful heat that is pumped to a higher temperature, to a unit amount of work that is put in. We will look at COP in terms of air-source heat pumps.

A general expression for the efficiency of a heat engine can be written as:

Using the same logic that was used for heat engines, this expression becomes:

Where, Q_{Hot} = Heat input at high temperature and Q_{cold}= Heat rejected at low temperature. The expression can be rewritten as:

Note: T_{hot} and T_{cold} must be expressed in the Kelvin Scale.

Source URL: https://www.e-education.psu.edu/egee102/node/2090

Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-3

An Examination of the US Residential Heating Market

Background, Behavior, Policy, and Prospective Companies

Jonathan Lorentzen, Harrison Rogers, Shidong Zhang

Faculty Advisor: Dr. Lauren Bigelow
Client: Andy Lubershane, Energy Impact Partners

A project submitted in partial fulfillment of the requirements
for the degree of Master of Science (Environment & Sustainability)
at the University of Michigan -- December 2018

December 11, 2018

SEAS SCHOOL FOR ENVIRONMENT AND SUSTAINABILITY
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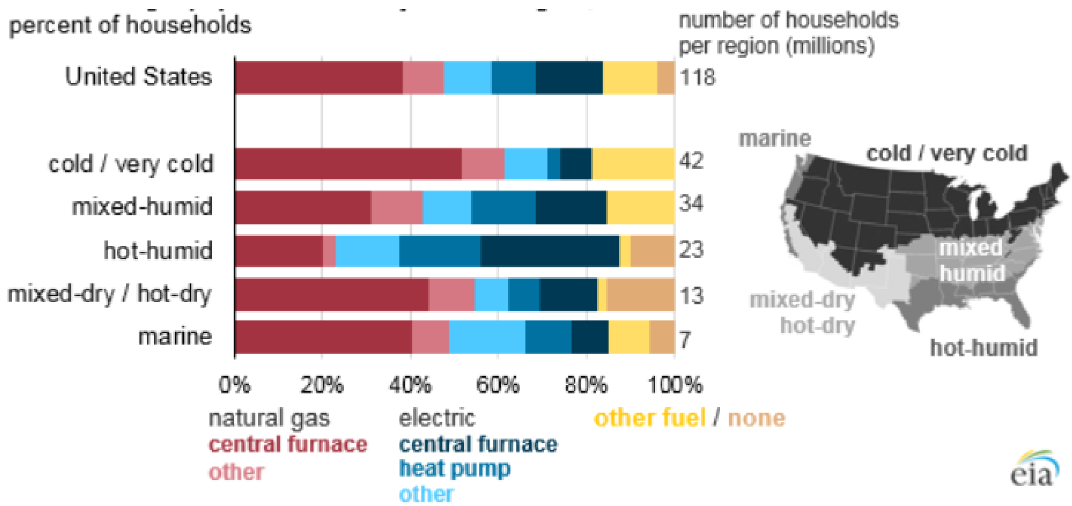


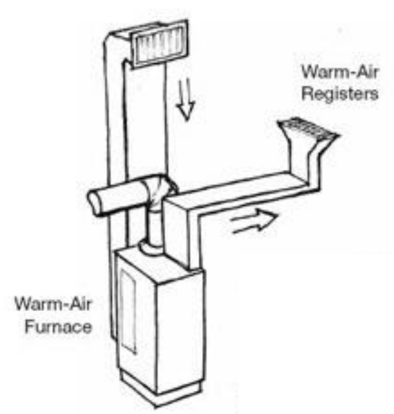
Figure 12 Main Heating Equipment Choice by Climate Region, 2015[9]

A brief description of each major technology's operation and mix in the U.S. heating market follows below:

Central Furnace

How does it work

Smarter House reports: "A Furnace works by blowing heated air through ducts in the house that deliver the warm air to rooms. Furnaces can be powered by electricity, natural gas, or fuel oil. Inside a gas- or oil-fired Furnace, the fuel is mixed with air and burned. The flames heat a metal heat exchanger where the heat is transferred to the air. Air is pushed through the heat exchanger by the Furnace fan and then forced through the ductwork downstream of the heat exchanger. Combustion bi-products are vented out of the building through a flue pipe" (Smarter House, 2015).



Historic Mix Change

Central Furnaces make up at least 50% of all residential space heating technology in each major region (Northwest, South, etc.) of the United States. Between 2001 and 2015, central Furnaces have declined from roughly 65% of the market to 61% (See Figure 13), due mainly to an expansion

[9] US Energy Information Administration (EIA) 2015 Residential Energy Consumption Survey

Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-4

Hot Stock

Malakoff falls 3.49% as Putrajaya cancels IPP project

Surin Murugiah / theedgemarkets.com
October 25, 2018 13:36 pm +08

KUALA LUMPUR (Oct 25): Shares in Malakoff Corp Bhd fell 3.49% at the midday break today after the Pakatan Harapan government decided to cancel the licences for four independent power producer (IPP) projects for failure to adhere to conditions stipulated in the respective offer letters.

At 12.29pm, Malakoff fell 3 sen to 83 sen with 698,800 shares done.

The four cancelled IPPs were Malakoff and Tenaga Nasional Bhd's 700MW gas powered plant in Kapar, Selangor; the Aman Majestic Sdn Bhd and Tenaga's 1,400MW plant in Paka, Terengganu; the Sabah Development Energy (Sandakan) Sdn Bhd and SM Hydro Energy Sdn Bhd hydropower plant at the Palm Oil Industrial Cluster (POIC) in Sandakan, Sabah as well as the solar power quota of 400MW to Edra Power Holdings Sdn Bhd for the utilisation of solar power plant.

In a reply to a question in Parliament today from Ipoh Timur MP Wong Kah Woh, the Minister of Energy, Science, Technology, Environment and Climate Change Yeo Bee Yin said the IPP projects had been awarded via direct negotiations.

Yeo explained that the cancellation of the four IPPs would optimise capacity payment for electric supply.

She said this was due to 30% of electric bill payments at present were toward capacity payment and that capacity payment was very much dependent on the reserve margin as well as terms in power purchase agreements with IPPs.

Yeo said if the national electric reserve margin remained at the optimal 32% and these projects were continued, it would increase the reserve margin to a higher-than-necessary level as well as raise capacity payments.

Yeo said the cancellations will not impose any negative financial implication on the government.

"The government is committed to ensure future power generation projects, whether fossil fuel or [renewable] energy-based, will be awarded through open tenders," she said.

RELATED NEWS

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Malakoff falls 3.49% as Putrajaya cancels IPP project
25 October 2018
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27 February 2014
Highlight: MMC 4Q net profit falls 49% y-o-y; FY2013 profit plunges 75%
27 February 2014
#Highlight* MMC 4Q net profit falls 49% y-o-y; FY2013 profit plunges 75%

FEATURED VIDEOS

Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-5

Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region

2018 Update, Final Draft

PREPARED FOR

Electric Reliability Council of Texas, Inc.

PREPARED BY

Samuel Newell
Rebecca Carroll
Ariel Kaluzhny
Kathleen Spees

Kevin Carden
Nick Wintermantel
Alex Krasny

October 12, 2018

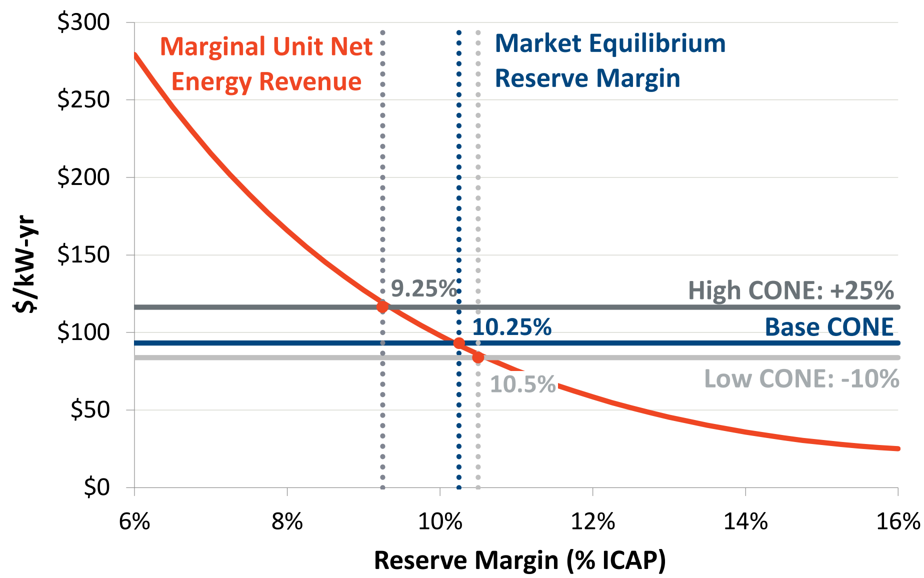
THE Brattle GROUP

challenges could affect reliability if not addressed adequately, and they are not expressed in the small change in MERM we estimate.

2. Cost of New Entry Sensitivity

The base case simulations assume that a combination of natural gas-fired CCs and CTs are the marginal resource with industry standard assumptions for capital costs. However, industry experience suggests that there is a range of uncertainty around technology cost estimates. Figure 14 shows the impact of varying gross CONE from –10% to +25% relative to our base assumptions.[33] Overall, the market equilibrium reserve margin could vary over a range of 9.25% to 10.50% depending on the range of gross CONE uncertainty.

Figure 14
Market Equilibrium Reserve Margin Sensitivity to Cost of New Entry



Note: Marginal Unit Net Energy Revenue reflects a mix of CCs and CTs. This ratio is applied in each sensitivity.

3. Probability Weighting of Weather Years Sensitivity

The high impact of weather on net energy revenue means that different weather expectations will influence the market equilibrium reserve margin. The base case assumes equal probability for all 38 weather years because 38 years should be a sufficient sample of the underlying

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33 We assumed a larger sensitivity on high end of the range of CONE values due to the potential for higher financing costs in the ERCOT energy-only market relative to the PJM energy and capacity market design and the potential for recent tariffs to increase costs more so than what the market prices already reflect.

distribution, assuming that distribution is representative of future weather patterns. We also examined the expected MERM under three alternative sets of weighting factors: (1) assign weights based on the number of consecutive days of greater than 100-degree weather using a Pareto distribution;[34] (2) equal weights to only the most recent 10 years of weather data and no weighting to the earlier years; (3) the same weights applied in the 2014 EORM study, a 1% weight to 2011 and equal weight to the remaining years from 1998 to 2012. This analysis shows that the MERM could vary over a range of 10.0% to 11.75% based on these alternative weighting schemes.

4. Forward Period and Load Forecast Uncertainty Sensitivity

In our base case analysis, we assume that all future supply decisions must be locked in three years in advance, approximately consistent with the lead time needed to construct new natural gas-fired generation resources.[35] However, unlike weather-related load uncertainty, non-weather load forecasting error (LFE) increases with the forward period. The forward period may increase if investors require a longer planning period and decrease if there are significant short-term resources (such as demand response, switchable units, mothballed units, and even renewable resources) to respond more quickly to market conditions than traditional new builds. Depending on the expected forward periods the market equilibrium will vary from 9.25% to 10.25%.

5. Summary of Sensitivities

Our estimate of the MERM is sensitive to a number of study assumptions as we have explained in previous sections, and summarized in Figure 15 and Table 7. As shown in the table, the MERM is between 9.25% and 11.75% for all sensitivities.

Each sensitivity does not necessarily have a symmetric effect on the MERM. As discussed in Section III.D.1, the resource mix of renewable additions influences the effect on the MERM. Having a higher ratio of solar to wind installed in the high renewable penetration case decreases the MERM more than the low renewable penetration case decreases the MERM. The change in the VOLL is not considered to shift the operating reserves demand curve (ORDC), and will not

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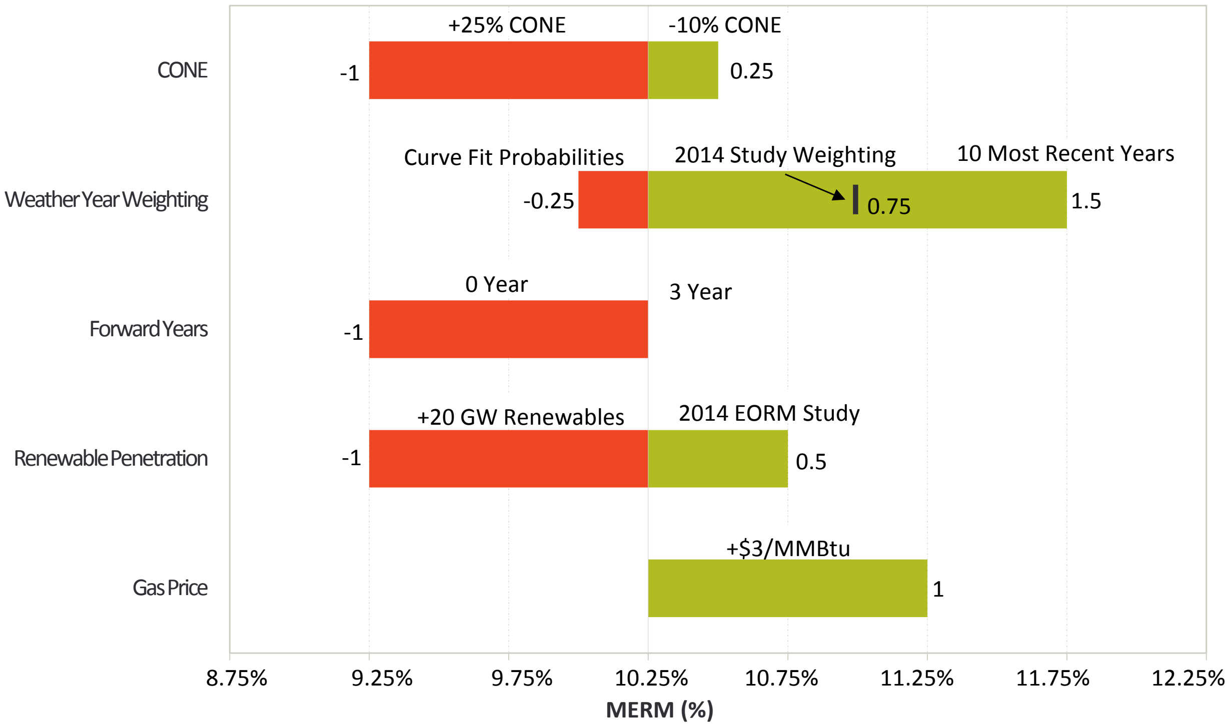
[34] This is an updated version of the Weather-risk Index weighting discussed in Section 10.2.1 of ERCOT 2017b.

[35] This construction timeframe is why the PJM and ISO-NE capacity markets rely on a three-year forward period.

affect the MERM.[36] Moving from a three-year LFE forward period to no forward period reduces the MERM by one percentage point. Each one-year increase in the forward period increases the MERM by 0.5%, but each additional year of LFE has a smaller incremental effect on the MERM.

Figure 15
Sensitivity of the Market Equilibrium Reserve Margin to Study Assumptions



Notes:
Varying the VOLL is not shown because it does not affect the MERM.

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36 The ORDC is discussed in Appendix 1.E.4; varying the VOLL to range from $5,000 to $30,000 changes the EORM to range from 8.25% to 10.5%, respectively.

Table 7
Sensitivity of the Market Equilibrium Reserve Margin to Study Assumptions

	Reserve Margin *(%)*	Base Assumptions	Low/High Sensitivity
Base Case	**10.25%**		
Vary Gross CONE	9.25% - 10.50%	\$88.5/kW-yr (CT) \$94.5/kW-yr (CC)	\$79.7-\$110.6/kW-yr (CT) \$85.1-\$118.1/kW-yr (CC)
Vary VOLL	10.25%	\$9,000/MWh	\$5,000-\$30,000/MWh
Vary Probability of Weather Years	10.0% - 11.75%	Equal Probability to all 38 weather years	Equal Probability to last 10 years; 2014 EORM Base Case Weather Probability; Consecutive Days >100 Pareto Distribution
Vary Forward Years	9.25% - 10.25%	3 years	0 years to 2 years
High Renewables Scenario	**9.25%**		10 GW of new solar, 10 GW of new wind
Low Renewables Scenario	**10.75%**		Wind and Solar capacities equal to those in the 2014 EORM report.
High Gas Price	**11.25%**		\$3.00 increase in Gas price.

Notes:
Varying the VOLL does not affect the MERM.

Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-6

Applied Energy 253 (2019) 113513

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

A time-dependent model of generator failures and recoveries captures correlated events and quantifies temperature dependence

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HIGHLIGHTS

- We quantify the temperature dependence of forced outages for six generator types.
- Generator transition probabilities are modeled using logistic regression.
- Nonhomogeneous Markov models capture observed correlated generator failures.
- Resource adequacy can be improved by accounting for temperature dependence.

ARTICLE INFO

Keywords:
Resource adequacy
Generating availability data system
Correlated failures
Nonhomogeneous Markov model
Logistic regression

ABSTRACT

Most current approaches to resource adequacy modeling assume that each generator in a power system fails and recovers independently of other generators with invariant transition probabilities. This assumption has been shown to be wrong. Here we present a new statistical model that allows generator failure models to incorporate correlated failures and recoveries. In the model, transition probabilities are a function of exogenous variables; as an example we use temperature and system load. Model parameters are estimated using 23 years of data for 1845 generators in the USA's largest electricity market. We show that temperature dependencies are statistically significant in all generator types, but are most pronounced for diesel and natural gas generators at low temperatures and nuclear generators at high temperatures. Our approach yields significant improvements in predictive performance compared to current practice, suggesting that explicit models of generator transitions using jointly experienced stressors can help grid planners more precisely manage their systems.

1. Introduction

Grid planners procure enough electric power generation to meet predicted demand and reserve generation to cover the statistical chance that one or more generators will fail. The process of determining how much generation to procure is called resource adequacy modeling (RAM). It is well known that severe environmental conditions can lead to elevated failure probabilities for power system components [1–3]. PJM, a large system operator in the USA, documents generator outage rates three times the historical winter average during the January 2014 Polar Vortex event [2]; and generator outage rates nearly twice the historical winter average during a milder cold snap that occurred in January 2018 [3]. Yet most current approaches to resource adequacy modeling are unable to account for these risks because they treat generators as homogeneous Markov models (i.e., having time-invariant transition probabilities) [1,4–7].[1]

This assumption is inconsistent with results from recent empirical work using four years of Generating Availability Data System (GADS) data from the North American Electric Reliability Corporation (NERC) that demonstrated the existence of correlated failures in most NERC reliability regions [8]. The correlated failures demonstrated in [8] are consistent with a numerical example presented by Gaver et al. [1] that shows much higher reliability adverse effects under adverse weather conditions. The observation that generators fail simultaneously leaves open the question of how to model correlated failures and recoveries. Severe environmental conditions experienced by many generators

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[1] Standard RAM practice in the U.S. is as follows. First, the most recent five years of historical availability data are used to calculate an availability statistic for each generator. Second, the availability statistics are combined to calculate a distribution of available capacity for a future planning year for the power system. RAM assumes that the availability statistic corresponds to the generator's probability of being unavailable due to an unscheduled failure in every hour of the planning year.

https://doi.org/10.1016/j.apenergy.2019.113513
Received 18 February 2019; Received in revised form 10 June 2019; Accepted 9 July 2019
Available online 15 July 2019

Nomenclature

Symbols

A	available state of two-state Markov model
AA	available-to-available transition
AD	available-to-derated transition
α_i	equals 1 if the i^{th} observation used to fit the available model is AA, and 0 otherwise
β_A, β_D	parameter vectors for the available and derated models, respectively
D	derated state of two-state Markov model
DA	derated-to-available transition
DD	derated-to-derated transition
Δ_i	equals 1 if the i^{th} observation used to fit the derated model is DD, and 0 otherwise
EFDH	equivalent forced derating hours, the sum of hours where the generator experiences a forced derating, reported in full-outage-equivalent hours
EFOF	equivalent forced outage factor, a common availability statistic
FOH	forced outage hours, the sum of hours where the generator experiences a forced outage
$\mathscr{L}(\cdot)$	likelihood function
PH	period hours, total number of hours in the calculation period of interest
P_i	probability of the generator remaining derated in the next hour when it is currently derated
Q_i	probability of the generator remaining available in the next hour when it is currently available
X_i	vector of covariate observations

Abbreviations and acronyms

C	celsius
CC	combined cycle gas generator
CT	simple cycle gas generator (combustion turbine)
DS	diesel generator
eGRID	emissions and Generation Resource Integrated Database
GADS	generating Availability Data System
GW	Gigawatts
HD	hydroelectric or pumped storage generator
IEEE	institute of Electrical and Electronics Engineers
NERC	north American Electric Reliability Corporation, the electric reliability organization for the United States
NU	nuclear generator
PJM	the PJM Interconnection, an independent system operator / regional transmission organization in the mid-Atlantic United States
RAM	resource adequacy modeling
ST	steam turbine generator (used equivalently as coal generator in PJM)

simultaneously is one possible explanation of these results.

Here we test this possibility with a time-varying (nonhomogeneous) Markov model fit using 23 years of data for 1845 generators in the USA's largest electricity market. The nonhomogeneous Markov model's probabilities of transitioning, e.g. from fully available to partially or fully derated, depend on exogenous variables such as temperature and system load (the electric energy being used by customers). Many factors could affect transition probabilities. However, if failures (transitions from working to not working) depend on variables that are jointly experienced by many generators, such an approach could capture the observed correlated failures. Understanding the causes of correlated failures and recoveries can help in the procurement of reserves, payments for which amount to billions of dollars per year in the USA [9].

Markov models are widely used in power system reliability analyses. The traditional two-state model assumes generators are either fully available or fully unavailable [10,11]. Common generalizations allow additional states [12], different two-state models over a discrete set of environments: e.g. "normal weather" versus "adverse weather" [1,13–15], or generator "in demand" versus "not in demand" [16–18]. Billinton and Bollinger [13] derive steady-state probability distributions for one-, two-, and three-line transmission systems. Liu and Singh [14] use Bayesian networks to study common-cause and independent failures due to hurricanes in a composite power system. Billinton and Li [15] allow segments of a single transmission line to experience different weather states so as to not over-estimate failure bunching in power systems that cover large geographic areas. Bhavaraju et al. [16] use a generalizable multi-state homogeneous Markov model to develop steady-state probability distributions for peaking generators; Billinton and Chowdhury [17] employ a three-state model. An IEEE task group [18] describes multiple models incorporating "in demand" versus "not in demand" states to improve upon the traditional two-state models for estimating the probability of being unavailable when needed by the system for peaking generators.

Particularly with respect to transmission and distribution system reliability, there has been significant scholarly attention to the effects of extreme weather and natural disasters [19–23]. Bramer et al. [19] develop penalized logistic regression models to predict grid stress as a function of a suite of weather variables in the eastern USA. Li et al. [20] evaluates the hazard effects of wind storms on distribution systems in the northeastern USA using multiple metrics including system average interruption frequency index (SAIFI), system average interruption duration index (SAIDI), and expected energy not supplied (EENS). Bernstein et al. [21] develop a cascading transmission line outage model that allows for non-proximate line failures using the network topology of the western USA. Panteli and Mancarella [22] use a sequential Monte Carlo simulation-based time series simulation model to capture the effect of weather dependent failure probabilities on a six-bus system. Wei et al. [23] model distribution failures in the eastern USA during Hurricane Ike using a Poisson process estimated using observed failure data.

Homogeneous Markov models are most commonly employed, which means that transition probabilities are constant [10,24]. To model correlated failures, a new state must be created for each combination of generators failing simultaneously [25–27]; the state space therefore grows geometrically as the number of generators increases. While this approach can be successfully used to model multiple generators in a power plant or a small number of transmission lines, the intractability of applying it to a fleet of generators in a large power system has led researchers to define states in terms of system capabilities or to merge states [28,29]. Hou et al. [29] use a continuous time Markov chain where higher-order outage states are merged to improve tractability of a bottom-up reliability assessment of a composite generation and transmission power system. Felder [28] instead proposes a top-down model where system states are defined based on system capabilities rather than component states. Computing transition probabilities that depend on variables such as temperature and load to capture correlated failures can require long time series of generator-level data; these data were not previously available.

Using these generator-level data, we model each generator with only two states, but allow transition probabilities to depend on exogenous variables such as temperature. Similar approaches have been employed to study distribution and transmission system reliability

[23,30–32], but to our knowledge none have been used to study correlated generator failures in a large power system. Andreasson [30] examines the implications of correlated transmission line failures for risk of load shed to a 470-bus model of the Nordic power system. Wang et al. [31] allow failure rates of transmission lines to vary by season to account for failures caused by meteorological events. Ertekin et al. [32] model distribution system failures in New York City as a nonhomogeneous Poisson process accounting for maintenance and other line features. To conduct this analysis we create hourly time series of transitions for 1845 generators in the eastern USA using 23 years of GADS data from the PJM Interconnection (PJM), the largest electric power market in the USA. For each generator, the two-state Markov model's time-varying probabilities are modeled as functions of exogenous variables using logistic regression. We model transition probabilities as a function of temperature and system load, though the model can be extended to include additional covariates. Both temperature and load vary with time and are jointly experienced by many generators, thus transition probabilities in generators' Markov chains can be correlated.

2. Model

We use logistic regression to model each generator's transition probabilities as a function of covariates. We fit these models using the GLM library in R, with default initial values. While there are many binary classification algorithms, logistic regression is relatively insensitive to unbalanced data [33]. This is an important attribute for this analysis, as most generators fail infrequently. Unbalanced data makes accurately estimating transition probabilities more difficult [34].

We employ a two-state Markov model wherein each generator is treated as either fully available (subsequently referred to as available and abbreviated A) or at least partially unavailable (subsequently referred to as derated and abbreviated D). For each generator we separately model two pairs of transition probabilities: the probability of an available generator remaining available in the next hour versus becoming derated (failing), and the probability of a derated generator remaining derated in the next hour versus becoming available (recovering).

As in [32], we allow transition probabilities to be a function of covariates. We consider temperature and load because they have time series dependence and affect multiple generators simultaneously. As a result, if they are found to have statistically significant associations with changes in transition probabilities, our model may be able to explain the correlated failures identified in [8]. If no covariates are statistically significant, this model reduces to the familiar homogeneous (time-invariant) Markov model of [11] (Fig. 1). Our modeling approach therefore allows us to relax the assumptions of unconditional independence and constant generator availability where empirically warranted. It instead assumes that generator transitions are conditionally independent (after conditioning on relevant covariates) and allows generator availability to vary over time.

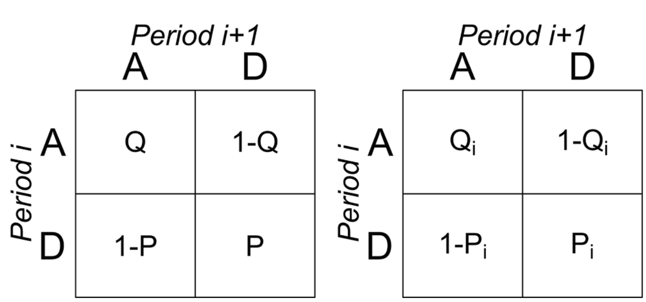

Fig. 1. Homogeneous (left) and nonhomogeneous (right) two-state Markov models. A indicates the available state, D indicates the derated state. Q and Q_i are the constant and time-varying probabilities of an AA transition, respectively. P and P_i are the constant and time-varying probabilities of a DD transition, respectively.

We fit our models using maximum likelihood estimation (iteratively reweighted least squares). Consistency and asymptotic normality of our coefficient estimates flow from traditional maximum likelihood estimation theory, which holds in our setting because all covariates are bounded [35]. The estimation procedure is conducted on each generator, using its hourly series of Markov state transitions and covariate data, described below. If the transition probabilities were constant, this would be equivalent to determining the probability of a coin coming up heads. The likelihood functions are:

$$\mathscr{L}(\beta_A) = \prod_{i=1}^{\mathrm{count(A)}} Q_i(\beta_A)^{\alpha_i} * (1 - Q_i(\beta_A))^{1-\alpha_i} \tag{1}$$

$$\mathscr{L}(\beta_D) = \prod_{i=1}^{\mathrm{count(D)}} P_i(\beta_D)^{\delta_i} * (1 - P_i(\beta_D))^{1-\delta_i} \tag{2}$$

where β_A and β_D are vectors of parameters for the available and derated models, respectively; Q_i is the probability of the generator remaining available in the next hour when it is currently available; P_i is the probability of the generator remaining derated in the next hour when it is currently derated; count(A) is the number of observations used to fit the available model; count(D) is the number of observations used to fit the derated model; $\alpha_i = 1$ if the ith available observation is AA and 0 otherwise; $\delta_i = 1$ if the ith derated observation is DD and 0 otherwise; and the sum of count(A) and count(D) equals the number of Markov state transitions in the reporting period for the generator. The available and derated models are fit separately for each generator (Fig. 2). A generator's hourly states are independent and identically distributed conditional on the covariate values; dependence in the covariate values leads to a richer time series structure for the generator's observations.

We allow Q_i and P_i to be functions of covariates while still ensuring all transition probabilities are bounded by [0,1] by employing the logistic function:

$$Q_i(\beta_A) = 1/(1 + \exp(-\beta_A X_i)) \tag{3}$$

$$P_i(\beta_D) = 1/(1 + \exp(-\beta_D X_i)) \tag{4}$$

where X_i is a vector of covariate observations in hour i, with as many elements as the number of constants and covariates in the model.

We consider the following model specification for both available and derated models for each generator:

$$\begin{aligned}\mathrm{Index}_i = {} & \beta_1 * \mathrm{constant}_{\mathrm{hot}i} + \beta_2 * \mathrm{constant}_{\mathrm{cool}i} + \beta_3 * \mathrm{degrees}_{\mathrm{hot}i} + \beta_4 \\ & * (\mathrm{degrees}_{\mathrm{hot}i})^2 + \beta_5 * \mathrm{degrees}_{\mathrm{cool}i} + \beta_6 * (\mathrm{degrees}_{\mathrm{cool}i})^2 + \beta_7 \\ & * \mathrm{system\_load}_i\end{aligned} \tag{5}$$

where $\beta X_i = \mathrm{Index}_i$ (linking Eqs. (3)–(5)), $\mathrm{degrees\_hot}_i = \max(\mathrm{temperature}_i - 18.3, 0)$, $\mathrm{degrees\_cool}_i = \max(18.3 - \mathrm{temperature}_i, 0)$, $\mathrm{system\_load}_i$ is the load residual in hour i, $\mathrm{constant\_hot}_i = 1$ if $\mathrm{temperature\_cool}_i = 0$ (and 0 otherwise), $\mathrm{constant\_cool}_i = 1$ if $\mathrm{temperature\_cool}_i > 0$ (and 0 otherwise), and $\mathrm{temperature}_i$ is the temperature in hour i, reported in degrees Celsius.[2] This specification allows for an asymmetric response to hot and cold temperature.

So that our model can better generalize to temperatures and loads not observed in the data, we employ stepwise regression (backward elimination) as described in Procedure 1, selecting a significance

[2] 18.3 degrees Celsius is approximately 65 degrees Fahrenheit. This corresponds to the demarcation point used to define heating degree days and cooling degree days in the USA by the National Oceanic and Atmospheric Administration [49]. It also corresponds to the flattest region of the temperature-load relationship in the PJM area found by [50].

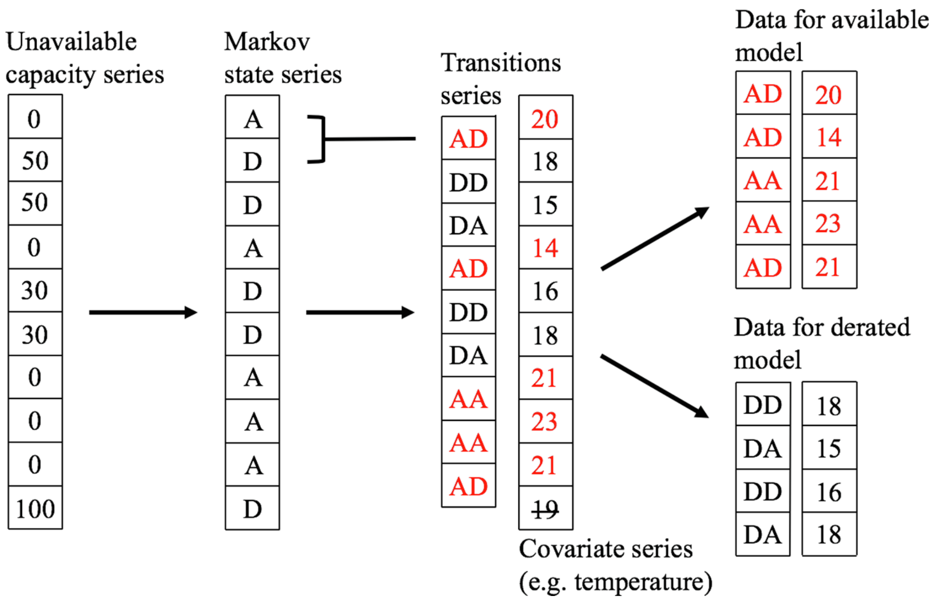

Fig. 2. Defining a generator's time series of transitions and allocating them to the available and derated models. The generator's hourly time series of unavailable capacity is first used to determine which Markov state the generator is in in each hour. The series of hour-over-hour state transitions is then determined. These observations, along with our covariates (illustrated as a single vector of hourly temperatures for clarity of presentation) are then allocated to the available and derated models. Any observation in which a generator begins in the A state is assigned to the available model, whereas any observation in which a generator begins in the D state is assigned to the derated model. Note that there are one fewer transitions than original observations, so the final covariate observation is not used.

level of 0.05. To reduce bias, we then eliminate any generator having fewer than 10 DA or AD transitions per statistically significant model covariate [36].[3]

Procedure 1 (*Adaptive logistic regression model fitting*).

For each generator, do:
- *For each model (i.e., available and derated), do:*
  - o *Fit full model specification (Eq. (5))*
  - o *While model has one or more linearly dependent or statistically insignificant covariates, do:*
    - ■ *If model has one or more linearly dependent covariates, remove one linearly dependent covariate and re-estimate model*
    - ■ *Else, remove covariate with smallest t-value magnitude and re-estimate model*
  - o *Save final model*

Remove generators that do not have at least 10 AD and 10 DA transitions per final model parameter

2.1. Simulating unavailable capacity from nonhomogeneous Markov models

Procedure 2 simulates time series of unavailable capacity for each generator according to the hourly failure and recovery probability distributions defined by the historical series of covariate values. Any hour that was ignored when fitting a generator's available or derated model is set to zero in both the empirical and simulated series. In order to have a true out-of-sample test of model performance, we refit the models using only 1995–2015 data (rather than 1995–2018) and retain just the 1047 generators that have sufficient transitions over the shortened time series. This leaves 2016–2018 as test data. We carry out this procedure 5000 times and generate pointwise median and 95% confidence intervals from the result, which we plot along with the empirical time series (Fig. 4). Given the data limitations discussed in Section 3.2.4, we repeat the process fitting only on 2004–2015 data, again leaving 2016–2018 as test data (Supplementary materials Fig. B.1[4]). For reference, we report annual installed capacity values for these generators (Table A.1 and Table B.1).

Procedure 2 (*Simulating unavailable capacity from nonhomogeneous Markov models*).

For each simulation, do:
- *For each generator, do:*
  - o *Initialize the state of the generator to match its reported state during its first hour of data reporting*
  - o *For each subsequent hour of the generator's reporting period, do:*
    - ■ *Use the current state of the generator and the current values of all model covariates to define the current transition probability distribution (AA/ADif currently available; DD/DA if currently derated)*
    - ■ *Draw 0 or 1 using the probability distribution defined above, where 0 indicates the generator is available and 1 indicates the generator is derated*
  - o *Replace all 1 s with the generator's average unscheduled capacity reduction to yield a time series of unscheduled unavailable capacity*
  - o *Zero out any unavailable capacity occurring during hours removed during model fitting*
- *Sum over generators' time series to obtain one simulated system-level time series*

Compute desired quantiles from simulation results (e.g. 2.5%, 50%, 97.5%) and save

2.2. Simulating unavailable capacity from time-invariant (homogeneous) Markov models per current RAM practice

We compute the equivalent forced outage factor (EFOF[5]), a common availability statistic, as follows [37]:

$$\mathrm{EFOF} = (\mathrm{FOH} + \mathrm{EFDH})/\mathrm{PH} \tag{6}$$

where FOH (forced outage hours) is the sum of hours where the generator experiences a forced outage, EFDH (equivalent forced derating hours) is the sum of hours where the generator experiences a forced derating, reported in full-outage-equivalent hours, and PH (period hours) is the total number of hours in the period of interest. In accord with current RAM practice, we define the period supporting each planning year as the preceding five calendar years. For consistency with

[3] DA or AD is always the least-experienced transition.

[4] Appendix A (with figures and tables numbered A.1, A.2, etc.) and Appendix B (with figures and tables numbered B.1, B.2, etc.) may be found in the supplementary materials, available online at https://doi.org/10.1016/j.apenergy.2019.113513.

[5] More commonly, the equivalent forced outage rate (EFOR) is used [37].EFOR = (FOH + EFDH)/(FOH+SH + Synch + Pump+EFDHRS), where SH (service hours) is the total number of hours the generator produces electricity, Synch is the number of hours the generator operates in synchronous condensing mode, Pump is the number of hours a pumped-storage hydroelectric generator operates in pumping mode, and EFDHRS (equivalent forced derating hours during reserve shutdown) is the number of hours the generator experiences a forced derating during a reserve shutdown event, reported in full-outage-equivalent hours [39]. However, using EFOF allows us to not worry about incomplete reporting of reserve shutdown events prior to 2004.

the logistic regression results, we carry out the procedure for the 1047 generators retained when fitting models on 1995–2015 data and we ignore contributions to FOH and EFDH that occur during any hour removed during model fitting.

Procedure 3 (*Simulating unavailable capacity from homogeneous Markov models*).

Define duration of data period supporting each planning year (*e.g.* 5 *years*)*For each simulation, do*:

- *For each planning year* (*e.g.* 2000–2018), *do*:
  - o *For each generator, do*:
    - ▪ *If the generator was active during period supporting planning year and does not retire prior to planning year, do*:
      - *Compute EFOF* (*Eq.* (6)) *using all of generator's data supporting current planning year, except for hours removed during model fitting*
      - *For each hour in planning year, draw a* 1 *with probability equal to generator's EFOF and* 0 *otherwise, where* 0 *indicates the generator is available and* 1 *indicates the generator is unavailable*
      - *Replace all* 1 *s with the generator's nameplate capacity*
  - o *Sum over generators' time series to get one simulated system-level series for current planning year*

Compute desired quantiles from simulation results (*e.g.* 2.5%, 50%, 97.5%) *and save*

2.3. Characterizing unavailable capacity as a function of temperature

Procedure 4 (*Characterizing unavailable capacity as a function of temperature*).

For each desired quantile of load (*e.g.* 50*th*, 90*th*), *do*:

- *For each desired temperature value* (*e.g. spanning the range of temperatures experienced by the fleet, in* 5*-degree intervals*), *do*:
  - o *Fix the value of temperature*
  - o *Fix the value of load at the current load quantile, calculated on observations in the "neighborhood" of the current temperature value* (*e.g. within* +/-10 *degrees*)
  - o *For each generator, do*:
    - ▪ *Compute predicted transition probabilities using generator's available and derated model and current temperature and load values*
    - ▪ *Define transition probability matrix as the transpose of* Fig. 1
    - ▪ *Normalize the first eigenvector of the eigendecomposition of the transition probability matrix to obtain the proportion of the time the generator is unavailable in expectation*
    - ▪ *Multiply result by generator's nameplate capacity and its average unscheduled capacity reduction to obtain expected unavailable capacity*
  - o *Sum expected unavailable capacity values over generators and save*

3. Data

3.1. GADS data description

The GADS database records availability and design information for all generators serving the PJM control area, with the exception of wind, solar, and behind-the-meter generation. Reporting to GADS is mandatory, regardless of generator size [38]. We work primarily with the Events, Units, and Performance tables. The Events table reports any event affecting the ability of a generator to produce electricity, as well as other event types defined by the Institute of Electrical and Electronics Engineers (IEEE) Standard 762 [37]. The Units table reports design details of each generator, such as generator type and nameplate capacity.[6] The Performance table reports monthly summary statistics of each generator's operating and non-operating time. We analyze data from January 1, 1995 (database inception) through March 31, 2018. Over this period 1845 generators representing 267 GW (GW) of capacity have reported to GADS.

3.2. GADS data processing

3.2.1. Obtaining time series of availability state transitions

PJM's GADS database is virtually identical to that of NERC (albeit covering many more years), thus we prepare it for analysis as described in [8]. We calculate the magnitude of each derating event and then process events into time series of unavailable capacity. We restrict each generator's time series to complete calendar years. We then use each generator's time series of unavailable capacity to define a corresponding time series of hour-over-hour Markov state transitions (Fig. 2). For example, an AA transition occurs when the generator is available in two adjacent hours.

3.2.2. Determining when a generator is available to transition

Our model assumes each generator is able to transition out of its current state in each hour (i.e., the generator can experience a failure if it is currently available and recover if currently derated). We attempt to exclude hours in which this assumption is violated in order to minimize bias. When fitting the available model, we remove mothball, inactive reserve, and all scheduled outage events because the generator cannot be operating when these events are underway [39]. The generator can still operate when a scheduled derating is in effect, so these hours are not removed.

When fitting the derated model, we remove only mothball and inactive reserve events. This is because no repair work is allowed to occur when these events are in progress [39]. Repair work on unscheduled failures can occur during scheduled outage and scheduled derating events, so these hours are not removed. In addition, some failures are catastrophic and take many months to repair. Including these events would bias recovery probabilities downward. To correct for this, we remove hours when a generator remains in the derated state without interruption for more than six months.

3.2.3. Calculating the average derating magnitude for each generator

Because derating magnitudes can take any value up to a generator's nameplate capacity, but our model allows only one derated state, we calculate the average failure magnitude for each generator (Fig. A.1). We calculate this as a duration-weighted average of all unscheduled events experienced by the generator, excluding any hour removed when fitting either the available or derated model. The average and median failure magnitudes are 78% and 96% of nameplate capacity, respectively.

3.2.4. A note on reserve shutdown events

Reserve shutdown events are used to indicate when a generator is offline for economic reasons but is capable of coming online within its normal startup time if needed. With the exception of hydroelectric and pumped storage generators without automatic reporting equipment, all conventional generators participating in the PJM market became obligated to report reserve shutdown events to GADS in January 2004, nine years after the beginning of our data.

When a reserve shutdown event is underway, a generator should neither be in service nor have repair work conducted. If one assumes that the incidence of a failure while a generator is not operating and not being repaired is much lower than when operating or when being repaired, reserve shutdown hours should also be excluded from both available and derated model fits. However, given that most generators fail infrequently and that we require a minimum of 10 AD and DA transitions per statistically significant covariate to keep a generator in our analysis, eliminating the first nine years of data results in significantly fewer generators retained, particularly for CTs.

As a result, we fit our models twice: first using the full data period (1995–2018) ignoring reserve shutdown events, and second restricting to 2004–2018 and removing reserve shutdown hours from both

[6] The generator types include combined cycle gas (abbreviated as CC in figures and tables), simple cycle gas (CT), diesel (DS), hydroelectric and pumped storage (HD), nuclear (NU), and steam turbine (ST). In 2017, the vast majority (95%) of ST generation in PJM was from coal, thus we use the two terms interchangeably [48].

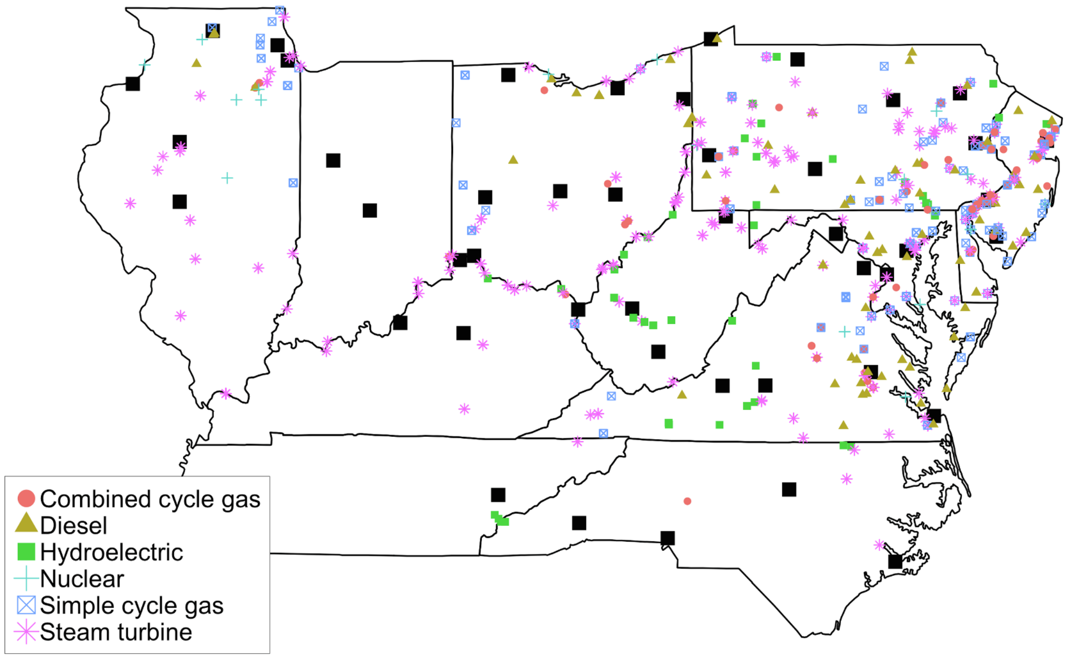

Fig. 3. Locations of 1111 retained generators and linked weather stations, overlaid on corresponding USA states (1995–2018 model fits). Only generators with at least 10 failure and recovery transitions per statistically significant model parameter are retained. All generators in multi-generator power plants have identical locations. Large black squares indicate weather stations. A small number of retained generators are not shown for presentation considerations: Alabama (3), Louisiana (5), Michigan (23), Mississippi (3), South Carolina (1), Texas (8).

available and derated model fits. Results based upon the former are presented in the main text and in Appendix A, while results based upon the latter are included in Appendix B. In general, we find reasonable agreement between the two sets of results.

3.3. Geographic, weather, and load data processing

3.3.1. Geocoding generators

To determine the location of each generator, we match the GADS data to the Emissions and Generation Resource Integrated Database (eGRID), maintained by the USA Environmental Protection Agency [40–43]. This task was completed using a combination of automated and manual matching using generator names and other descriptive fields. We manually confirm each automated match and then associate the eGRID latitude/longitude data with the generator.

3.3.2. Weather station data

We obtain temperature data from the Global Surface Hourly database, maintained by the USA National Oceanic and Atmospheric Administration [44]. We include all weather stations active for the full study period in any state containing or adjacent to any generator. We process these data into hourly time series for each weather station by first rounding observations to the nearest hour and then removing observations with duplicate time stamps. We discard any weather station missing more than 100 sequential observations or more than 5000 total observations over the 23 years, with three exceptions to increase coverage in Pennsylvania.[7] We then fill missing observations by propagating forward the most recent non-missing observation.[8] Finally, we link each generator to its nearest weather station meeting our data criteria. We map the retained generators and matched weather stations (Fig. 3 and Fig. B.2).

3.3.3. Load data

Finally we obtain hourly metered load data by PJM transmission zone for the full study period. We sum over all zones that have been part of the control area since January 1995 to develop an hourly load series for the system.[9] To account for non-stationarities in that series, we regress the load data on a constant, a linear time trend, and a quadratic time trend. The residuals from this linear regression are used as the load signal experienced by each generator. We plot the load time series with regression trend and residuals (Fig. A.2 and Fig. B.3).

3.4. Model significance summaries

When fitting models on the full dataset, we retain 1111 of 1845 generators, representing 78% of the capacity that has ever reported to GADS (Fig. A.3); when restricting to 2004–2018, we retain 748 generators representing 67% of capacity (Fig. B.4). While failures and recoveries for the remaining generators may indeed be influenced by temperature and/or load, they have so few transitions that we would not have confidence in the fitted models. We summarize the count and capacity of these generators (Table A.2 and Table B.2).

We summarize marginal statistical significance of the covariates by plotting parameter t-values by generator type (Figs. A.4-A.5 and Figs. B.5-B.6) and reporting the number of times each model term is statistically significant at the 95% level by generator type (Tables 1, 2 and Tables B.3-B.4). We include corresponding summaries of model coefficients (Figs. A.6-A.7 and Figs. B.7-B.8).

When fitting on the full dataset, linear and quadratic hot-temperature variables are statistically significant for 19% and 17% of

[7] These three stations had 268, 65, and 103 sequential missing observations and 2937, 8962, and 1370 total missing observations.

[8] We initially filled missing observations by propagating forward the most recent non-missing observation at the same hour of the day, but discovered that several weather stations were systematically missing observations at particular times of the day over long durations.

[9] We include: Allegheny Power, Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Metropolitan Edison Company, PPL Electric Utilities Corporation, Pennsylvania Electric Company, Philadelphia Electric Company, Potomac Electric Power Company, and UGI.

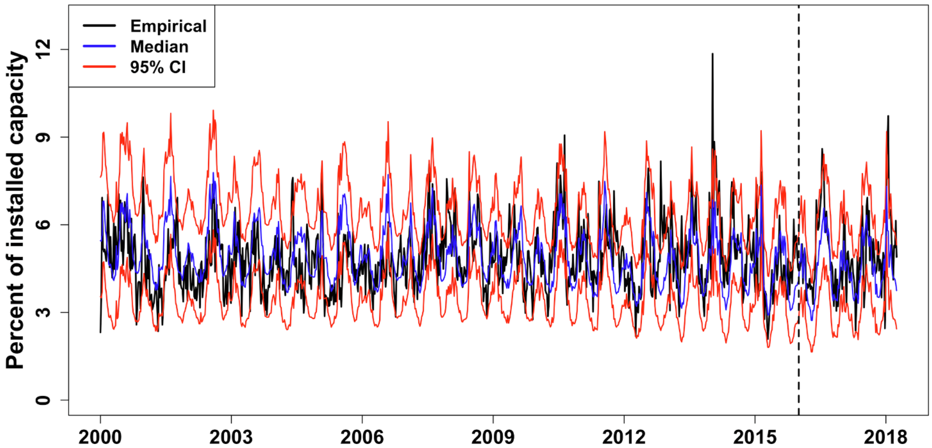

Fig. 4. Simulated time series from logistic regression model (1995–2015 model fits). Results presented for 1047 generators with at least 10 failure and recovery transitions per statistically significant model parameter when fitting on 1995–2015; 2016–2018 used as test of model performance. The split between training and testing periods is denoted with a dashed vertical line. Presented for 2000–2018 for consistency with Fig. 5. Weekly averages rather than hourly series. 5000 simulations conducted. Refer to Table A.1 for installed capacity by calendar year. Black trace is the empirical time series; blue trace is the concatenation of pointwise median simulation values; red traces are the concatenation of pointwise 2.5% and 97.5% simulation values.

Table 1
Number of times each model term is statistically significant at the 95% level for the available model (1995–2018 model fits). Only generators with at least 10 failure and recovery transitions per statistically significant model parameter are retained. CC is combined cycle, CT is simple cycle, DS is diesel, HD is hydroelectric and pumped storage, NU is nuclear, ST is steam turbine.

Generator type	Generator count	Mean hot	Mean cool	Temp hot	Temp hot^2	Temp cool	Temp cool^2	Load
CC	148	148	148	25	26	75	115	41
CT	274	274	274	59	53	110	203	228
DS	132	131	132	32	30	59	29	104
HD	125	125	125	16	14	22	35	43
NU	35	35	35	10	10	9	7	15
ST	397	397	397	70	61	103	134	285
All	1111	1110	1111	212	194	378	523	716

generators' available models; linear and quadratic cold-temperature variables are statistically significant for 34% and 47% of generators' available models; and load is statistically significant for 64% of generators' available models. For the derated model, linear and quadratic hot-temperature variables are statistically significant for 23% and 20% of generators; linear and quadratic cold-temperature variables are statistically significant for 36% and 35% of generators; and load is statistically significant for 68% of generators.

We summarize the joint statistical significance of model covariates by creating scatterplots of parameter t-values between all non-orthogonal covariate pairs, excluding constants (Figs. A.8-A.9 and Figs. B.9-B.10).[10] We observe systematic joint statistical significance between linear and quadratic temperature parameters in both sets of models, suggesting true temperature dependence rather than individual temperature parameters being significant by random chance. We include corresponding bivariate summaries of model coefficients (Figs. A.10-A.11 and Figs. B.11-B.12).

We report the number of statistically significant parameters for each generator (Table A.3 and Table B.5). We report similar information when restricting attention to linear and quadratic temperature parameters (Table A.4 and Table B.6). When fitting on the full dataset, 69% of generators have at least one statistically significant temperature covariate for the available model; 67% do for the derated model. These results demonstrate that temperature and load can have independent effects on transition probabilities. Finally, we compactly summarize variation in model predictions over the experienced covariate observations for each generator (Supplementary materials Fig. A.12 and Fig. B.13).

[10] Recall that hot-temperature covariates are defined orthogonal to cool-temperature covariates.

4. Results

In the previous section, we demonstrate that temperature and load can predict state transitions at the generator level. We use Monte Carlo simulation to demonstrate that the models can also predict correlated failures (Procedure 2). Even with our simple model specification using only temperature and load as covariates, we find that the median simulation generally tracks the empirical time series quite well (Fig. 4 and Fig B.1). The correlation between weekly average median simulation values and weekly average empirical values is 0.47 and 0.67 over the training and testing periods, respectively, for the 1995–2015 model fits and 0.47 and 0.69 during training and testing periods for the 2004–2015 fits. The motivation for fitting models using two different time periods is explained in the previous section.

Furthermore, it is rare for an empirical event to exceed the upper confidence band of our model. The largest instances of under-prediction by our model occurred during two known events in which significant generator outages were due to causes not included as covariates: the 2014 Polar Vortex (due to fuel unavailability events, which increase non-linearly in cold weather) and Hurricane Sandy (an extreme weather event but not with regard to temperature). While many other factors may contribute to generator failures and recoveries [45–47], these results demonstrate that temperature and load are strongly correlated with system-level unavailable capacity dynamics.

We next compare the performance of our model to that of current RAM practice. This entails computing an availability statistic for each generator in each planning year (Eq. (6)), and then using those statistics in Monte Carlo simulations (Procedure 3).

We plot the pointwise median and 95% confidence intervals from 5000 simulations of the current RAM practice (Fig. 5). As anticipated, the current practice approach does not capture correlated failures because the distribution of unavailable capacity is the same in every hour of a given planning year. The correlation between weekly average median simulation values and weekly average empirical values is 0.15

Table 2
Number of times each model term is statistically significant at the 95% level for the derated model (1995–2018 model fits). Only generators with at least 10 failure and recovery transitions per statistically significant model parameter are retained. CC is combined cycle, CT is simple cycle, DS is diesel, HD is hydroelectric and pumped storage, NU is nuclear, ST is steam turbine.

Generator type	Generator count	Mean hot	Mean cool	Temp hot	Temp hot^2	Temp cool	Temp cool^2	Load
CC	148	147	148	38	35	61	52	100
CT	274	270	272	65	54	104	124	242
DS	132	131	130	40	31	56	67	113
HD	125	124	124	24	16	39	41	93
NU	35	35	35	13	11	12	6	10
ST	397	397	397	73	79	125	101	192
All	1111	1104	1106	253	226	397	391	750

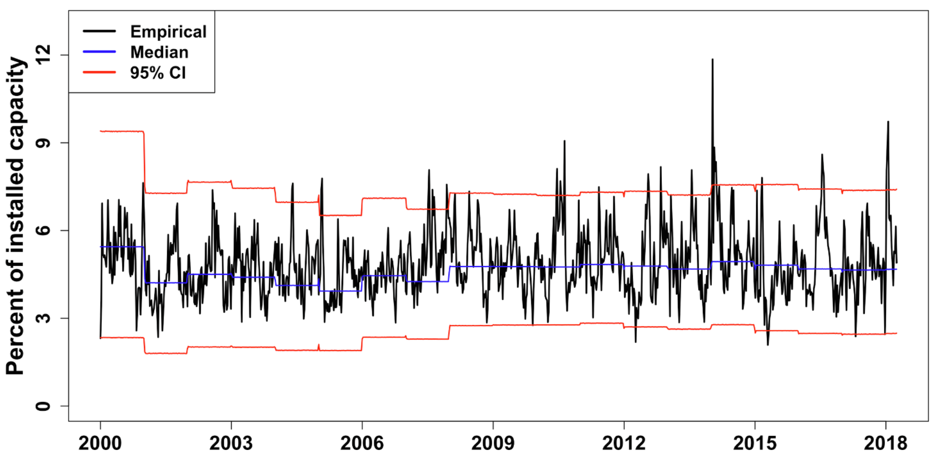

Fig. 5. Simulated time series from current practice model (1995–2015 model fits). Results presented for the same set of 1047 generators as in Fig. 4. Time series restricted to 2000–2018 because five years of data are used to calculate the availability statistic (Eq. (6)). Traces are flat within each calendar year because current practice model assumes failure probabilities are constant in each hour of a given year. Small discontinuities at year boundaries are due to weekly averaging not respecting calendar year boundaries, in conjunction with capacity additions and retirements occurring at the start of the year. Weekly averages rather than hourly series. 5000 simulations conducted. Refer to Table A.1 for installed capacity by calendar year. Black trace is the empirical time series; blue trace is the concatenation of pointwise median simulation values; red traces are the concatenation of pointwise 2.5% and 97.5% simulation values.

over 18 years and 0.11 during the testing period.[11] In addition, the pointwise 95% confidence intervals are wider than those for our model, averaging 5% of installed capacity over 18 years compared to 3.1% of installed capacity for the logistic regression model.

Comparing the two figures, we observe that the homogeneous Markov model simulating current RAM practice would both under-procure reserve generation for ~10 events and over-procure reserves most of the time. That the nonhomogeneous model tracks observed failure dynamics substantially better than the current practice model suggests its potential utility both for improving the accuracy of RAM and for predicting correlated failures over time horizons relevant to procurement of operating reserves.

4.1. Resource adequacy risk as a function of temperature and load

We next examine resource adequacy risks for the fleet of generators in PJM. For fixed values of temperature and load, each generator's available and derated models imply a stationary distribution over the available and derated states. We make use of this fact to determine the proportion of the time each generator is unavailable in expectation. By calculating this result over a range of temperature values, we determine expected unavailable capacity as a function of temperature for the modeled fleet (Procedure 4). We determine the analogous result under current modeling practice by first computing an unconditional transition probability matrix for each generator using all available years of data and then following the remainder of the inner loop of Procedure 4. We present results by generator type (Fig. 6 and Fig. B.14) and report the prevalence of temperatures experienced by the fleet of modeled generators (Fig. A.13 and Fig. B.15).

With the exception of nuclear, all generator types perform worse in very cold weather than recognized under current modeling practice. This result is consistent with analysis conducted by PJM [2]. Poor cold-weather performance is particularly pronounced for gas and diesel generators. In addition, all generator types perform worse in very hot weather than recognized under current practice. Because loads are high at both temperature extremes, the resource adequacy risk implied by these performance penalties is compounded: less generation capacity is available when demand is greatest. In power systems with organized forward-capacity markets, these temperature-dependent performance penalties could be used to improve capacity payments. Rather than use a generator's unconditional forced outage rate to determine capacity payments [48], thereby penalizing the generator for its average unavailability, the grid planner could calculate a conditional forced outage rate during relevant extreme weather conditions that represent increased resource adequacy risk.

Finally, we repeat the preceding analysis switching the role of temperature and load in order to visualize resource adequacy risk as a function of load. Because the relationship between load and unavailable capacity could be different at high and low temperatures, we generate two sets of results: one for observations where the temperature is below 18.3 degrees, and one for observations where temperature is above 18.3 degrees. With these modifications, we repeat Procedure 4. We again present results by generator type (Figs. A.14-A.15 and Figs. B.16-B.17).

In Fig. A.14, at median temperature values, only coal generators at very high loads show noticeable divergence from the unconditional level of unavailable capacity. When considering low-percentile temperatures, gas and diesel generators also exhibit divergence from the unconditional result at higher loads. Nuclear generators show no load response for cold-temperature observations, regardless of load level or temperature quantile, consistent with Fig. 6. In Fig. A.15, coal and nuclear generators diverge from their respective unconditional levels of unavailable capacity at high loads regardless of temperature percentile considered. Diesel generators show some divergence at very low loads.

[11] Note that the predictions of the current practice model are always out of sample, in contrast with those of the logistic regression model prior to 2016.

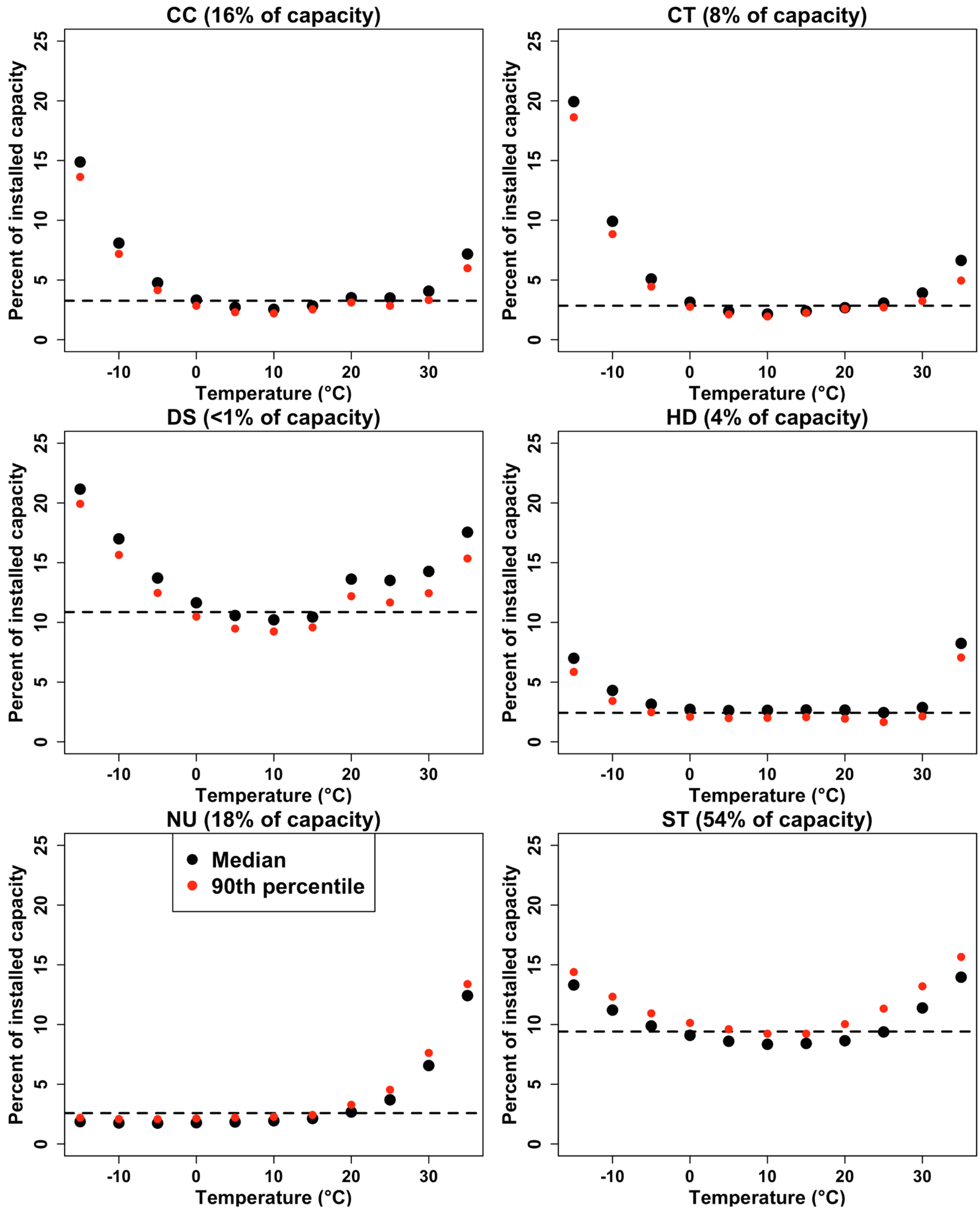

Fig. 6. Expected levels of unavailable capacity as a function of temperature under logistic regression (dots) and current practice (dashed horizontal line) (1995–2018 model fits). Black dots calculated using median load from temperature neighborhood, red dots calculated using 90th percentile load from temperature neighborhood. Temperature neighborhood is defined as ± 10 degrees. Not all generators experience full temperature range; see Fig. A.13 for prevalence of temperatures. CC is combined cycle, CT is simple cycle, DS is diesel, HD is hydroelectric and pumped storage, NU is nuclear, ST is steam turbine.

5. Discussion

We have presented a model of how correlated failures previously identified in the North American power system [8] can occur. Our approach is a novel, computationally tractable generalization of the traditional two-state Markov model widely used in power system reliability analyses [11]. We demonstrate a simple specification in which transition probabilities between the available and derated states are modeled as a function of temperature and load, but we note that any desired covariates could be employed.

We fit these models using logistic regression with 23 years of availability data for 1845 generators serving the PJM regional transmission organization. To reduce bias, we discard any generator with fewer than 10 failure or recovery events per statistically significant covariate. We retain 78% of the generation capacity that has ever reported to PJM GADS. We find that temperature and load can predict generator transitions: temperature and load are each statistically significant for two-thirds of the retained generators.

We demonstrate that our model specification captures most of the correlated failures observed in PJM since 2000 and that it significantly outperforms the homogeneous Markov model underlying current resource adequacy modeling practice. The correlation of our median simulation with the observed series of unavailable capacity at the weekly level is 0.47 over 18 years, whereas that of the median simulation from current practice is 0.15. Our model also has narrower confidence intervals, averaging 3.1% of installed capacity compared to 5% for current practice.

6. Conclusions

We demonstrate that all generator types are susceptible to increased probability of failure at extreme temperatures. With the exception of nuclear generators, which have reduced availability during only hot weather, all generator types have reduced availability at both temperature extremes. The cold-weather penalty for gas and diesel generators is particularly pronounced, as is the hot-weather penalty for nuclear generators. These availability penalties, which represent temperature-dependent forced outage rates, could be used to determine capacity payments that better incentivize generators to be available during key times of grid stress. Finally, we demonstrate that nuclear and coal generators experience an availability penalty at high loads; for nuclear generators this penalty is present only in conjunction with high temperatures. These risks are not captured in current approaches to resource adequacy modeling.

Taken together, our results demonstrate that there are systematic relationships between temperature, load, and generator availability. Accounting for these relationships, as we have done here, is likely to enable more accurate determination of power system reserve capacity requirements. In particular, given that peak loads typically coincide with either very low or very high temperatures, the relationships we have identified suggest that current RAM practice may be underestimating power system reserve capacity requirements. Future work should examine the specific causes of the temperature dependence of generator availability and what improvements in reserves procurement can be achieved now that correlated failures can be successfully modeled.

Acknowledgements

This research was supported in part by the Carnegie Mellon Climate and Energy Decision Making Center (CEDM), formed through a cooperative agreement between the National Science Foundation and CMU (SES-0949710) and in part by the Electric Power Research Institute. No funding source had any role in study design, in analysis or interpretation of data, in the writing of the paper, or in the decision to submit it for publication. We are grateful to Tom Falin for access to the PJM GADS data. We thank Patricio Rocha-Garrido and Francis J. Bell III for many helpful discussions.

Declaration of Competing Interest

The authors declare no conflicts of interest.

Appendix A. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2019.113513.

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Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-7

2019 PJM Reserve Requirement Study

11-year Planning Horizon:

June 1st 2019 - May 31st 2030

Analysis Performed by PJM Staff

Reviewed by Resource Adequacy Analysis Subcommittee

October 8, 2019

pjm

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I. Results and Recommendations

PJM RRS Executive Summary

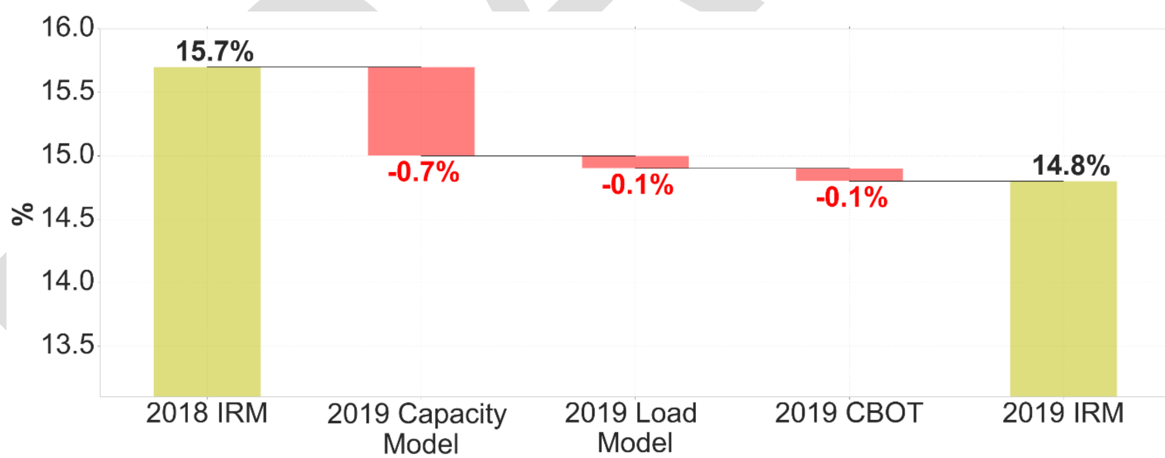
- The PJM Reserve Requirement Study's (RRS) purpose is to determine the Forecast Pool Requirement (FPR) for future Delivery Years, through calculating the Installed Reserve Margin (IRM). In accordance with the Reliability Pricing Model (RPM) auction schedule, results from this study will re-establish the FPR for the 2020/2021, 2021/2022, and 2022/2023 Delivery Years (DY) and establish the FPR for the 2023/24 Delivery Year.

- PJM uses this Study to satisfy the North America Electric Reliability Corporation (NERC) / ReliabilityFirst (RF) Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment and Documentation. This Standard requires that the Planning Coordinator performs and documents a resource adequacy analysis that applies a Loss of Load Expectation (LOLE) of one occurrence in ten years. Per the final 2010 RF audit report, PJM was found to be fully compliant with Standard BAL-502-RFC-02.

- Based on results from this Study, PJM Staff recommends a **15.5% IRM (1.0882 FPR) for the 2020/2021 Delivery Year, a 15.1% IRM (1.0870 FPR) for the 2021/2022 Delivery Year, a 14.9% IRM (1.0867 FPR) for the 2022/2023 Delivery Year, and a 14.8% IRM (1.0860 FPR) for the 2023/2024 Delivery Year**.

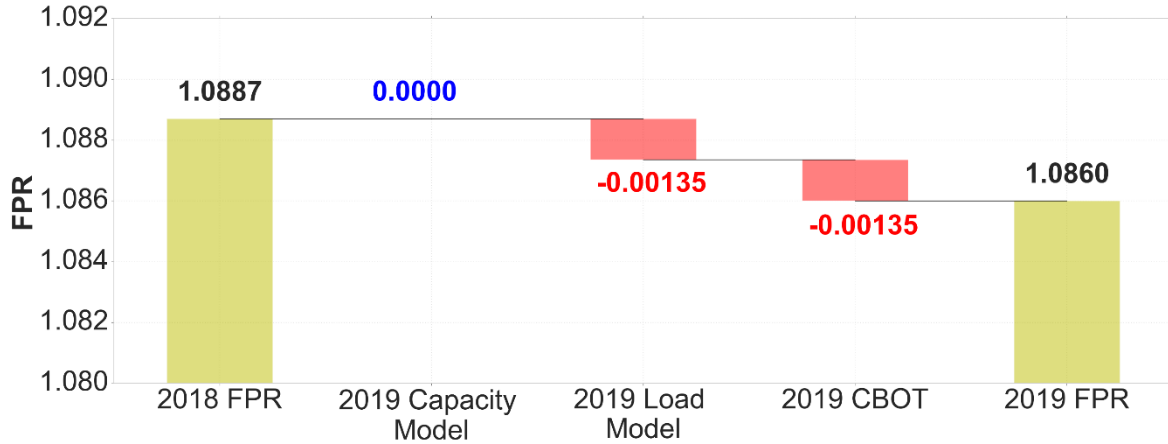
- The 14.8% IRM for 2023/2024 calculated in this year's study represents a decrease of 0.9 percentage points with respect to the IRM computed for 2022/2023 in last year's study. The decrease can be attributed to the factors and their estimated corresponding quantitative impacts depicted in Figure I-1.

Figure I-1: 2019 Installed Reserve Margin Waterfall Chart



- The 1.0860 (8.60%) FPR for 2023/2024 calculated in this year's study represents a decrease of 0.27 percentage points with respect to the FPR computed for 2022/2023 in last year's study (1.0887 or 8.87%). The decrease can be attributed to the factors and their estimated corresponding quantitative impacts depicted in Figure I-2 below.

Figure I-2: 2019 Forecast Pool Requirement Waterfall Chart



- The IRM decrease is driven by a lower average EEFORd in the 2019 PJM Capacity Model (6.1%) relative to the average EEFORd in the 2018 PJM Capacity Model (6.7%). To a lesser extent, the IRM decrease can also be attributed to: i) a lower August-to-July PJM peak ratio (96.5% in the 2019 Load Model compared to 97.0% in the 2018 Load Model) and ii) an increase in the emergency imports available from the World into PJM (i.e., an increase in the Capacity Benefit of Ties or CBOT).

- The FPR decrease is driven by the lower August-to-July PJM peak ratio and the increase in emergency imports available from the World into PJM, both discussed above. Changes to the capacity model largely have no impact on the FPR because the FPR corresponds to the IRM expressed in unforced capacity units (i.e., the FPR corresponds to the IRM decremented by the average forced outage rate).

- The results of the 2019 RRS are summarized below in Table I-1. PJM Staff recommends the values shown in bold in the following table.

Table I-1: 2019 Reserve Requirement Study Summary Table

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2019	2020 / 2021	15.46%	**15.5%**	5.78%	**1.0882**
2019	2021 / 2022	15.14%	**15.1%**	5.56%	**1.0870**
2019	2022 / 2023	14.89%	**14.9%**	5.42%	**1.0867**
2019	2023 / 2024	14.84%	**14.8%**	5.40%	**1.0860**

- For comparison purposes, the results from the 2018 RRS Study are below in Table I-2:

Table I-2: 2018 Reserve Requirement Study Summary Table

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2018	2019 / 2020	15.97%	**16.0%**	6.08%	**1.0895**
2018	2020 / 2021	15.89%	**15.9%**	6.04%	**1.0890**
2018	2021 / 2022	15.84%	**15.8%**	6.01%	**1.0884**
2018	2022 / 2023	15.66%	**15.7%**	5.90%	**1.0887**

- The Winter Weekly Reserve Target (WWRT) for the **2019/2020 winter period is recommended to be 22% for December 2019, 28% for January 2020, and 24% for February 2020**. The analysis supporting this recommendation is detailed in the "Operations Related Assessments" section of this report.

- The winter peak week capacity model changes approved by the Markets and Reliability Committee (MRC) in June 2018 and first implemented in the 2018 RRS were also used in the 2019 RRS. These changes had no practical impact on the recommended IRM and FPR values. The recommended WWRT value for January described in the bullet point above, however, is impacted by these changes due to the fact that the winter peak week is modeled to occur in January.

- The IRM and FPR recommended in Table I-1 are reviewed and considered for endorsement by the following succession of groups.

  - Resource Adequacy Analysis Subcommittee (RAAS)
  - Planning Committee (PC)
  - Markets and Reliability Committee (MRC)
  - PJM Members Committee (MC)
  - PJM Board of Managers (for final approval)

- PJM's Probabilistic Reliability Index Study Model (PRISM) program is the primary reliability modeling tool used in the RRS. PRISM utilizes a two-area Loss of Load Probability (LOLP) modeling approach consisting of: Area 1 - the PJM RTO and Area 2 - the neighboring World.

- The PJM RTO includes the PJM Mid-Atlantic Region, Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (Dom), Duquesne Light Co. (DLCO), American Transmission System Inc. (ATSI), Duke Energy Ohio and Kentucky (DEOK), and East Kentucky Power Cooperative (EKPC). In addition, the PJM RTO includes for the first time the recently integrated Ohio Valley Electric Corporation (OVEC).

- The Outside World (or World) area consists of the North American Electric Reliability Corporation (NERC) regions adjacent to PJM. These regions include New York ISO (NYISO) from the Northeast Power Coordinating Council

(NPCC), TVA and VACAR from the South Eastern Reliability Corporation (SERC), and the Midcontinent Independent System Operator (MISO) (excluding MISO-South).

- Modeling of the World region assumes a Capacity Benefit Margin (CBM) of 3,500 MW into PJM, which serves as a maximum limit on the amount of external assistance. The CBM is set to 3,500 MW per Schedule 4 of the PJM Reliability Assurance Agreement. Figure I-7 shows the benefit of this interconnection at various values of CBM.
- There is a net addition of approximately 6,400 MW of generation within the PJM RTO in the period 2019-2023. This reflects approximately 15,000 MW of new generation and 8,600 MW of retired generation. The RRS study does not include Demand Resources.
- For the fifth year in a row, the load model time period 2003-2012 was used in the RRS study. This load model time period was endorsed at the July 11, 2019 Planning Committee meeting.
- Consistent with the requirements of ReliabilityFirst (RF) Standard BAL-502-RFC-02 - Resource Planning Reserve Requirements, the 2019 RRS provides an eleven-year resource adequacy projection for the planning horizon that begins June 1, 2019 and extends through May 31, 2030. (See Table I-4)

Results from the last ten RRS Reports are summarized below in Table I-3:

Table I-3: Historical RRS Parameters

RRS Year	Delivery Year	Calculated IRM	**Approved IRM**	Avg. EFORd	**FPR**
2009	2012/2013	15.4%	**15.4%**	6.28%	**1.0815**
2009	2013/2014	15.3%	**15.3%**	6.30%	**1.0804**
2010	2012/2013	15.5%	**15.5%**	6.26%	**1.0827**
2010	2013/2014	15.3%	**15.3%**	6.25%	**1.0809**
2010	2014/2015	15.3%	**15.3%**	6.25%	**1.0809**
2011	2012/2013	15.6%	**15.6%**	6.58%	**1.0869**
2011	2013/2014	15.4%	**15.4%**	6.52%	**1.0859**
2011	2014/2015	15.4%	**15.4%**	6.51%	**1.0860**
2011	2015/2016	15.4%	**15.4%**	6.52%	**1.0859**
2012	2013/2014	15.9%	**15.9%**	6.73%	**1.0889**
2012	2014/2015	15.9%	**15.9%**	6.72%	**1.0889**
2012	2015/2016	15.3%	**15.3%**	6.59%	**1.0849**
2012	2016/2017	15.6%	**15.6%**	6.38%	**1.0902**
2013	2014/2015	16.2%	**16.2%**	6.66%	**1.0926**
2013	2015/2016	15.7%	**15.7%**	6.26%	**1.0920**
2013	2016/2017	15.7%	**15.7%**	6.29%	**1.0917**
2013	2017/2018	15.7%	**15.7%**	6.29%	**1.0916**
2014	2015/2016	15.6%	**15.6%**	6.19%	**1.0913**
2014	2016/2017	15.5%	**15.5%**	6.30%	**1.0896**
2014	2017/2018	15.7%	**15.7%**	6.34%	**1.0911**
2014	2018/2019	15.7%	**15.7%**	6.35%	**1.0835**
2015	2016/2017	16.4%	**16.4%**	6.57%	**1.0952**
2015	2017/2018	16.5%	**16.5%**	6.59%	**1.0959**
2015	2018/2019	16.5%	**16.5%**	6.58%	**1.0883**
2015	2019/2020	16.5%	**16.5%**	6.60%	**1.0881**
2016	2017/2018	16.6%	**16.6%**	6.54%	**1.0967**
2016	2018/2019	16.7%	**16.7%**	6.59%	**1.0901**
2016	2019/2020	16.6%	**16.6%**	6.59%	**1.0892**
2016	2020/2021	16.6%	**16.6%**	6.59%	**1.0892**
2017	2018/2019	16.1%	**16.1%**	6.07%	**1.0905**
2017	2019/2020	15.9%	**15.9%**	5.99%	**1.0896**
2017	2020/2021	15.9%	**15.9%**	5.97%	**1.0898**
2017	2021/2022	15.8%	**15.8%**	5.89%	**1.0898**
2018	2019/2020	16.0%	**16.0%**	6.08%	**1.0895**
2018	2020/2021	15.9%	**15.9%**	6.04%	**1.0890**
2018	2021/2022	15.8%	**15.8%**	6.01%	**1.0884**
2018	2022/2023	15.7%	**15.7%**	5.90%	**1.0887**

Introduction

Purpose

The annual PJM Reserve Requirement Study (RRS) calculates the reserve margin that is required to comply with the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA) and ReliabilityFirst (RF) Standard BAL-502-RFC-02. This study is conducted each year in accordance with PJM Manual 20 (M-20), PJM Resource Adequacy Analysis. M-20 focuses on the process and procedure for establishing the resource adequacy (capacity) required to reliably serve customer load in the PJM RTO.

The RRS results are key inputs to the PJM Reliability Pricing Model (RPM). These inputs include the Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR). More specifically, the FPR is used to calculate the Reliability Requirement for the PJM Regional Transmission Organization (RTO) in RPM Auctions.

The results of the RRS are also incorporated into PJM's Regional Transmission Expansion Plan (RTEP) process for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the PJM Region.

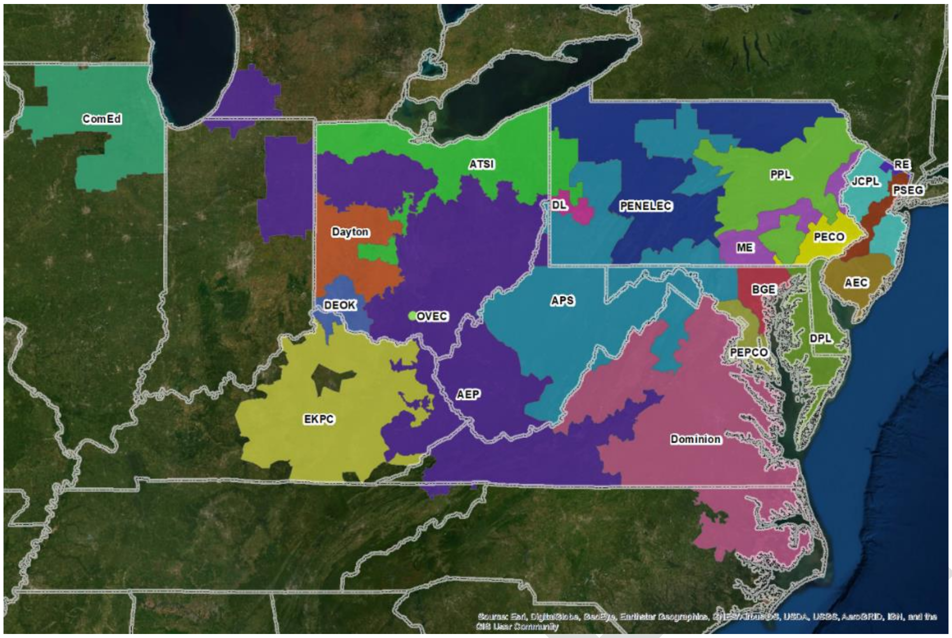
Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR)

In addition to serving as inputs for the RPM market, the IRM and FPR calculated in the RRS are critical values as they satisfy compliance requirements for ReliabilityFirst (RF). (See Section II. For further details on the process, contact regional_compliance@pjm.com.)

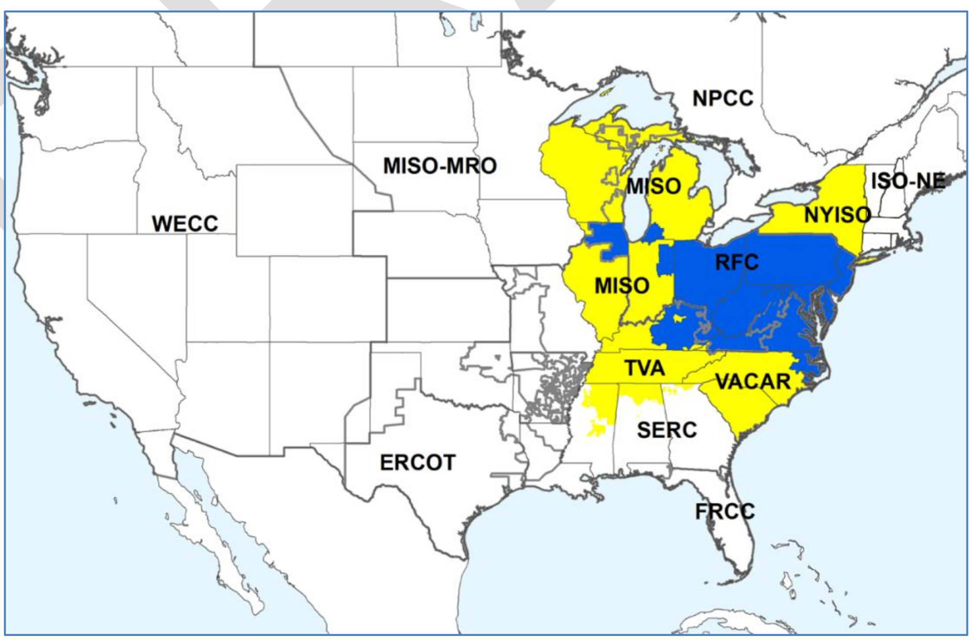
The timetable for calculating and approving these values is shown in the June 2019 study assumptions letter to the PC, reviewed as agenda item 5 at the June 13, 2019 PC meeting.

Regional Modeling

This study examines the combined PJM footprint area (
Figure I-3) that consists of the PJM Mid-Atlantic Region plus Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (DOMVP), Duquesne Light Co. (DLCO), American Transmission System Inc. (ATSI), Duke Energy Ohio and Kentucky (DEOK), and East Kentucky Power Cooperative (EKPC). In addition, the PJM RTO includes for the first time the recently integrated Ohio Valley Electric Corporation (OVEC).



Areas adjacent to the PJM Region are referred to as the World (Figure I-4) and consist of MISO (excluding MISO-South), TVA and VACAR (both in SERC), and NYISO from the Northeast Power Coordinating Council (NPCC). Areas outside of PJM and the World are not modeled in this study.



Summary of RRS Results

Eleven-Year RRS Results

Table I-4 shows an eleven-year forward projection from the study for informational purposes. The Delivery Years for which the parameters must be reported are highlighted in yellow. These results do not reflect any previous modeling or approved values. Note that the projected reserves in column H exceed the IRM in column A for each of the next eleven Delivery Years. The study, therefore, indicates there are no gaps between the needed amount of planning reserves and the projected planning reserves over the eleven-year study period.

Table I-4: Eleven-Year Reserve Requirement Study

	Calculated IRM					Forecast Reserve				
	A	B	C	D	E	F	G	H	I	J
Delivery Year	IRM PJM RTO % (2 area)	IRM Outside World %	Average PJM EEFORd %	Average Weekly Maintenance %	Forecast Pool Require-ment (FPR)	Capacity MW	Restricted Load MW	Forecast Reserve PJMRTO %	Forecast Unrestricted Reserve PJM RTO %	PJM Reliability Index without World Assistance (years/day)
2019	15.6%	16.6%	6.7%	8.5%	1.0879	187,434	143,204	30.9%	23.8%	5.9
2020	15.5%	16.6%	6.6%	8.4%	1.0882	183,991	141,743	29.8%	22.0%	5.8
2021	15.1%	16.6%	6.3%	8.2%	1.0870	185,507	142,429	30.2%	22.4%	5.9
2022	14.9%	16.6%	6.2%	8.1%	1.0867	189,151	143,193	32.1%	24.4%	5.9
2023	14.8%	16.6%	6.1%	8.2%	1.0860	192,142	143,771	33.6%	25.9%	5.9
2024	14.8%	16.6%	6.1%	8.3%	1.0861	193,269	144,310	33.9%	26.1%	5.9
2025	14.8%	16.6%	6.1%	8.4%	1.0861	193,269	144,821	33.5%	25.7%	5.9
2026	14.8%	16.5%	6.1%	8.4%	1.0861	193,269	145,283	33.0%	25.3%	5.9
2027	14.8%	16.5%	6.1%	8.4%	1.0861	193,269	145,873	32.5%	24.8%	5.9
2028	14.8%	16.5%	6.1%	8.4%	1.0861	193,269	146,620	31.8%	24.2%	5.9
2029	14.8%	16.5%	6.1%	8.4%	1.0861	193,269	147,373	31.1%	23.5%	5.9

Calculated IRM Columns (PRISM Run # 57086)

- Calculated IRM, column A is at an LOLE criterion of 1 day in 10 years.
- Column A is based on the PRISM solved load, not the January 2019 load forecast values issued by PJM.
- Calculated IRM, column B is the World IRM at an LOLE criterion of 1 day in 10 years which is within the valid range shown in Table I-5 (15.24% to 20.14%). The exact World reserve value depends on World load management actions at the time of the PJM RTO's need for assistance. The World reserve levels in Column B that yield a PJM Reliability Index (RI) equal to an LOLE of 1 day in 10 years are within the valid range.
- Results reflect calculated (to the nearest decimal) reserve requirements for the PJM RTO (column A) and the Outside World (column B).
- Calculated IRM results are determined using a 3,500 MW Capacity Benefit Margin (CBM).
- The Average Effective Equivalent Demand Forced outage rate (EEFORd) (column C) is a pool-wide average effective equivalent demand forced outage rate for all units in the PJM RTO model (about 1,500 units). These are not the forced outage rates used in the RAA Obligation formula (as mentioned earlier in the document, EFORd

values are used in the FPR formula). The EEFORd of each unit is based on a five-year period (2014-2018, for this year's study).

- The average weekly maintenance (column D) is the percentage of the average annual total capacity in the model out on weekly planned maintenance.

Forecast Reserve Columns

- The capacity values in Column F include external firm capacity purchases and sales.
- 2,500 MW of unit deratings were modeled to reflect generator performance impacts during extreme hot and humid summer conditions. These 2,500 MW are included in the Column F value.
- The Restricted Load in Column G corresponds to Total Internal Demand (at peak time) minus load management as per the 2019 PJM Load Forecast.
- The PJM forecast reserves are above the calculated requirement (see Column H vs. Column A for years in yellow).
- Reserves in Column H (as well as the capacity value in Column F) include about 15,000 MW of new generation projects identified through the Regional Transmission Expansion Plan (RTEP). Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) are included in the study at their capacity MW value.
- The RTEP is dynamic and actual PJM reserve levels may differ significantly from those forecasted in Column H. An additional factor contributing to future reserve margin uncertainty is the fact that PJM allows units to retire with as little as 90 days' notice as per PJM's Manual 14D.

PJM Reliability Index without World Assistance

- The values in Column J are for informational purposes only. PJM Reliability Index (RI) is expressed in years per day (the inverse of the days per year LOLE). This column indicates reliability when all external ties into PJM are cut ("zero import capability" scenario) for the corresponding PJM IRM in Column A.
- In other words, the values in Column J represent the frequency of loss of load occurrences if the PJM RTO were not part of the Eastern Interconnection. Compared to the 1 in 10 criteria (RI = 10), the values in Column J are much lower. This comparison provides a sense of the value of PJM being strongly interconnected. More specifically, if PJM were not interconnected, it could experience loss of load events roughly twice as often (at a reserve margin level equal to the IRM).

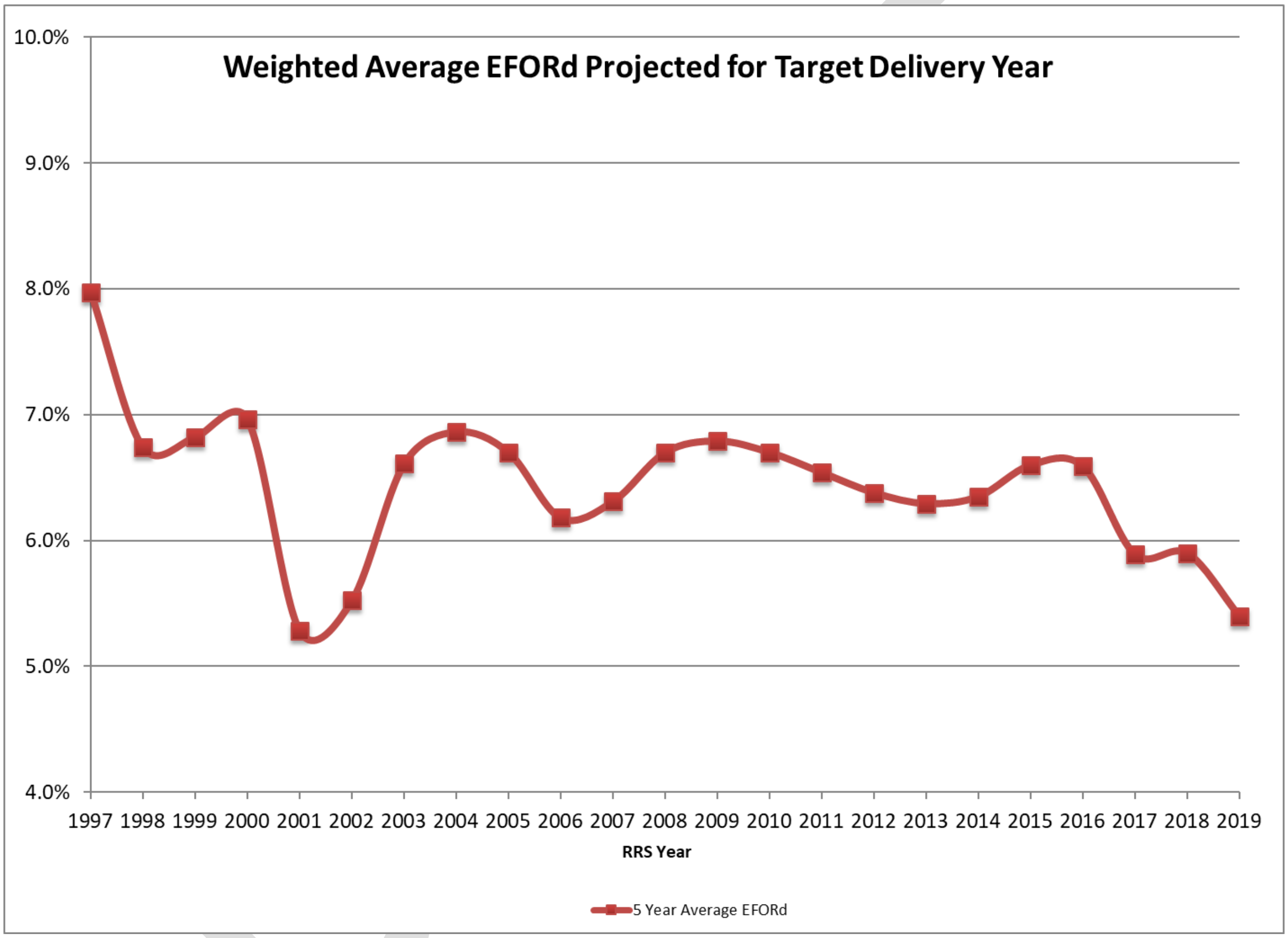
Key Observations

- General Trends and Observations
    - Pool wide average forced outage rate values (EFORd) for the target Delivery Year, in each of the annual RRS capacity models, are shown in Figure I-5. The forced outage rates of each unit are based on the historical five-year period used in a given study. It is important to note that the collection of generators included in each year's case varies greatly over time as new generators are brought in-service, some generators retire or mothball, and new generators are added due to PJM market expansion.

    - As shown in Figure I-5, average unit performance in the 2019 study model is significantly better than the unit performance in the 2018 study model (the weighted average EFORd in the 2019 RRS is 5.40% while in the 2018 RRS it was 5.90%). As a result, there is downward pressure on the IRM (estimated at 0.7 percentage points).

- This decrease in weighted average EFORd is due to the changes in the projected composition of the fleet for Delivery Year 2023/24: a large amount of deactivations (~8,600 MW) with high weighted average EFORd (10.8%) and a large amount of additions (~15,000 MW) with low weighted average EFORd (3.6%) are projected to occur prior to Delivery Year 2023/24.

Figure I-5: Historical Weighted-Average Forced Outage Rates (Five-Year Period)



- The World reserves were assessed and modeled in a similar manner as performed in previous RRS studies. Among the regions modeled as part of the World, the New York and MISO regions have firm reserve requirements, while the TVA and VACAR regions have soft targets. The soft targets chosen are consistent with general statements of the NERC targets for these regions. Table I-5 summarizes the values used to determine a valid range for a World reserve level of 15.24% to 20.14%. The reserve requirements considered for each region are shown in the IRM column. The diversity values shown are from an assessment of historic data, using the average of the values observed over the summer season. See Table II-3 for further details. Please reference Appendix F which presents a discussion of the modeling assumptions. It was agreed upon by the RAAS in previous years that the appropriate choice for World reserves is the one that satisfies the 1 in 10 reliability criterion for the World as long as it is within the valid range. This value in the 2019 study is 16.6% and it is within the valid range shown in Table I-5.

Table I-5: World Reserve Level, Valid Range to Consider

	NCP	IRM	Diversity	CP	LM	LM as % NCP	NCP- LM (NID)	CAP based on NID	CP- LM	Reserves as % of CP	Reserves as % of CP- LM
NY	32429	16.8%	0.9458	30670	925	2.85%	31504	36797	29745		
MISO	95216	16.8%	0.9902	94287	4552	4.78%	90664	105896	89735		
TVA	41526	15.0%	0.9536	39600	1795	4.32%	39731	45691	37805		
VACAR	42684	15.0%	0.9469	40419	1090	2.55%	41594	47833	39329		
Total Composite Region =	211855			204977	8362	3.95%	203493	236216	196615	15.24%	20.14%

LM: Load Management NCP: Non-Coincident Peak CP: Coincident Peak

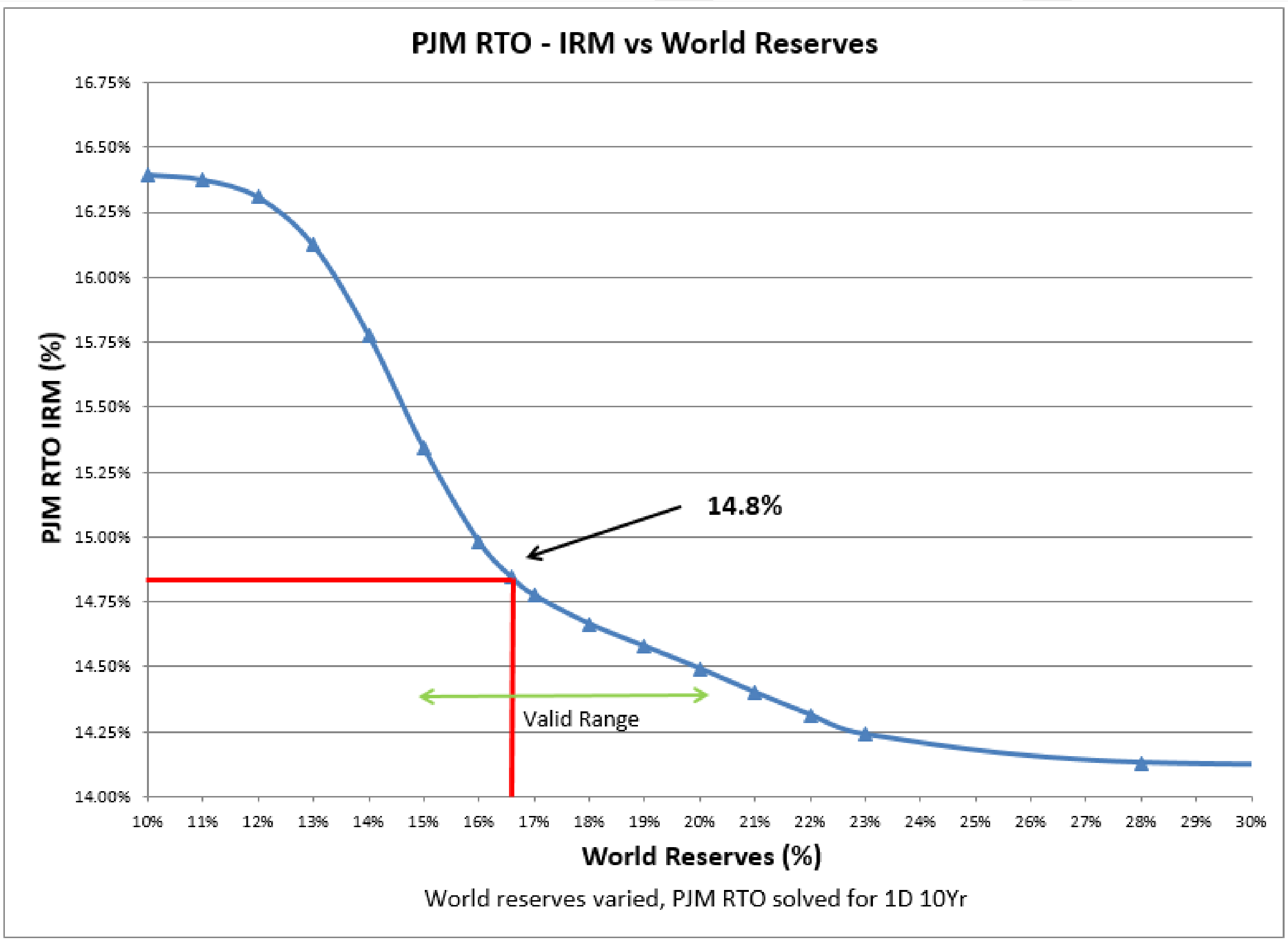
Data Sources

NY - NPCC Reliability Assessment for Summer 2019, Appendix VIII, Table 4 & Table 6, April 2019
Available at https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_2019_Summer_Assessment.pdf
MISO - 2018 NERC ES&D Report - Peak Hour Demand Seasonal, 1st Year column
MISO excludes MISO-South
MISO LM Total from 2018 NERC ES&D Report- Controllable and Dispatchable Demand Response - Available (Year 1)
TVA and VACAR - 2018 NERC ES&D Report
Peak Hour Demand Seasonal, 1st Year column. TVA = SERC N (Summer), VACAR = SERC E (Winter)
Demand & Resources - Summer, Controllable and Dispatchable Demand Response - Available (Year 1). TVA = SERC N, VACAR = SERC E
NY and MISO are modeled at their approved IRMs as per the documents below:
http://www.nysrc.org/pdf/Reports/2019%20IRM%20Study%20Body-Final%20Report[6815].pdf
https://cdn.misoenergy.org/2019%20LOLE%20Study%20Report285051.pdf
TVA and VACAR are modeled at the soft target IRM of 15%.

- Load diversity between PJM and the World is addressed by two modeling assumptions. First, the historical period used to construct the hourly load model is the same for PJM and the World. Second, the world load model corresponds to coincident peaks from the four individual sub-regions.

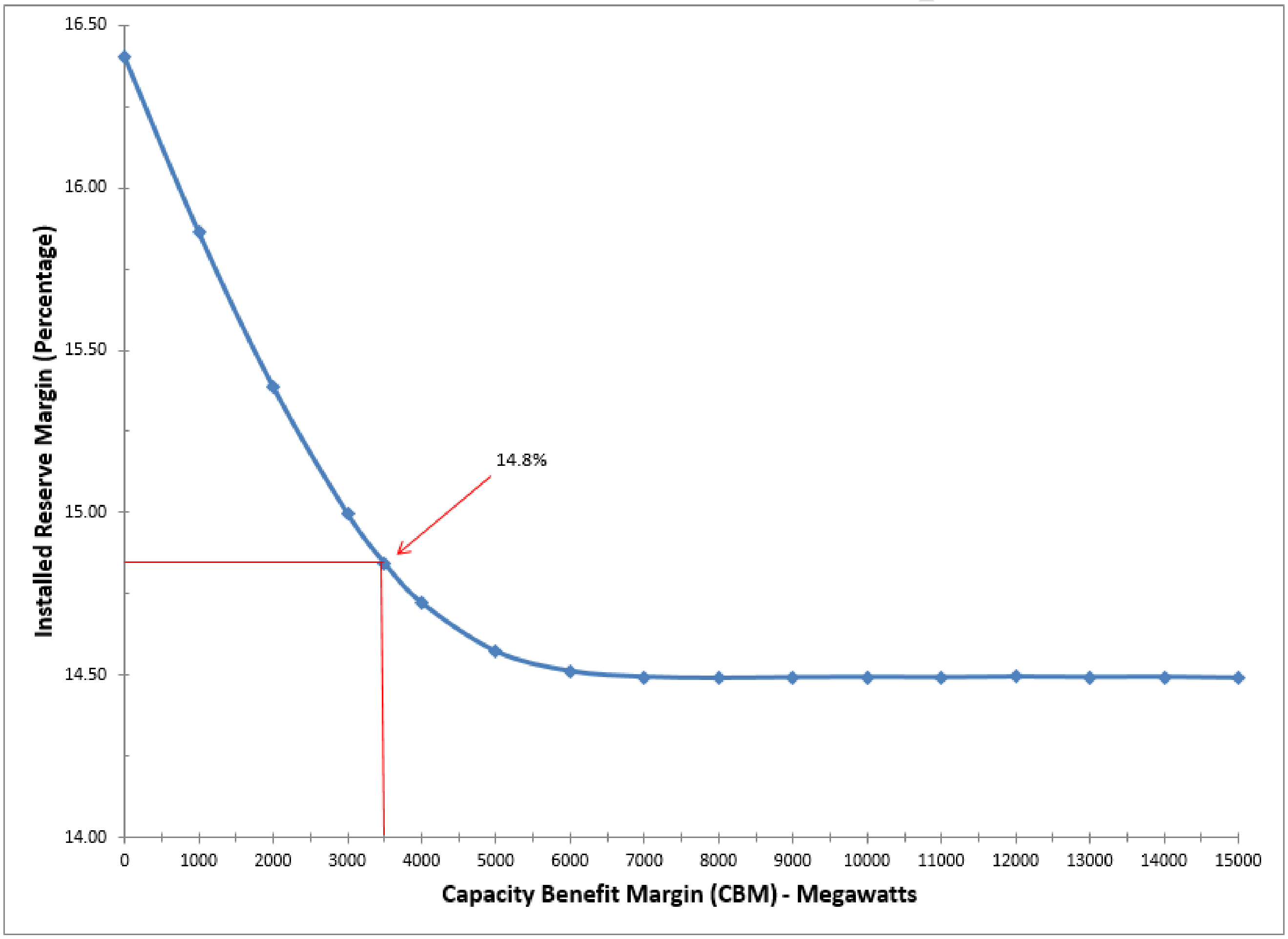
- Figure I-6 shows the impact of the World reserves on the PJM RTO IRM. This figure assumes a CBM value of 3,500 MW at all World reserve levels. The green horizontal line labeled “valid range” shows the range of World generation reserve levels depending on the amount of World load management assumed to be curtailed or to have voluntarily reduced consumption in response to economic incentives, at the time of a PJM capacity emergency. The lower end of the range (at 15.24%) represents the World reserve level if no World load management were implemented. The higher end (at 20.14%) is the reserve level assuming all World load management is implemented or customers have reduced their loads at the time of a PJM emergency. Figure I-6 indicates that the impact of additional World Reserves on PJM’s IRM tends to decrease as World Reserves are outside of the valid range (above 19%).
- The PJM IRM at this “1 in 10” World reserve level is 14.84%. This is the basis for the recommended IRM, for Delivery Year 2023/2024, of 14.8%.

Figure I-6: Relation between the IRM and World Reserves



- Figure I-7 shows how the PJM IRM varies as the CBM is varied. As indicated by the red line, the official CBM value of 3,500 MW results in a PJM IRM of 14.8%. Thus, the PJM IRM is reduced by 1.6% due to the CBM (from 16.4%, the intercept with the y-axis, to 14.8 %). Based on the forecasted load for 2023/2024, this 1.6% IRM reduction eliminates the need for about 152,624 MW x 1.6% = 2,442 MW of installed capacity. Therefore, the Capacity Benefit of Ties (CBOT) in this year's study is 2,442 MW.

Figure I-7: Relation between the IRM and the CBM



- The underlying modeling characteristics of load, generation, and neighboring regions' reserves / tie size are the primary drivers for the results of the study. Although consideration of the amount in MW of either load or generation can be a factor, it is not as significant due to the method employed to adjust an area's load until its LOLE meets the 1 day in 10 years reliability criterion. Small changes to the parameters that capture uncertainties associated with load and generation can impact the assessment results.

Recommendations

- Installed Reserve Margin (IRM) — based on the study results and the additional considerations mentioned above, PJM recommends endorsement of an IRM value of 15.5% for the 2020/2021 Delivery Year, 15.1% for the 2021/2022 Delivery Year, 14.9% for the 2022/2023 Delivery Year, and 14.8% for the 2023/2024 Delivery Year. The IRM is applied to the official 50/50 PJM Summer Peak Forecast which corresponds to the Expected Weekly Maximum (EWM) of the peak summer week in PRISM.

- Forecast Pool Requirement (FPR) — the approved IRM is converted to the FPR for use in determining capacity obligations. The FPR expresses the reserve requirement in unforced capacity terms. The FPR is defined by the following equation:
    - FPR = (1 + IRM) * (1 – PJM Avg. EFORd)

- Based on the recommended IRM values, the resulting FPRs would therefore be:
    - 2020 / 2021 Delivery Year FPR = (1.155) * (1 – 0.0578) = 1.0882
    - 2021 / 2022 Delivery Year FPR = (1.151) * (1 – 0.0556) = 1.0870
    - 2022 / 2023 Delivery Year FPR = (1.149) * (1 – 0.0542) = 1.0867
    - 2023 / 2024 Delivery Year FPR = (1.148) * (1 – 0.0540) = 1.0860

- Winter Weekly Reserve Target — the recommended 2019 / 2020 Winter Weekly Reserve Target is 22% for December 2019, 28% for January 2020, and 24% for February 2020. This recommendation is discussed later in the report.

II. Modeling and Analysis

Load Forecasting

PJM Load Forecast – January 2019 Load Report

The January 2019 PJM Load Forecast is used in the 2019 RRS. The load report is available on the PJM web site at: https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx?la=en. The methods and techniques used in the load forecasting process are documented in Manual 19 (Load Forecasting and Analysis).

Monthly Forecasted Unrestricted Peak Demand and Demand Resources

The monthly loads used in the RRS are based on forecasted monthly unrestricted peak loads. PJM monthly loads are from the 2019 PJM Load Forecast report. World monthly loads are derived through an examination of data from NERC's Electric Supply and Demand (ES&D) dataset. These values are in Table II-1 on a per-unit basis relative to the annual peak.

Table II-1: Load Forecast for 2023 / 2024 Delivery Years

Month	PJMRTO Unrestricted Loads	WORLD Unrestricted Loads
June	0.939852	0.954062
July	1.000000	1.000000
August	0.965418	0.994266
September	0.858779	0.903074
October	0.715088	0.731715
November	0.724906	0.760636
December	0.829480	0.834440
January	0.874708	0.859573
February	0.835339	0.820173
March	0.752269	0.763302
April	0.715241	0.688069
May	0.789726	0.805279

Forecast Error Factor (FEF)

The Forecast Error Factor (FEF) represents the increased uncertainty associated with forecasts covering a longer time horizon. The FEF is 1.0% for all future delivery years. See PJM Manual 20 and the "PJM Generation Adequacy Analysis – Technical methods" (at http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx) and the Modeling and Analysis Section for discussion of how the FEF is used in the determination of the Expected Weekly Maximum (EWM).

With the implementation of the RPM capacity market in 2006, the FEF used in the RRS was changed to 1.0% for all future delivery years, based on a stakeholder consensus. This is due to the ability for PJM to acquire additional resources in incremental auctions close to the delivery year. This mitigates the uncertainty of the load forecast as RPM mimics a one-year-ahead forecast. Sensitivity number 8 in Appendix B shows the impact of different FEF values on the IRM.

21 point Standard Normal Distribution, for daily peaks

PRISM's load model is a daily peak load model aggregated by week (1-52). The uncertainty in the daily peak load model is modeled via a standard normal distribution. The standard normal distribution is represented using 21 points with a range of +/- 4.2 sigma away from the mean. The modeling used is based on work by C.J. Baldwin, as presented in the Westinghouse Engineer journal titled "Probability Calculation of Generation Reserves", dated March 1969. See PJM Manual 20 for further details.

Week Peak Frequency (WKPKFQ) Parameters

The load model used in PRISM is developed with an application called WKPKFQ. The application's primary input is hourly data, determining the daily peak's mean and standard deviation for each week. Each week within each season for a year of historical data is magnitude ordered (highest to lowest) and those weeks are averaged across years to replicate peak load experience. The annual peak and the adjusted WKPKFQ mean and standard deviation are used to develop daily peak standard normal distributions for each week of the study period. The definition of the load model, per the input parameters necessary to submit a WKPKFQ run, define the modeling region and basis for all adequacy studies. WKPKFQ required input parameters include:

- Historic time period of the model.
- Sub-zones or geographic regions that define the model.
- Vintage of Load forecast report (year of report).
- Start and end year of the forecast study period.
- 5 or 7 days to use in the load model. All RRS studies use a 5 day model, excluding weekends.
- Holidays to exclude from hourly data include: Labor Day, Independence Day, Memorial Day, Good Friday, New Year's Day, Thanksgiving, the Friday after Thanksgiving, and Christmas Day.

The Peak Load Ordered Time Series (PLOTS) load model is the result of performing the WKPKFQ calculations. The resulting output is 52 weekly means and standard deviations that represent parameters for the daily normal distribution. The beginning of Week 1 corresponds to May 15th. Table II-2 shows these results of PJM RTO WKPKFQ run 7324 used in this study, which uses 10 years of historical data from 2003 to 2012. This was reviewed and endorsed by both the Resource

Adequacy Analysis Subcommittee[1] and Planning Committee[2].

Table II-2: PJM RTO Load Model Parameters (PJM LM 7324)

ARC Week	Mean Seasonal	Standard Deviation	ARC Week	Mean Seasonal	Standard Deviation
1	0.65436	0.02944	27	0.70019	0.04620
2	0.68925	0.04663	28	0.71884	0.04083
3	0.76412	0.05557	29	0.74058	0.03928
4	0.81344	0.05707	30	0.78485	0.04761
5	0.80330	0.05538	31	0.80699	0.04942
6	0.90576	0.06357	32	0.77433	0.06537
7	0.87737	0.04230	33	0.74894	0.03925
8	0.90792	0.04359	34	0.80956	0.05960
9	0.91469	0.06762	35	0.75741	0.06388
10	1.00000	0.07922	36	0.81896	0.06926
11	0.93346	0.07587	37	0.82765	0.07006
12	0.97631	0.06377	38	0.76081	0.06198
13	0.94157	0.07390	39	0.79305	0.05889
14	0.88007	0.05793	40	0.77745	0.04844
15	0.83235	0.07556	41	0.76400	0.04366
16	0.81480	0.06856	42	0.75089	0.05112
17	0.76557	0.08462	43	0.72687	0.04386
18	0.73587	0.05861	44	0.69908	0.03665
19	0.71803	0.05010	45	0.68468	0.04300
20	0.66700	0.04289	46	0.67109	0.03821
21	0.68913	0.05606	47	0.65509	0.03981
22	0.67391	0.04061	48	0.64958	0.03292
23	0.65738	0.02339	49	0.64068	0.03125
24	0.65956	0.02998	50	0.63584	0.02441
25	0.66911	0.03178	51	0.66621	0.04262
26	0.69596	0.07585	52	0.67557	0.07709

PJM-World Diversity

PJM-World diversity reflects the timing of when the World area peaks compared to when the PJM RTO area peaks. The greater the diversity, the more capacity assistance the World can give at the time when PJM needs it and, therefore, the lower the PJM IRM. Diversity is a modeling characteristic assessed in the selection of the most appropriate load model time period for use in the RRS. A comprehensive method to evaluate and choose load models, with diversity as one of the considerations, was approved by the Planning Committee and used for the 2019 RRS.

Historic hourly data was examined to determine the annual monthly peak shape of the composite World region. Monthly World coincident peaks are magnitude ordered (highest to lowest) and averaged across years to replicate peak load experience. Magnitude-ordered months are assigned to calendar months according to average historical placement. These results are highlighted in yellow below in Table II-3.

[1] https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20190702/20190702-pjm-load-model-selection.ashx

[2] https://www.pjm.com/-/media/committees-groups/committees/pc/20190711/20190711-item-06-pjm-load-model-selection-for-2019-rss.ashx

To examine seasonal diversity, an average of all historic years was used. The upper portion of Table II-3 summarizes the underlying historic data that led to a modeling choice of the values highlighted in yellow. Seasonal diversity is used in the determination of World sub-region coincident peaks in evaluating the range of permissible World reserve margins seen in Table I-5.

Table II-3: Intra-World Load Diversity

Annual Diversity

Area	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	18 year avg*
WORLD	2.39%	2.39%	3.62%	3.38%	2.82%	4.40%	6.22%	3.78%	2.23%	2.44%	2.78%	2.93%	2.22%	3.32%	3.50%	3.06%	2.82%	2.25%	2.60%	3.11%
MISO	0.00%	0.00%	1.74%	0.00%	0.74%	1.93%	7.81%	0.00%	1.44%	0.00%	0.21%	0.40%	0.00%	0.00%	2.23%	0.91%	0.86%	0.00%	0.26%	0.98%
NY	2.38%	3.40%	5.59%	4.50%	2.32%	7.42%	3.40%	5.22%	6.30%	5.58%	5.31%	6.44%	4.08%	4.20%	6.75%	7.01%	8.70%	8.04%	6.42%	5.42%
VACAR	4.96%	5.49%	5.50%	5.93%	5.21%	6.67%	6.53%	10.71%	1.14%	4.09%	5.62%	3.90%	5.23%	6.97%	3.49%	5.35%	3.65%	3.74%	6.65%	5.31%
TVA	5.09%	3.75%	4.58%	8.12%	5.56%	5.25%	4.53%	4.74%	2.26%	4.43%	4.28%	5.01%	2.94%	7.58%	3.88%	2.89%	3.61%	3.21%	2.68%	4.44%

Monthly Diversity

Month Number	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Forecast Shape**
1	87.4%	85.5%	83.8%	88.7%	83.6%	90.6%	83.7%	84.9%	85.4%	83.5%	88.6%	92.1%	84.8%	89.3%	88.9%	83.1%	83.3%	89.0%	85.6%	86.0%
2	83.2%	81.3%	79.4%	84.8%	79.6%	85.1%	80.0%	81.2%	81.6%	79.2%	83.7%	86.4%	81.1%	84.7%	83.8%	78.6%	79.4%	84.6%	81.4%	82.0%
3	78.0%	76.3%	74.8%	79.3%	74.9%	78.7%	75.4%	76.4%	76.4%	74.8%	77.8%	80.0%	76.4%	79.0%	77.9%	73.5%	74.9%	79.2%	76.2%	76.3%
4	69.6%	68.4%	67.7%	70.6%	67.8%	69.5%	68.0%	68.9%	68.2%	68.1%	69.1%	70.8%	69.0%	70.5%	69.5%	66.3%	67.6%	70.9%	68.4%	68.8%
5	80.9%	80.2%	79.7%	82.1%	79.8%	80.8%	79.8%	81.0%	79.7%	80.4%	80.4%	82.1%	80.6%	82.3%	81.1%	77.9%	79.9%	82.2%	80.1%	80.5%
6	95.2%	95.3%	95.0%	96.2%	94.8%	95.5%	94.9%	95.8%	94.5%	95.2%	95.4%	96.1%	95.4%	96.5%	95.6%	92.6%	95.4%	96.2%	95.1%	95.4%
7	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	99.7%	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	98.7%	**100.0%**	**100.0%**	**100.0%**	**100.0%**
8	99.7%	99.6%	99.1%	99.0%	99.6%	99.5%	99.3%	99.1%	**100.0%**	99.2%	99.2%	98.6%	99.0%	98.5%	99.2%	**100.0%**	99.4%	98.3%	98.7%	99.4%
9	90.5%	90.5%	90.1%	89.8%	90.3%	90.6%	90.3%	90.0%	91.4%	89.7%	90.2%	88.8%	89.7%	88.7%	90.2%	92.3%	90.4%	88.0%	89.6%	90.3%
10	73.5%	73.6%	73.6%	73.3%	73.1%	74.0%	73.6%	73.3%	74.7%	72.9%	73.5%	71.7%	72.9%	71.7%	73.4%	76.0%	73.4%	71.1%	73.1%	73.2%
11	75.5%	76.6%	75.9%	76.1%	74.9%	77.1%	75.7%	76.6%	77.2%	74.8%	75.6%	74.4%	75.8%	73.2%	75.8%	79.2%	75.7%	73.5%	75.5%	76.1%
12	81.4%	83.5%	82.4%	82.9%	80.8%	84.4%	82.1%	84.1%	83.9%	80.8%	81.4%	81.4%	82.5%	78.8%	81.8%	87.0%	82.0%	79.8%	82.0%	83.4%

**Annual Diversity is used to convert reported Subarea forecasts to coincident values associated with the World peak*
***Forecast shape takes into account historical diversity, current World composition, and forecasted World Subarea growth*

Generation Forecasting

GADS, eGADS and PJM Fleet Class Average Values

The Generator Availability Data System (GADS) is a NERC-based program and database used for entering, storing, and reporting generating unit data concerning generator outages and unit performance. GADS data is used by PJM and other RTOs in characterizing and evaluating unit performance.

The PJM Generator Availability Data System (eGADS) is an Internet based application which supports the submission and processing of generator outage and performance data as required by PJM and the NERC reporting standards. The principal modeling parameters in the RRS are those that define the generator unit characteristics. All generation units' performance characteristics are derived from PJM's eGADS web based system. For detailed information on PJM Generation Availability Data System (GADS), see the eGADS' help selection available through the PJM site at: https://www.pjm.com/markets-and-operations/etools/egads.aspx.

The eGADS system is based on the IEEE Standard 762-2006. IEEE Standard 762-2006 is available by going to the IEEE web site: http://standards.ieee.org/findstds/standard/762-2006.html

The PJM Reliability Assurance Agreement (RAA), Schedule 4 and Schedule 5 are related to the concepts used in generation forecasting.

For units with missing or insufficient GADS data, PJM utilizes class average data developed from PJM's fleet-based historical unit performance statistics. This process is called blending. Blending is therefore used for future units, neighboring system units, and for those PJM units with less than five years of GADS events. The term blending is used when a given generating unit does not have actual reported outage events for the full five-year period being evaluated.

The actual generator unit outage events are blended with the class average values according to the generator class category for that unit. For example, a unit that has three years' worth of its own reported outage history will have two years' worth of class average values used in blending. The statistics, based on the actual reported outage history, will be weighted by a factor of 3/5 and the class average statistics will be weighted by a factor of 2/5. The values are added together to get a statistical value for each unit that represents the entire five-year time period.
The class average categories are from NERC's Brochure while the statistics' values are determined from PJM's fleet of units. A five-year period is used for the statistics, with 73 unique generator class keys. The five-year period is based on the data available in the NERC Brochure or in PJM's eGADS, using the latest time period (2014-2018 for 2019 RRS). A generator class category is given for each unit type, primary fuel and size of unit. Furthermore, this five-year period is used to calculate the various statistics, including (but not limited to):

- Equivalent Demand Forced Outage Rate (EFORd)
- Effective Equivalent Demand Forced Outage Rate (EEFORd)
- Equivalent Maintenance Outage Factor (EMOF)
- Planned Outage Factor (POF)

The class average statistical values used in the reserve requirement study for the blending process are shown in Table II-4.

In Appendix B, Sensitivity number 14 shows that a 1% increase in the pool-wide EEFORd causes a 1.39% increase in the IRM – indicating a direct, positive correlation between unit performance and the IRM.

Generating Unit Owner Review of Detailed Model

The generation owner representatives are solicited to provide review and submit changes to the preliminary generation unit model. This review provides valuable feedback and increases confidence that the model parameters are the best possible for use in the RRS. This review improves the data integrity of the most significant modeling parameters in the RRS.

Forced Outage Rates: EFORd and EEFORd

All forced outages are based on eGADS reported events.

- Effective Equivalent Demand Forced Outage Rate (EEFORd) – This forced outage rate, determined for demand periods, is used for reliability and reserve margin calculations. There are traditionally three categories for GADS reported events: forced outage (FO), maintenance outage (MO) and planned outage (PO). The PRISM program can only model the FO and PO categories. A portion of the MO outages is placed within the FO category, while the other portion is placed with the PO category. In this way, all reported GADS events are modeled.

  For a more complete discussion of these equations see Manual 22 at:

  https://www.pjm.com/-/media/documents/manuals/m22.ashx.
  The equation for the EEFORd is as follows:

  Equation II-1: Calculation of Effective Equivalent Demand Forced Outage Rate (EEFORd)

  $$\boxed{\mathbf{EEFORd = EFORd + (1/4 * EMOF)}}$$

  The statistic used for MO is the equivalent maintenance outage factor (EMOF).

- Equivalent Demand Forced Outage Rate (EFORd) – This forced outage rate, determined for demand periods, is used in reliability and reserve margin calculations. See Manual M-22 and RAA Schedule 4 and Schedule 5 for more specific information about defining and using this statistic. The EFORd forms the basis for the EEFORd and is the statistic used to calculate the unforced capacity (UCAP) value of generators in the marketplace.

Table II-4: PJM RTO Fleet Class Average Generation Performance Statistics (2014-2018)

Start Date	End Date	Unit Type & Primary Fuel Category	Gen Class Key	EFORd	EEFORd	XEFORd	POF Weeks/Year	EMOF	Variance
1/1/2014	12/31/2018	FOSSIL All Fuel Types All Sizes	1	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	FOSSIL All Fuel Types 001-099	2	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL All Fuel Types 100-199	3	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL All Fuel Types 200-299	4	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL All Fuel Types 300-399	5	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL All Fuel Types 400-599	6	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL All Fuel Types 600-799	7	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL All Fuel Types 800-999	8	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL All Fuel Types 1000 Plus	9	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary All Sizes	10	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	FOSSIL Coal Primary 001-099	11	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Coal Primary 100-199	12	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Coal Primary 200-299	13	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary 300-399	14	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary 400-599	15	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary 600-799	16	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary 800-999	17	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Coal Primary 1000 Plus	18	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil Primary All Sizes	19	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	FOSSIL Oil Primary 001-099	20	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Oil Primary 100-199	21	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Oil Primary 200-299	22	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil Primary 300-399	23	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil Primary 400-599	24	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil Primary 600-799	25	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil Primary 800-999	26	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Gas Primary All Sizes	28	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	FOSSIL Gas Primary 001-099	29	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Gas Primary 100-199	30	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Gas Primary 200-299	31	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Gas Primary 300-399	32	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Gas Primary 400-599	33	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Gas Primary 600-799	34	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Gas Primary 800-999	35	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Lignite Primary All Sizes	37	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	NUCLEAR All Types All Sizes	38	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR All Types 400-799	39	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR All Types 800-999	40	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR All Types 1000 Plus	41	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR PWR All Sizes	42	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR PWR 400-799	43	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR PWR 800-999	44	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR PWR 1000 Plus	45	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR BWR All Sizes	46	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR BWR 400-799	47	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR BWR 800-999	48	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR BWR 1000 Plus	49	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	NUCLEAR CANDU All Sizes	50	1.301%	1.492%	1.267%	3	0.474	16447
1/1/2014	12/31/2018	JET ENGINE All Sizes	51	12.437%	12.776%	11.061%	2	1.227	405
1/1/2014	12/31/2018	JET ENGINE 001-019	52	19.652%	19.948%	18.327%	1	1.349	28
1/1/2014	12/31/2018	JET ENGINE 20 Plus	53	12.335%	12.643%	10.679%	2	1.4	155
1/1/2014	12/31/2018	GAS TURBINE All Sizes	54	12.437%	12.776%	11.061%	2	1.227	405
1/1/2014	12/31/2018	GAS TURBINE 001-019	55	19.652%	19.948%	18.327%	1	1.349	28
1/1/2014	12/31/2018	GAS TURBINE 020-049	56	12.335%	12.643%	10.679%	2	1.4	155
1/1/2014	12/31/2018	GAS TURBINE 50 Plus	57	8.193%	8.576%	6.953%	3	1.05	781
1/1/2014	12/31/2018	COMBINED CYCLE All Sizes	58	4.391%	4.756%	3.598%	5	0.916	99999
1/1/2014	12/31/2018	HYDRO All Sizes	59	14.703%	13.922%	13.575%	1	2.463	46
1/1/2014	12/31/2018	HYDRO 001-029	60	14.703%	13.922%	13.575%	1	2.463	46
1/1/2014	12/31/2018	HYDRO 30 Plus	61	14.703%	13.922%	13.575%	1	2.463	46
1/1/2014	12/31/2018	PUMPED STORAGE All Sizes	62	2.066%	2.525%	1.728%	5	1.024	2812
1/1/2014	12/31/2018	MULTIBOILER/MULTI-TURBINE All Sizes	63	12.437%	12.776%	11.061%	2	1.227	405
1/1/2014	12/31/2018	DIESEL Landfill	64	19.183%	18.285%	18.767%	0	0.412	2
1/1/2014	12/31/2018	DIESEL All Sizes	65	8.431%	7.004%	7.645%	0	1.663	2
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary All Sizes	66	12.145%	12.330%	11.758%	4	2.234	20179
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 001-099	67	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 100-199	68	12.729%	12.710%	12.166%	3	1.799	4095
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 200-299	69	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 300-399	70	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 400-599	71	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 600-799	72	11.538%	11.791%	11.350%	5	2.776	27288
1/1/2014	12/31/2018	FOSSIL Oil/Gas Primary 800-999	73	10.864%	11.791%	10.792%	5	2.776	27288
1/1/2014	12/31/2018	Wind All Sizes	74	0.000%	0.000%	0.000%	0	0	0
1/1/2014	12/31/2018	Solar All Sizes	75	0.000%	0.000%	0.000%	0	0	0

Table II-5: Comparison of Class Average Values - 2018 RRS vs. 2019 RRS

Unit Type & Primary Fuel Category	Gen Class Key	EFORd Change	EEFORd Change	XEFORd Change	POF Change Weeks/Year	EMOF Change	Variance Change
FOSSIL All Fuel Types All Sizes	1	0.02%	-0.74%	0.27%	0.04	0.25	1765
FOSSIL All Fuel Types 001-099	2	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL All Fuel Types 100-199	3	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL All Fuel Types 200-299	4	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL All Fuel Types 300-399	5	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL All Fuel Types 400-599	6	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL All Fuel Types 600-799	7	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL All Fuel Types 800-999	8	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL All Fuel Types 1000 Plus	9	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL Coal Primary All Sizes	10	0.02%	-0.74%	0.27%	0.04	0.25	1765
FOSSIL Coal Primary 001-099	11	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Coal Primary 100-199	12	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Coal Primary 200-299	13	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Coal Primary 300-399	14	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Coal Primary 400-599	15	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Coal Primary 600-799	16	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Coal Primary 800-999	17	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL Coal Primary 1000 Plus	18	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL Oil Primary All Sizes	19	0.02%	-0.74%	0.27%	0.04	0.25	1765
FOSSIL Oil Primary 001-099	20	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Oil Primary 100-199	21	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Oil Primary 200-299	22	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil Primary 300-399	23	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil Primary 400-599	24	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil Primary 600-799	25	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil Primary 800-999	26	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL Gas Primary All Sizes	28	0.02%	-0.74%	0.27%	0.04	0.25	1765
FOSSIL Gas Primary 001-099	29	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Gas Primary 100-199	30	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Gas Primary 200-299	31	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Gas Primary 300-399	32	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Gas Primary 400-599	33	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Gas Primary 600-799	34	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Gas Primary 800-999	35	1.26%	-1.37%	1.31%	0.11	0.29	309
FOSSIL Lignite Primary All Sizes	37	0.02%	-0.74%	0.27%	0.04	0.25	1765
NUCLEAR All Types	38	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR All Types	39	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR All Types	40	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR All Types	41	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR PWR All Sizes	42	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR PWR 400-799	43	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR PWR 800-999	44	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR PWR 1000 Plus	45	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR BWR All Sizes	46	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR BWR 400-799	47	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR BWR 800-999	48	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR BWR 1000 Plus	49	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
NUCLEAR CANDU All Sizes	50	-0.10%	-0.12%	-0.07%	-0.06	-0.01	-865
JET ENGINE All Sizes	51	-0.62%	-0.72%	0.05%	0.15	0.02	-41
JET ENGINE 001-019	52	1.50%	1.35%	1.43%	0.08	-0.01	2
JET ENGINE 20 Plus	53	-1.41%	-1.65%	-0.15%	0.21	0.07	-4
GAS TURBINE All Sizes	54	-0.62%	-0.72%	0.05%	0.15	0.02	-41
GAS TURBINE 001-019	55	1.50%	1.35%	1.43%	0.08	-0.01	2
GAS TURBINE 020-049	56	-1.41%	-1.65%	-0.15%	0.21	0.07	-4
GAS TURBINE 50 Plus	57	-1.40%	-1.38%	-0.67%	0.15	0.01	-97
COMBINED CYCLE All Sizes	58	-0.01%	-0.14%	0.05%	-0.09	-0.12	-134
HYDRO All Sizes	59	1.10%	-0.43%	1.34%	-0.06	0.33	5
HYDRO 001-029	60	1.10%	-0.43%	1.34%	-0.06	0.33	5
HYDRO 30 Plus	61	1.10%	-0.43%	1.34%	-0.06	0.33	5
PUMPED STORAGE All Sizes	62	-0.25%	-0.20%	0.03%	0.42	0.09	-268
MULTIBOILER/MULTI-TURBINE All Sizes	63	-0.62%	-0.72%	0.05%	0.15	0.02	-41
DIESEL Landfill	64	0.30%	-0.25%	0.31%	0.00	-0.04	0
DIESEL All Sizes	65	-0.06%	-2.16%	-0.28%	0.11	-0.08	0
FOSSIL Oil/Gas Primary All Sizes	66	0.02%	-0.74%	0.27%	0.04	0.25	1765
FOSSIL Oil/Gas Primary 001-099	67	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Oil/Gas Primary 100-199	68	0.15%	-0.60%	0.35%	0.04	0.26	1970
FOSSIL Oil/Gas Primary 200-299	69	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil/Gas Primary 300-399	70	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil/Gas Primary 400-599	71	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil/Gas Primary 600-799	72	-0.43%	-1.37%	-0.08%	0.11	0.29	309
FOSSIL Oil/Gas Primary 800-999	73	1.26%	-1.37%	1.31%	0.11	0.29	309
Wind All sizes	74	0.00%	0.00%	0.00%	0.00	0.00	0
Solar All sizes	75	0.00%	0.00%	0.00%	0.00	0.00	0

Fleet-based Performance by Primary Fuel Category

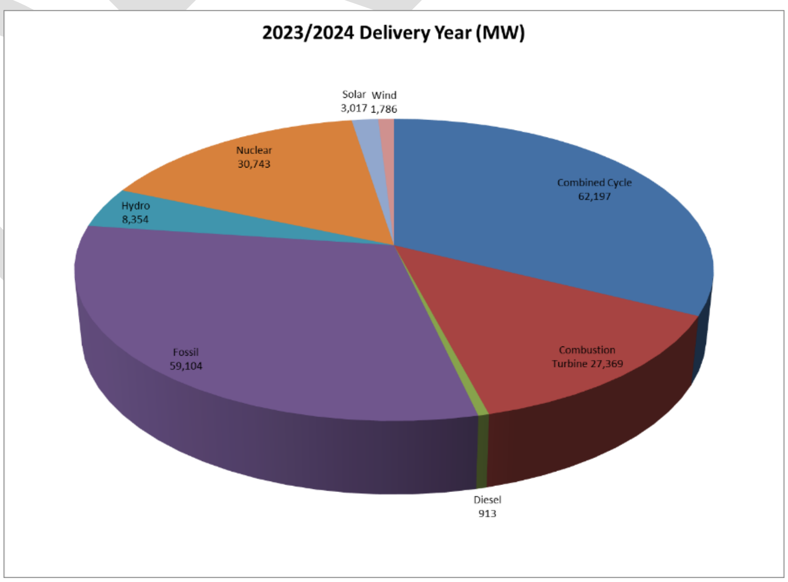
The PJM RTO fleet of units is summarized, by primary fuel, in Table II-6 for the 2023/2024 delivery year. This summary reflects the blending process discussed above. This summary also uses the summer net dependable rating (SND) of all units.

The outage rate and actual capacity for wind and solar units, however, reflects the PJM stakeholder process modeling, not actual outage event data. This modeling assigns a forced outage rate of 0% to solar and wind units and an ICAP value equal to the wind and solar unit's capacity credit. The capacity credit is calculated as per PJM Manual 21. Figure II-1 shows all PJM RTO capacity by fuel type for the 2023/2024 Delivery Year.

Table II-6: PJM RTO Fleet-based Unit Performance

2023/2024 Delivery Year	# of Units	Actual Capacity MW	% Total MW	Forced Outage Rates %	Ambient Temperature Derating (MW)
Combined Cycle	231	62,197	32.4%	3.79%	439
Combustion Turbine	393	26,028	13.5%	7.88%	551
Diesel	187	913	0.5%	11.84%	0
Fossil	192	59,104	30.8%	8.73%	1,370
Hydro	190	8,354	4.3%	4.01%	148
Nuclear	29	30,743	16.0%	1.26%	0
Solar	223	3,017	1.6%	0.00%	0
Wind	100	1,786	0.9%	0.00%	0
PJM RTO Total	**1545**	**192,142**	**100.00%**	**5.41%**	**2,508**

Figure II-1: PJM RTO Capacity



Modeling of Generating Units' Ambient Deratings

Per the approved rules in place for PJM Operations, Planning and Markets, a unit can operate at less than its SND rating and still not incur a GADS outage event. All modeled units' performance statistics are based on eGADS submitted data. The ambient derate modeling assumption, in addition to the eGADS data, allow all observed outages to be modeled in the RRS.

Derating certain generating units in the RRS is included to capture the limited output from certain generators caused by more extreme-than-expected ambient weather conditions (hot and humid summer conditions).

In the 2019 RRS, 2,500 MW of ambient derates in the peak summer period were modeled via planned outage maintenance. The impact of this assumption is an increase in the IRM of 1.38%.

Units on planned outage maintenance representing ambient derates were selected based on average characteristics of the types of units affected. PJM will continue to assess the impact of these ambient weather conditions on generator output.

Generation Interconnection Forecast

The criterion for planned generation units is to model only interconnection queue units with a signed Interconnection Service Agreement (ISA) without further adjustments to each unit's size (in other words, a commercial probability of 100% is assumed for these units).

The criterion for planned generation units matches the assumptions in the Capacity Emergency Transfer Objective (CETO) studies. Furthermore, a signed ISA is the final milestone in the PJM Interconnection Queue process; historically, a large proportion of the units achieving this milestone have ultimately ended up as in-service units.

For informational purposes only, Table II-7 shows the Average Commercial Probabilities for the projects in each of the Stages in the PJM interconnection queue. The commercial probabilities are calculated for each unit using a logistic regression model fitted to historical data (queues 'T' and after). The logistic regression models include predictors such as current stage in the queue (feasibility, impact, facilities, interconnection service agreement (ISA)), unit type (coal, gas, wind, etc.), location (US State), project type (new or uprate) and unit size (in MW).

Table II-7: Average Commercial Probabilities for Expected Interconnection Additions

Queue Stage	Average Commercial Probability
In the Queue, up to Feasibility Study Stage	5%
All of the above, plus Impact Study Completed	16%
All of the above, plus Facilities Study Completed	54%
All of the above and ISA executed	80%
Successful Completion	100%

Transmission System Considerations

PJM Transmission Planning (TP) Evaluation of Import Capability

PJM's Transmission Planning Staff performs the yearly Capacity Import Limit study to establish the amount of power that can be reliably transferred to PJM from outside regions (details of this study can be found in PJM's Manual 14b Attachment G). Although the PJM RTO has the physical capability of importing more than the 3,500 MW Capacity Benefit Margin (CBM, defined below), the additional import capability is reflected in Available Transfer Capability (ATC) through the OASIS postings and not reserved as CBM. This allows for the additional import capability to be used in the marketplace.

The use of CBM (on an annual basis) in this study is consistent with the time period of the RF criteria, and the Reliability Assurance Agreement, Schedule 4.

Capacity Benefit Margin (CBM)

The CBM value of 3,500 MW is specified in the PJM Reliability Assurance Agreement (RAA), Schedule 4. The CBM is the amount of import capability that is reserved for emergency imports into PJM. As a sensitivity case for this study, the CBM was varied between 0 MW and 15,000 MW. The relationship of IRM with CBM is graphically depicted in Figure I-7. A decrease in the CBM from 3,500 MW to 0 MW increases the pool's reserve requirement by about 1.6%. This value is influenced by the amount of PJM-World load diversity, and the World reserve level.

Per an effective date of April 1, 2011 concerning capacity benefit margin implementation documentation, compliant with NERC MOD Standard MOD-004-1, PJM staff has developed a CBM Implementation document (CBMID) that meets or exceed the NERC Standards, and NAESB Business Practices. This document is part of the PJM compliance efforts and is available via the PJM stakeholder process by contacting regional_compliance@pjm.com .

Capacity Benefit of Ties (CBOT)

The CBOT is a measure of the reliability value that World interface ties bring into the PJM RTO. The CBOT is the difference between an RRS run with a 3,500 MW CBM and an RRS run with a 0 MW CBM. The CBOT result was 1.6% of the PJM forecasted load or roughly 2,442 MW of installed capacity. The CBOT is directly affected by the PJM/World load diversity in the model (more diversity results in a higher CBOT) and the availability of assistance in the World area. Firm capacity imports, which are treated as internal capacity, are not part of the CBOT. The CBOT is a mathematical expectation related to the total 3,500 CBM value. The expected value is the weighted mean of the possible values, using their probability of occurrence as the weighting factor.

Coordination with Capacity Emergency Transfer Objective (CETO)

CETO studies assumptions are consistent with RRS assumptions due to marketplace requirements and to ensure the validity of the RRS assumption stating that the PJM aggregate of generation resources can reliably serve the aggregate of PJM load. By passing the load deliverability test, wherein CETO is one of the main components, this assumption is validated. See PJM Manual 14 B, attachment C for details on the Load Deliverability tests and refer to the RPM website cited in the RPM section for specific analysis details and results: http://pjm.com/markets-and-operations/rpm.aspx.

OASIS postings

The value of CBM is directly used in the various transmission path calculations for Available Transfer Capability (ATC). See the OASIS web site, specifically the ATC section for further specifics: http://www.pjm.com/markets-and-operations/etools/oasis/atc-information.aspx

Modeling and Analysis Considerations

Generating Unit Additions / Retirements

Planned generating units in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) are included in the study at their capacity MW value. Table II-8 gives a summary of the generator additions and retirements as modeled in the 11 year RRS model.

Table II-8: New and Retiring Generation within PJM RTO

Zone Name	Total Additions/Changes (MW)	Retirements (MW)	Total
AE	447	0	447
AEP	4,002	860	3,142
APS	3,515	1,278	2,237
ATSI	1,105	1,536	-431
BGE	0	403	-403
ComEd	1,265	304	961
Dayton	1,407	0	1,407
DLCO	4	1,811	-1,807
DomVP	2,681	889	1,792
DPL	550	102	448
DUKE	76	0	76
JCPL	93	7	87
METED	21	803	-782
PECO	26	66	-40
PEPCO	1	0	1
PN	55	198	-143
PPL	122	45	77
PSEG	10	0	10
Grand Total	**15,381**	**8,302**	**7,079**

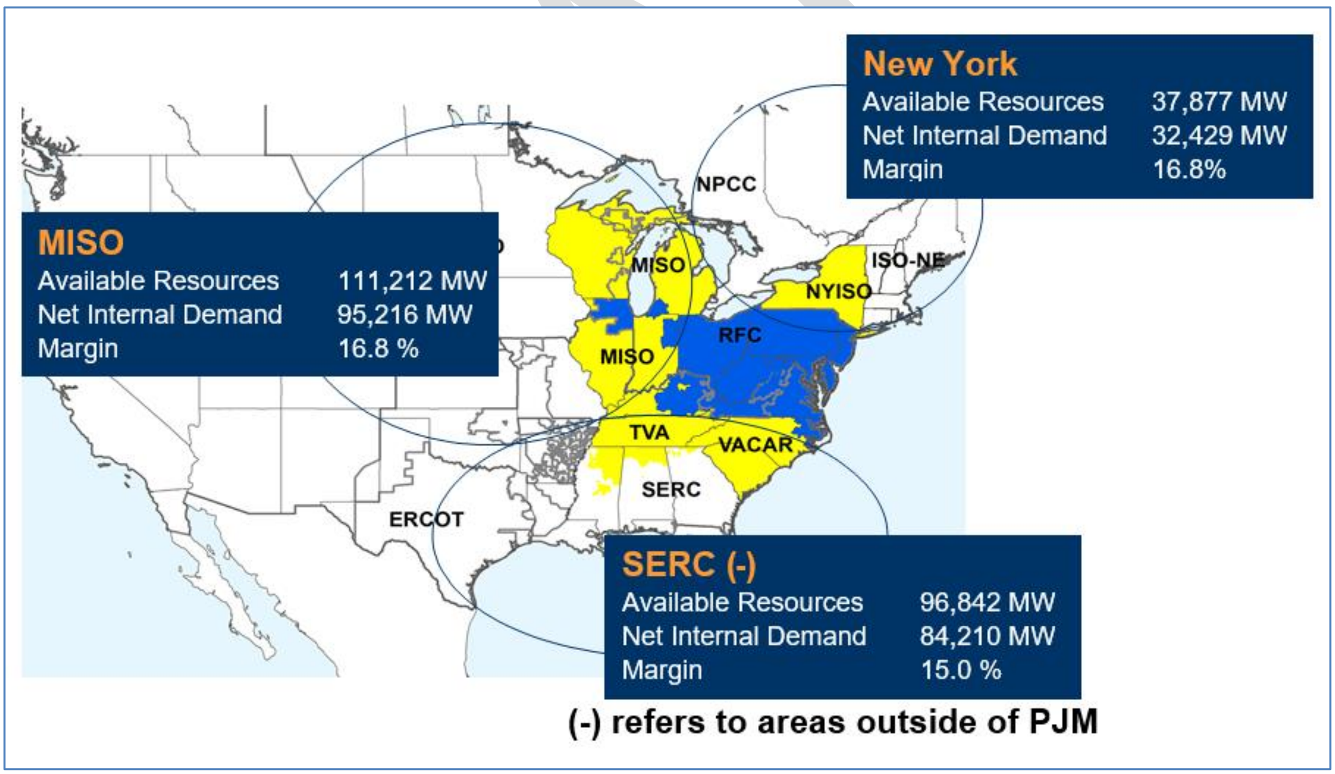
World Modeling

This data is publicly available through the NERC Electric and Supply Database – and is a compilation of all the EIA-411 data submissions. Per the June study assumptions, approved at the June 2019 PJM Planning Committee meeting, each of the individual regions was modeled at its required reserve requirement. The world region immediately adjacent to the PJM RTO was deemed to be the most appropriate region to use in the study, per previous RRS assessments. Modeling the immediately adjacent region helps to address concerns for deliverability of outside world resources to the PJM RTO border.

Among the regions included in the World, only New York and MISO have a firm reserve requirement target. For these regions, their latest published reserve requirements were used for the delivery years of this study. For the TVA and VACAR sub regions of SERC, a reserve target of 15% was used; this is consistent with NERC's modeling for assessment purposes.

Figure II-2 depicts the assumed capacity summer outlook within each of the Outside World regions that are adjacent to PJM for the delivery year 2019. The West region includes most of MISO (except MISO-South). The SERC (-) region includes the World zones: TVA and VACAR (excluding Dominion which is part of PJM).

Figure II-2: PJM and Outside World Regions - Summer Capacity Outlook



Expected Weekly Maximum (EWM), LOLE Weekly Values, Convolution Solution, IRM Audience

The Expected Weekly Maximum value (EWM) is the peak demand used by the PRISM program to calculate the loss of load expectation (LOLE). Both the EWM and LOLE are important values to track in assessing the study results. From observing these values over several historic studies, 99.9% of the risk is concentrated within a few weeks of the summer period. It is these summer weeks that have the highest EWM values (Refer to "PJM Generation Adequacy Technical Methods" and PJM Manual 20, for clarification and specifics of how the EWM is used and the resulting weekly LOLE). The EWM value is calculated per the following equation:

Equation II-2: Expected Weekly Maximum

$$EWM_X = \mu_X + 1.16295 * \sqrt{\sigma_X^2 + FEF^2}$$

Where:

μ_X = Weekly Mean,

1.16295 = A Constant, the Order Statistic when n=5

σ_X^2 = Weekly variance

FEF = Forecast Error Factor, for given delivery Year

x ranges from 1 to 52

In Figure II-3, the following EWM pattern can be seen for the PJM RTO and World regions. For all weeks not shown, the weekly LOLE approaches zero. The EWM pattern for PJM and the World in this year's study (blue line) are almost identical to the patterns observed in the 2018 RRS (dashed blue line).

Figure II-3: Expected Weekly Maximum Comparison – 2018 RRS vs. 2019 RRS

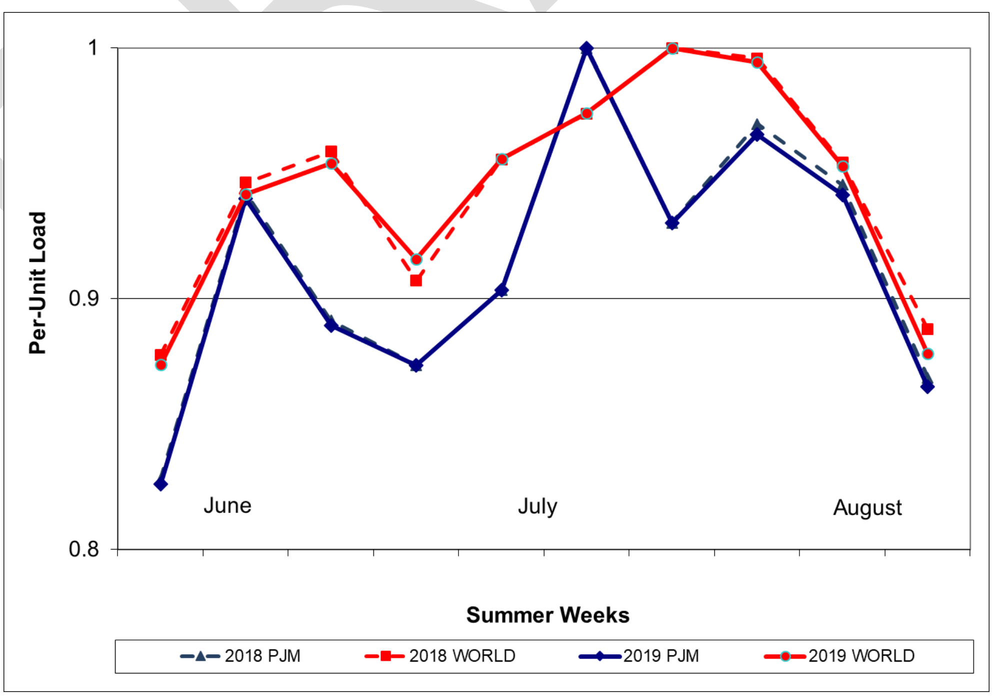


Figure II-4 shows the weekly share of Loss of Load for the PJMRTO in the 2018 RRS and 2019 RRS. No major differences in the weekly share of LOLE are observed between the two studies.

Figure II-4: PJMRTO LOLE Comparison 2018 RRS vs. 2019 RRS

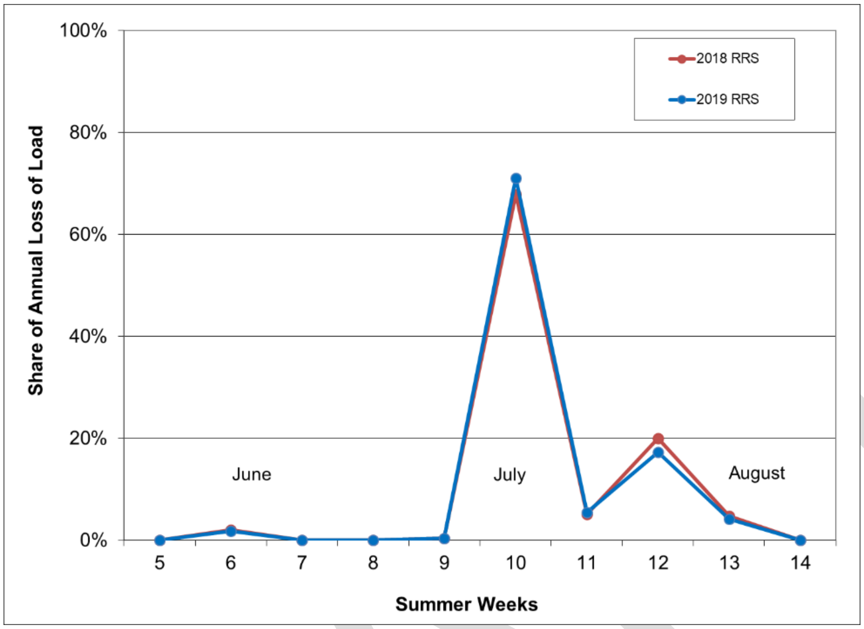
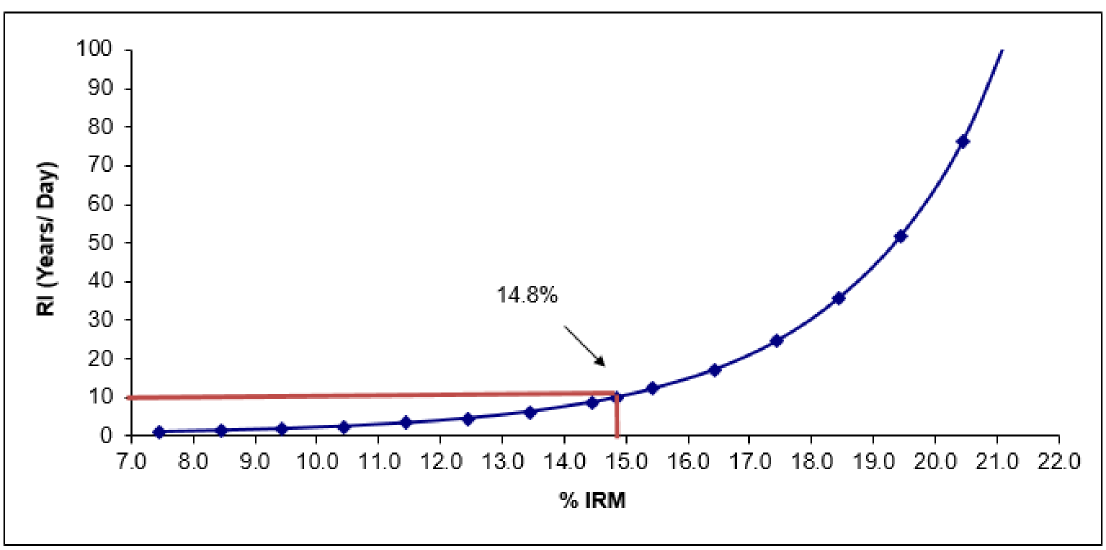


Figure II-5 shows how the PJM Reliability Index (RI) varies with the installed reserve margin. The plot is constructed by running a one area study, manually varying the PJM RTO reserve levels while assuming a constant CBOT at 1.6%. It can be observed that a reserve level of about 14.8% yields a loss of load event once every ten years.

Figure II-5: Installed Reserve Margin (IRM) vs. RI (Years/Day)



Standard BAL-502-RFC-02 clarification items

To provide clarity concerning several items in the Standard BAL-502-RFC-02 requirement section R1 titled "The planning Coordinator shall perform and document a Resource Adequacy analysis annually", the following is supplied:

R1.3.3.1 The criteria for including planned Transmission facilities: This is given in the RTEP assessments. The RTEP is overseen by the Transmission Expansion Advisory Committee (TEAC), a stakeholder group within the PJM committee structures. The Planning Committee also can establish and recommend appropriate criteria to be used for transmission facilities. See the Transmission System Considerations section for further details. The Criteria for inclusion of planned transmission facilities is given in the meeting minutes and presentations of the TEAC, PC, and the PJM manuals 14 A - E. The RRS is closely coordinated and integrated with these RTEP analyses, and with the decisions by the PC and TEAC as all are parts of the PJM Planning division efforts.

R1.4 Availability and Deliverability of fuel: An adhoc assessment was completed in July 2003, titled "Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generating Sector" addresses this topic. The Executive Summary of this report, pages v – xviii, provides the results of this assessment. This is a confidential report.

R1.4 Common Mode Outages that affect resource availability: The report, "Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generating Sector", address this issue in part. In general, these types of outages are considered by discrete modeling, with most outages assumed to be independent events. The assumption of independent outage events applies to both the resource and load models and avoids any need for a matrix of covariance states. The solution techniques for including a covariance matrix are considered not practically possible (long solution times). The Industry standard in the known solution methods is to make the assumption of independence for all outage events, treating any common mode outages by discrete modeling techniques. For example, for a "run of river" issue, more planned outages are modeled over the critical summer peak weeks due to several units using the same water source (same river). However, care should be used in drawing conclusions from the assumption for independence in the 21 point daily peak calculations. For example, there are steps involved in developing the load model parameters that do incorporate a correlation, particularly for the adjusted mean and standard deviations for each week. From a conceptual perspective this allows similar relationships, as those that exist in the development of the load forecast values, which allows the model to establish relationships between the weeks, such as magnitude ranking of weeks and the adjustment due to the load forecast monthly shape. The assumption of independence, understanding all the associated complexities, is implemented in the RRS modeling and calculation methods, which includes modeling of appropriate discrete common mode outage scenarios.

In addition, the methodology implemented to develop the winter peak week capacity model (approved by the MRC in 2018) partially addresses this issue as well by better accounting for the risk caused by the large volume of concurrent outages observed historically during the winter peak period. The methodology considers the development of a cumulative capacity outage probability table using historical actual RTO-aggregate outage data.

R1.4 Environmental or regulatory restrictions of resource availability: In the Generation Forecasting section, it is discussed that the resource performance characteristics are primarily modeled per the PJM manuals, 21, 22. In the eGADS reporting, there is consideration and methods to account for both environmental and regulatory restrictions. The RRS modeling of resources uses performance statistics, directly from these reported events. Both discrete modeling techniques and sensitivity analysis are performed to gain insights about impacts concerning environmental or regulatory restrictions. In the modeling of resources this can reduce the rating of a unit impacted by this type of restriction. The RRS model is coordinated with the Capacity Injection Rights (CIR) for each unit, which can be affected by these restrictions.

R1.4 <u>Any other demand response programs not included in the load forecast characteristics</u>: All load modeled and its characteristics are part of R1.3.1, per BAL-502-RFC-02. There are no other load response programs in the RRS model.

R1.4 <u>Market resources not committed to serving load</u>: In general, all resources modeled have capacity injection rights, are part of the EIA-411 filing and coordinated with the RTEP Load deliverability tests, documented in PJM Manual 14 B, attachment C. In addition, coordination with the RPM capacity market modeling is performed. An example of this is allowing the modeling of Behind-The-Meter (BTM) units, per the modeling assumptions. See Appendix A for further details regarding BTM modeling (See Manual M19, page 12; Manual 14D, Appendix A).

R1.5 <u>Transmission maintenance outage schedules</u>: Discussed in the Transmission System Considerations section is the coordination with the RTEP process and procedures. This issue is specifically addressed in the load deliverability tests, as discussed in this section. The CETO analysis is closely coordinated with the RRS modeling and report, and is fundamental to addressing and verifying the assumption that the PJM aggregate of generation resources can reliably serve the aggregate of PJM load.

Standard MOD - 004 - 01, requirement 6, clarification items

Capacity Benefit Margin (CBM) is established per the Reliability Assurance Agreement (RAA) section 4 and used in Planning Division studies and assessments. The Regional Transmission Expansion Planning Process (RTEP) provides a 15 year forecast period while the reserve requirement study provides an 11 year forecast period. Each individual year of these periods (15 and 11) are assessed. The RTEP and Reserve Requirement Study (RRS) are performed on an annual basis.

The RTEP and the RRS processes use full network analysis. Available Transmission Capability (ATC) and Flowgate analysis disaggregates the full network model in the short term (daily, weekly, monthly through month 18) as a proxy for full network analysis. The Available Flowgate Capability (AFC) calculator applies the impacts of transmission reservations (or schedules as appropriate) and calculates the AFC by determining the capacity remaining on individual flowgates for further transmission service activity. The disaggregated model used for the AFC calculation provides faster solution time than the full network model. The RTEP assessment is coordinated with the CBM, shown in the RAA, by its use of Capacity Emergency Transfer Objective (CETO) and load forecast modeling. CETO requirements are based on Loss of Load Expectation (LOLE) requiring appropriate aggregation of import paths for a valid statistical model.

Evidence:

- Annual RTEP baseline assessment report http://www.pjm.com/planning/rtep-development/baseline-reports.aspx
- Reliability Assurance Agreement (http://www.pjm.com/documents/~/media/documents/agreements/raa.ashx)
- Annual RRS report(s) http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx
  - CETO load deliverability studies
  - Section 4, Manual 20 (http://www.pjm.com/~/media/documents/manuals/m20.ashx)
  - Section C.4, Manual 14B (http://www.pjm.com/~/media/documents/manuals/m14b.ashx)
- AFC/ATC calculations, Section 2 and 3 of PJM Manual 2 http://www.pjm.com/~/media/documents/manuals/m02.ashx

RPM Market

The Reliability Pricing Model (RPM) is the PJM's forward capacity market program that was implemented on June 1, 2007. The RPM requires the following input values derived from the RRS: IRM and FPR.

PJM's web based application, eRPM, is used to perform capacity transactions in the market place. The planning parameters derived from the RRS that are used in RPM are available at: http://www.pjm.com/markets-and-operations/rpm.aspx

IRM and FPR

The Installed Reserve Margin (IRM) is a percentage which represents the amount of installed capacity required above the forecast restricted 50/50 peak load demand. It is the buffer above expected peak load required to meet the reliability criterion. The IRM is a key input used to determine Load Serving Entity (LSE) capacity obligations. Calculation of the IRM is necessary to the determination of the Forecast Pool Requirement (FPR). The PRISM model adjusts the load level until it finds the solution load that meets the one day in ten years reliability standard. The IRM is calculated based on this solution load, for the peak day (which is also the peak week), using the installed capacity for that week in the numerator and the solution load in the denominator.

The FPR is a multiplier that converts load values into capacity obligation. The FPR has two necessary inputs to determine its value: the IRM and the PJM RTO pool-wide EFORd (equivalent demand forced outage rate). The FPR is defined by the following equation:

Equation II-3: Calculation of Forecast Pool Requirement (FPR)

$$\boxed{\textbf{FPR} = (1 + \textbf{Approved IRM}) * (1 - \textbf{PJM Avg. EFORd})}$$

The IRM and the FPR therefore represent identical levels of reserves expressed in different units. The IRM is expressed in units of installed capacity (or ICAP) whereas the FPR is expressed in units of unforced capacity (or UCAP). Unforced capacity is defined in the RAA to be the megawatt (MW) level of a generating unit's capability after removing the effect of forced outage events[3].

The capacity obligation associated with a particular PJM zone is an allocation of RTO resources procured in the RPM auction. The obligation is expressed in units of unforced capacity.

PJM's objectives are to establish an IRM that preserves reliability while not imposing an undue cost on load to pay for unnecessary generation reserves. PJM has used judgment in past recommendations for establishing an FPR due to some of the uncertainties associated with the current unforced capacity structure.

[3] This definition of Unforced Capacity largely applies to non-intermittent generators. For the purposes of this report, the UCAP value of an intermittent generator (such as wind or solar) is equal to its ICAP value, which in turn is equal to its capacity credit. The capacity credit is calculated as per PJM's Manual 21.

Operations Related Assessments

Winter Weekly Reserve Target Analysis

PJM calculates a Winter Weekly Reserve Target (WWRT) for each of the months in the 2019 / 2020 winter period (December 2019, January 2020 and February 2020). The WWRT is established to cover against uncertainties associated with load and forced outages during these winter months. It accomplishes this by ensuring that the total winter LOLE is practically zero. This year, PJM Staff recommends the values shown in Table II-9. The recommended values are required to be integers due to computer application requirements.

Table II-9: Winter Weekly Reserve Target

Month	WWRT
December 2019	22%
January 2020	28%
February 2020	24%

The procedure implemented to calculate the values in Table II-9 considers the following steps:

Step 1: Using GE-MARS, set up an RRS case with an annual LOLE equal to 0.1 days/year.

Step 2: In addition to the required planned maintenance schedule, simulate additional planned maintenance during each week of the three winter months until the annual LOLE is worse than 0.1 days/year.

Step 3: Calculate the available reserves in each of the winter weeks as a percentage of the corresponding monthly peak.

Step 4: The WWRT for each month is the highest weekly reserve percentage (rounded up to the next integer value).

Table II-10 shows the weekly available reserves that result from applying the above procedure.

Table II-10: Weekly Available Reserves in WWRT Analysis

Month	% Available Reserves	Max % Available Reserves (by Month)
December	17.38%	22%
	21.25%	
	21.60%	
	9.76%	
January	19.38%	28%
	13.15%	
	23.95%	
	27.19%	
February	19.43%	24%
	23.36%	
	17.53%	
	14.03%	

Monthly WWRT values were introduced for the first time in the 2016 RRS with the objective of addressing the larger load uncertainty in January compared to February and December. Prior to the 2016 RRS, the WWRT was a single value that applied to the entire winter season. Historically, January is the month where the PJM Winter peak is most likely to occur and also the winter month that historically has exhibited more peak load variability.

With this recommendation, the PJM Operations Department will coordinate generator maintenance scheduling over the winter period seeking to preserve a 22% margin in December 2019, 28% margin in January 2020 and 24% margin in February 2020 after units on planned and maintenance outages are removed**.** These margins are guides to be used by PJM Operations and are not an absolute requirement.

III. Glossary

Adequacy

The ability of a bulk electric system to supply the aggregate electric demand and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components. One part of the Reliability term.

Available Transfer Capability (ATC)

Available Transfer Capability (ATC) is the amount of energy above base case conditions that can be transferred reliably from one area to another over all transmission facilities without violating any pre- or post-contingency criteria for the facilities in the PJM RTO under specified system conditions. ATC is the First Contingency Incremental Transfer Capability (FCITC) reduced by applicable margins.

BPS

The Bulk Power System (BPS) refers to all generating facilities, bulk power reactive facilities, and high voltage transmission, substation and switching facilities. The BPS also includes the underlying lower voltage facilities that affect the capability and reliability of the generating and high voltage facilities in the PJM Control Area. As defined by the Regional Reliability Organization, the BPS is the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

BRC

The PJM Board of Managers' Board Reliability Committee (BRC) is made up of PJM board members who conduct activities to review and assess reliability issues to bring to the full board of managers. The BRC is one of the groups that review the RRS report in the process to establish a FPR.

Capacity

The amount of electric power (measured in megawatts) that can be delivered to both firm energy to load located electrically within the PJM Interconnection and firm energy to the border of the PJM Control Area for receipt by others. Installed capacity and Unforced capacity are related measures of this quantity.

Capacity Benefit Margin (CBM)

Capacity Benefit Margin (CBM), expressed in megawatts, is the amount of import capability that is reserved for the emergency import of power to help meet LSE load demands during peak conditions and is excluded from all other firm uses.

Capacity Emergency Transfer Objective (CETO)

The import capability required by a sub area of PJM to satisfy the RF's resource adequacy requirement of loss of load expectation. This assessment is done in a coordinated and consistent manner with the annual RRS, but is an independent evaluation. The CETO value is compared to the Capacity Emergency Transfer Limit (CETL) which represents the sub area's actual import capability as determined from power flow studies. The sub area satisfies the criteria if its CETL is equal to or exceeds its CETO. PJM's CETO/CETL analysis is typically part of the PJM's deliverability demonstration. See Manual 20 section 4, and Manual 14B, attachment C for details.

Capacity Performance (CP)

Capacity product created within the RPM framework for 2018/2019 DY and subsequent DYs. CP is a more robust product than the capacity products available in auctions for DYs prior to 2018/2019 since it is required to provide enhanced performance during peak conditions. Additional information on CP can be found at http://www.pjm.com/directory/etariff/FercDockets/1368/20141212-er15-623-000.pdf

Control Area (CA)

An electric power system or combination of electric power systems bounded by interconnection metering and telemetry. A common generation control scheme is applied in order to:

- Match the power output of the generators within the electric power system(s) plus the energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- Maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council of NERC;
- Maintain power flows on Transmission Facilities within appropriate limits to preserve reliability; and
- Provide sufficient generating Capacity to maintain Operating Reserves in accordance with Good Utility Practice.

Delivery Year (DY)

The Delivery Year (DY) is the twelve-month period beginning on June 1 and extending through May 31 of the following year. As changing conditions may warrant, the Planning Committee may recommend other Delivery Year periods to the PJM Board of Managers. In prior studies, the DY was formerly referred to as the "Planning Period".

Deliverability

Deliverability is a test of the physical capability of the transmission network for transfer capability to deliver generation capacity from generation facilities to wherever it is needed to ensure, only, that the transmission system is adequate for delivery of energy to load under prescribed conditions. The testing procedure includes two components: (1) Generation Deliverability; and (2) Load Deliverability.

Demand Resource (DR)

A resource with the capability to provide a reduction in demand. DR is a component of PJM's Load Management (LM) program. The DR is bid into the RPM Base Residual Auction (BRA). See Load Management (LM).

Demand Resource (DR) Factor

Ratio of LM aggregate Load Carrying Capability (LCC) to total amount of LM in PJM. The LM LCC is determined by modeling LM in the PJM reliability program. The DR Factor is reviewed and changed, if necessary, each planning period by the PJM Board for use in determining the capacity credit for DR and Interruptible Load for Reliability (ILR). The use of the DR Factor was discontinued with the introduction of Capacity Performance in 2018/2019 DY.

Demand

The rate at which electrical energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand is equal to load when integrated over a given period of time. See Load.

Diversity

Diversity is the difference of the sum of the individual maximum demands of the various subdivisions of a system, or part of a system, to the total connected load on the system, or part of the system, under consideration. The two regions modeled in the RRS are the PJM RTO and the surrounding World region. If the model has peak demand periods occurring at the same time, for both regions (PJM RTO and World), there is little or no diversity (PJM-World Diversity). The peak demand period values are determined as the Expected Weekly Maximum (EWM). A measure of diversity can be the amount of MWs that account for the difference between a Transmission Owner zone's forecasted peak load at the time of its own peak and the coincident peak load of PJM at the time of PJM peak.

Eastern Interconnection

The Eastern Interconnection refers to the bulk power systems in the eastern portion of North America. The area of operation of these systems is bounded on the east by the Atlantic Ocean, on the west by the Rocky Mountains, on the south by the Gulf of Mexico and Texas, and includes the Canadian provinces of Quebec, Ontario, Manitoba and Saskatchewan. The Eastern Interconnection is one of the three major interconnections within the NERC and includes the Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst (RF), Southeast Reliability Corporation (SERC) and the Southwest Power Pool, Inc. (SPP).

EEFORd

The Effective Equivalent Demand Forced Outage Rate (EEFORd) is used for reliability and reserve margin calculations. For each generating unit, this outage rate is the sum of the EFORd plus ¼ of the equivalent maintenance outage factor. See manual 22, pages 14-15 (http://www.pjm.com/~/media/documents/manuals/m22.ashx)

EFORd

The Equivalent Demand Forced Outage Rate (EFORd) is the portion of time that a generating unit is in demand, but is unavailable due to a forced outage.

eGADS

eGADS is PJM's Web-based Generator Availability Data System where generation data is collected to track and project unit unavailability – as required for PJM adequacy and capacity market calculations. eGADS is based on the NERC GADS data reporting requirements, which in turn are based on IEEE Standard 762-2006 (March 15, 2007).

EMOF

The Equivalent Maintenance Outage Factor (EMOF). For each generating unit modeled, the portion of time a unit is unavailable due to maintenance outages.

EWM

The Expected Weekly Maximum (EWM) is the weekly peak load corresponding to the 50/50 load forecast, typically based on a sample of 5 weekday peaks. The EWM parameter is used in the PJM PRISM program. Also see PJM Manual 20 pages 19-23.

FEF

The Forecast Error Factor (FEF) is a value that can be entered in the PRISM program per Delivery Year to indicate the percent increase of uncertainty within the forecasted peak loads. As the planning horizon is lengthened, the FEF generally increases 0.5% per year. FEF is held constant at 1.0% for all delivery years in the RRS, per stakeholder agreement of the approved assumptions.

FERC

The Federal Energy Regulatory Commission (FERC) is the federal agency responsible with overseeing and regulating the wholesale electric market within the US. (http://www.ferc.gov/)

Forced Outage

Forced outages occur when a generating unit is forcibly removed from service, due to either: 1) availability of a generating unit, transmission line, or other facility for emergency reasons; or 2) a condition in which the equipment is unavailable.

Forced Outage Rate (FOR)

The Forced Outage Rate (FOR) is a statistical measurement as a percentage of unavailability for generating units and recorded in the GADS. FOR indicates the likelihood a unit is unavailable due to forced outage events over the total time considered. It is important to note that there is no attempt to separate out forced outage events when there is no demand for the unit to operate.

Forecast Peak Load

Expected peak demand (Load) representing an hourly integrated total in megawatts, measured over a given time interval (typically a day, month, season, or delivery year). This expected demand is a median demand value indicating there is a 50 % probability actual demand will be above or below the expected peak.

Forecast Pool Requirement (FPR)

The amount, stated in percent, equal to one hundred plus the percent reserve margin for the PJM Control Area required pursuant to the Reliability Assurance Agreement (RAA), as approved by the Reliability Committee pursuant to Schedule 4 of the RAA. Expressed in units of “unforced capacity”.

GEBGE

GEBGE is a resource adequacy calculation program, used to calculate daily LOLE that was jointly developed in the 1960s/1970s by staff at General Electric (GE) and Baltimore Gas and Electric (BGE). The GEBGE program has since been largely superseded and replaced by PJM’s PRISM program in the conduct and evaluation of IRM studies at PJM. (See

PRISM.) GEBGE does prove useful to measure reliability calculations and to increase PJM staff efficiency in some sensitivity assessments.

Generating Availability Data System (GADS)

GADS is a NERC-based computer program and database used for entering, storing, and reporting generating unit data concerning outages and unit performance.

Generation Outage Rate Program (GORP)

GORP is a computer program maintained by the PJM Planning staff that uses GADS data to calculate outage rates and other statistics.

Generator Forced/Unplanned Outage

An immediate reduction in output, capacity, or complete removal from service of a generating unit by reason of an emergency or threatened emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility. A reduction in output or removal from service of a generating unit in response to changes in or to affect market conditions does not constitute a Generator Forced Outage.

Generator Maintenance Outage

The scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility approved by the PJM Office of Interconnection (OI).

Generator Planned Outage

A generator planned outage is the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair – with the approval of the PJM OI.

Good Utility Practice

Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include practices, methods, or acts generally accepted in the region.

ICAP

For non-intermittent generators, installed capacity (ICAP) commonly refers to "iron in the ground" – or rated capacity of a generation unit prior to derating or other performance adjustments. For the purposes of this report, the ICAP of intermittent generators such as wind and solar refers to the capacity credit calculated for each such generator as per PJM's Manual 21.

ILR

Interruptible Load for Reliability (IRL) is a component of PJM's Load Management (LM) program. In the RPM program, just prior to the final incremental auction, load with verifiable existing interruptible capability may declare themselves an Interruptible Load for Reliability (ILR). This component will end for the 2012 delivery year RPM market place. See Load Management and Demand Resources.

Import Capability

Import Capability, expressed in megawatts, is a single value that represents the simultaneous imports into PJM that can occur during peak PJM system conditions. The capabilities of all transmission facilities that interconnect the PJM Control Area to its neighboring regions are evaluated to determine this single value. (See SIL)

IRM

The Installed Reserve Margin (IRM) is the percent of aggregate generating unit capability above the forecasted peak load that is required for adherence to meet a given adequacy level. IRM is expressed in units of installed capacity (ICAP). The PJM IRM is the level of installed reserves needed to meet the ReliabilityFirst criteria for a loss of load expectation (LOLE) of one day, on average, every 10 years

ISO-NE

The Independent System Operator of New England (ISO-NE) is an independent system operator (ISO) and not-for-profit corporation responsible for reliably operating New England's bulk electric power generation, transmission system and wholesale electricity markets. Created in 1997 and with headquarters in Holyoke, MA, the ISO-NE control extends throughout New England including Maine, New Hampshire, Vermont, Rhode Island, Massachusetts and Connecticut. (http://www.iso-ne.com/)

LDA

Locational Deliverability Areas (LDAs) are zones that comprise the PJM RTO as defined in the RAA schedule 10.1 and can be an individual zone, a combination of two or more zones, or a portion of a zone. There are currently 25 LDAs within the PJM footprint.

Load

Integrated hourly electrical demand, measured as generation net of interchange. Loads generally can be reported and verified to the tenth of a megawatt (0.1 MW) for this report.

Load Analysis Subcommittee (LAS)

A PJM subcommittee, reporting to the Planning Committee that provides input to PJM on load related issues.

Load Management (LM)

Load Management, previously referred to as Active Load Management (ALM), applies to interruptible customers whose load can be interrupted at the request of PJM. Such a request is considered an emergency action and is implemented prior to a voltage reduction. This includes Demand Resources (DR), Energy Efficiency, and Interruptible Load for Reliability (ILR) –

ILR is only applicable in RPM markets prior to the 2012/13 delivery year, with ILR an inherent piece of all forecast load management values.

LCC

Load Carrying Capability (LCC), typically expressed in megawatts, is the amount of load that a given resource or resources can serve at a predetermined adequacy standard (typically one day in ten years).

LOLE

Generation system Adequacy is determined as Loss of Load Expectation (LOLE) and is expressed as days (occurrences) per year. This is a measure of how often, on average, the available capacity is expected to fall short of the restricted demand. LOLE is a statistical measure of the frequency of firm load loss and does not quantify the magnitude or duration of firm load loss. The use of LOLE to assess Generation Adequacy is an internationally accepted practice.
Let's consider the difference between probability and expectation. Mathematical expectation [E (x)] for a model is based on a given probability for each outcome. An equation for the calculation of expectation is:

$$E(x) = P_1 X_1 + P_2 X_2 + P_3 X_3 + \ldots + P_n X_n$$

$$E(x) = \sum_{i=1}^{n} P_i X_i$$

Where

$P =$ probabilty of outcome

$X =$ definded outcome (Example: on or off)

The expected value is the weighted mean of the possible values, using their probability of occurrence as the weighting factor. There is no implication that it is the most frequently occurring value or the most highly probable, in fact it might not even be possible. The expected value is not something that is "expected" in the ordinary sense but is actually the long term average as the number of terms (trials) increase to infinity.[4]

For generation Adequacy the focus of these calculations, the LOLE, can be expressed in terms of probability as:

$$LOLE = \sum_{i=1}^{260} LOLE_i = \sum_{i=1}^{260} \sum_{j=1}^{21} LOLP_j$$

Where

$LOLE_i =$ Loss of Load Expectation for daily peak distribution

$LOLP_j =$ Loss of Load Probabilty for two state outcome, generation value is less than demand or not.

260 = Number of weekdays in a delivery year

Daily peak = The integrated hourly average peak, or Demand.

4 Power System Reliability Evaluation", Roy Billinton, 1970, Gordon and Breach, Science Publishers for further details on calculation methods.

The LOLEi for daily peak is calculated or convolved as:

$$LOLE_i = \sum_{j=1}^{21} LOLP_j = \sum_{j=1}^{21} PD_j(XD_j) * PG_j(XG_j)$$

$$\begin{aligned}&Where\\ &PG(XG) = \text{Probabilty of generation at 1st generation value(outcome) less than demand}\\ &PD(XD) = \text{Probabilty at given Demand value(outcome)}\\ &21 = \text{Discrete Distribution values to assess all likely values of Demand}\\ &\text{Demand} = \text{The integrated hourly average peak, or Daily peak.}\end{aligned}$$

LOLP

The Loss of Load Probability (LOLP), which is the probability that the system cannot supply the load peak during a given interval of time, has been used interchangeably with LOLE within PJM. LOLE would be the more accurate term if expressed as days per year. LOLP is more properly reserved for the dimensionless probability values. LOLP must have a value between 0 and 1.0. See LOLE.

LSE

Load Serving Entity (LSE) is defined and discussed thoroughly at the following link. This is a PJM training class concerning requirements of an LSE, including: LSE Obligations, Who are LSEs?, PJM Membership, Capacity Obligations (RAA) for PJM, Agreements and Tariffs, Transmission Service, FTRs, Ways to supply Energy, Energy Load Pricing, Energy Market – Two Settlement, Ancillary Services, http://www.pjm.com/sitecore/content/Globals/Training/Courses/ol-req-lse.aspx .

MARS

The General Electric Multi-Area Reliability Simulation (MARS) model is a probabilistic analysis program using sequential Monte Carlo simulation to analyze the resource adequacy for multiple areas. MARS is used by ISOs, RTOs, and other organizations to conduct multi-area reliability simulations.

MC

The PJM Members Committee (MC) is reviews and decides upon all major changes and initiatives proposed by committees and user groups. The MC is the lead standing committee and reports to the PJM Board of Managers.

MIC

The PJM Market Implementation Committee (MIC) initiates and develops proposals to advance and promote competitive wholesale electricity markets in the PJM region for consideration by the Electricity Markets Committee. Along with the OC and the PC, the MIC reports to the MRC.

MISO

The Midcontinent Independent System Operator (MISO) is an independent, nonprofit regional transmission (RTO) organization that supports the constant availability of electricity in 15 U.S. states throughout the Midwestern U.S. and the Canadian province of Manitoba. The Midwest ISO was approved as the nation's first regional transmission organization

(RTO) in 2001. The organization is headquartered in Carmel, Indiana with operations centers in Carmel and St. Paul, Minnesota. (http://www.midwestiso.org/home)

MRC

The PJM Markets and Reliability Committee (MRC) are responsible for ensuring the continuing viability and fairness of the PJM markets. The MRC also is responsible for ensuring reliable operation and planning of the PJM system. The MRC reports to the MC.

MRO

The Midwest Reliability Organization (MRO) is one of eight Regional Reliability Councils that comprise the North American Electric Reliability Council (NERC). The MRO is a voluntary association committed to safeguarding reliability of the electric power system in the north central region of North America. The MRO region is operated in the states of Wisconsin, Minnesota, Iowa, North Dakota, South Dakota, Nebraska, Montana and Canadian provinces of Saskatchewan and Manitoba. (http://www.midwestreliability.org/)

NERC

The North American Electric Reliability Corporation (NERC) is a super-regional electric reliability organization whose mission is to ensure the reliability of the bulk power system in North America. Headquartered in Atlanta, GA, NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada. (http://www.nerc.com/)

NPCC

The Northeast Power Coordinating Council (NPCC) is a regional electric reliability organization within NERC that is responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the Northeast region comprising parts or all of: New York, Maine, Vermont, New Hampshire, Connecticut, Rhode Island, Massachusetts, and the Canadian provinces of Ontario, Quebec, Nova Scotia, New Brunswick, and Prince Edward Island. (http://www.npcc.org/)

NYISO

The New York Independent System Operator (NYISO) operates New York State's bulk electricity grid, administers the state's wholesale electricity markets, and provides comprehensive reliability planning for the state's bulk electricity system. A not-for-profit corporation, the NYISO began operating in 1999. The NYISO is headquartered in Rensselaer, NY with an operation center in Albany, NY. (http://www.nyiso.com/public/index.jsp)

NYSRC

The New York State Reliability Council (NYSRC) a nonprofit, sub-regional electric reliability organization (ERO) within the NPCC. Working in conjunction with the NYISO, the NYSRC's mission is to promote and preserve the reliability of electric service on the New York Control Area (NYCA) by developing, maintaining and updating reliability rules which shall be complied with by the New York Independent System Operator (NYISO). (http://www.nysrc.org/)

OC

The PJM Operating Committee (OC) reviews system operations from season to season, identifying emerging demand, supply and operating issues. Along with the MIC and the PC, the OC reports to the MRC.

OI

The Office of the Interconnection (OI), typically referring to the PJM Operations staff.

OMC

Outside Management Control (OMC) events are a category of data events recorded in the eGADS data. This data category was implemented per the IEEE Standard 762 titled, "IEEE Standard for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity", approved September 15, 2006, available in March 2007. PJM staff, consistent with NERC staff efforts, adopted this new reporting category, starting in January of 2006. Annex D of the IEEE Standard 762 gives examples for these event types including; substation failure, transmission operation error, acts of terrorism, acts of nature such as tornadoes and ice storms, special environmental limitations, and labor strikes or disputes. OMC events are eliminated with the introduction of Capacity Performance in 2018/2019 DY.

PC

The PJM Planning Committee (PC) reviews and recommends planning and engineering strategies for the transmission system. Along with the MIC and the OC, the PC reports to the MRC. Technical subcommittees and working groups reporting to the PC include: Relay Subcommittee (RS), Load Analysis Subcommittee (LAS), Transmission and Substation Subcommittee (TSS), Relay Testing Subcommittee (RTS), Regional Planning Process Task Force (RPPTF), and the Resource Adequacy Analysis Subcommittee (RAAS).

pcGAR

NERC's personal computer based Generator Availability Report (pcGAR) is a database of all NERC generator data and provides reporting statistics on generators operating in North America. This data and application is distributed by NERC annually, with interested parties paying a set fee for this service.

Peak Load

The Peak Load is the maximum hourly load over a given time interval, typically a day, month, season, or delivery year. See Forecast Peak Load.

Peak Load Ordered Time Series (PLOTS)

The Peak Load Ordered Time Series (PLOTS) load model is the result of the Week Peak Frequency application. This is one of the load model's input parameters. This is discussed in the load forecasting, Week Peak Frequency (WKPKFQ) parameters section of Part II – Modeling and analysis.

Peak Season

Peak Season is defined to be those weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week begins on a Monday and ends on the following Sunday, except for the week containing the 36th Wednesday, which ends on the following Friday. Please note that the load forecast report used in this study define peak season as June, July and August.

PJM-MA

The PJM Mid-Atlantic region (PJM-MA) of the PJM RTO, established pursuant to the PJM Reliability Assurance Agreements dated August 1994 or any successor. A control area of the PJM RTO responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the PJM Mid-Atlantic Region through coordinated operations and planning of generation and transmission facilities. The PJM Mid-Atlantic Control Area is operated in the states of Pennsylvania, Maryland, Delaware, New Jersey, and Virginia. The PJM-MA control area is the Eastern edge of the PJM RTO region.

PRISM

The Probabilistic Reliability Index Study Model (PRISM) is PJM's planning reliability program. PRISM replaced GEBGE, using the SAS programming language. The models are based on statistical measures for both the load model and the generating unit model. This is a computer application developed by PJM that is a practical application of probability theory and is used in the planning process to evaluate the generation adequacy of the bulk electric power system.

RI

The Reliability Index (RI) is a value that is used to assess the bulk electric power system's future occurrence for a loss-of-load event. A RI value of 10 indicates that there will be, on average, a loss of load event every ten years. A given value of reliability index is the reciprocal of the LOLE.

Reliability

In a bulk power electric system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service. Bulk Power electric reliability cab be addressed be considering two basic and functional aspects of the bulk power system – adequacy and security.

ReliabilityFirst (RF)

ReliabilityFirst is a not-for-profit super-regional electric reliability organization whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory.   Beginning operations on January 1, 2006, RF is composed of the former Mid-Atlantic Areas Council (MAAC), East Central Area Reliability Coordination Agreement (ECAR) and parts of the Mid-America Interconnected Network (MAIN). RF is one of the eight Regional Reliability Organizations under NERC in North America.   RF is headquartered in Canton, OH with another office in Lombard, IL. The RF Control Area is operated in the states of Pennsylvania, Maryland, Delaware, New Jersey, Virginia, Illinois, Michigan, Wisconsin, Kentucky, West Virginia, Ohio, and Indiana. (http://www.rfirst.org/)

Reliability Assurance Agreement (RAA)

One of four agreements that define authorities, responsibilities and obligations of participants and the PJM OI. The agreement is amended from time to time, establishing obligation standards and procedures for maintaining reliable operation of the PJM Control Area. The other principal PJM agreements are the Operating Agreement, the PJM Transmission Tariff,

and the Transmission Owners Agreement.
(http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx)

Reliability Pricing Model (RPM)

PJM's Reliability Pricing Model (RPM) is the forward capacity market in the PJM RTO Control Area. PJM Manual 18 outlines many aspects of this market place. (http://www.pjm.com/markets-and-operations/rpm.aspx)

Reserve Requirement Study (RRS)

PJM Reserve Requirement Study, which is performed annually. The primary result of the study is a single calculated percentage, the IRM and FPR, which represents the amount above peak load that must be maintained to meet the RF adequacy criteria. The RF adequacy criteria are based on a probabilistic requirement of experiencing a loss-of-load event, on average, once every ten years. Also referred to as the R-Study. (http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx)

Resource Adequacy Analysis Subcommittee (RAAS)

Reporting to the PC, the RAAS assists PJM staff in performing the annual Reserve Requirement Study (RRS) and maintains the reliability analysis documentation (http://pjm.com/committees-and-groups/subcommittees/raas.aspx). See Resource Adequacy Analysis Subcommittee web site.

Restricted Peak Load

For the given forecast period, the restricted peak load equals the forecasted peak load minus anticipated load management.

RTEP

PJM's Regional Transmission Expansion Planning (RTEP) process identifies transmission enhancements to preserve regional transmission system reliability, the foundation for thriving competitive wholesale energy markets. PJM's FERC-approved, region-wide planning process provides an open, non-discriminatory framework to identify needed system enhancements. (http://www.pjm.com/planning/rtep-upgrades-status.aspx)

Security

The ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components or switching operations. One part of the Reliability term.

SERC

The Southeastern Electric Reliability Council (SERC) is a regional electric reliability organization (ERO) within NERC that is responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems in all or portions of 16 central and southeastern states, including Virginia, North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Arkansas, Kentucky, Louisiana, Missouri, Texas, and West Virginia. SERC is divided geographically into five diverse sub-regions that are identified as Central, Delta, Gateway, Southeastern and VACAR. SERC is headquartered in Charlotte, NC. (http://www.serc1.org/Application/HomePageView.aspx)

SIL

Simultaneous transmission Import Limit (SIL) study is a series of power flow studies that, per FERC order 697, assess the capabilities of all PJM transmission facilities connected to neighboring regions under peak load conditions to determine the simultaneous import capability. FERC Order, 124 FERC 61,147, issued August 6, 2008; found that PJM's studies, as amended, met the requirements for a SIL study. The purpose is to assist our members in responding to FERC regarding their two Market Power Indicative screens and their Delivered Price Test Analysis.

SND

The Summer Net Dependable (SND) rating for a given generation unit is used in the summer period. All processes use the SND rating as the basis for evaluating a unit.

SPP

The Southwest Power Pool (SPP) is a regional transmission organization (RTO) responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the Southwest U.S. region, including all or parts of: Kansas, Oklahoma, Texas, Arkansas, Louisiana, and New Mexico. (http://www.spp.org/)

THI

The Temperature-Humidity Index (THI) reflects the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. The temperature-humidity index, THI, is defined as follows: THI = Td – (0.55 – 0.55RH) * (Td - 58) where Td is the dry-bulb temperature and RH is the percentage of relative humidity.

Unrestricted Peak Load

The unrestricted peak load is the metered load plus estimated impacts of Load Management.

Variance

A measure of the variability of a unit's partial forced outages which is used in reserve margin calculations. See PJM manual 22, page 12 and Section 3 Item C, (http://www.pjm.com/~/media/documents/manuals/m22.ashx).

XEFORd

XEFORd is a statistic that results from excluding OMC events from the EFORd calculation. The use of the XEFORd was discontinued with the introduction of Capacity Performance in 2018/2019 DY.

Zone / Control Zone

An area within the PJM Control Area, as set forth in PJM's Open Access Transmission Tariff (OATT) and the Reliability Assurance Agreement (RAA). Schedule 10 and 15 of the RAA provide information concerning the distinct zones that comprise the PJM Control Area.

IV. Appendices

Appendix A
Base Case Modeling Assumptions for 2019 PJM RRS

Parameter	2018 Study Modeling Assumptions	2019 Study Modeling Assumptions	Basis for Assumptions
Load Forecast			
Unrestricted Peak Load Forecast	152,887 MW (2022/2023 DY)	152,854 MW (2023/2024 DY)	Forecasted Load growth per 2019 PJM Load Forecast Report, using 50/50 normalized peak.
Historical Basis for Load Model	2003-2012	TBD	Load model selection method approved at the June 16, 2019 PC meeting (see Attachment V).
Forecast Error Factor (FEF)	Forecast Error held at 1 % for all delivery years.	Forecast Error held at 1 % for all delivery years.	Consistent with consensus gained through PJM stakeholder process.
Monthly Load Forecast Shape	Consistent with 2018 PJM Load Forecast Report and 2017 NERC ES&D report (World area).	Consistent with 2019 PJM Load Forecast Report and 2018 NERC ES&D report (World area).	Updated data.
Daily Load Forecast Shape	Standard Normal distribution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week.	Standard Normal distribution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week.	Consistent with consensus gained through PJM stakeholder process.
Capacity Forecast			
Generating Unit Capacities	Coordinated with eRPM databases, EIA-411 submission, and Generation Owner review.	Coordinated with eRPM databases, EIA-411 submission, and Generation Owner review.	New RPM Market structure required coordination to new database Schema. Consistency with other PJM reporting and systems.
New Units	Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value. .	Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.	Consistent with CETO cases.
Wind Resources	A wind generator with three or more years of operating data is modeled at a capacity value based on its actual performance. For a wind unit with fewer than three years of operating data, its capacity value is based on a blend of its actual performance and the class average capacity factor.	A wind generator with three or more years of operating data is modeled at a capacity value based on its actual performance. For a wind unit with fewer than three years of operating data, its capacity value is based on a blend of its actual performance and the class average capacity factor.	Based on Manual 21 Appendix B for Intermittent Capacity Resources. Capacity factors based on PJM stakeholder process, February July 13, 2017 Planning Committee, Agenda Item 10.

Parameter	2018 Study Modeling Assumptions	2019 Study Modeling Assumptions	Basis for Assumptions
Solar Resources	A solar generator with three or more years of operating data is modeled at a capacity value based on its actual performance. For a wind unit with fewer than three years of operating data, its capacity value is based on a blend of its actual performance and the class average capacity factor.	A solar generator with three or more years of operating data is modeled at a capacity value based on its actual performance. For a wind unit with fewer than three years of operating data, its capacity value is based on a blend of its actual performance and the class average capacity factor.	Based on Manual 21 Appendix B for Intermittent Capacity Resources. Capacity factors based on PJM stakeholder process, July 13, 2017 Planning Committee, Agenda Item 10.
Firm Purchases and Sales	Firm purchase and sales from and to external regions are reflected in the capacity model. External purchases reduce the World capacity and increase the PJM RTO capacity. External Sales reduce the PJM RTO capacity and increase the World capacity. This is consistent with EIA-411 Schedule 4 and reflected in RPM auctions.	Firm purchase and sales from and to external regions are reflected in the capacity model. External purchases reduce the World capacity and increase the PJM RTO capacity. External Sales reduce the PJM RTO capacity and increase the World capacity. This is consistent with EIA-411 Schedule 4 and reflected in RPM auctions.	Match EIA-411 submission and RPM auctions.
Retirements	Coordinated with PJM Operations, Transmission Planning models and PJM web site: http://www.pjm.com/planning/generation-retirements.aspx . Consistent with forecast reserve margin graph.	Coordinated with PJM Operations, Transmission Planning models and PJM web site: http://www.pjm.com/planning/generation-retirements.aspx . Consistent with forecast reserve margin graph.	Updated data available on PJM's web site, but model data frozen in May 2019.
Planned and Operating Treatment of Generation	All generators that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements: 1.Firm Transmission service to the PJM border 2.Firm ATC reservation into PJM 3.Letter of non-recallability from the native control zone Assuming that these requirements are fully satisfied, the following comments apply: •Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World. •Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale.	All generators that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements: 1.Firm Transmission service to the PJM border 2.Firm ATC reservation into PJM 3.Letter of non-recallability from the native control zone Assuming that these requirements are fully satisfied, the following comments apply: •Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World. •Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale. •Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control	Consistency with other PJM reporting and systems.

Parameter	2018 Study Modeling Assumptions	2019 Study Modeling Assumptions	Basis for Assumptions
	•Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area. •Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.	area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area. •Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.	
Unit Operational Factors			
Forced and Partial Outage Rates	5-year (2013-17) GADS data. (Those units with less than five years data will use class average representative data.).	5-year (2014-18) GADS data. (Those units with less than five years data will use class average representative data.).	Most recent 5-year period. Use PJM RTO unit fleet to form class average values.
Planned Outages	Based on eGADS data, History of Planned Outage Factor for units.	Based on eGADS data, History of Planned Outage Factor for units.	Updated schedules.
Summer Planned Outage Maintenance	In review of recent Summer periods, no Planned outages have occurred.	In review of recent Summer periods, no Planned outages have occurred.	Review of historic 2014 to 2018 unit operational data for PJM RTO footprint.
Gas Turbines, Fossil, Nuclear Ambient Derate	Ambient Derate includes several categories of units. Based on analysis of the Summer Verification Test data from the last 3 summers, 2,500 MW out on planned outage over summer peak was confirmed to be the best value to use at this time. This analysis was performed early 2016 under the auspices of the RAAS.	Ambient Derate includes several categories of units. Based on analysis of the Summer Verification Test data from the last 3 summers, 2,500 MW out on planned outage over summer peak was confirmed to be the best value to use at this time. This analysis was performed early 2016 under the auspices of the RAAS.	Operational history and Operations Staff experience indicates unit derates during extreme ambient conditions. Summer Verification Test data confirms this hypothesis.
Generator Performance	For each week of the year, except the winter peak week, the PRISM model uses each generating unit's capacity, forced outage rate, and planned maintenance outages to develop a cumulative capacity outage probability table. For the winter peak week, the cumulative capacity outage probability table is created using historical actual (DY 2007/08 – DY 2017/18) RTO-aggregate outage data (data from DY	For each week of the year, except the winter peak week, the PRISM model uses each generating unit's capacity, forced outage rate, and planned maintenance outages to develop a cumulative capacity outage probability table. For the winter peak week, the cumulative capacity outage probability table is created using historical actual (DY 2007/08 – DY 2018/19) RTO-aggregate outage data (data from DY 2013/14 will be dropped and replaced with data from DY 2014/15).	New methodology to develop winter peak week capacity model to better account for the risk caused by the large volume of concurrent outages observed historically during the winter peak week.

Parameter	2018 Study Modeling Assumptions	2019 Study Modeling Assumptions	Basis for Assumptions
	2013/14 will be dropped and replaced with data from DY 2014/15).		
Class Average Statistics	PJM RTO fleet Class Average values. 73 categories based on unit type, size and primary fuel.	PJM RTO fleet Class Average values. 73 categories based on unit type, size and primary fuel.	PJM RTO values have a sufficient population of data for most of the categories. The values are more consistent with planning experience.
Uncommitted Resources	Behind the meter generation (BTMG) is not included in the capacity model because such resources cannot be capacity resources. The impact of behind the meter generation (BTMG) is reflected on the load side.	Behind the meter generation (BTMG) is not included in the capacity model because such resources cannot be capacity resources. The impact of behind the meter generation (BTMG) is reflected on the load side.	Consistency with other PJM reporting and systems.
Generation Owner Review	Generation Owner review and sign-off of capacity model.	Generation Owner review and sign-off of capacity model.	Annual review to insure data integrity of principal modeling parameters.
Load Management and Energy Efficiency			
Load Management and Energy Efficiency	PJM RTO load management modeled per the January 2018 PJM Load Forecast Report (Table B7)	PJM RTO load management modeled per the January 2019 PJM Load Forecast Report (Table B7)	Model latest load management and energy efficiency data. Based on Manual 19, Section 3 for PJM Load Forecast Model.
Emergency Operating Procedures	IRM reported for Emergency Operating Procedures that include invoking load management but before invoking Voltage reductions.	IRM reported for Emergency Operating Procedures that include invoking load management but before invoking Voltage reductions.	Consistent reporting across historic values.
Transmission System			
Interface Limits	The Capacity Benefit Margin (CBM) is an input value used to reflect the amount of transmission import capability reserved to reduce the IRM. This value is 3,500 MW.	The Capacity Benefit Margin (CBM) is an input value used to reflect the amount of transmission import capability reserved to reduce the IRM. This value is 3,500 MW.	Reliability Assurance Agreement, Schedule 4, Capacity Benefit Margin definition.
New Transmission Capability	Consistent with PJM's RTEP as overseen by TEAC.	Consistent with PJM's RTEP as overseen by TEAC.	Consistent with PJM's RTEP as overseen by TEAC.

Parameter	2018 Study Modeling Assumptions	2019 Study Modeling Assumptions	Basis for Assumptions
Modeling Systems			
Modeling Tools	ARC Platform 2.0	ARC Platform 2.0	Per recommendation by PJM Staff. Latest available version.
Modeling Tools	Multi-Area Reliability Simulation (MARS) Version 3.16	Multi-Area Reliability Simulation (MARS) Version 3.16	Per recommendation by PJM Staff and General Electric Staff. Latest available version.
Outside World Area Models	Base Case world region include: NY, MISO, TVA and VACAR.	Base Case world region include: NY, MISO, TVA and VACAR.	Updated per publicly available data and by coordination with other region's planning staffs.

Appendix B

Description and Explanation of 2019 Study Sensitivity Cases

Case No.	Description and Explanation	Change in 2018 Base Case IRM in percentage points (pp)
	Individual and New Modeling Characteristic Sensitivity Case	
	The first six sensitivities use the previous 2018 reserve requirement study Base Case as the reference. For the sensitivity cases in red (Case No. 1-6), all differences are with respect to the 2018 Base Case result (2022 DY PJM RTO IRM = 15.66%).	
1	**Load model update – Weekly shape (#57128 2Area)**	**Decrease by 0.01 ***
	Modeling characteristics from the Weekly Peak distributions, or 52 mean and standard deviation values, were impacted by updated historical data. The 2019 weekly load model for PJM and the World is based on the same historical time period as in the 2018 study (2003 to 2012).	
2	**Load model update – Monthly Forecast shape (#57131 2Area)**	**Decrease by 0.14 ***
	Impact of using the monthly forecast from the 2019 PJM Load Forecast Report in place of the 2018 version. The monthly forecast for the World is also included in this sensitivity.	
3	**Load model update – Both weekly and monthly shape (#57134 2Area)**	**Decrease by 0.16 ***
	Impact of using both the 2019 PJM Load Forecast Report and the updated weekly parameters simultaneously. This is a combination of Case No. 1 and Case No. 2.	
4	**PJM Capacity Model update**	**Decrease by 0.71 ***
	Impact of using updated PJM RTO capacity model and associated unit characteristics.	
5	**World Capacity Model update**	**Increase by 0.01 ***
	Impact of using updated World region capacity model.	
6	**PJM RTO and World Capacity Model update**	**Decrease by 0.70 ***
	Impact of using both the updated PJM RTO Capacity Model and the updated World Capacity Model simultaneously. This is a combination of Case No. 4 and Case No. 5.	

Case No.	Description and Explanation	Change in 2019 Base Case IRM in percentage points (pp)
	Load Model Sensitivity Cases	
	Sensitivity numbers 7 and higher are based on the 2019 Base Case. All differences are with respect to the 2019 Base Case result (2023 DY).	
7	**No Load Forecast Uncertainty (LFU) (#57125)**	**Decrease by 4.85**
	This scenario represents "perfect vision" for forecast peak loads, i.e., forecast peak loads for PJM RTO and the Outside World areas have a 100% probability of occurring. The results of this evaluation help to quantify the effects of weather and economic uncertainties on IRM requirements. This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.	
8	**Vary the Forecast Error Factor (#57126 and 57127)**	**See Below**
	This two-area sensitivity gauges the impact of the FEF on the IRM. When the FEF is decreased to 0% compared to the 1% used in the base case, the IRM falls by 0.16pp. When instead the FEF is increased to 2.5%, the IRM rises by 0.97pp. This sensitivity does not affect the forced outage rate portion in the FPR calculation, thus the FPR will change in the same amount.	
9	**Number of Years in Load Model (#57149 and 57151)**	**See below**
	These two-area sensitivity cases replace the time period used for the load model in the base case of 2003 to 2012 with other candidate load models considered in the selection process by RAAS.	

PRISM #	Time Period	PJM LM #	World LM #	2023 IRM %	Difference (PP)
57086	2003-2012 (10 Year LM)	51995	51997	14.84	-
57149	2004-2014 (11 Year LM)	52003	52004	14.86	0.02
57151	2002-2014 (13 Year LM)	52005	52006	14.78	-0.06

Case No.	Description and Explanation	Change in 2019 Base Case IRM in percentage points (pp)
10	**PJM Monthly Load Shape (#57154 and #57155)**	**See below**
	These two-area sensitivity cases test the impact of making adjustments to the PJM monthly load profile relative to the base case assumption in Table II-1. In the base case, the August peak is 96.5% of the annual peak. Increasing this August ratio by one percentage point (to 97.5%) increases the IRM to 15.23%, or 0.39 pp higher than the base case. Reducing this August ratio by one percentage point (to 95.5%) decreases the IRM to 14.56%, or 0.29 pp lower than the base case.	
11	**World Monthly Load Shape (#57156)**	**See below**
	This two-area sensitivity case tests the impact of making adjustments to the World monthly load profile relative to the base case assumption in Table II – 1. In the base case, the World peaks in July while its August peak is 99.4% of the annual (July)	

	peak. Switching the World's annual peak to August and making its July peak to be 99.4% of the annual peak reduces the IRM by 0.07 pp to 14.77%.	
	Generation Unit Model Sensitivity Cases	
12	**High Ambient Temperature Unit Derating (#57184 2Area)**	**Decrease by 1.38**
	Assessment of performance of PJM RTO units on high ambient temperature conditions indicated that some units cannot produce their summer net dependable rating on these days. This type of derating is per PJM's Operations rules and is not considered a GADS derated outage event. This assessment assumes that all units are not affected by high ambient temperature conditions and that they can produce their full summer net dependable rating. This sensitivity removes the 2500 MW on planned outage for the peak summer period (weeks 6-15)	
13	**Replace the EEFORd values with EFORd values for all units in the model. (#57185 2Area)**	**Decrease by 0.94**
	This case replaces the EEFORd statistic with the EFORd statistic, for all units. It assumes that EMOF is not included in the EEFORd computation.	
14	**Impact of change in EEFORd: F-Factor (#57186 1Area)**	**Increase by 1.39**
	There is a direct correlation to the forced outage rate of the PJM RTO units vs. the PJM IRM. This sensitivity increases the (EEFORd) by 1 percentage point.	
	Capacity Benefit Margin Sensitivity Cases	
15	**Various values of Capacity Benefit Margins**	**See Figure I-7**
	Figure I-7 shows the impact to IRM as the value of Capacity Benefit Margin (CBM) is increased. CBM is a measure of transfer assistance available from the outside neighboring region. This graph indicated what value PJM's interconnected ties have on the calculated IRM, and where the value of CBM saturates (becomes constant).	

<table>
<tr><th colspan="3">Reserve Modeling Sensitivity Cases</th></tr>
<tr><td>16</td><td>PJM RTO at cleared RPM auction (#57138)</td><td>RI = 82.9</td></tr>
<tr><td></td><td colspan="2">In this sensitivity, PJMRTO reserves are modeled as per the most recent RPM auction while the World is solved to meet the 1 in 10 criterion.

This sensitivity should have been run using results from the 2022/2023 RPM Base Residual Auction (BRA) but since that BRA has not been run yet, results from the 2021/2022 RPM BRA are used.

The 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 163,627.3 MW of unforced capacity in the RTO representing a 22.0% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2021/2022 Delivery Year as procured in the BRA is 21.5%, or 5.7% higher than the target reserve margin of 15.8%. This reserve margin was achieved at clearing prices that are between approximately 44% to 82% of Net CONE, depending upon the Locational Deliverability Area (LDA). The auction also attracted a diverse set of resources, including a significant increase in Demand Response and Energy Efficiency resources, additional wind and solar resources, and one new combined cycle gas resource

The full report can be found at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en</td></tr>
<tr><td>17</td><td>PJM RTO IRM Vs. World Reserves (#56628-56643)</td><td>See below</td></tr>
<tr><td></td><td colspan="2">For a two area study, World Reserves were varied from the calculated requirement (1 day in 10) to the forecasted reserves. The runs are made by solving the World for a fixed load (corresponding to an installed reserve level) and PJM RTO is solved to its criterion (1 day in 10). The results are in Figure I-6. The valid range of world reserves is determined through consideration of different load management assumptions. Within this valid range of world reserves, as the reserves of the world increase, the IRM requirement for PJM RTO declines at a decelerating rate.</td></tr>
<tr><td>18</td><td>PJM RTO RI Vs. PJM RTO Reserves (#56662-56676)</td><td>See below</td></tr>
<tr><td></td><td colspan="2">A two area study when PJM RTO reserves were varied from the calculated requirement (1 day in 10). The runs are made by solving the PJM RTO for a fixed load (corresponding to an installed reserve level) and World is at its 1D/10 YR level.

As the PJM RTO reserves increase, the reliability Index (measured by the LOLE value) increases exponentially. See Figure II-5.</td></tr>
</table>

Topological Modeling Sensitivity Cases		
19	**Single Area PJM RTO Model (#57087)**	**Increase by 1.56**
	This models only the PJM RTO in a single area case. The solution is for a Reliability Index (RI) of 10, or once every 10 years. When compared to the official case results, this represents the value of the interconnected ties, or Capacity Benefit Of Ties (CBOT). The difference between the base run and this sensitivity in the load carrying capability (LCC), multiplied by the reserve requirement, yields an approximate 2,442 MW of capacity that does not need to be inside the PJM RTO. This megawatt amount represents the value of the 3,500 MW CBM that is specified in Schedule 4 of the PJM Reliability Assurance Agreement (RAA).	
20	**Two Area Model with Ambient Derates for World Area -3,110 MW out on PO for World area**	**Increase by 0.01**
	This sensitivity models the Base Case with ambient derates for the World region too. The same proportion of impact of ambient conditions on the World fleet of units is modeled as are modeled for the PJM generation fleet. The impact of ambient conditions on the generation fleet affects several generation categories as shown in Table II-6. Ambient conditions are modeled as Planned outages over the ten week Summer period, similar to the 2,500 MW derating used in the PJMRTO area.	
21	**Relationship between IRM and ambient impact on unit performance**	**See Below**
	This sensitivity adjusts the total amount of ambient derates, for the appropriate generation categories affected by high ambient (THI) conditions (See Table II-6 for categories). Ambient derates are modeled as planned outages over the high LOLE summer period. The range of impact to the unit fleet due to high ambient conditions, for the entire PJM RTO fleet of units, was 2,500 – 8,500 megawatts. The increase in the IRM for every additional 1000 megawatts of ambient derates, on average, was 0.62 pp.	

Appendix C
Resource Adequacy Analysis Subcommittee (RAAS)

RAAS Main Deliverables and Schedule

There are 3 primary deliverables of the RAAS.

1. The assumptions letter for the upcoming RRS

    Per the below time line, this activity is scheduled to start in June and be completed in July.

2. The IRM, FPR Analysis Report

    Per the below time line, this activity is scheduled to start in July and be completed in September.

3. The Winter Weekly Reserve Target in the Report

    Per the below time line, this activity is shown as item number thirteen, scheduled to be completed in September, for the upcoming winter period.

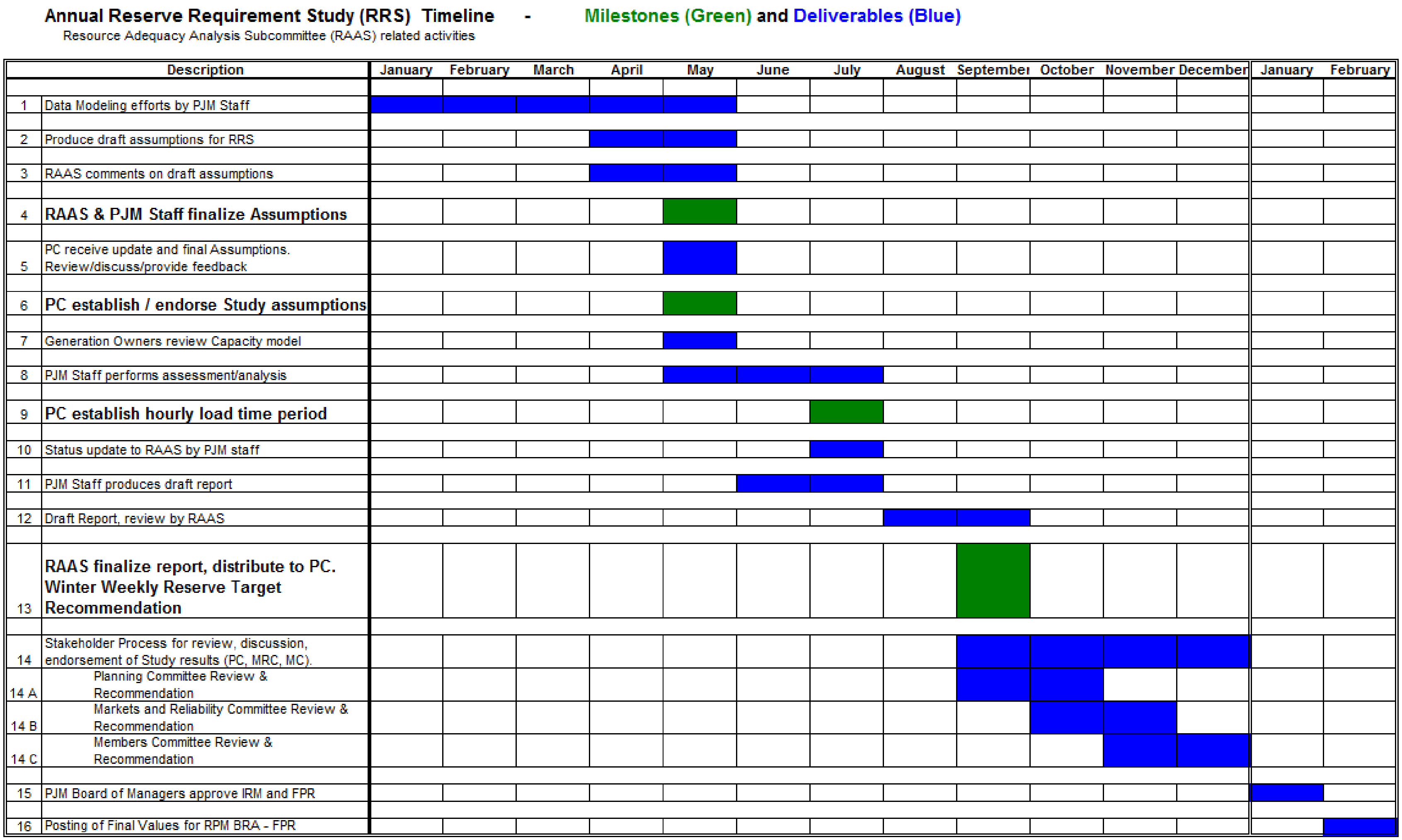
This technical working group was established by and reports to the PJM Planning Committee.

The activities of the PJM RAAS are shown at the following web link:

http://pjm.com/committees-and-groups/subcommittees/raas.aspx

Timeline for 2019 Reserve Requirement Study

Figure IV-1: Timeline for 2019 RRS



The 2019 Study activities last for approximately 14 months. Some current Study activities, shown in items 1 and 2, overlap the previous Study timeframe. The posting of final values occurs on or about February 1st.

Appendix D has not yet been updated

Appendix D

ISO Reserve Requirement Comparison

The following compares the MISO, NYISO, ISO-NE and PJM RTO reserve requirements, on a 1) IRM, 2) IRM adjusted by load diversity, and 3) Unforced Margin adjusted by load diversity.

Observations from this comparison:

- The smaller NYISO and ISO-NE regions have lower load diversity which tends to inflate their *IRM adjusted by load diversity*.
  - NYISO's *Unforced Margin adjusted by load diversity* is higher than PJMs due to a starting IRM that is also higher (18.2% vs 16.2% for 2018) and the aforementioned lower load diversity.
- MISO's *Unforced Margin adjusted by load diversity* is lower than PJM's due to a larger amount of emergency assistance from neighboring regions into MISO. This understates MISO's IRM relative to PJM's.

Table IV-1: Comparison of reserve requirements on a coincident, unforced basis.

	MISO	ISO-NE	NYISO	PJM	PJM	PJM	PJM	PJM
Delivery Year	2018	2021	2018	2018	2019	2020	2021	2022
IRM	**17.10%**	**17.80%**	**18.20%**	**16.20%**	**16.00%**	**15.90%**	**15.80%**	**15.70%**
Load Diversity	3.55%	1.00%	1.91%	3.74%	3.74%	3.80%	3.78%	3.85%
IRM (adj. by div)	**13.09%**	**16.63%**	**15.99%**	**12.02%**	**11.82%**	**11.66%**	**11.59%**	**11.41%**
Average EFORd***	8.13%	8.01%	7.90%	6.20%	6.08%	6.04%	6.01%	5.90%
Unforced Margin	7.58%	8.36%	8.86%	9.00%	8.95%	8.90%	8.84%	8.87%
Unforced Margin (adj. by div)	**3.89%**	**7.28%**	**6.82%**	**5.07%**	**5.02%**	**4.91%**	**4.88%**	**4.84%**

*** Values from period 2012-2016 for MISO, ISO-NE, NYISO; 2013-2017 for PJM
Unforced Margin = ((1 + IRM) * (1- EFORd)) - 1
IRM w/div = ((1 + IRM) / (1 + Load Diversity)) - 1
Unforced Margin w/div = (IRM w/div * (1 - EFORd) / (1 + Load Diversity)) - 1
PJM RTO Load Diversity includes both Inter-regional and intra-regional diversity, per Table B1 of the January 2018 load forecast report (Diversity Interregional plus Diversity PJM Western plus Diversity Mid-Atlantic)
ISO-NE and NYISO columns use estimated values for load diversity. MISO and ISO-NE columns use estimated values for EFORd

Appendix E
RAAS Review of Study - Transmittal Letter to PC

October 17, 2019

Kenneth Seiler
Chairman Planning Committee
PJM Interconnection
2750 Monroe Blvd.
Audubon, PA 19403

Dear Mr. Seiler,

The Resource Adequacy Analysis Subcommittee (RAAS) has completed its review of the 2019 PJM Reserve Requirement Study (RRS) report.

The review efforts are in accordance with the RAAS Charter, as approved by the Planning Committee and posted at: http://pjm.com/committees-and-groups/subcommittees/~/media/committees-groups/subcommittees/raas/postings/charter.ashx

The review included the following efforts:

- Development and completion of the Study assumptions, including an activity timeline
- Participation in subcommittee meetings to discuss and review PJM staff progress in developing the Study model
- Identification of modeling improvements for incorporation into the analysis and report, as described in the June 2019 RRS Study Assumptions letter
- Participation in subcommittee meetings to discuss and review preliminary analysis results
- Verification that all base case study assumptions are fully and completely adhered to
- Review of a draft version of the study report

After review and discussion of the study results, the subcommittee unanimously endorsed the PJM recommendation shown in the table below.

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2019	2020 / 2021	15.46%	**15.5%**	5.78%	**1.0882**
2019	2021 / 2022	15.14%	**15.1%**	5.56%	**1.0870**
2019	2022 / 2023	14.89%	**14.9%**	5.42%	**1.0867**
2019	2023 / 2024	14.84%	**14.8%**	5.40%	**1.0860**

PJM will be requesting Planning Committee endorsement of the recommendations detailed above at your October 17, 2019 meeting.

The review efforts of the RAAS will be concluded upon acceptance of this report by the Planning Committee.

Respectfully,

Thomas A Falin
RAAS Chair

Appendix F
Discussion of Assumptions

This appendix's intent is to document assumptions and modeling items that affect the calculated IRM for the base case run. The following considerations were included in the modeling and analysis

- Trends observed over several Study models are significant and are considered at the time of validating the recommendations resulting from this report.

- Historically significant drivers of the Study results include the overall unit forced outage rates, forecasted monthly load profile, load model diversity, forecast reserve for both Area1 (PJM RTO) and Area2 (World), size of the neighboring region modeled, and time period used in the hourly load model to create the weekly statistical parameters.

- The sensitivities presented in Appendix B provide an important tool for validating assumptions and results of the study.

- Mitigating uncertainty to the forward capacity market is an important consideration.

A discussion of the assumptions considered in the study is presented below,

Independence of Unit Outage Events (no recognition of common cause failures): Historically, this has been an assumption widely used throughout the industry. All production grade commercial applications used to perform probabilistic reliability indexes use this assumption. However, changes in the makeup of the industry, such as the current trend to build mostly units that rely on the shared gas transmission system, could invalidate this assumption for some units that do have a correlation for outages due to the shared gas transmission pipeline.

Forecast Error Factor (FEF): The RRS models a 1% Forecast Error Factor for all delivery years. This modeling, which began in the 2005 Study, represents a switch from the previous practice of increasing the FEF as the planning horizon lengthens.

Intra-World Load Diversity: The diversity values used are from an assessment of historic hourly data. See Table II-3 for further details. Using the average of the historic diversity values was considered to be a reasonable assumption (as opposed to using the minimum of the values which was deemed to be very conservative).

Assistance from World area: The value of the outside world's assistance is associated with two modeling characteristics: the timing of PJM's need for assistance and the ability of the World to supply assistance at this time of need. The assumption that the outside world adjacent to PJM will help PJM avoid Loss-of-Load events is based on historic operating experience.

Modeling all External NERC Regions in a Single Area: PRISM is limited to a 2-area model: PJM and the World Area. Thus, all external NERC regions are modeled in a single area, ignoring the transmission constraints between the areas. This approach assumes that all external NERC regions share loss-of-load events which are not the case in practice. Furthermore, PRISM solves the World to collectively be at a 1 in 10 reliability level whereas, in practice, each external NERC Region is at 1 in 10 and hence the World is collectively at a level worse than 1 in 10.

Units out on planned maintenance over summer peak period due to ambient conditions: The moving of planned outage events to the summer peak period is an assumption that has been used since 1992. This is consistent with what has been observed by Operations over the summer period and reflects PJM's experience with a control region that includes about 1,300 units. Currently, 2,500 MW are modeled out to reflect reduced unit output during high ambient conditions (hot and humid). Verification of this quantity was performed in early 2016 using Summer Verification Test data from 2013-2015.

Holding World at known reserve requirement level rather than forecast reserves: The World is modeled at the reserve requirement known for each of the surrounding individual sub-regions that make up the World region. This assumption ensures that PJM does not depend on World "excess" reserves that may be committed to other regions. Any excess reserves, however, may be uncommitted and actually available to serve PJM under a capacity emergency. Thus, this assumption may understate the amount of assistance available to PJM from the World area.

Normally-distributed load model: The uncertainty in the daily peak load model is assumed to be normally distributed. The normal distribution is approximated using a histogram with 21 points ranging from -4.2 to +4.2 standard deviations from the mean. This 21-point approximation is used in all weeks (and in each of the 5 days within a week) of the analysis. The means and standard deviations vary from week to week and are computed by a separate program. This program uses historic weekly load data, magnitude ordered within a season, to compute the mean and standard deviation for each of the 52 weeks in the model. The 21 point daily peak distribution is defined by each week's mean and standard deviation in the calculation of loss of load expectation.

PJM and World regions load diversity: The value of the Capacity Benefit Margin (CBM) is associated with the timing of PJM load model peaks relative to the timing of the World load model peaks. This difference in timing is assessed by the PJM-World Diversity. The PJM-World Diversity is a measure of the World's load value at the time of PJM's annual peak. This measure is expressed as a percentage of the World's annual peak (see Table II-3). Note that the greater the diversity, the more capacity assistance the World can provide at PJM's peak (or other PJM high load events). The value of PJM-World diversity might change depending on the dataset of historical hourly peaks considered.

Perfect correlation between two load models: As mentioned earlier in the report, PJM's load is assumed to be normally distributed (approximated via a 21-point histogram). The World's load model is modeled in the same way. When PJM is assumed to be facing a particular load level (for instance, load level 2, the second highest load level), the World is assumed to be facing the corresponding magnitude-ordered load level (i.e. the second highest out of the 21 load levels for the World). In other words, there is a perfect correlation between the two load models. In practice though, the World could be facing any other of the 20 remaining load levels.

World Load Management: The criteria to select the World reserve level stipulates that the World will be assumed to be at the higher of the following two reserve levels: 1) the reserve level that satisfies 1 in 10 (as found by PRISM) or 2) the composite reserve level as a percentage of the World peak (see Table I-5) excluding load management as an available resource. In the event that reserve level 1) is selected, then implicitly some load management is being assumed as an available resource in the World. On the other hand, when reserve level 2) is selected, no load management is assumed as available.

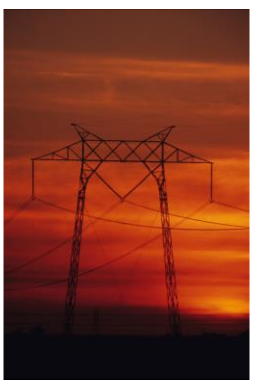
Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-8

Technical Study Report

New York Control Area Installed Capacity Requirement

For the Period May 2019 to April 2020



December 7, 2018

New York State Reliability Council, LLC
Installed Capacity Subcommittee

About the New York State Reliability Council

The New York State Reliability Council (NYSRC) is a not-for-profit corporation responsible for promoting and preserving the reliability of the New York State power system by developing, maintaining and, from time to time, updating the reliability rules which must be complied with by the New York Independent System Operator and all entities engaging in electric power transactions on the New York State power system. One of the responsibilities of the NYSRC is the establishment of the annual statewide Installed Capacity Requirement for the New York Control Area.

Table of Contents

NOTE: Appendices A, B, C and D are included in a separate document.

EXECUTIVE SUMMARY

A New York Control Area (NYCA) Installed Reserve Margin (IRM) Study is conducted annually by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee (ICS). ICS has the overall responsibility of managing studies for establishing NYCA IRM requirements for the following Capability Year,[1] including the development and approval of all modeling and database assumptions to be used in the reliability calculation process. This year's report covers the period May 2019 through April 2020 (2019 Capability Year).

Results of the NYSRC technical study show that the required NYCA IRM for the 2019 Capability Year is 16.8% under base case conditions. This IRM satisfies the NYSRC and Northeast Power Coordinating Council (NPCC) reliability criteria of a Loss of Load Expectation (LOLE) of no greater than 0.1 days per year. The base case, along with other relevant factors, will be considered by the NYSRC Executive Committee in December 2018 for its adoption of the Final NYCA IRM requirement for the 2019 Capability Year.

This study also determined corresponding *preliminary* Locational Capacity Requirements (LCRs) of 82.7% and 101.5% for New York City and Long Island, respectively. In accordance with its responsibility of setting the LCRs, the New York Independent System Operator, Inc. (NYISO) will calculate and approve *final* LCRs for all NYCA localities using a separate process using the NYSRC approved Final IRM that adheres to NYSRC Reliability Rules and Policies.

The 16.8% IRM base case value for the 2019 Capability Year represents a *1.4% decrease* from the 2018 base case IRM of 18.2%. Table 6-1 shows the IRM impacts of individual updated study parameters that result in this change. There are three parameter drivers that in combination *increased* the 2019 IRM from the 2018 base case by 0.7%. Of these three drivers, the principal driver is the addition of new wind generation with a total capacity of 158 MW and an updated wind shape model, which increased the IRM by 0.4%.

Ten parameter drivers in combination *decreased* the IRM from the 2018 base case by 2.1%. The largest decreases – 0.4% each – are attributed to an updated load forecast and load shapes and a reduction in generation fleet outage rates.

This study also evaluated IRM impacts of several sensitivity cases. The results of these sensitivity cases are summarized in Table 7-1, and in greater detail in Appendix B, Table B.1. In addition, a confidence interval analysis was conducted to demonstrate that there is a high confidence that

[1] A Capability Year begins on May 1 and ends on April 30 of the following year.

the base case 16.8% IRM will fully meet NYSRC and NPCC resource adequacy criteria that require a Loss of Load Expectation (LOLE) of no greater than 0.1 days per year.

The base case and sensitivity case IRM results, along with other relevant factors, will be considered by the NYSRC Executive Committee in adopting the final NYCA IRM requirement for 2019. The 2019 IRM Study also evaluated Unforced Capacity (UCAP) trends. UCAP is the manner by which the NYISO values installed capacity – considering the forced outage ratings of individual generating units. This analysis shows that required UCAP margins, which steadily decreased over the 2006-2012 period to 5%, have gradually increased to approximately 8% in the 2019 Capability Year (see Table 8-1).

1. Introduction

This report describes a technical study, conducted by the NYSRC Installed Capacity Subcommittee (ICS), for establishing the NYCA Installed Reserve Margin (IRM) for the period of May 1, 2019 through April 30, 2020 (2019 Capability Year). This study is conducted each year in compliance with Section 3.03 of the NYSRC Agreement, which states that the NYSRC shall establish the annual statewide Installed Capacity Requirement (ICR) for the NYCA. The ICR relates to the IRM through the following equation:

$$\text{ICR} = \left(1 + \frac{\text{IRM Requirement (\%)}}{100}\right) * \text{Forecasted NYCA Peak Load}$$

The base case and sensitivity case study results, along with other relevant factors, will be considered by the NYSRC Executive Committee for its adoption of the Final NYCA IRM requirement for the 2019 Capability Year.

The NYISO will implement the Final NYCA IRM as determined by the NYSRC, in accordance with the NYSRC Reliability Rules;[2] NYSRC Policy 5-13, *Procedure for Establishing New York Control Area Installed Capacity Requirement*;[3] the NYISO Market Administration and Control Area Services Tariff; and the NYISO Installed Capacity (ICAP) Manual.[4] The NYISO translates the required IRM to a UCAP basis. These values are also used in a Spot Market Auction based on FERC-approved Demand Curves. The schedule for conducting the 2019 IRM Study was based on meeting the NYISO's timetable for conducting this auction.

The study criteria, procedures, and types of assumptions used for the study for establishing the NYCA IRM for the 2019 Capability Year (2019 IRM Study) are set forth in NYSRC Policy 5-13. The primary reliability criterion used in the IRM study requires a Loss of Load Expectation (LOLE) of no greater than 0.1 days per year for the NYCA. This NYSRC resource adequacy criterion is consistent with the Northeast Power Coordinating Council (NPCC) resource adequacy criterion. IRM study procedures include the use of two study methodologies: the *Unified Methodology* and the *IRM Anchoring Methodology.* The NYSRC reliability criterion and IRM study methodologies are described in Policy 5-13 and discussed in detail later in this report.

The NYSRC process for determining the IRM also identifies *preliminary* Locational Capacity Requirements (LCRs) for the New York City and Long Island localities. The LCR values determined

[2] http://www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.asp
[3] http://www.nysrc.org/policies.asp
[4] http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

in this 2019 IRM Study are considered *preliminary* because the NYISO, using a separate process – in accordance with NYISO tariff and procedures, while adhering to NYSRC Reliability Rules and NYSRC Sections 3.2 and 3.5 of Policy 5-13 – is responsible for setting *final* LCRs. For its determination of LCRs for the 2019 Capability Year, the NYISO will be utilizing a new economic optimization methodology.

The 2019 IRM Study was managed and conducted by the NYSRC Installed Capacity Subcommittee (ICS) and supported by technical assistance from NYISO staff.

Previous IRM Study reports, from year 2000 to year 2018, can be found on the NYSRC website.[5] Appendix C, Table C.1 provides a record of previous NYCA base case and final IRMs for the 2000 through 2018 Capability Years. Figure 8-1 and Appendix C, Table C.2, show UCAP reserve margin trends over previous years. Definitions of certain terms in this report can be found in the Glossary (Appendix D).

2. NYSRC Resource Adequacy Reliability Criterion

The acceptable LOLE reliability level used for establishing NYCA IRM Requirements is dictated by Requirement 1 of NYSRC Reliability Rule A.1, *Establishing NYCA Statewide Installed Reserve Margin Requirements,* which states:

> *The NYSRC shall annually perform and document an analysis to calculate the NYCA installed Reserve Margin (IRM) requirement for the following Capability Year. The IRM analysis shall probabilistically establish the IRM requirement for the NYCA such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and de-ratings, forced outages and de-ratings, assistance over interconnections with neighboring control areas, NYS Transmission System transfer capability, and capacity and/or load relief from available operating procedures*.

This NYSRC Reliability Rule is consistent with NPCC Resource Adequacy Requirement 4 in Section 3.0 of NPCC Directory 1, *Design and Operation of the Bulk Power System*.

In accordance with NYSRC Reliability Rule A.2, *Establishing Load Serving Entity (LSE) Installed Capacity Requirements and Deliverable External Area Installed Capacity*, the NYISO is required to

[5] http://www.nysrc.org/reports3.asp

establish LSE installed capacity requirements, including LCRs, for meeting the statewide IRM requirement established by the NYSRC for complying with NYSRC Reliability Rule A.1 above.

3. IRM Study Procedures

The study procedures used for the 2019 IRM Study are described in detail in NYSRC Policy 5-13, *Procedure for Establishing New York Control Area Installed Capacity Requirements*. Policy 5-13 also describes the computer program used for reliability calculations and the types of input data and models used for the IRM Study.

This study utilizes a *probabilistic approach* for determining NYCA IRM requirements. This technique calculates the probabilities of generator unit outages, in conjunction with load and transmission representations, to determine the days per year of expected resource capacity shortages.

General Electric's Multi-Area Reliability Simulation (GE-MARS) is the primary computer program used for this probabilistic analysis. This program includes detailed load, generation, and transmission representation for eleven NYCA load zones — plus four external Control Areas (Outside World Areas) directly interconnected to the NYCA. The external Control Areas are: Ontario, New England, Quebec, and the PJM Interconnection. The eleven NYCA zones are depicted in Figure 3-1.[6] GE-MARS calculates LOLE, expressed in days per year, to provide a consistent measure of system reliability.[7] The GE-MARS program is described in detail in Appendix A, Section A.1.

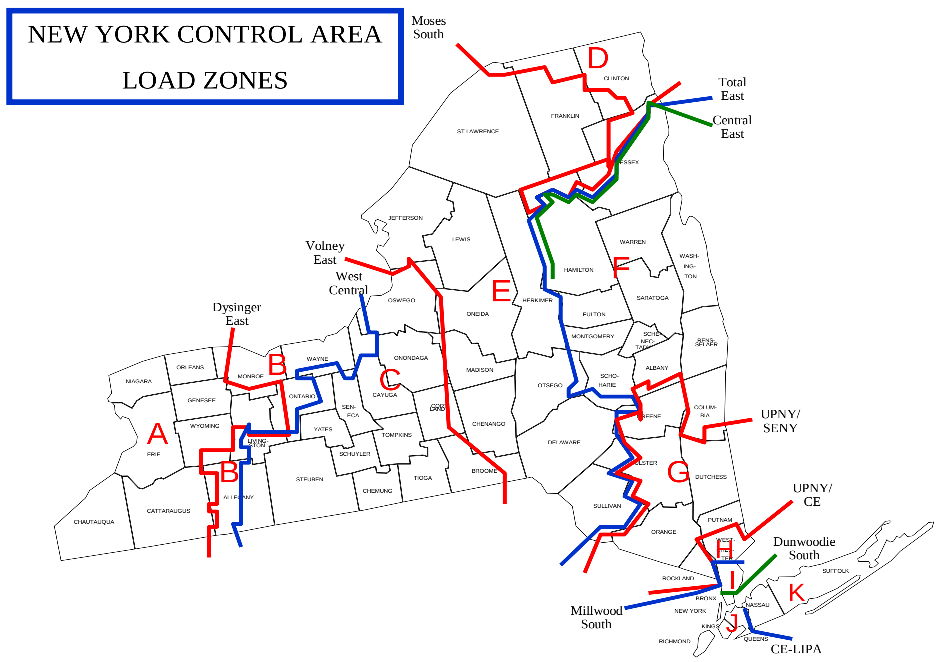
Prior to the 2016 IRM Study, IRM, base case, and sensitivity analyses were simulated using only weekday peak loads rather than evaluating all 8,760 hours per year in order to reduce computational run times. However, the 2016 IRM Study determined that the difference between study results using the daily peak hour versus the 8,760 hour methodologies would be significant. Therefore, the base case and sensitivity cases in the 2016 IRM Study and all later studies, were simulated using all hours in the year.

[6] The Federal Energy Regulatory Commission ordered the creation of a capacity zone within the NYISO's ICAP market encompassing Load Zones G, H, I, and J (the "G-J Locality"). The creation of the G-J Locality did not impact the current Unified and IRM Anchoring Methodologies and NYSRC's calculation of the NYCA IRM that is discussed in this report. The NYISO establishes the LCR for the G-J Locality.

[7] A change was adopted for the 2019 IRM Study to target the New York Balancing Area ("NYBA") to meet the LOLE criterion instead of NYCA, with the difference being that NYCA includes dummy zones for which MARS occasionally calculates loss of load events despite not containing load. The use of NYBA with the removal of dummy zones was recommended by the NYISO and GE and approved by ICS.

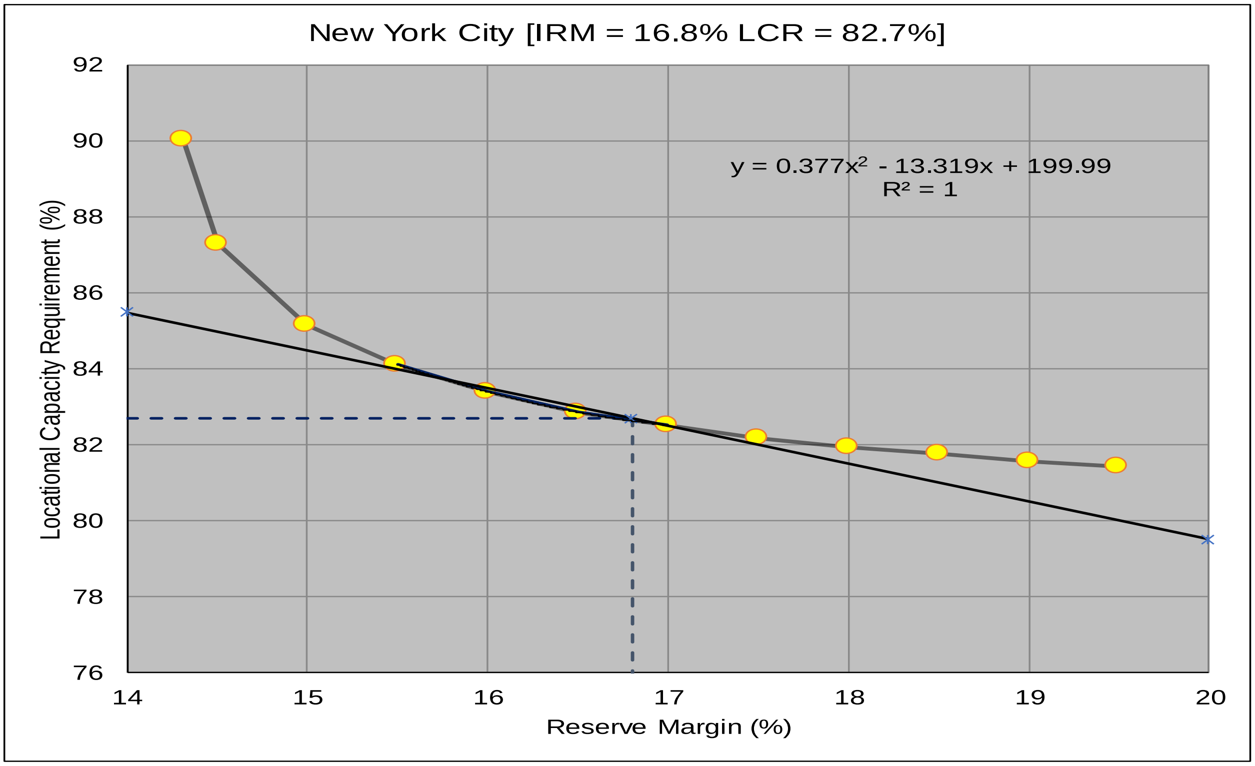
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology*) which establishes a relationship between NYCA IRM and preliminary LCRs, as illustrated in Figure 3-2. All points on these curves meet the NYSRC 0.1 days/year LOLE reliability criterion described above. Note that the area above the curve is more reliable than the criterion, and the area below the curve is less reliable. This methodology develops a pair of curves for two zones with locational capacity requirements, New York City (NYC), Zone J; and Long Island (LI), Zone K. Appendix A of NYSRC Policy 5-13 provides a more detailed description of the Unified Methodology.

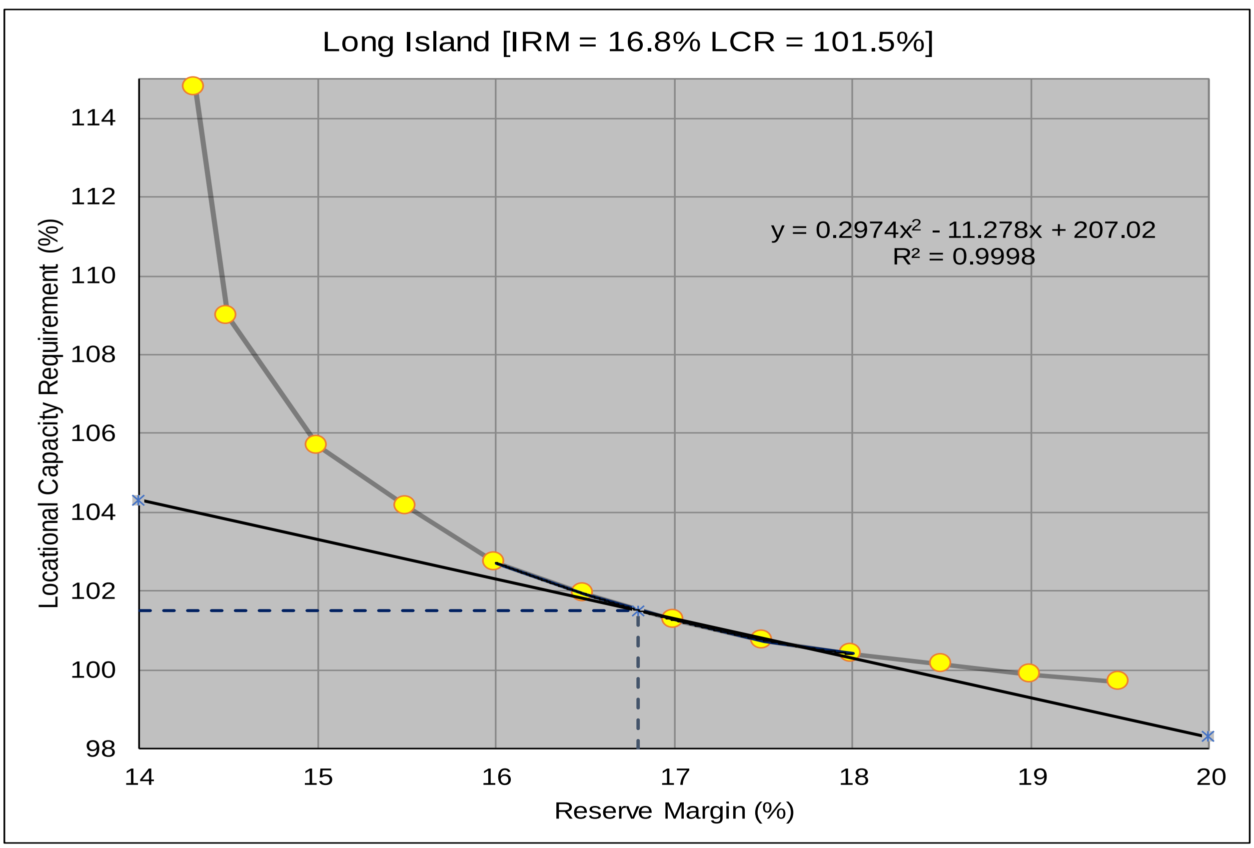
Figure 3-1 NYCA Load Zones



Base case NYCA IRM requirements and related preliminary LCRs for Zones J and K are established by a supplemental procedure (termed the *IRM Anchoring Methodology*), which is used to define an *inflection point* on each of these curves. These inflection points are selected by applying a tangent of 45 degrees (Tan 45) analysis at the bend (or "knee") of each curve. Mathematically, each curve is fitted using a second order polynomial regression analysis. Setting the derivative of the resulting set of equations to minus one yields the points at which the curves achieve the Tan 45 degree inflection point. Appendix B of NYSRC Policy 5-13 provides a more detailed description of the methodology for computing the Tan 45 inflection point.

Figure 3-2 Locational Requirements vs. Statewide Requirements





4. Study Results – Base Case

Results of the NYSRC technical study show that the required NYCA IRM is 16.8% for the 2019 Capability Year under base case conditions. Figure 3-2 on page 8 depicts the relationship between NYCA IRM requirements and resource capacity in NYC and LI.

The tangent points on these curves were evaluated using the Tan 45 analysis. Accordingly, maintaining a NYCA IRM of 16.8% for the 2019 Capability Year, together with corresponding preliminary LCRs of 82.7% and 101.5% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A.3.

Comparing the preliminary LCRs in this 2019 IRM Study to 2018 IRM Study results (NYC LCR=80.7%, LI LCR=103.2%), the preliminary 2019 NYC LCR increased by 2.0%, while the preliminary LI LCR decreased by 1.7%.

In accordance with NYSRC Reliability Rule A.2, *Load Serving Entity ICAP Requirements,* the NYISO is required to separately calculate and establish final LCRs. The most recent NYISO LCR study,[8] dated January 18, 2018, determined that for the 2018 Capability Year, the final LCRs for NYC and LI were 80.5% and 103.5%, respectively. An LCR Study for the 2019 Capability Year is scheduled to be completed by the NYISO in January 2019.

On October 5, 2018, FERC accepted proposed revisions to the methodology that the NYISO uses for determining LCRs[9]. The NYISO's previous methodology determined LCRs based on the Unified and Tan 45 methodologies[10] used by the NYSRC for calculating IRM requirements. The NYISO's new methodology utilizes an economic optimization algorithm to minimize the total cost of capacity for the NYCA. This new methodology will continue to maintain NYSRC's 0.1 days/year LOLE reliability standard while respecting the NYSRC-approved IRM. An LCR study for the 2019 Capability Year, scheduled to be completed by the NYISO in January 2019, will utilize the NYISO's new economic optimization methodology.

A Monte Carlo simulation error analysis shows that there is a 95% probability that the above base case result is within a range of 16.6% and 17.0% (see Appendix A.1.1) when obtaining a standard error of 0.025 per unit or less at 2,750 simulated years. This analysis demonstrates that there is

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[8] See *Locational Installed Capacity Requirements Study, http://www.nyiso.com/public/markets_operations/services/planning/planning_studies*

[9] The FERC Order accepting the NYISO tariff revisions can be found at: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14710049

[10] The Unified/Tan 45 methodology is described in Section 3.0.

a high level of confidence that the base case IRM value of 16.8% is in full compliance with the one day in 10 years LOLE criterion in NYSRC Reliability Rule A.1.

5. Models and Key Input Assumptions

This section describes the models and related input assumptions for the 2019 IRM Study. The models represented in the GE-MARS analysis include a *Load Model, Capacity Model, Transmission Model, and Outside World Model*. Potential IRM impacts of pending *Environmental Initiatives* and *Database Quality Assurance Review* are also addressed in this section. The input assumptions for the final base case were approved by the Executive Committee on October 12, 2018. Appendix A, Section A.3 provides more details of these models and assumptions and comparisons of several key assumptions with those used for the 2019 IRM Study.

5.1 Load Model

5.1.1 Peak Load Forecast

A 2019 NYCA summer peak load forecast of 32,488 MW was assumed in the 2019 IRM Study, a decrease of 380 MW from the 2018 summer peak forecast used in the 2018 IRM Study. This "Fall 2019 Load Forecast" was prepared for the 2019 IRM Study by the NYISO staff in collaboration with the NYISO Load Forecasting Task Force and presented to the ICS on October 3, 2018. This forecast considered actual 2018 summer load conditions. A 2018 "normalized" peak load[11] was determined to be 32,444 MW, 508 MW higher than the actual 2018 peak load and 424 MW lower than the fall forecast for 2018 (see Table 5-1 below for more details).

Table 5-1: Comparison of 2018 and 2019 Load Forecasts (MW) Used for IRM Studies

	Fall 2018 Forecast	2018 Actual	2018 Normalized	Fall 2019 Forecast	Forecast Change
Zones A-I	15,882	15,496	15,524	15,557	-325
Zones J&K	16,986	16,440	16,920	16,931	-55
NYCA	32,868	31,936	32,444	32,488	-380

Use of the fall 2019 peak load forecast and an updated load shape in the 2019 IRM Study decreased the IRM by 0.4% compared to the 2018 IRM Study (Table 6-1). This is due to the greater load decrease forecast for upstate (Zones A-I) in 2019 compared to the

[11] The "normalized" 2019 peak load reflects an adjustment of the actual 2918 peak load to account for the load impact of actual weather conditions, demand response programs, and muni self-generation.

downstate (Zones J&K) forecast load decrease (see Table 5-1). The NYISO will prepare a final 2019 summer peak forecast by the end of 2018 that will be used for the NYISO's calculation of Locality LCRs for 2019.

5.1.2 Load Forecast Uncertainty (LFU)

Some uncertainty exists relative to forecasting NYCA loads for any given year. This uncertainty is incorporated in the base case model by using a load forecast probability distribution that is sensitive to different weather conditions. Recognizing the unique LFU of individual NYCA areas, separate LFU models are prepared for four areas: New York City (Zone J), Long Island (Zone K), Westchester (Zones H and I), and the rest of New York State (Zones A-G).

There were no changes from the LFU models used for the 2018 IRM study based on data and analyses provided by the NYISO, Con Edison, and LIPA. Therefore, the LFU model used in the 2019 IRM Study did not change IRM requirements from the 2018 IRM Study. Appendix A, Section A.3.1 describes the LFU models in more detail.

5.1.3 Load Shape Model

A feature in GE-MARS that allows for the representation of multiple load shapes was utilized for the 2019 IRM Study. This multiple load shape feature enables a different load shape to be assigned to each of seven load forecast uncertainty bins. ICS has established criteria for selecting the appropriate historical load shapes to use for each of these load forecast uncertainty bins. For this purpose, a combination of load shape years 2002, 2006, and 2007 were selected as representative years. The load shape for the year 2007 was selected to represent a typical system load shape over the 1999 to 2017 period. The load shape for 2002 represents a flatter load shape, *i.e.*, a shape that has numerous daily peaks that are close to the annual peak. The load shape for 2006 represents a load shape with a small number of days with peaks that are significantly above the remaining daily peak loads. The combination of these load shapes on a weighted basis represents an expected probabilistic LOLE result.

5.2 Capacity Model

5.2.1 Planned New Non-Wind Generation, Re-ratings, Retirements, Deactivations, and Ineligible Capacity

Planned new non-wind facilities and retirements that are represented in the 2019 IRM Study are shown in Appendix A, Section A.3.2. The rating for each existing and planned resource facility in the capacity model is based on its Dependable Maximum Net

Capability (DMNC). In circumstances where the ability to deliver power to the grid is restricted, the value of the resource is limited to its Capacity Resource Interconnection Service (CRIS) value. The source of DMNC ratings for existing facilities is seasonal tests required by procedures in the NYISO Installed Capacity Manual.

A planned new generating unit, Arthur Kill Cogen, having a capacity of 11.1 MW, is included in the 2019 IRM Study. In addition, the ratings of several existing generating units increased by a total of 209.3 MW.

Also, the 2019 IRM Study reflected the deactivation of 399.2 MW of capacity from three existing generating units and 389.4 MW of ineligible ICAP from 10 existing units. No retirements were reflected in the study.

The NYISO has identified several state and federal environmental regulatory programs that could potentially impact operation of NYS Bulk Power System. A NYISO analysis concluded that these environmental initiatives would not result in NYCA capacity reductions or retirements that would impact IRM requirements during the 2019 Capability Year. For more details, see Appendix A, Section B.2.

A “BTM:NG” or behind the meter net generation program resource, for this study’s purpose, contributes its full capacity while its entire host load is exposed to the electric system. Two BTM:NG resources with a total resource capacity of 150.0 MW and a total host load of 52.2 MW are included in 2019 IRM Study. The resource capacity of these BTM:NG facilities is included in the NYCA capacity model, while their host loads are included in the NYCA 2019 summer peak load forecast used for this study.

5.2.2 Wind Generation

It is projected that during the 2019 summer period there will be a total wind capacity of 1,892 MW participating in the capacity market in New York State. This includes 158 MW of planned new wind capacity. All wind farms are located in upstate New York in Zones A-E.

GE-MARS allows the input of multiple years of wind data. This multiple wind shape model randomly draws wind shapes from historical wind production data. The 2019 IRM Study used available wind production data covering the years 2013 through 2017. For new wind facilities, zonal hourly wind shape averages or the wind shapes of nearby wind units are modeled.

Overall, inclusion of the projected 1,892 MW of wind capacity in the 2019 IRM Study accounts for 4.8% of the 2019 IRM requirement (Table 7-1, Case 4). This relatively high IRM impact is a direct result of the relatively low capacity factor of wind facilities during the summer peak period. The impact of wind capacity on *unforced capacity* is discussed in Appendix C.3, "Wind Resource Impact on the NYCA IRM and UCAP Markets." A detailed summary of existing and planned wind resources is shown in Appendix A, Table A.7.

5.2.3 Generating Unit Availability

Generating unit forced and partial outages are modeled in GE-MARS by inputting a multi-state outage model that represents an equivalent forced outage rate during demand periods (EFORd) for each unit represented. Outage data used to determine the EFORd is received by the NYISO from generator owners based on outage data reporting requirements established by the NYISO. Capacity unavailability is modeled by considering the average forced and partial outages for each generating unit that have occurred over the most recent five-year time period. The time span considered for the 2019 IRM Study covered the 2013-2017 period.

The weighted average five-year EFORd for NYCA thermal and large hydro generating units calculated for the 2013-2017 period is lower than the 2012-2016 average value used for the 2018 IRM Study. This decrease in forced outage rates reduced the 2019 IRM by 0.4% compared to the 2018 IRM Study (Table 6-1). Appendix A, Figure A.4 depicts NYCA EFORd trends from 2004 to 2017.

5.2.4 Emergency Operating Procedures (EOPs)

(1) Special Case Resources (SCRs)

SCRs are loads capable of being interrupted, and distributed generators that are rated at 100 kW or higher. SCRs are ICAP resources that provide load curtailment only when activated when as needed in accordance with NYISO emergency operating procedures. GE-MARS represents SCRs as an EOP step, which is activated to avoid or to minimize expected loss of load. SCRs are modeled with monthly values based on July 2018 registration. For the month of July, the forecast SCR value for the 2019 IRM Study base case assumes that 1,309 MW will be registered, with varying amounts during other months based on historical experience. The 2019 IRM Study had assumed a registered amount of 1,309 MW, 90 MW higher than that assumed for the 2018 IRM Study. The number of SCR calls in the 2019 Capability Year for the 2019 IRM base case was limited to five calls per month.

The SCR performance model is based on discounting registered SCR values to reflect historical availability. The SCR model used for the 2019 IRM Study is based on performance data from 2012 through 2017. The SCR analysis for the 2019 IRM Study determined a SCR model value of 903 MW with an overall performance factor of 69.0%, 2.2% lower than the performance assumed in the 2018 IRM Study (refer to Appendix A, Section A.3.7 for more details). This lower SCR performance, together with the increase in the amount of registered SCRs, resulted in an IRM increase of 0.2% compared to the 2018 IRM Study (Table 6-1).

The 2019 IRM Study determined that for the base case, approximately 9.3 SCR calls would be expected during the 2019 Capability Period.

(2) Emergency Demand Response Program (EDRP)

The EDRP is a separate EOP step from the SCR Program that allows registered interruptible loads and standby generators to participate on a voluntary basis, and be paid for their ability to restore operating reserves after major emergencies have been declared. The 2019 IRM Study assumes that 5.5 MW of EDRPs will be registered in 2019, 10.5 MW lower than the amount assumed in the 2018 IRM Study. The 2019 EDRP capacity was discounted to a base case value of only one MW to reflect past performance. This value is implemented in the study in July 2019 and proportional to monthly peaks loads in other months, while being limited to a maximum of five EDRP calls per month. Both SCRs and EDRP are included in the Emergency Operating Procedure (EOP) model. Unlike SCRs, EDRPs are not ICAP suppliers and, therefore, are not required to respond when called upon to operate.

Incorporation of SCR and EDRP in the NYCA capacity model has the effect of increasing the IRM by 2.9% (Table 7-1, Case 5). This increase is because the overall availability of SCRs and EDRP is lower than the average statewide resource fleet availability.

(3) Other Emergency Operating Procedures

In addition to SCRs and the EDRP, the NYISO will implement several other types of EOPs, such as voltage reductions, as required, to avoid or minimize customer disconnections. Projected 2019 EOP capacity values are based on recent actual data and NYISO forecasts. Refer to Appendix B, Table B.2 for projected EOP frequencies for the 2019 Capability Year assuming the 16.8% base case IRM.

5.2.5 Unforced Capacity Deliverability Rights (UDRs)

The capacity model includes UDRs, which are capacity rights that allow the owner of an incremental controllable transmission project to provide locational capacity benefits. Non-locational capacity, when coupled with a UDR to deliver capacity to a Locality, can be used to satisfy locational capacity requirements. The owners of the UDRs elect whether they will utilize their capacity deliverability rights. This decision determines how this transfer capability will be represented in the MARS model. The IRM modeling accounts for both the availability of the resource that is identified for each UDR line as well as the availability of the UDR facility itself.

LIPA's 330 MW High Voltage Direct Current (HVDC) Cross Sound Cable, LIPA's 660 MW HVDC Neptune Cable, Hudson Transmission Partners 660 MW HVDC Cable, and the 315 MW Linden Variable Frequency Transformer are facilities that are represented in the 2019 IRM Study as having UDR capacity rights. The owners of these facilities have the option, on an annual basis, of selecting the MW quantity of UDRs they plan on utilizing for capacity contracts over these facilities. Any remaining capability on the cable can be used to support emergency assistance, which may reduce locational and IRM requirements. The 2019 IRM Study incorporates the confidential elections that these facility owners made for the 2019 Capability Year.

5.3 Transmission Model

A detailed NYCA transmission system model is represented in the GE-MARS topology. The transmission system topology, which includes eleven NYCA zones and four Outside World Areas, along with transfer limits, is shown in Appendix A, Figure A.12. The transfer limits employed for the 2019 IRM Study were developed from emergency transfer limit analysis included in various studies performed by the NYISO, and from input from Transmission Owners and neighboring regions. The transfer limits are further refined by additional assessments conducted specifically for this cycle of the development of the topology. The assumptions for the transmission model included in the 2019 IRM Study are listed in the Appendix A, Tables A.7 and A.8 and Figure A.13, and described in detail in Appendix Section A.3.3.

Forced outages based on historic performance are represented in the GE-MARS model for the IRM study for the underground cables that connect New York City and Long Island to surrounding zones. The GE-MARS model uses transition rates between operating states for each interface, which are calculated based on the probability of occurrence from the failure rate and the time to repair. Transition rates into the different operating states for each interface were calculated based on the circuits comprising each interface, which includes failure rates and repair times for the individual cables, and for any transformer and/or phase angle regulator associated with that particular cable. Updated LIPA cable outage rates in the 2019 IRM Study reduced the IRM by 0.3% compared to the 2018 IRM Study, while updated Con Edison cable outage rates had no impact on the IRM (Table 6-1).

As in all previous IRM studies, forced outage rates for overhead transmission lines were not represented in the 2019 IRM Study. Historical overhead transmission availability was evaluated in a study conducted by ICS in 2015, *Evaluation of the Representation of Overhead Transmission Outages in IRM Studies*, which concluded that representing overhead transmission outages in IRM studies would have no material impact on the IRM (see www.nysrc.org/reports).

The impact of NYCA transmission constraints on NYCA IRM requirements depends on the level of resource capacity in any of the downstream zones from a constraining interface, especially in the NYC and LI Zones J and K. To illustrate the impact of transmission constraints on IRM, if there were no internal NYCA transmission constraints, the required 2019 IRM could decrease by 2.4% (Table 7-1, Case 2).

There are several topology changes for the 2019 IRM Study compared to the topology used in the 2018 IRM Study. These changes are:

1. **B and C Lines Out of Service**

   The B and C lines from PJM to Zone J are currently unavailable due to an extended forced outage. These lines are not expected to be returned to service in time for the 2019 Capability Year. As a result, the capability from PJM is estimated to be reduced from 315 MW on the grouped interface limit for the A, B, and C lines down to 105 MW and a zeroing of the individual B and C line total capability from 1,000 MW to 0 MW. An impact of removing the B and C lines during the 2019 Capability Year will be to increase the IRM by 0.2% (Table 7-1, Case 9).

2. **PAR on Line 33 Out of Service**

   The PAR controlling Line 33 from Ontario to Zone D is currently unavailable due to forced outage. This PAR is not expected to be returned to service in time for the 2019 Capability Year. A reduction in capability of 150 MW from Ontario to Zone D is estimated on the grouped interface limit leaving Ontario, which falls from 1,900 MW down to 1,750 MW, while the grouped interface entering Ontario is reduced from 1,650 MW down to 1,500

MW. The individual tie from Ontario to and from Zone D has been reduced from 300 MW down to 150 MW (both directions). The effects of this removal from service is being studied.

3. Other Modeling Changes

A review of the topology for this 2019 IRM Study found that the paths from the HTP and VFT dummy zones back to PJM were affecting the total transfer capability from PJM to Zone J. These dummy zones house the generation units in PJM that are contracted to supply capacity to New York. When forced outages occur on the lines entering Zone J the units were able to flow capacity back to PJM. This back flow increased the 2,000 MW grouped interface allowing more emergency assistance to be available to New York. The correction changes the return paths to circumvent the grouped interface.

These changes are described in detail in Appendix A, Section A.3.3.

5.4 Outside World Model

The Outside World Model consists of four interconnected external control areas contiguous with NYCA: Ontario, Quebec, New England, and the PJM Interconnection (PJM). NYCA reliability is improved and IRM requirements reduced by recognizing available emergency capacity assistance support from these neighboring interconnected control areas, in accordance with control area agreements governing emergency operating conditions. Representing all such external interconnection support arrangements in the 2019 IRM Study base case for permitting emergency assistance to NYCA would reduce the NYCA IRM requirements by 8.2% (Table 7-1, Case 1). This "reserve value of NYCA interconnections" compares to 8.0% in the 2018 IRM Study. The load and capacity and topology representation of neighboring control areas in the 2019 IRM Study was the same as used in the 2018 IRM Study. Further, this study incorporates the same Emergency Assistance Limit as used for the 2018 IRM Study that limits or caps available emergency assistance, which is discussed later in this section. The assumptions for the Outside World Model included in the 2019 IRM Study are listed in Appendix A, Tables A.12 and A.13.

The primary consideration for developing the base case load and capacity assumptions for the Outside World Areas is to avoid overdependence on these Areas for emergency assistance support. For this purpose, a rule from NYSRC Policy 5-13 is applied whereby an Outside World Area's LOLE cannot be lower than its own LOLE criterion. Therefore, for each of the Ontario, Quebec and New England control areas, a minimum LOLE of 0.1 days/year is modeled in accordance with NPCC requirements and the Areas' own individual resource adequacy criteria. For PJM, the 2019 IRM Study assumed a minimum LOLE of 0.14 day/year, which PJM uses for its planning studies. This is based on PJM's LOLE or resource adequacy criterion of 0.10 days/year, plus a PJM internal transmission constraint risk adder of 0.04 days/year. Also, each of these control areas' IRM can be no higher than that Area's minimum requirement.

In addition, NYSRC Policy 5-13 does not allow EOPs to be represented in Outside World Area models for providing emergency assistance to NYCA because of the uncertainties associated with the performance and availability of these resources.

Another consideration for developing models for the Outside World Areas is to recognize internal transmission constraints within those Areas that may limit emergency assistance into the NYCA. This recognition can be explicitly considered through direct multi-area modeling of well-defined external area "bubbles" and their internal interface constraints. The model representation explicitly requires adequate data to accurately model transmission interfaces, load areas, resource and demand balances, load shape, and coincidence of peaks among the load zones within these Outside World Areas. If adequate data is unavailable, the area can also be modeled implicitly either by aggregating bubbles and associated interfaces and reflecting the constraint limits at the interfaces between aggregated bubbles and at the NYCA border, or by increasing the LOLE of the Outside World Areas.

For this study, two Outside World Areas, New England and PJM, are each represented as multi-area models—*i.e.,* 13 zones for New England and five zones for the PJM Interconnection. These zonal representations align with these Control Areas' own models that they use for their reserve margin studies.

The existing PJM-SENY group transfer limit is imposed to reflect internal constraints in both the PJM and NYCA systems. The transmission model in IRM studies up through and including the 2016 IRM Study allowed for the contractual delivery of 1,000 MW at Waldwick and PJM re-delivery of 1,000 MW at the Hudson and Linden interface ("PJM wheel"). The PJM wheel was discontinued in 2017 and was replaced with changes in the NYISO-PJM Joint Operating Agreement which were incorporated in the 2018 and 2019 IRM studies.

As earlier discussed, excess generation capacity is delivered as emergency assistance from neighboring control areas to NYCA, recognizing interconnection limits, to avoid load shedding. As a result, the modeling of emergency assistance permits NYCA to operate at an IRM lower than otherwise required. In 2016, a concern was raised that calculated emergency transfer levels from neighboring control areas in prior GE-MARS studies may have been overstated compared to actual operating conditions. The concern is that a portion of the excess generation in the neighboring control areas, as identified by MARS as available to potentially provide emergency assistance, could actually be unavailable at the time when emergency assistance is needed by NYCA. In consideration of this concern, a study to examine issues related to the amount of emergency assistance that can be reasonably relied on was conducted by the NYISO in 2016. Building on the results of this study, ICS reviewed alternate models for representing emergency assistance. ICS determined that limiting total emergency assistance to a maximum of 3,500 MW (EA Limit), based on an analysis of total actual excess ten-minute operating reserves above required operating reserves in the four neighboring external areas, is appropriate.[12] This limit was applied in the 2018 IRM Study and again in this 2019 IRM Study. Elimination of the 3,500 MW EA Limit in the 2019 Study would have allowed additional emergency assistance, thereby decreasing the IRM by 0.3% (Table 7-1, Case 8).

5.5 Database Quality Assurance Review

It is critical that the database used for IRM studies undergo sufficient review in order to verify its accuracy. The NYISO, General Electric (GE), and two New York Transmission Owners (TOs) conducted independent data quality assurance reviews after the preliminary base case assumptions were developed and prior to preparation of the final base case. Masked and encrypted input data was provided by the NYISO to the two TOs for their review. Also, certain confidential data are reviewed by two independent NYSRC consultants as required.

The NYISO, GE, and TO reviews found several minor data errors, none of which affected IRM requirements in the preliminary base case. The data found to be in error by these reviews were corrected before being used in the final base case studies. A summary of these quality assurance reviews for the 2019 IRM Study input data is shown in Appendix A, Section A.4.

6. Parametric Comparison with 2018 IRM Study Results

The results of this 2019 IRM Study show that the base case IRM result represents a 1.4% decrease from the 2018 IRM Study base case value. Table 6-1 compares the estimated IRM impacts of updating several key study assumptions and revising models from those used in the 2018 IRM Study. The estimated percent IRM change for each parameter was calculated from the results of a parametric analysis in which a series of IRM studies were conducted to test the IRM impact of individual parameters. The IRM impact of each parameter in this analysis was normalized such that the net sum of the -/+ % parameter changes total the 1.4% IRM decrease from the 2018 IRM

[12] For more information about this analysis, refer to the NYSRC white paper, "MARS Emergency Assistance Modeling ", at http://www.nysrc.org/reports3.html.

Study. Table 6-1 also provides the reason for the IRM change for each study parameter from the 2018 IRM Study.

There are three parameter drivers that in combination *increased* the 2019 IRM from the 2018 base case by 0.7%. Of these three drivers, the principal driver is the addition of new wind generation with a total capacity of 158 MW and an updated wind shape model, which increased the IRM by 0.4%.

Ten parameter drivers in combination *decreased* the IRM from the 2018 base case by 2.1%. The largest decreases – 0.4% each – are attributed to an updated load forecast and load shapes and a reduction in generation fleet outage rates.

The parameters in Table 6-1 are discussed under *Models and Key Input Assumptions*.

Table 6-1: Parametric IRM Impact Comparison– 2018 IRM Study vs. 2019 IRM Study

Parameter	Estimated IRM Change (%)	IRM (%)	Reasons for IRM Changes
2018 IRM Study – Final Base Case		**18.2**	
2019 IRM Study Parameters that increased the IRM			
Wind Units and Shapes for 2013-2017	+0.4		Two new wind units with lower than fleet average availability
Updated SCRs	+0.2		Decreased performance and Increased enrollment
NYCA Topology	+0.1		Cumulative effect of topology changes outside of the removal of the B and C lines (see below)
Total IRM Increase	**+0.7**		
2019 IRM Study Parameters that decreased the IRM			
Updated 2019 Load Forecast & Load Shapes	-0.4		Lower load forecasts especially downstate
Generator Transition Rates (EFORds) for 2013-2017	-0.4		Improved historic availability
LIPA Cable Transition Rates for 2013-2017	-0.3		Historical performance including the phasing out of a major outage on the Neptune line
Updated non SCR/EDRP EOPs	-0.3		Increase in 5% Voltage Reduction and voluntary load relief
Removal of B & C lines	-0.2		Causes increase in LCRs and slight lowering of IRM
Change Study Year	-0.1		Misalignment of renewable & load shapes
MARS 3.22.6	-0.1		Long term fix of seeding order issue
Use NYBA for LOLE criteria	-0.1		Removal of dummy zones from LOLE calc.
New Thermal Units & Rerates	-0.1		Lower EFORs on new & incremental units
Run of River Hydro Shapes for 2013-2017	-0.1		Dramatic increase in hydrological conditions for 2017
Total IRM Decrease	**-2.1**		
2019 IRM Study Parameters that did not change the IRM			
NYPA Sales 2019	0		
2018 Gold Book DMNC	0		
Maintenance 2019	0		
Con Ed Transition Rates (2013-2017)	0		
Net Change from 2018 Study		**-1.4**	
2019 IRM Study – Final Base Case		**16.8**	

7. Sensitivity Case Study

Determining the appropriate IRM requirement to meet NYSRC reliability criteria depends upon many factors. Variations from base case assumptions will, of course, yield different results. Table 7-1 shows IRM requirement results for selected sensitivity cases.

Sensitivity Cases 1 through 5 in Table 7-1 illustrate how the IRM would be impacted if certain major IRM study parameters were not represented in the IRM base case. The next set of cases – Cases 6 through 11 – illustrate IRM impacts recognizing that there is uncertainty associated with certain selected base case assumptions used in the 2019 IRM Study. These six cases change the base case assumptions to reasonable alternative values. NYSRC Executive Committee members may consider one or more of these sensitivity case results, in addition to the base case IRM and other factors, when the Committee develops the Final IRM for 2019 Capability Year.[13] The final sensitivity case – Case 12 – provides the IRM impact of a possible future system change that may occur beyond the 2019 Capability Period. This case has been conducted for informational purposes.

Appendix B, Table B-1 includes a more detailed description and explanation of each sensitivity case.

The methodology used to conduct sensitivity cases starts with the preliminary base case IRM results and adds or removes capacity from all NYCA zones until the NYCA LOLE approaches 0.1 days/year. Because of the lengthy computer run time and manpower needed to perform a full Tan 45 analysis in IRM studies, this method was applied for only Sensitivity Cases 9 and 11 in the 2019 Study. It should be recognized, therefore, that some accuracy is sacrificed when a Tan 45 analysis is not utilized.

[13] See Section 5 of Policy 5-13 for a description of the process the NYSRC Executive Committee uses to establish the Final IRM.

Table 7-1: Sensitivity Cases – 2019 IRM Study

Case	Description	IRM (%)	% Change from Base Case
0	**2019 IRM Base Case**	16.8	0
	IRM Impacts of Key MARS Study Parameters		
1	NYCA isolated	25.0	+8.2
2	No internal NYCA transmission constraints	14.4	-2.4
3	No load forecast uncertainty	9.2	-7.6
4	No wind capacity	12.0	-4.8
5	No SCRs and EDRP	13.9	-2.9
	IRM Impacts of Assumption Uncertainties		
6	Remove CPV Valley from service	17.0	+0.2
7	Limit Emergency Assistance from PJM to NYCA to 1500 MW	16.8	0
8	Remove 3,500 MW Emergency Assistance Limit into NYCA	16.5	-0.3
9	Restore the B and C lines to service (tan 45)	17.0	+0.2
10	Remove Public Appeals from EOP Model	17.2	+0.4
11	Incorporate Quebec to New England wheel (tan 45)	17.1	+0.3
	IRM Impact of a Possible Future System Change		
12	Combine Cedars and Quebec Areas	16.9	+0.1

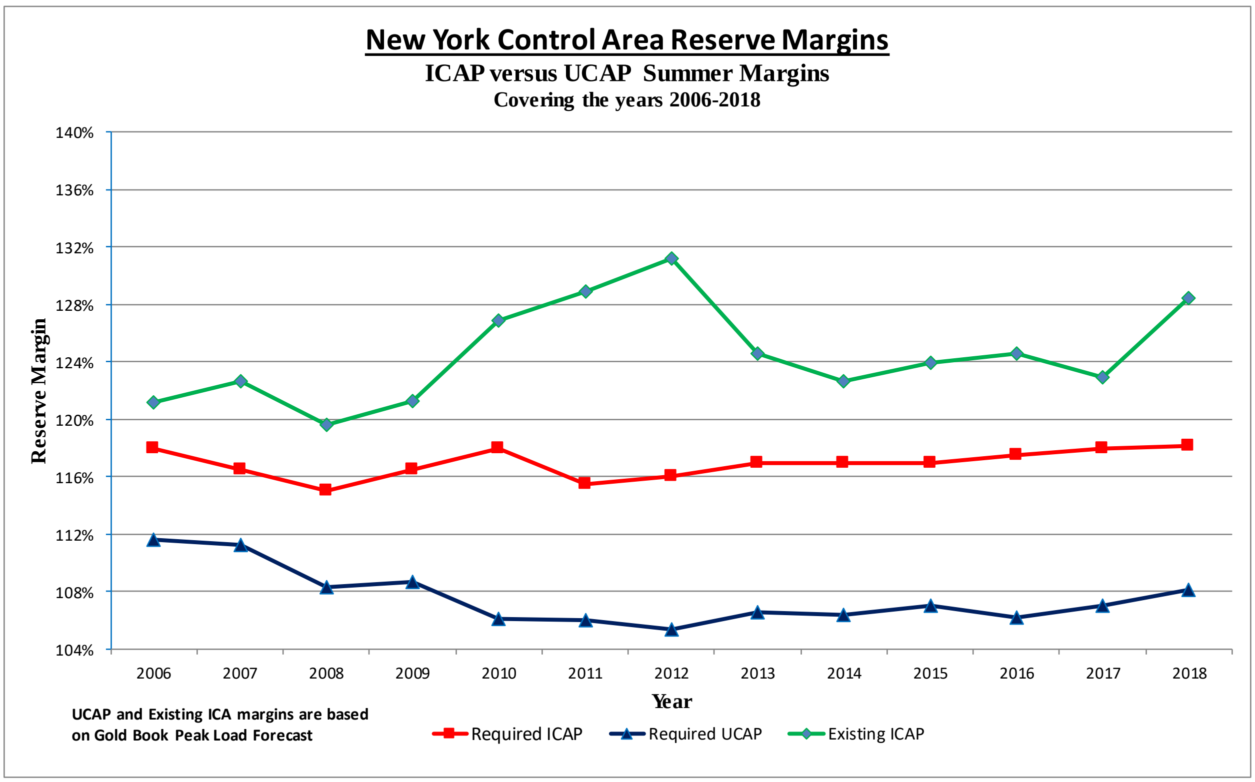
8. NYISO Implementation of the NYCA Capacity Requirement

The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings (UCAP) of individual units. To maintain consistency between the DMNC rating of a unit translated to UCAP and the statewide ICR, the ICR must also be translated to an unforced capacity basis. In the NYCA, these translations occur twice during the course of each capability year, prior to the start of the summer and winter capability periods.

Additionally, any LCRs in place are also translated to equivalent UCAP values during these periods. The conversion to UCAP essentially translates from one index to another; it is not a reduction of actual installed resources. Therefore, no degradation in reliability is expected. The NYISO employs a translation methodology that converts ICAP requirements to UCAP in a manner that ensures compliance with NYSRC Resource Adequacy Rule A.1 (R1). The conversion to UCAP provides financial incentives to decrease the forced outage rates while improving reliability.

The increase in wind resources raises the IRM because wind capacity has a relatively lower peak period capacity factor than traditional resources. On the other hand, there is a negligible impact on the need for UCAP. Figure 8-1 below illustrates that required UCAP margins, which steadily decreased over the 2006-2012 period to about 5%, have gradually increased to approximately 8% in 2018. Appendix C provides details of the ICAP to UCAP conversion process used for this analysis.

Figure 8-1 NYCA Reserve Margins



Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-9

Estimating the Value of Lost Load

Briefing paper prepared for the Electric Reliability Council of Texas, Inc. by London Economics International LLC

June 17th, 2013

London Economics International LLC ("LEI") was retained by the Electric Reliability Council of Texas, Inc. ("ERCOT") to determine a value of lost load ("VOLL"), in aggregate and by customer class, as it relates specifically to rotating outages caused by insufficient operating reserves in the ERCOT region. As an initial step in the engagement, LEI undertook two tasks to lay the foundation for developing a robust approach to estimate VOLL in ERCOT: a literature review and a macroeconomic analysis. LEI has prepared this report on the work completed to date (i.e., the literature review and macroeconomic analysis) in response to a request made by the Public Utility Commission of Texas ("PUCT") during its Open Meeting on June 6, 2013.

In the literature review, LEI reviewed prior VOLL studies, identified estimated VOLLs for other jurisdictions (both in the US and abroad), and distilled best practices in survey design and other empirical techniques for estimating VOLL. LEI found a wide range of VOLL estimates across jurisdictions and even within a single jurisdiction across customers. LEI concluded that the estimates of VOLL for other regions would be misleading proxies for an ERCOT VOLL due to the limited comparability of these regions to ERCOT. Nevertheless, the literature review provided a valuable foundation for determining the type of survey techniques that should be used if in the future ERCOT requests a survey of affected customers in the ERCOT region.

LEI also used macroeconomic analysis to provide indicative estimates of foregone economic value when electricity service is disrupted in Texas using assumptions such as state gross domestic product and average rates paid by electricity customers in Texas. The macroeconomic analysis, by its nature, does not specifically look at the types of interruptions that customers are likely to experience as a result of resource inadequacy (e.g., rotating load shed events of relatively short durations occurring at the distribution level). Therefore, the macroeconomic analysis may not be sufficient to estimate a VOLL for the purposes identified by ERCOT. In addition, a macroeconomic approach has a number of other commonly acknowledged shortcomings. That is, this approach assumes a linear relationship between interruption duration and costs, tends to underestimate VOLL in the short-run, does not account for indirect and induced effects of outages, and presents "average" VOLLs as it cannot account for either the timing or duration of an outage. Nevertheless, the macroeconomic analysis provides a useful benchmark for any future customer survey-based findings.

Given the sensitivity of VOLL to a variety of specific factors such as customer's consumption profile, a region's macroeconomic and climatic attributes, as well as the types of outages experienced/examined, this report does not – and cannot – provide a single VOLL estimate for the ERCOT region at this time for purposes of establishing the economic impact of rotating outages at the distribution level due to inadequate operating reserves. Arriving at an accurate VOLL estimate for ERCOT will require a comprehensive customer survey process. The economic literature review and the macroeconomic analysis could be useful, however, as indicators or points of reference on the general magnitude of the VOLL.

Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-10

The Brattle Group

ERCOT Investment Incentives and Resource Adequacy

June 1, 2012

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Prepared for

Electric Reliability Council of Texas

Overall, it appears that this mechanism has failed to introduce sufficiently high prices reflective of scarcity conditions to meet long-term resource adequacy needs. While it does not appear that this mechanism must be revised, it does appear that ERCOT will require supplemental mechanisms to produce needed scarcity premiums. We believe that this observation is consistent with the observations and recent market design activities of the PUCT, ERCOT, and stakeholders.

b. Price Cap and High System Offer Cap

ERCOT's high system offer cap (HCAP) is set to $3,000/MWh; while ERCOT does not have any enforced price cap, it would be unusual for prices to rise above the offer cap.[149] Commissioners of the PUCT have stated plans to further increase the offer cap to possibly $4,500 to $9,000/MWh, motivated by concerns that the current cap is too low to attract a desired level of investment.[150] Neither the current offer cap nor the proposed offer cap increases are based on an analysis of customers' VOLL or an analysis of the price cap needed to sustain investments.

We recommend creating a locational marginal price (LMP) cap set at the average customer VOLL, which would also impose a maximum limit on other parameters such as the offer caps and the Power Balance Penalty Curve (PBPC) shadow price. This is the efficient price level during severe scarcity conditions when ERCOT must enact involuntary load shedding, because this is the price that the average customer would have been willing to pay to avoid curtailment. A VOLL-based price cap approximates what the demand curve would have been had customers been actively bidding to avoid curtailment. Setting the price cap at VOLL is supported by a rich theoretical literature demonstrating the economic efficiency of this approach.[151]

Determining an accurate estimate of VOLL is difficult, however, and could range from a few thousand to tens of thousands of dollars depending on customer class. For example, in its 2006 review of VOLL studies, MISO found that VOLL ranged from $1,500-$3,000/MWh for residential, $10,000-$50,000/MWh for commercial, and $10,000-$80,000/MWh for industrial customers.[152] Ultimately, MISO decided to set its price cap at the low end of $3,000/MWh, consistent with residential VOLL estimates.[153] As another example, Australia's National Energy Market (NEM) price cap is at a VOLL of $12,500/MWh AUD ($12,200 USD), with the parameter subject to periodic study and updating.[154] The VOLL estimate appropriate in ERCOT is likely in the same range as VOLL estimates elsewhere, but a study would need to be conducted to estimate the number accurately. In particular, the study would have to consider: (1) the VOLL of different classes of customers; (2) the likely ratio of load shed events that would be imposed on each customer class, including considering that utility protocols may result in more load shedding for residential rather than large C&I customers; and (3) that certain very high-VOLL customers should be excluded from the analysis because they will already have

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[149] Some nodal prices may rise above the offer cap if, for example, the penalty factor on a certain system constraint had a very high shadow price.

[150] See, for example, PUCT (2012a), Item Number 106.

[151] See Hogan (2005), pp. 9-11; and Joskow and Tirole (2004) p. 14.

[152] See MISO (2006).

[153] See MISO (2012a), Section 5.

[154] See AEMO (2012). Exchange rate assumed is USD/AUD = $1.02 from Bloomberg (2012).

invested in backup generation or dual distribution feeds and will therefore not experience a full outage even during a load shed event.

Another way to set the price cap would be to derive it, along with other administrative scarcity pricing parameters, based on an estimate of the price levels needed to attract a desired level of investment. We more fully examine this option under Section VI.B.2 below, although we do not recommend this as a dependable way to achieve a particular reserve margin.

Finally, we recommend creating a functional distinction among: (1) ERCOT's price cap, which is currently undefined, meaning that prices may exceed the offer cap depending on transmission constraints; (2) the high, low, and other offer caps created for market mitigation purposes and implementing the small fish rule; and (3) administrative scarcity pricing thresholds used to set prices during scarcity events. Each of these mechanisms has a different purpose, and so they should not be forced to have identical values in all cases. The purpose of imposing a price cap at VOLL is to prevent LMPs from exceeding customers' willingness to pay to avoid outages during load-shed events.[155] The high and low offer caps used under the small fish swim free rule might be set to a separate, lower level based on PUCT and market monitor analyses of market power mitigation concerns. Administrative scarcity pricing thresholds might be set to different levels as discussed in the next Section.

Increasing the offer and price caps would introduce some risks associated with potential defaults. We have not analyzed all of the credit requirements, qualifications, and other provisions that might be required to ensure that market participants are able to cover their day-ahead and forward bilateral positions without defaulting. However, we are concerned that as reserve margins tighten and offer caps increase, an unscrupulous REP with little to lose might find ways to exploit asymmetric risk exposures, if any exist. Such a REP could under-hedge in order to make money in the likely event that realized spot prices are lower than forward prices, while ignoring the risk that spot prices could spike to levels they cannot pay in the unlikely event of 2011-like weather. Instead of paying the cost of such an extreme event, they could simply default and exit the retail electric business, and ERCOT's other customers would have to pay. Given risks such as these, we recommend that the PUCT revisit its credit and qualification provisions for REPs, as we understand ERCOT is already doing for settlements under their purview.

c. Administrative Price-Setting during Scarcity Events

There are three key objectives when developing price-setting mechanisms during scarcity events: (1) ensuring that administrative reliability interventions do not artificially suppress prices during scarcity events; (2) incorporating DR into price-setting as much as possible as discussed in Section V.B.4 below; and (3) developing administrative price-setting mechanisms that will accurately reflect marginal system costs.

Price suppression during administrative reliability interventions is a risk in any market because these interventions make incremental supplies available for dispatch. If those actions add supply at a low offer price (or reduce demand), then the typical result will be to reduce prices just when

[155] Note that in the absence of a price cap, increasing the offer cap to $9,000/MWh means that actual realized prices could exceed $9,000/MWh and the VOLL at specific nodes, depending on system constraints.

Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-11

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2016 Probabilistic Assessment

March, 2017

RELIABILITY | ACCOUNTABILITY

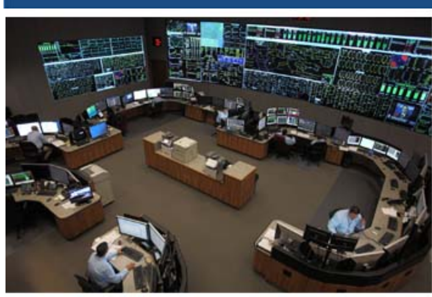

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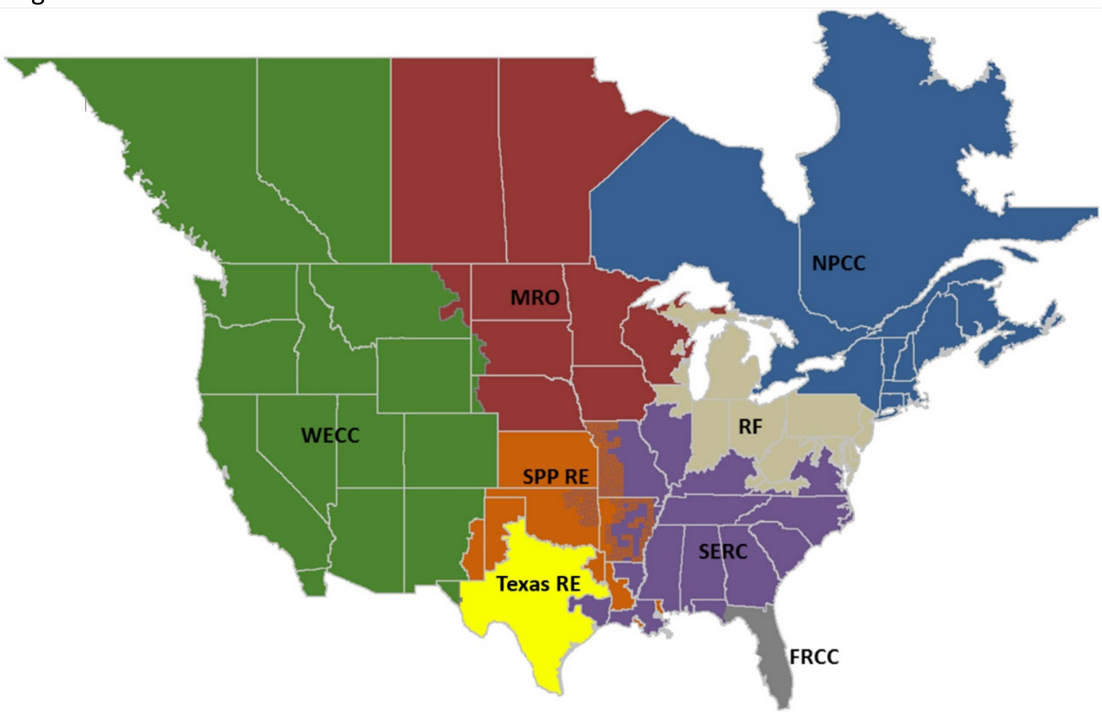
Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

NERC Regions and Assessment Areas

FRCC – Florida Reliability Coordinating Council

FRCC

MRO – Midwest Reliability Organization

MISO

MRO-Manitoba Hydro

MRO-SaskPower

NPCC – Northeast Power Coordinating Council

NPCC-Maritimes

NPCC-New England

NPCC-New York

NPCC-Ontario

NPCC-Québec

RF – ReliabilityFirst

PJM

SERC – SERC Reliability Corporation

SERC-East

SERC-North

SERC-Southeast

SPP RE – Southwest Power Pool Regional Entity

SPP

Texas RE – Texas Reliability Entity

Texas RE-ERCOT

WECC – Western Electricity Coordinating Council

WECC-CA/MX

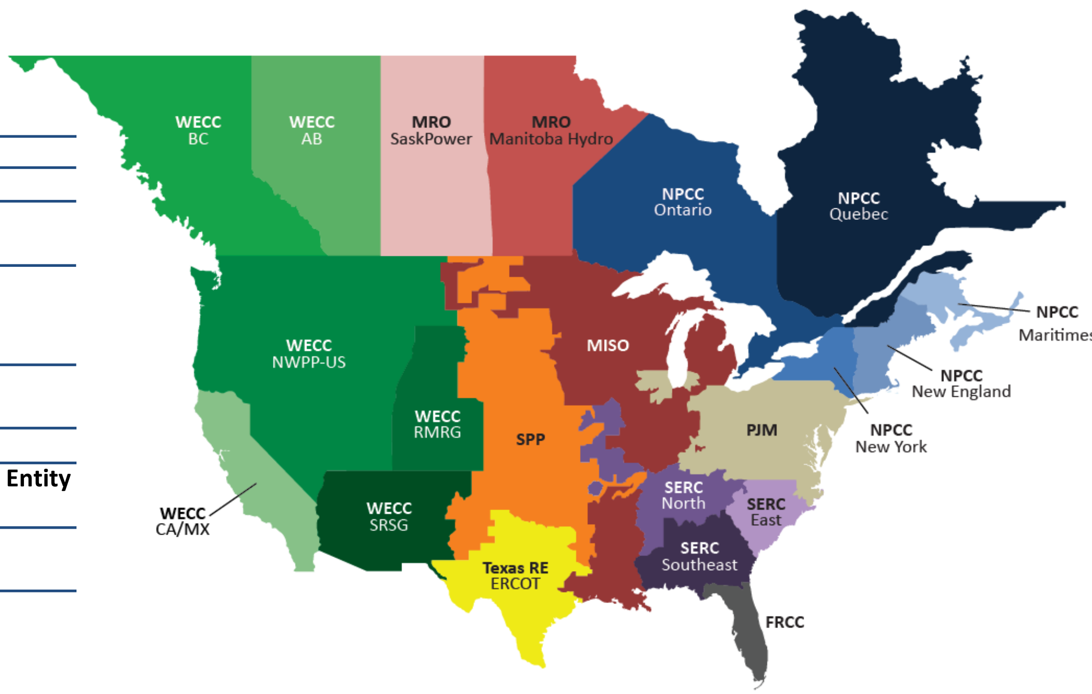
WECC-NWPP-AB

WECC-NWPP-BC

WECC-NWPP-US

WECC-RMRG

WECC-SRSG



Executive Summary

The 2016 Probabilistic Assessment is an addendum to the *2016 Long-Term Reliability Assessment* (2016 LTRA) to provide a more comprehensive understanding of resource adequacy beyond the reserve margin analysis offered by the 2016 LTRA. A brief summary of this analysis has already been included in the 2016 LTRA.[1] This report contains a fuller set of the assessment results and additional description of the methods used in each of the Regions.

A probabilistic assessment offers a different approach for examining the complexity of the changing BPS that is necessary for identifying reliability issues and developing prompt industry actions to address them. Specifically, the objectives of this assessment are to:

- Calculate a complete and non-overlapping set of monthly and annual probabilistic reliability metrics across the NERC footprint
- Perform a resource adequacy assessment covering all hours (compared to only the peak demand hour of each season in the LTRA)
- Provide probabilistic reliability metrics, loss of load hours (LOLH), and expected unserved energy (EUE), for each NERC assessment area and convey a clear understanding of the reserve margin implications
- Compare results over time and between studies
- Examine the availability of non-firm capacity transfers between assessment areas
- Provide a composite generation and transmission assessment (resource adequacy), which considers the ability of load to receive power supplied by aggregate resources
- Calculate probabilistic reliability metrics under a sensitivity case with increased in load growth

This probabilistic assessment uses a similar process to the LTRA: The Reliability Assessment Subcommittee (RAS), at the direction of the PC, supports LTRA development. Specifically, NERC and the RAS performed a thorough peer review that leveraged the knowledge and experience of industry subject matter experts while providing a balance to ensure the validity of data and information provided by the Regions. Each assessment area section is peer reviewed by members from other Regions to achieve a comprehensive analysis that is verified by RAS in open meetings. The review process ensures the accuracy and completeness of the data and modeling provided by each Region. The probabilistic assessment uses a similar process.

NERC recognizes that a changing resource mix with significant increases in energy–limited resources, changes in off-peak demand, and other factors can have an effect on resource adequacy. As a result, NERC is incorporating more probabilistic approaches into this assessment and other ongoing analyses that will provide further insights into how to best establish adequate reserve margins amidst a BPS undergoing unprecedented changes. Historically, NERC has gauged resource adequacy through planning reserve margins which are a deterministic assessment metric. Planning reserve margins are a measure of available capacity over and above the capacity needed to meet normal (50/50) forecast peak demand.

As a result of the Probabilistic Analysis Improvement Task Force (PAITF) recommendations, monthly reporting of LOLH and EUE were added for this report.[2]

[1] 2016 Long-Term Reliability Assessment

[2] Probabilistic Assessment Improvement Task Force

The 2016 ProbA report includes a sensitivity case in which monthly and annual LOLH and EUE measures are calculated while increasing net energy for load (demand in all hours) by two percent for both 2018 and 2020 and increasing total internal demand (TID) by two percent in 2018 and by four percent in 2020. This sensitivity case is usually interpreted as the impact of increased load growth, but it can also be used to better understand the effect of increased retirements.

NERC has identified the following key findings:

- Most of the assessment areas showed no loss of load probability in either the base or sensitivity cases. This was expected with the high reserve margins in those areas as reported in the LTRA.
- Monthly LOLH and EUE statistics were reported for the first time this year. Monthly patterns are only available for the seven assessment areas with nonzero annual values. FRCC, MISO, NPCC-New England, and TRE-ERCOT show almost all of the LOLH in July and August as expected for these summer peaking utilities. FRCC and TRE-ERCOT only show useable statistics for the sensitivity case. Determining the precise reasons for monthly patterns is useful for resource planning and future probabilistic resource adequacy analysis.
- Monthly loss of load probabilities have been a very useful addition to the analysis and should be continued. As more variable resources come online, which may impact the viability of other resources, increased loss of load probability may be observed.
- The sensitivity case of two percent and four percent load increases was useful to find the point at which loss of load probabilities started increasing in some areas and to verify that the analyses were reacting as expected.
- Assessment area boundary changes can cause challenges in measuring changes from year to year and study to study. Most of the areas have remained the same as in the 2014 ProbA report. However, only two of the six areas in WECC are substantially the same as in the 2014 Report (i.e., CAMX & SRSG), and MAPP has been included in SPP for this report.
- Modeling for variable energy resources is increasingly important as these resources become a larger portion of the generating mix. Most areas are still modeling wind and especially solar as a flat load adjustment, varying by season. Probabilistic approaches should be used to represent the stochastic behavior of wind and solar as these resources increase penetration.
- Assessment areas are increasing the amount of both internal and external transmission modeling. Transmission modeling is very area specific and it may not be necessary to have multiple subareas modeled for wide-area analysis.
- Peer review for the probabilistic assessment analysis is largely methodology-based. Critical methodology review is needed as probabilistic approaches introduce increased complexity and relatively new assumptions.

Introduction

This report presents the third probabilistic resource adequacy assessment conducted as a complement to the Long-Term Reliability Assessment. Previous probabilistic analyses were run in conjunction with the 2012 and 2014 LTRAs. All assessments calculated loss of load hours (LOLH) and expected unserved energy (EUE) for the third and fifth years of the LTRA. This year's analysis calculates the probabilistic resources measures for 2018 and 2020.

As in the previous two probabilistic assessments, probabilistic analyses were conducted for all assessment areas within NERC. The LOLH, EUE, and reserve margins from the 2014 are included here to show trending between the 2016 and 2014 analyses.[3][4]

For 2016, some of the probabilistic assessment results included in the *2016 LTRA* and monthly LOLH and EUE reliability statistics were added to evaluate annual patterns of outages and further emphasize the objective of looking at reliability at all times of the year and not only seasonal peaks.

This report presents additional results, comparisons with the *2014 ProbA*, discussions, and details on the methodologies used in each of the assessment areas.

Background

In 2010, the Generation and Transmission Reliability Planning Models Task Force (GTRPMTF) concluded that existing reliability models could be used to develop one common composite generation and transmission assessment of resource adequacy. The task force also noted the importance of having complete coverage of the North American BPS as well as the elimination of overlaps. As this premise is already adopted and executed annually in the LTRA, the approach for this probabilistic assessment follows suit. The assessment areas (i.e., Regions, Planning Coordinators (PCs), independent system operators (ISOs), and regional transmission organizations (RTOs)) used for this assessment are identical to those used for the LTRA.

The objectives of the probabilistic assessment are:

- Calculate a complete and non-overlapping set of monthly and annual probabilistic reliability metrics across the NERC footprint.
- Perform a resource adequacy assessment covering all hours (compared to only the peak demand hour of each season in the LTRA).
- Provide probabilistic reliability metrics, loss of load hours (LOLH) and expected unserved energy (EUE) for each NERC assessment area and convey a clear understanding of the reserve margin implications.
- Compare results over time and between studies.
- Examine the availability of non-firm capacity transfers between assessment areas.
- Provide a composite generation and transmission assessment (resource adequacy) that considers the ability of load to receive power supplied by aggregate resources.

In this effort to improve NERC's continuing probabilistic and deterministic assessments, the Probabilistic Assessment Improvement Task Force (PAITF) was formed in May of 2015 from members of the Planning Committee (PC), the Reliability Assessment Subcommittee (RAS), and selected observers from industry to identify improvement opportunities for NERC's Long-Term Reliability Assessment and complementary probabilistic analysis.

[3] NERC 2012 Probabilistic Assessment Report
[4] NERC 2014 Probabilistic Assessment Report

PAITF developed two reports; the *NERC Probabilistic Assessment Improvement Plan* report published in December 2015, over which possible recommendations by PAITF were provided based on recent LTRA key findings for NERC core and proposed coordinated special probabilistic assessment reports. The second report of *NERC Technical Guideline Document* published in August of 2016 over which detailed probabilistic modeling guidelines and technical recommendations were presented that serve as a platform for detailing probabilistic analytical enhancements that apply to resource adequacy. [5]

The PAITF defined five different probabilistic resource adequacy statistics that are widely used, summarized in the below table. Only LOLH and EUE are reported for all assessment areas.

Probabilistic Assessment Primary Measures

The Probabilistic Assessment reports two metrics—EUE and LOLH. These and other probabilistic metrics are defined below.

Expected Unserved Energy (EUE)

This is defined as a measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. The EUE is energy-centric and analyzes all hours of a particular year. Results are calculated in megawatt hours (MWh). The EUE is the summation of the expected number of megawatt hours of load that will not be served in a given year as a result of demand exceeding the available capacity across all hours. Additionally, this measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load, etc.). Normalizing the EUE provides a measure relative to the size of a given assessment area. One example of calculating a Normalized EUE is defined as [(Expected Unserved Energy) / (Net Energy for Load)] x 1,000,000 with the measure of per unit parts per million.

Loss-of-Load Hours (LOLH)

This is generally defined as the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period (or the load duration curve) instead of using only the daily peak in the classic LOLE calculation. To distinguish this expected value from the classic calculation, the hourly LOLE is often called LOLH. It must be noted that the classic LOLE in days per year is not interchangeable with the LOLH in hours per year (i.e., LOLE of 0.1 days per year is not equivalent to a LOLH of 2.4 hours per year.) Unlike the classic LOLE metric, there is currently no generally acceptable LOLH criterion.

Loss-of-Load Expectation (LOLE)

This is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. This is the original classic metric that is calculated using only the peak load of the day (or the daily peak variation curve). However, this metric is not being reported as part of this assessment. Currently some assessment areas also calculate the LOLE as the expected number of days per year when the available generation capacity is insufficient to serve the daily load demand (instead of the daily peak load) at least once during that day.

Loss-of-Load Probability (LOLP)

This is defined as the probability of system daily peak or hourly demand exceeding the available generating capacity during a given period. The probability can be calculated either using only the daily peak loads (or daily peak variation curve) or all the hourly loads (or the load duration curve) in a given study period.

Loss-of-Load Events (LOLEV)

This is defined as the number of events in which some system load is not served in a given year. A LOLEV can last for one hour or for several continuous hours and can involve the loss of one or several hundred megawatts of load. Note that this is not a probability index but a frequency of occurrence index.

LOLE, LOLEV, and LOLP are often used by assessment areas to define a target metric of reliability. The classic definition of reliability as one day in 10 years is a LOLP target and is often translated into an LOLE target of 0.1 day/year or LOLEV of 0.1 event/year. These metrics are not provided in this report to avoid potential conflicts with regional practices based on different methods.

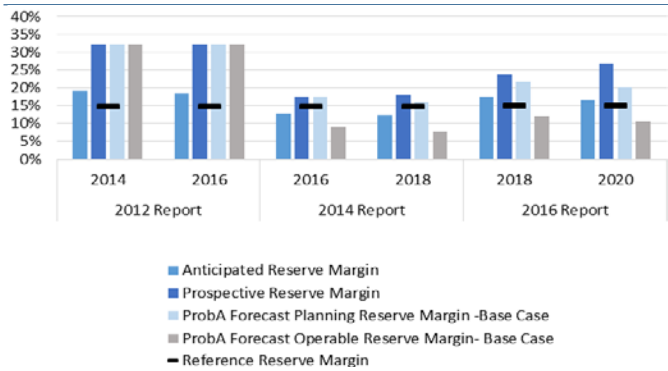
The 2016 ProbA report is divided into two main sections and two appendices. The first section is an overview of the study, a comparison of the probabilistic analysis methods used in the various assessment areas, and overall conclusions and recommendations. The second section is a brief description of the analysis and presentation of the results for each assessment area. Appendix II: Detailed Probabilistic Modeling Table, is a per assessment area high-level modeling category description included in the 2016ProbA. Appendix II is available as another volume of

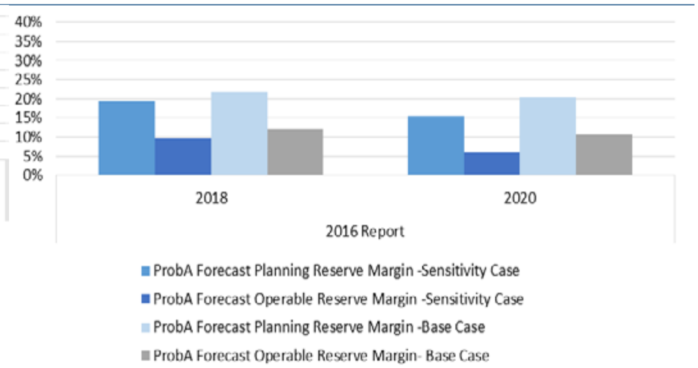
Probabilistic Assessment Improvement Task Force - Technical Guideline Document

MISO

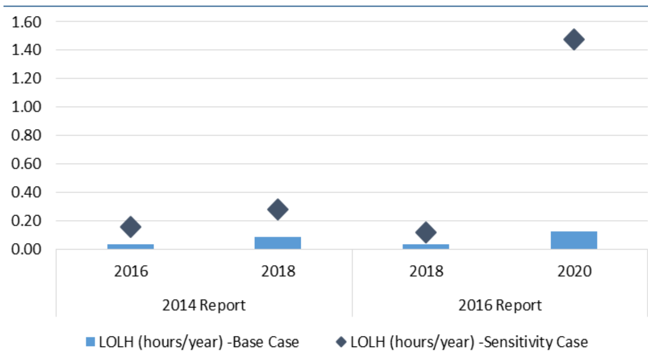
The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

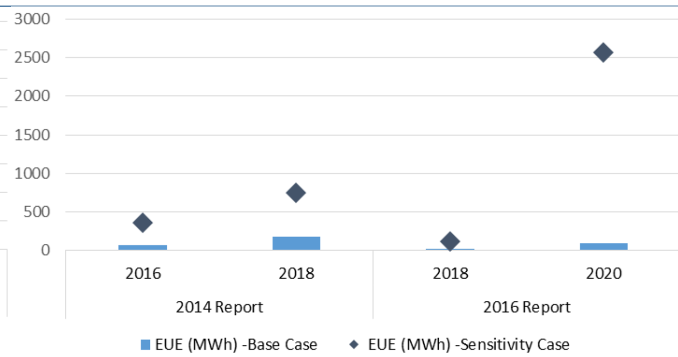
Base Case Reserve Margins (Left) and Sensitivity Case Reserve Margins (Right)





LOLH Results (Left) and EUE Results (Right)





For this analysis MISO's 10 Local Resource Zones were modeled with their respective load and generation. The 10 zones were modeled with their respective import and export limits to model the entire MISO region. External firm and nonfirm support were also modeled. The 2016 Probabilistic Assessment was performed at NERC's request as a complement to the Long-Term Reliability Assessment by providing additional probabilistic statistics of loss of load hours (LOLH) and expected unserved energy (EUE) for the years 2018 and 2020. The annual Planning Reserve Margin (PRM) study that MISO conducts determines a PRM such that all available resources are committed to meet firm load without any remaining to respond to outages and contingencies. The Base Case for the 2016 Probabilistic Assessment was run in the same manner and no resources were held aside.

The LTRA deterministic reserve margins decrement the capacity constrained within MISO south due to the 2,500 MW limit which reflects a decrease in reserve margin. The constraint was explicitly modeled for the probabilistic analysis and determined if sufficient capacity was available to transfer from south to north and vice versa. The modeling of this limitation produces an increase for the ProbA Forecast Planning Reserve Margin.

Assessment transmission is modeled based on MISO's Local Resource Zones capacity import and capacity export limit. . Within GE MARS this was modeled as a hub and spoke topology. External to the MISO system, transmission constraints are determined by analysis on historical high observed summer Network Scheduled Interchange (NSI) as well as resource availability. MISO ties and interfaces with the external system are not explicitly modeled but are contained in the amount of external firm and non-firm support modeled. MISO connects each Local Resource Zone to a central hub with infinite ties and models each LRZ with its own LFU.

The 2016 Probabilistic Assessment model included a constant 2,331 MW of external non-firm support for assistance to MISO in a time of need. This non-firm support amount is based off of historical probabilistic resource availability analysis as well historical Net Scheduled Interchange (NSI) data.

Firm Imports from external areas to MISO are modeled at the individual unit level. The specific external units were modeled with their specific installed capacity amount and their corresponding Equivalent Forced Outage Rate demand (EFORd). This better captures the probabilistic reliability impact of firm external imports.
Firm exports from MISO to external areas were also included in the analysis. Any export was decremented from the capacity available to MISO.

These non-coincident MISO peak load forecast values from the LSEs were applied to individual historic 2005 and 2006 load shapes and aggregated to form the MISO hourly load models and MISO coincident load peak created for this assessment. The historic years 2005 (MISO North/Central) & 2006 (MISO South) were chosen because they represent a typical load pattern year for MISO.

Load Forecast Uncertainty (LFU), a standard deviation statistical coefficient, is applied to a base 50/50 load forecast to represent the various probabilistic load levels. MISO back-calculated the system wide LFU equivalent to MISO's current zonal methodology to be about 3.8 percent.

Behind-the-Meter generation is modeled as a generation resource. MISO models each behind-the-meter generator as any other thermal generating unit with a monthly capacity and a forced outage rate.

Direct Control Load Management and Interruptible Demand type of demand-response were explicitly included in the MARS model created for this assessment as energy-limited resources. These demand resources are implemented in the MARS simulation before accumulating LOLE or shedding of firm load. The LTRA utilizes these resources as a load modifier.

The LTRA deterministic reserve margins decrement the capacity constrained within MISO south due to the 2,500 MW limit which reflects a decrease in reserve margin. The constraint was explicitly modeled for the probabilistic analysis and determined if sufficient capacity was available to transfer from south to north and vice versa. The modeling of this limitation produces an increase for the ProbA Forecast Planning Reserve Margin.

Previous results in the 2014 Probabilistic Assessment resulted in 182.2 MWh EUE and 0.09 Hours/year LOLH. The results from this year's analysis resulted in a slight decrease for 2018 when compared to the analysis completed in the 2014 Probabilistic Assessment.

Base Case Study

- The bulk of the EUE and LOLH are accumulated in the summer peaking months with some off peak risk.
- Increasing loss of load statistics expected with decreasing reserve margins.

Sensitivity Case Study

The sensitivity was modeled as a demand increase, for MISO it is more representable to think of it as a good proxy for increased retirement risk along with risk of increased load forecasts. The 2018 2 percent increase is equal to 2,565 MW increase and the 2020 4 percent increase is equal to a 5,203 MW increase. i.e. the 2018 sensitivity case could be a good proxy for increased retirement and load forecast increases that would lower our reserve margin by 2,565 MW.

Monthly Reliability Measures

Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.000	0	0.000	0	0.000	0	0.000	0
Feb	0.000	0	0.000	0	0.000	0	0.000	0
Mar	0.000	0	0.000	0	0.000	0	0.000	0
Apr	0.000	0	0.000	0	0.000	0	0.000	0
May	0.000	0	0.001	0	0.000	0	0.012	4
Jun	0.000	0	0.016	5	0.001	0	0.024	9
Jul	0.027	14	0.065	39	0.082	66	0.704	815
Aug	0.006	4	0.041	51	0.036	48	0.727	1736
Sep	0.000	0	0.000	0	0.000	0	0.003	1
Oct	0.000	0	0.002	0	0.000	0	0.004	1
Nov	0.000	0	0.000	0	0.000	0	0.000	0
Dec	0.000	0	0.000	0	0.000	0	0.000	0
Annual	**0.033**	**18**	**0.125**	**96**	**0.119**	**114**	**1.474**	**2566**

SERC

SERC is a summer-peaking assessment area that covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC is divided into three assessment areas: SERC-E, SERC-N, and SERC-SE. The SERC Region includes 11 BAs: Alcoa Power Generating, Inc. – Yadkin Division (Yadkin), Associated Electric Cooperative, Inc. (AECI), Duke Energy Carolinas and Duke Energy Progress (Duke), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU)), PowerSouth Energy Cooperative (PowerSouth), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (Santee Cooper, SCPSA), Southern Company Services, Inc. (Southern), and Tennessee Valley Authority (TVA).

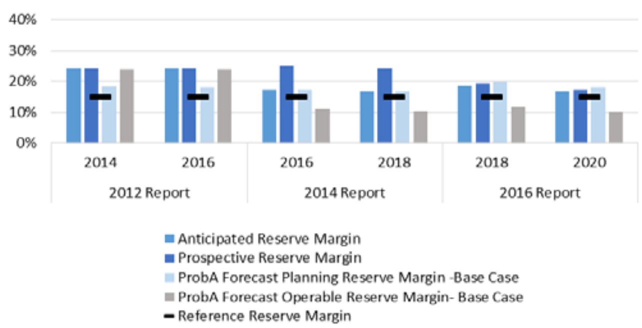
SERC-East Assessment Area Footprint

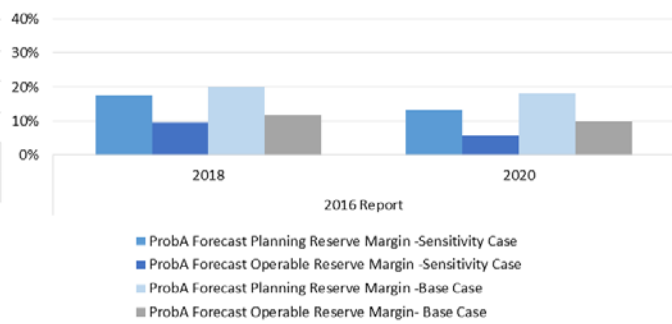
SERC-North Assessment Area Footprint

SERC-Southeast Assessment Area Footprint

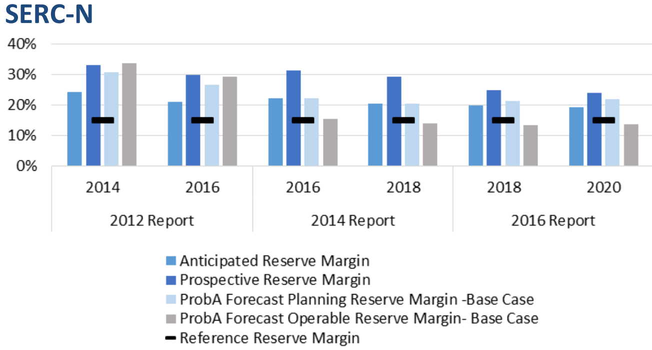
Base Case Reserve Margins (Left) and Probabilistic Measures (Right)

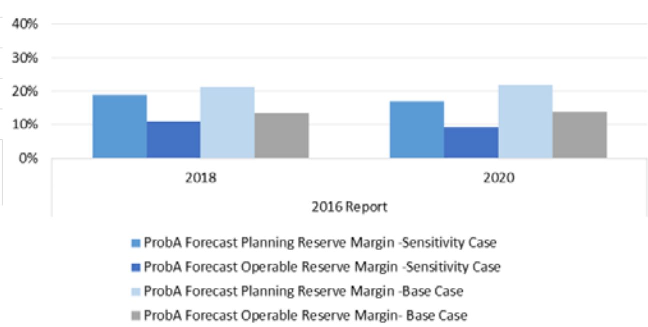
SERC-E



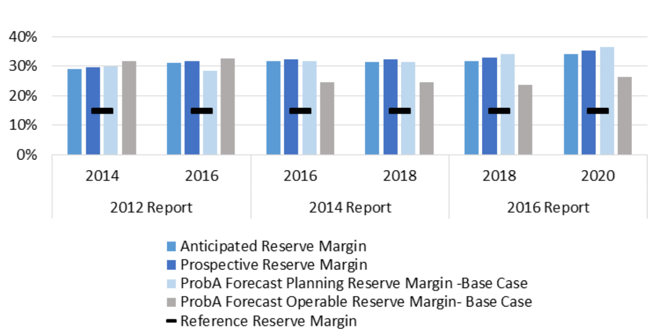


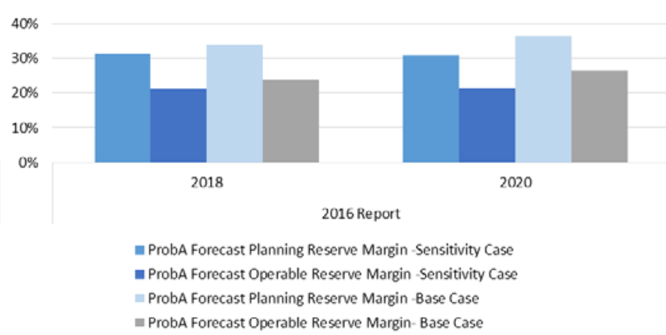
SERC-N





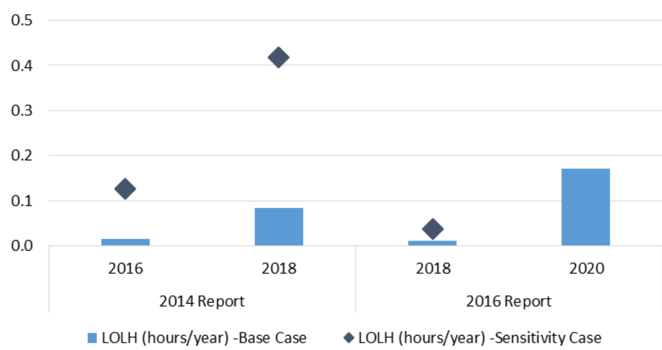
SERC-SE

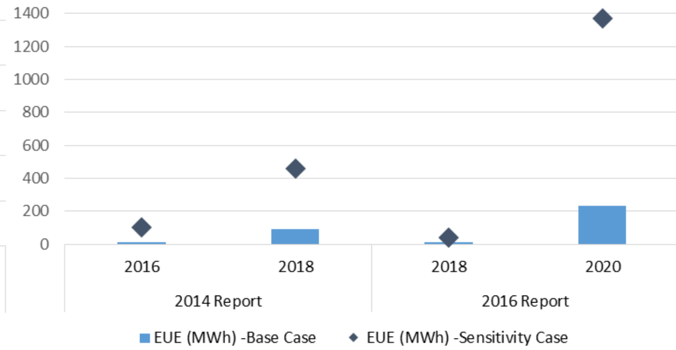




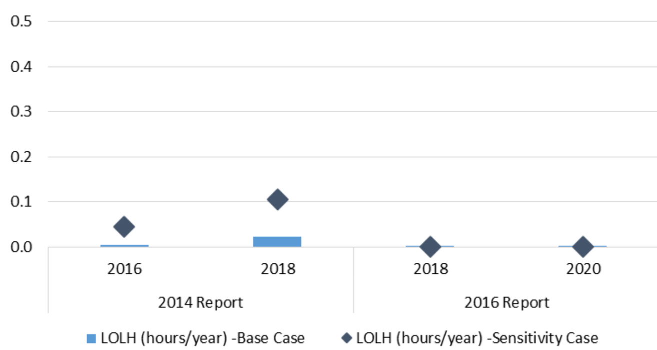
LOLH Results (Left) and EUE Results (Right)

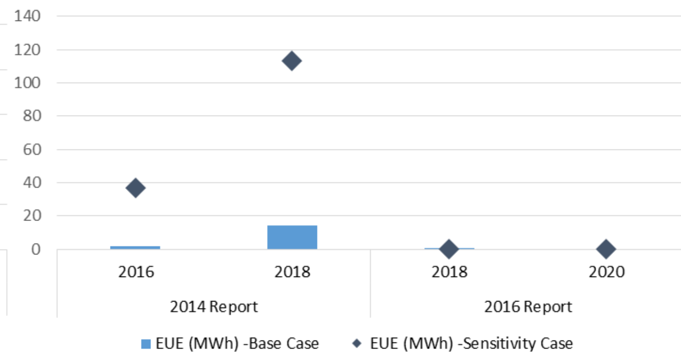
SERC-E



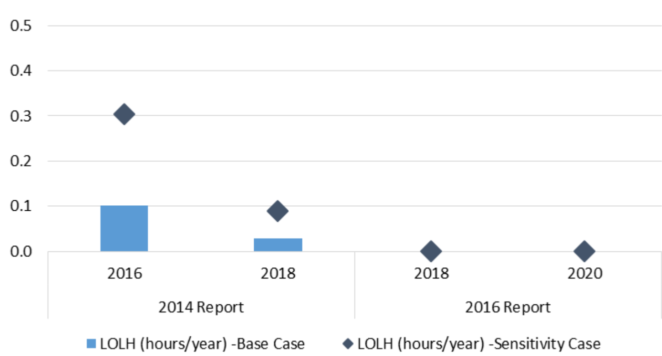


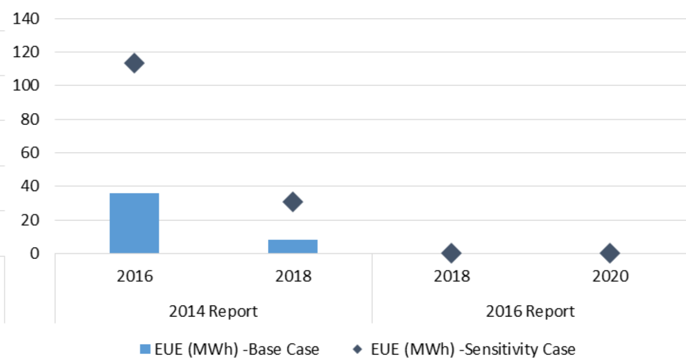
SERC-N





SERC-SE





SERC utilizes an 8760 hourly load, generation, and transmission simulation model consisting of 3 internal NERC assessment areas (SERC-E, SERC-N, and SERC-SE) and 7 connected external areas (10 total external areas). First Contingency Incremental Transfer Capability (FCITC) analysis sets limits for nonfirm support amongst internal and external areas, while positive and negative demand side resources represent net firm interchange schedules. Forecast assumptions for normal (50/50) coincident demand, net energy for load, and anticipated resources from the Long-term Reliability Assessment are input for the model, and further analysis determines uncertainty parameters such as load forecast uncertainty (LFU), generator forced outage rates, etc.

From 2014 Probabilistic Resource Assessment (PRA) to 2016 PRA, the SERC-E LOLH decreased by approximately 97 percent (0.085 to 0.002) for the same study year 2018. This is primarily driven by lower projected demand mentioned above, but also due to 2016 modeling corrections. The SERC PRA model now includes expected firm capacity transfers and improvements to winter historical load profiles. [17] After accounting for lower demand and modeling corrections, SERC-E base case 2018 results remain static from 2014.

[17] Approximations: 0.085 (2014 PRA- 2018 LOLH) minus 0.080 (decrease load forecasts from 2014 to 2016) minus 0.003 (modeling corrections) equals 0.002

The generation system reliability indices for the three SERC LTRA assessment areas being modeled were calculated for the current reserve level projections (base case) from the *2016 LTRA* filings, as well as for one increased demand and energy sensitivity case, for the purposes of the NERC probabilistic assessment effort. MARS was used to calculate the system reliability in terms of hourly LOLE (LOLH) and expected unserved energy (EUE).

This study assumes that there are no transmission limits within an area (with the exception of SERC-PJM, consequently, any generating units assigned to an area can serve any load associated with that area. This study models transfer limits between the areas, and so the areas are typically defined by the limiting interfaces that may exist throughout the transmission system.

The SERC Long-Term Study Group (LTSG) establish first contingency incremental transfer capability (FCITC) limits for the winter and summer seasons of each study year in each direction between pairs of interconnected areas (assessment areas and/or subareas). The study model holds these limits constant 24/7 for each study iteration. Transfer limits (FCITC) were calculated for each assessment area by simulating transfers with load-to-generation shifts into each area simultaneously from each adjacent area using linear transfer techniques. Incremental interface import capability was then allocated to each area participating in the transfer, including the areas external to SERC, based upon each area's participation factor.

For internal load modeling, SERC used annual load shapes for the several years between 2007 and 2013 with each year has its own weighted average value. For modeling the eternal areas, SERC used various typical years.

LFU was modeled independently for each of the three SERC areas.

The forecasted coincident annual peak demand for SERC-SE is 47,513 MW and 48,282 MW in 2018 and 2020 respectively. The average system diversity of the SERC LTRA area during the summer is 0.95 percent while during the winter it is 1.72 percent. SERC is typically a summer peaking LTRA area; however, areas in certain years did peak during winter months. On average though, the winter season peak is approximately 93 percent of the annual peak demand (SERC-E app. 96 percent; SERC-N app. 97 percent, and SERC-SE app. 90 percent).

For this study, statistical analysis of the SERC LTRA assessment area coincident historical hourly load data from the aggregation of entities' FERC 714 filings (1993-2014) establishes the load forecast uncertainty (LFU) for SERC-N, SERC-E, and SERC-SE. This study not only accounts for historical weather patterns, but also applies a probability weighting to each load shape based upon each shapes inherent risk to loss of load. In this study, the effects of such DSM are embedded in the 50/50 load forecasts.

Base Case Study

SERC-E LOLH and EUE increase from 0.002 hours/year and 1.4 MWh respectively in 2018 to 0.046 hours/year and 49.4 MWh respectively in 2020 due to an approximate 3 percent increase in peak demand and minimal increase in anticipated resources. However, the rise of the metrics in 2020 is not concerning considering the MW size of SERC-E. Measures not modeled in the 2016 PRA such as, but not limited to, voluntary and non-controllable demand response, operating procedures to cut nonfirm schedules or maintenance, public appeals, and other mechanisms should mitigate 49.4 MWh of annual expected unserved energy within SERC-E.

LOLH and EUE accrue relatively evenly across all months of the year in 2018; however, with increase in demand by 2020, the majority of LOLH and EUE accrues during the peak seasons of summer and winter. Actually, between 60 and 70 percent occurs during the winter months. This is contributable to a high per unit of annual 50/50 demand and higher winter load forecast uncertainty due to events like the 2014 Polar Vortex where annual peaks occurred for many entities within SERC-E during winter months.

SERC-N entities expect a 0.81 percent compound annual growth rate (CAGR). However, the model results for 2020 base summer yielded near 0 percent growth from 2018. However, since the expected growth is below 1 percent, the resulting impact on the indices is negligible.
SERC-SE Zero LOLH and EUE

Sensitivity Case Study

SERC-E entities expect a 1.44 percent compound annual growth rate (CAGR). The NERC sensitivity case doubles the SERC-E CAGR to 2.90 percent. In this load growth scenario, SERC-E LOLH and EUE increase to 0.009 hours/year and 7.6 MWh respectively in 2018 and to 0.373 hours/year and 467.7 MWh respectively in 2020.

SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analysis on load growth and load forecast uncertainty. These cases will further demonstrate the influence a decline in expected energy efficiency gains and changes in other demand factors may pose to SERC-E resource adequacy and will be published quarter one of 2017.

SERC-N the NERC sensitivity case doubles the SERC-N CAGR to 1.74 percent. In this load growth scenario, SERC-N LOLH and EUE increase, but of minimal consequence to resource adequacy, to 0.003 hours/year and 1.8 MWh respectively in 2018 and to 0.001 hours/year and 0.8 MWh respectively in 2020. The resulting metrics for 2020 are lower than 2018 due to gas-fired generation additions to SERC-N mid-year 2018. Subsequently, the winter months in 2020 reflect lower accrual of LOLH and EUE than in 2018.

SERC-SE the NERC sensitivity case doubles the SERC-SE CAGR to 2.52 percent. In this load growth scenario, SERC-SE LOLH and EUE still remain zero.

Monthly Reliability Measures

SERC-E

Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.008	10	0.078	117	0.018	24	0.268	486
Feb	0.001	1	0.022	32	0.002	2	0.074	130
Mar.	0.000	0	0.001	0	0.000	0	0.005	5
Apr.	0.000	0	0.000	0	0.000	0	0.001	1
May	0.000	0	0.004	5	0.000	0	0.027	39
Jun.	0.000	0	0.003	3	0.001	0	0.057	58
July	0.000	0	0.012	12	0.006	5	0.177	219
Aug.	0.001	1	0.015	14	0.006	6	0.191	233
Sept.	0.000	0	0.000	0	0.000	0	0.004	4
Oct.	0.000	0	0.000	0	0.000	0	0.000	0
Nov.	0.000	0	0.000	0	0.000	0	0.001	1
Dec.	0.001	1	0.035	47	0.003	3	0.119	194
Annual	**0.012**	**13**	**0.171**	**231**	**0.038**	**41**	**0.925**	**1,370**

SERC-N

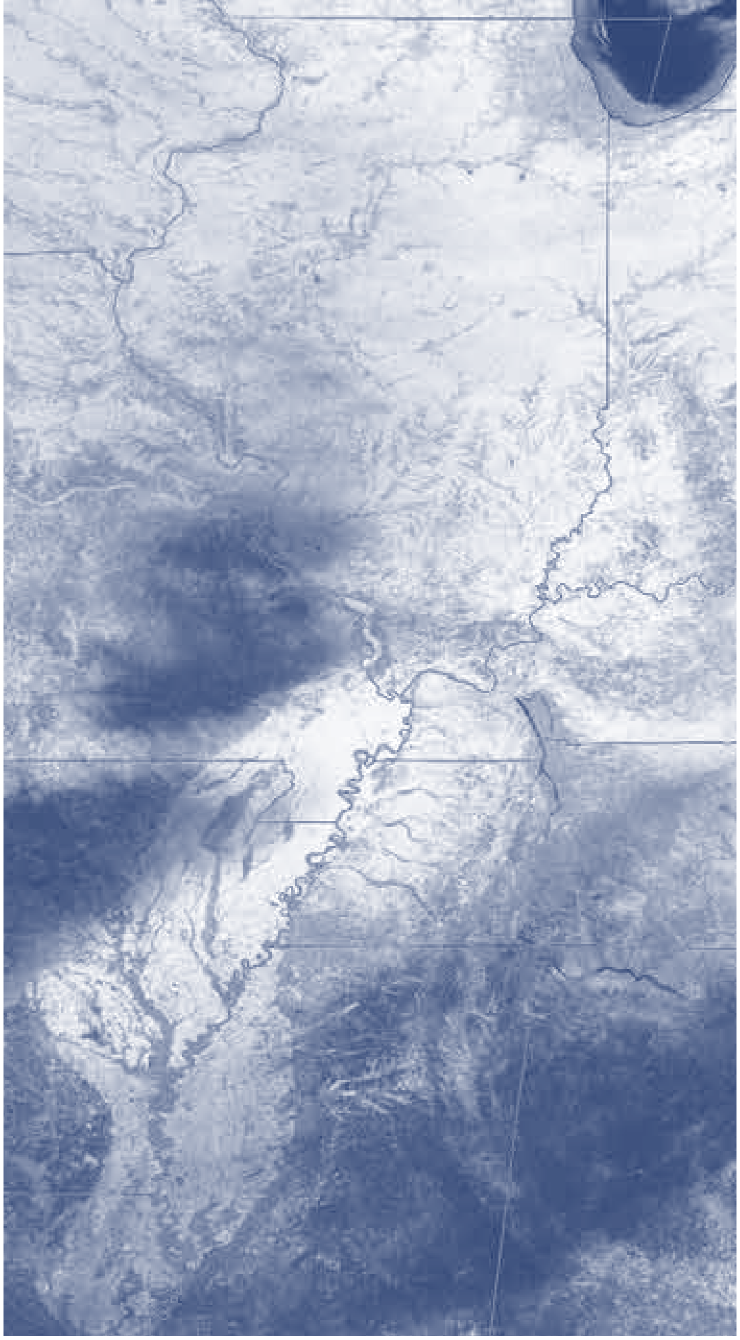
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.000	0	0.000	0	0.000	0	0.000	0
Feb	0.000	0	0.000	0	0.000	0	0.000	0
Mar.	0.000	0	0.000	0	0.000	0	0.000	0
Apr.	0.000	0	0.000	0	0.000	0	0.000	0
May	0.000	0	0.000	0	0.000	0	0.000	0
Jun.	0.000	0	0.000	0	0.000	0	0.000	0
July	0.000	0	0.000	0	0.000	0	0.000	0
Aug.	0.000	0	0.000	0	0.000	0	0.000	0
Sept.	0.000	0	0.000	0	0.000	0	0.000	0
Oct.	0.000	0	0.000	0	0.000	0	0.000	0
Nov.	0.000	0	0.000	0	0.000	0	0.000	0
Dec.	0.000	0	0.000	0	0.000	0	0.000	0
Annual	0.000	0	0.000	0	0.000	0	0.000	0

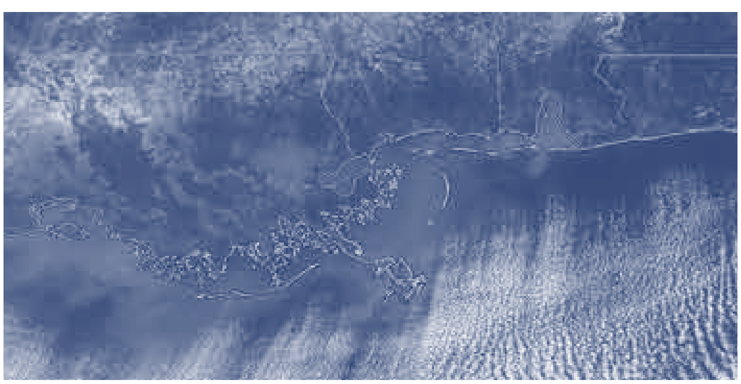
SERC-SE

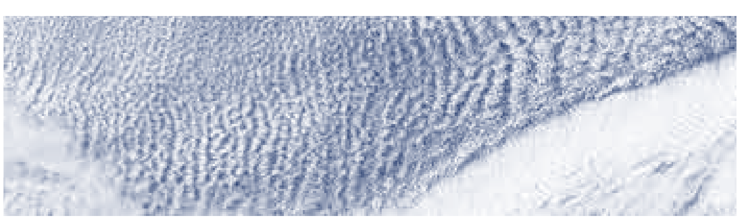
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.000	0	0.000	0	0.000	0	0.000	0
Feb	0.000	0	0.000	0	0.000	0	0.000	0
Mar.	0.000	0	0.000	0	0.000	0	0.000	0
Apr.	0.000	0	0.000	0	0.000	0	0.000	0
May	0.000	0	0.000	0	0.000	0	0.000	0
Jun.	0.000	0	0.000	0	0.000	0	0.000	0
July	0.000	0	0.000	0	0.000	0	0.000	0
Aug.	0.000	0	0.000	0	0.000	0	0.000	0
Sept.	0.000	0	0.000	0	0.000	0	0.000	0
Oct.	0.000	0	0.000	0	0.000	0	0.000	0
Nov.	0.000	0	0.000	0	0.000	0	0.000	0
Dec.	0.000	0	0.000	0	0.000	0	0.000	0
Annual	**0.000**	**0**	**0.000**	**0**	**0.000**	**0**	**0.000**	**0**

Rebuttal Testimony for Kevin D. Carden

Reb. Ex. KDC-12







2019 FERC and NERC Staff Report

The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018

FERC and NERC Staff Report
July 2019

*NASA Worldview Snapshot satellite image of The United States showing weather pattern for January 17, 2018.

I. Executive Summary

On January 17, 2018, a large area of the south central region of the United States experienced unusually cold weather. The below-average temperatures in this area resulted in a total of 183 individual generating units within the Reliability Coordinator (RC)[5] footprints of SPP, MISO, TVA,[6] and SeRC experiencing either an outage, a derate,[7] or a failure to start between January 15 and January 19, 2018. Between Monday, January 15, and the morning peak hour (between 7 and 8 a.m. Central Standard Time (CST)) on Wednesday, January 17, approximately 14,000 MW of generation experienced an outage, derate or failure to start. Including generation already on planned or unplanned outages or derated before January 15, the four RCs had over 30,000 MW of generation unavailable in the south central portions of their footprints by the January 17 morning peak hour. MISO declared an Energy Emergency,[8] because it had insufficient reserves to balance generation and load in the MISO South portion of its footprint, while all four of the RCs experienced constrained bulk electrical system (BES)[9] transmission

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[5] See Appendix E, "Categories of NERC Registered Entities."

[6] TVA is a Reliability Coordinator for its TVA Balancing Authority area as well as for the Balancing Authority areas of AECI and LG&E/KU. This report will clarify whether it is referring to TVA as the RC, including AECI and LG&E/KU, or only to TVA's own Balancing Authority area.

[7] Reductions in capacity of a generating unit short of a total outage.

[8] See Appendix C, "RC and TOP Tools and Actions to Operate the BES in Real Time."

[9] The Commission's jurisdiction extends to the Bulk-Power System, defined by Section 215(a) (1) of the Federal Power Act as "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability." The mandatory Reliability Standards apply to owners and operators of the bulk electric system (BES). In Order No. 773, the Commission approved a definition of BES that generally covers all elements operated at 100 kV or higher, with a list of specific inclusions and exclusions. Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure, Order No. 773, 141 FERC ¶ 61,236 (2012); order on reh'g, Order No. 773-A, 143 FERC ¶ 61,053 (2013), order on reh'g and clarification, 144 FERC ¶ 61,174 (2013). This report will use BES because its primary audience is most familiar with that term.

conditions across portions of their footprints, spanning all or parts of nine states. While the system remained stable, this combination of an Energy Emergency and wide-area constrained transmission conditions on January 17 meant that had MISO's next single contingency generation outage in MISO South of 1,163 MW[10] occurred, continued reliable BES operations would have depended on system operators shedding firm load promptly to prevent further degradation of BES conditions.

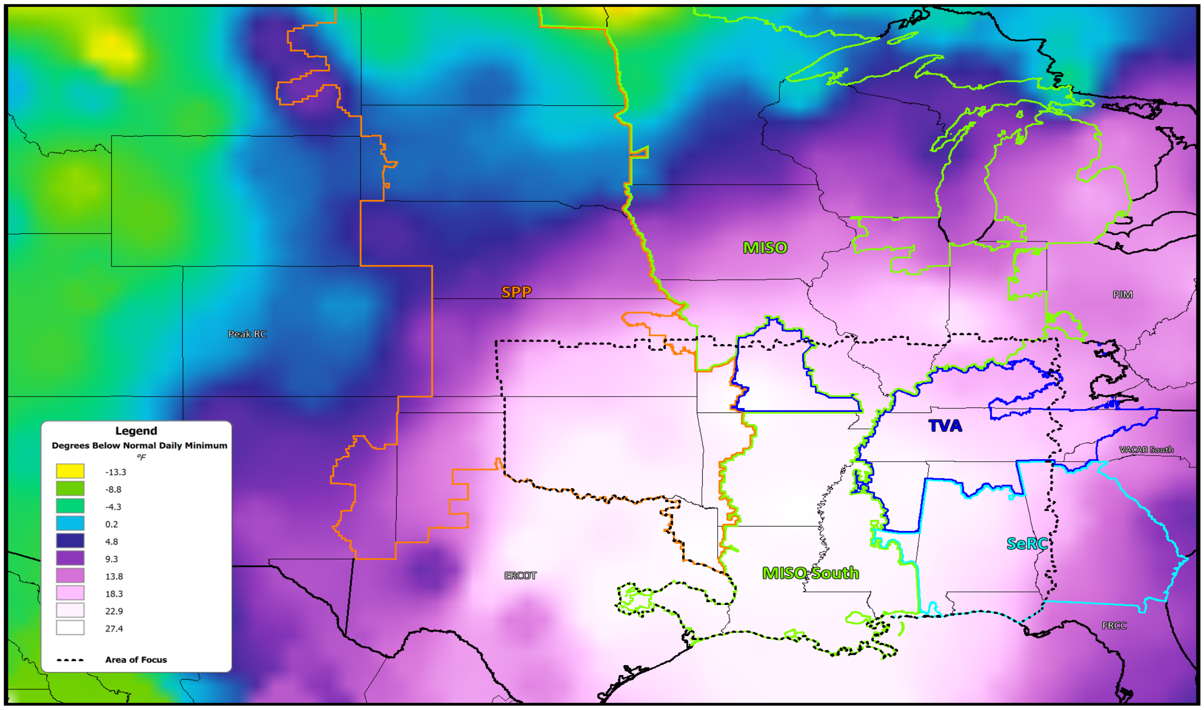
The combination of an Energy Emergency and wide-area constrained conditions constitutes the South Central U.S. Cold Weather BES Event of January 17, 2018, hereafter referred to as "the Event," which occurred in an area (the "Event Area")[11] consisting of:

- MISO South (Arkansas, eastern Texas, Louisiana, and Mississippi)
- Southeastern portion of the SPP RC footprint (lower Kansas-Missouri border, the eastern half of Oklahoma, Arkansas, eastern Texas, and Louisiana)
- Western portion of the TVA RC footprint (western Tennessee, lower Missouri, northeastern Oklahoma, northern Mississippi and Alabama)
- Western portion of the SeRC footprint (southern Mississippi and Alabama).

[10] The mandatory Reliability Standards set forth requirements that provide for the reliable operation of the BES. Federal Power Act (FPA) § 215(a)(3). In turn, "reliable operation" is defined in the FPA as "operating the elements of the [BES] within equipment and electric system thermal, voltage and stability limits, so that instability, uncontrolled separation or cascading will not occur as a result of a sudden disturbance, including a cybersecurity incident or unanticipated failure of system elements." *Id.*

[11] The sources or credits for all Figures are listed in Appendix H, "Source of Figures Used in the Report (begins at page 139)."

Figure 1: **January 17, 2018 Event Area – Low Temperature Deviation From the Normal Daily Minimum**



Below-average temperatures began to occur as early as Friday, January 12, from the Great Plains south through the Mississippi Valley. Going into the work week beginning Monday, January 15, MISO, SPP, and the other RCs, which are located within the MRO, SERC, and RF regions,[12] knew that Wednesday, January 17, was likely going to be the coldest day of an extremely cold week for much of their respective footprints. Because their footprints stretch further eastward than SPP's, MISO, TVA and SeRC also expected cold weather conditions for their respective areas on Thursday, January 18, as forecasts showed the cold weather moving eastward. With temperatures forecast by the National Oceanic and Atmospheric Administration to be "much below normal" for January 17, RCs in the Event Area expected very high system loads.

Planned and unplanned generation outages already existed going into the week of January 15, but as the colder weather conditions developed, MISO was projecting extremely tight reserve margins for MISO South in meeting its forecast peak load for the morning of January 17, beginning at 7 a.m. CST. Still, even with a high system load forecast and pre-existing generation outages, MISO did not expect to have a problem

[12] These are among the Regional Entities to which NERC has delegated some of its duties as the Electric Reliability Organization, as part of the statutory scheme which gave rise to mandatory Reliability Standards.

meeting customer demand on January 17 in MISO South, based on anticipated generator availability and precautionary measures that MISO took to increase projected reserves. However, an extraordinary amount of continuing generation outages and derates increasingly tightened already tight reserves, requiring emergency measures. In addition, MISO's five-day, four-day and three-day-out MISO South load forecasts for January 17 were less accurate (underestimating load by approximately 18.9%/6,000 MW, 10.2%/3,250 MW, and 6.1%/1,900 MW, respectively) than the other RCs' forecasts for the same period. Improved forecasting accuracy for future extreme weather conditions could increase MISO's ability to rely on long-lead-time resources and give it more time to prepare for severe weather events. The Team recommends that MISO work with its Local Balancing Authorities and adjacent RCs to improve the accuracy of its near-term load forecasts for MISO South.

In order to meet forecast load plus reserves for the morning peak hour (7 to 8 a.m.) on January 17, MISO instructed its local balancing authorities (LBAs) in MISO South to issue public appeals to reduce demand.[13] MISO estimated the total load reduction achieved from this effort was 700 MW. Some of the Load Modifying Resources (LMR)[14] participating in MISO's load reduction required more notice than MISO was able to provide at the time of this appeal.[15] MISO also needed to purchase emergency energy from suppliers in adjacent RCs to meet its peak load.

The MISO South footprint was severely stressed as the morning peak hour approached. During the peak hour, MISO system analysis showed that if it incurred the worst single contingency generation outage of 1,163 MW in MISO South (hereafter MISO South WSC),[16] it would need to rely on post-contingency manual firm load shed

[13] MISO attributed the need for public appeals to "forced generation outages and higher than forecast load."

[14] Load Modifying Resources are demand resources or behind-the-meter generation.

[15] On January 18, the day after the Event, when MISO was able to provide more notice, it achieved 930 MW of Load Modifying Resources.

[16] In addition to the Most Severe Single Contingency (MSSC) for its entire BA area (for the morning of January 17, 2018, MISO's MSSC was a 1,732 MW facility in the Midwest region of its BA), which MISO is required to cover under the Reliability Standards, MISO planned for sufficient reserves in MISO South to cover its worst single contingency in the MISO South portion of its footprint. It is this latter "worst single contingency" that the report will discuss and refer to as the MISO South WSC.

to maintain voltages within limits and shed additional firm load to maintain system balance and restore reserves for the MISO South region. MISO South's load peaked at 31,852 MW on January 17. At one point on January 17, MISO South had as much as 17,000 MW of generation unavailable, including 13,000 MW of it unplanned.[17]

MISO was not the only RC that lost generation in the Event Area. Going into Wednesday January 17, SPP, TVA RC and SeRC had 8,300 MW, 5,000 MW, and 1,400 MW of generation unavailable, respectively. The entire Event Area had as much as 33,500 MW of total unavailable generation (including planned outages) at one point on January 17, out of approximately 118,000 MW of capacity in the Event Area, and over 30,000 MW unavailable by the start of the morning peak load timeframe.[18]

The majority of the problems experienced by the many generators that experienced outages, derates, or failures to start during the Event were attributable, either directly or indirectly, to the cold weather itself. For the entire Event Area, from January 15 to January 19, Generator Owner/Operators (GO/GOPs) directly attributed 14 percent of the generator failures to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, low temperature cutoff limits, and the like. Another 30 percent were indirectly attributable to the weather, occasioned by natural gas curtailments to gas-fired generators (16%) and mechanical causes known to be related to cold weather (14%).[19] The Team found that total outages from January 15 to 19 increased as temperatures decreased, with correlation coefficients of between -0.5 to -0.7, depending on the city. More than one-third of the GO/GOPs that lost generation during the Event did not have a winterization plan. Given the relationship between the cold and generator outages, the wealth of prior voluntary recommendations for generators to prepare for winter weather,[20] and that 70% of the unplanned outages occurred in gas-fired units, with 16% of those outages were directly attributed to gas supply issues, the Team recommends a three-pronged approach to address generator

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[17] Substantial percentages of the MISO South generation fleet were unavailable in Louisiana (57.1%), Arkansas (23.5%), and Mississippi (16.8%).

[18] See Figure 22, Total Unavailable Generation. Peak non-coincident system loads for January 17 in the four BA footprints combined was 222,924 MW. See Figure 18, January 17, 2018 Peak Loads for Relevant Entities. The peak load figures cover the entire MISO, SPP, TVA and SeRC, footprints, whereas the capacity figure of 118,000 is an estimate of generating capacity just within the Event Area.

[19] All percentages in this and the preceding sentence are based on number of units.

[20] See discussion in Recommendation 1, in Section VIII below.

reliability during extreme cold weather. This approach includes NERC developing one or more mandatory Reliability Standards that require Generator Owner/Operators to prepare for the winter and to provide information regarding their preparations (or lack thereof) to their RCs and Balancing Authorities (BAs), as well as enhanced outreach to the GO/GOPs, and market incentives for those GO/GOPs in organized markets.

In addition to the primary cause of the Event, which was the significant unplanned loss of generators in the Event Area that correlated with the drop in ambient temperatures, several other factors contributed to the BES conditions faced by system operators, including:

- increased customer electricity demand across the Event Area due to extreme low temperatures;
- large power transfers:
    - MISO's Regional Directional Transfer (RDT)[21] from MISO Midwest to MISO South, which exceeded its contractual firm and non-firm limit (Regional Directional Transfer Limit (RDTL)) of 3,000 MW to provide replacement for MISO's generation outages and derates in MISO South; but also
    - remote generation power transfers, including MISO's and SPP's dispatch of wind generation output from distant locations; and
    - transfers between SPP and the ERCOT Interconnection via SPP's High Voltage Direct Current (HVDC) ties.

On January 17, MISO relied on its contractually-available transmission capacity under the RDT to schedule power to flow from generation in MISO Midwest into MISO South, to help cover the record winter electrical demand plus reserves. The RDT flow steadily increased in a north-to-south direction affecting the BES transmission system footprints of MISO, SPP, RC and SeRC, and it exceeded MISO's 3,000 MW RDTL during the early morning hours of January 17, reaching a maximum of 4,331 MW, as measured in real time, around 6:30 am CST. Although MISO exceeded the RDTL, and did not reduce the RDT below the 3,000 MW limit within 30 minutes as contemplated by the settlement agreement, MISO operators communicated with adjacent RCs (which are parties to the settlement agreement that established the RDT) that MISO would be exceeding the limit, and that if MISO's RDT flows caused a system emergency for the adjacent RCs, MISO would take appropriate actions. While the adjacent RCs did not determine that their systems were in an emergency state during the Event, they were made aware of the continuing generation outages and derates in MISO South, of MISO's

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[21] See section II.B and Figure 32 for background on MISO's RDT.

Energy Emergency declaration, and of MISO's likely need to perform firm load shed if its next-worst contingency occurred.

Before the morning of January 17, none of the RCs had anticipated the multiple-wide-area[22] constrained transmission conditions that simultaneously occurred in the SPP, TVA, SeRC, and MISO South RC footprints. The Team recommends seasonal studies that consider more-severe conditions, modeling same-direction simultaneous transfers and other stressed but realistic conditions, and sharing the results with operations staff to aid in planning for more extreme days like January 17. These widespread constrained conditions caused reserves to be stranded from MISO South.[23] The Team also recommends that RCs consider deliverability of reserves, and that MISO notify the other RCs when it is counting on the as-available, non-firm portion of the RDT to meet its reserves for MISO South, so that the RCs can timely communicate if conditions on the other RCs' systems are projected to limit MISO's ability to rely on the RDT.

The RCs also did not expect the numerous mitigation measures they would need to take to maintain BES reliability on January 17, including Transmission Loading Relief, transmission reconfiguration, and the need to be prepared to shed firm load in the event of an outage of the MISO South WSC of 1,163 MW. Had this outage occurred, during the morning peak hour on January 17, MISO would have likely had to order firm load shed in MISO South for two reasons. First, MISO would not have had sufficient deliverable reserves to cover its MISO South region peak load, and second, it concurrently would have likely needed to shed firm load to alleviate low voltages at many locations that were calculated to be significantly below their limits. Normally, voltage stability is a greater risk during summer than winter, however, there can be an increased risk of voltage stability under extreme cold winter weather conditions, heavy imports, and facility outage conditions.[24] Although the system remained stable on

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[22] The "wide area" each RC is responsible for includes its "entire RC Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits." (See NERC Glossary of Terms). The January 17 event involved critical flows experienced concurrently in four RC areas.

[23] By "stranded," the Team means reserves that cannot be delivered due to transmission constraints which cannot be alleviated.

[24] It has been studied that under high loads and heavy imports in a different winter-peaking area of the U.S., credible single and multiple contingencies could result in widespread post-contingency steady state voltage instability. The entity has identified these conditions as an Interconnection Reliability Operating Limit (IROL). In this

January 17, the Team recommends that MISO and other RCs perform voltage stability analysis when under similarly constrained conditions, benchmark planning and operations models against actual events which strained the system, perform periodic impact studies to identify which elements in the adjacent RCs' systems have the most impact on their own systems, and perform drills with entities involved in load shedding to prepare to execute load-shedding for maintaining reserves while at the same time alleviating severe transmission conditions.

Actions by operators to address real-time issues were effective and timely. The RC operators for SPP, MISO, TVA, and SeRC had situational awareness, communicating and coordinating their analyses and discussing mitigation actions necessary to maintain BES reliability, up to shedding firm load. RC operators also communicated as necessary with the Transmission Operators to verify that System Operating Limits (SOLs) took into account the extreme cold temperatures. Because some SOLs which operated as constraints on January 17 were based on summer temperatures or on static, year-round ratings, the Team recommends that SOLs and their associated equipment ratings be based on, at a minimum, ambient temperature conditions that would be expected during high summer load and high winter load conditions, respectively.

System conditions began to gradually improve after the morning peak ended at 8 a.m. CST and as the cold weather moved out of the Event Area. Warmer temperatures resulted in some generators returning to service, and decreased system loads. While MISO still sought emergency power for the evening peak on January 17, wide-area BES conditions were not as constrained as they were approaching the morning peak.

The affected RCs performed a post-Event analysis. Among the areas they identified for improvement was the joint Regional Transfer Operations Procedure (RTOP) used to govern MISO's use of the RDT, which was in effect at the time of the Event. The improvements they made to the RTOP, along with the Team's additional recommendations to add specificity and clarity during emergency situations, underscore the need for clear operating procedures for the system operators, to address similar multiple-wide-area constrained transmission conditions. The Team's recommended changes to the RTOP would clarify roles and timing, require affected entities to declare an emergency before MISO sheds firm load to reduce the RDT, and implement studies to

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instance, voltage stability analysis (VSA) is conducted daily for the next operating day to determine if the limit can be increased or decreased depending on system conditions (i.e., load, power flows, internal generation in the area, outages, etc.). The IROL is also monitored in real time using VSA to perform real-time calculations for the IROL limit based on real-time conditions.

be performed before temporarily changing the RDTL or making emergency energy purchases.

In addition to the Team's recommendations, the report discusses sound practices followed by the entities involved in the Event, and reaffirms recommendations from the 2011 Report.[25]

II. Background

A. Affected System Overview

The Event Area is located within the Eastern Interconnection (which stretches from the East Coast to the Rocky Mountains, omitting the majority of Texas), and from eastern Canada to the Gulf Coast. Of the 15 NERC-approved RCs in North America which are responsible for having the wide-area view to oversee grid reliability, four were responsible for the reliable operations of the BES in the Event Area: MISO, SPP, TVA and SeRC.

The extra-high voltage (EHV) (345 kilovolts (kV) and above) portion of the Event Area comprises 500 kV transmission facilities spanning Arkansas, western Tennessee, Mississippi, Louisiana and Alabama. These 500 kV facilities are connected to the north and west within the Event Area via transformers to 345 kV transmission facilities located in lower Missouri and Kansas, and which run through Oklahoma and along the eastern border of Texas. There are two asynchronous HVDC connections between these 345 kV transmission facilities and ERCOT (to the west, in Texas), which operates as a functionally separate interconnection. These two HVDC ties to ERCOT (the North DC Intertie, and the East DC Intertie) allow power exchanges with the Eastern Interconnection through SPP. SPP also has several DC ties with the Western Interconnection. Other high-voltage BES transmission facilities within the Event Area include 230 kV, 161 kV, 138 kV and 115 kV facilities.

[25] See Appendix G, "2011 Recommendations on Preparation for Cold-Weather Events."

January 27, 2020

Rebuttal Testimony of Alabama Power Company

Docket No. 32953

Volume 1

1. John B. Kelley (and rebuttal exhibit JBK-1)

2. Kevin D. Carden (and rebuttal exhibits KDC-1 – KDC-12)

Volume 2

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

2. Maria J. Burke (and rebuttal exhibits MJB -1 – MJB-5)

3. Michael A. Bush (and rebuttal exhibits MAB-1 – MAB-4)

4. M. Brandon Looney (and rebuttal exhibits MBL-1 – MBL-2)

5. Christine M. Baker (and rebuttal exhibit CMB-1)

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.

<u>RELIABILITY AND SEASONAL PLANNING</u>

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.

[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.

[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]

COLD WEATHER OUTAGES

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

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[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

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[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.

[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 Bradenburg

Notary Public

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

8350759.1

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

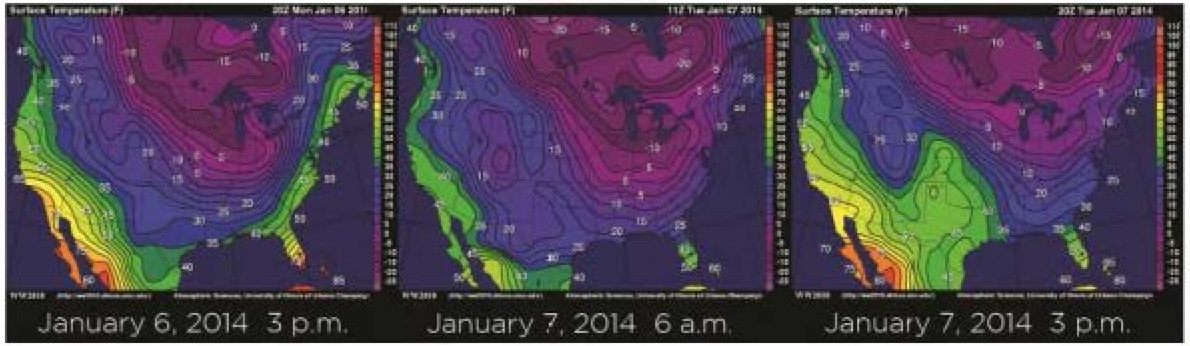
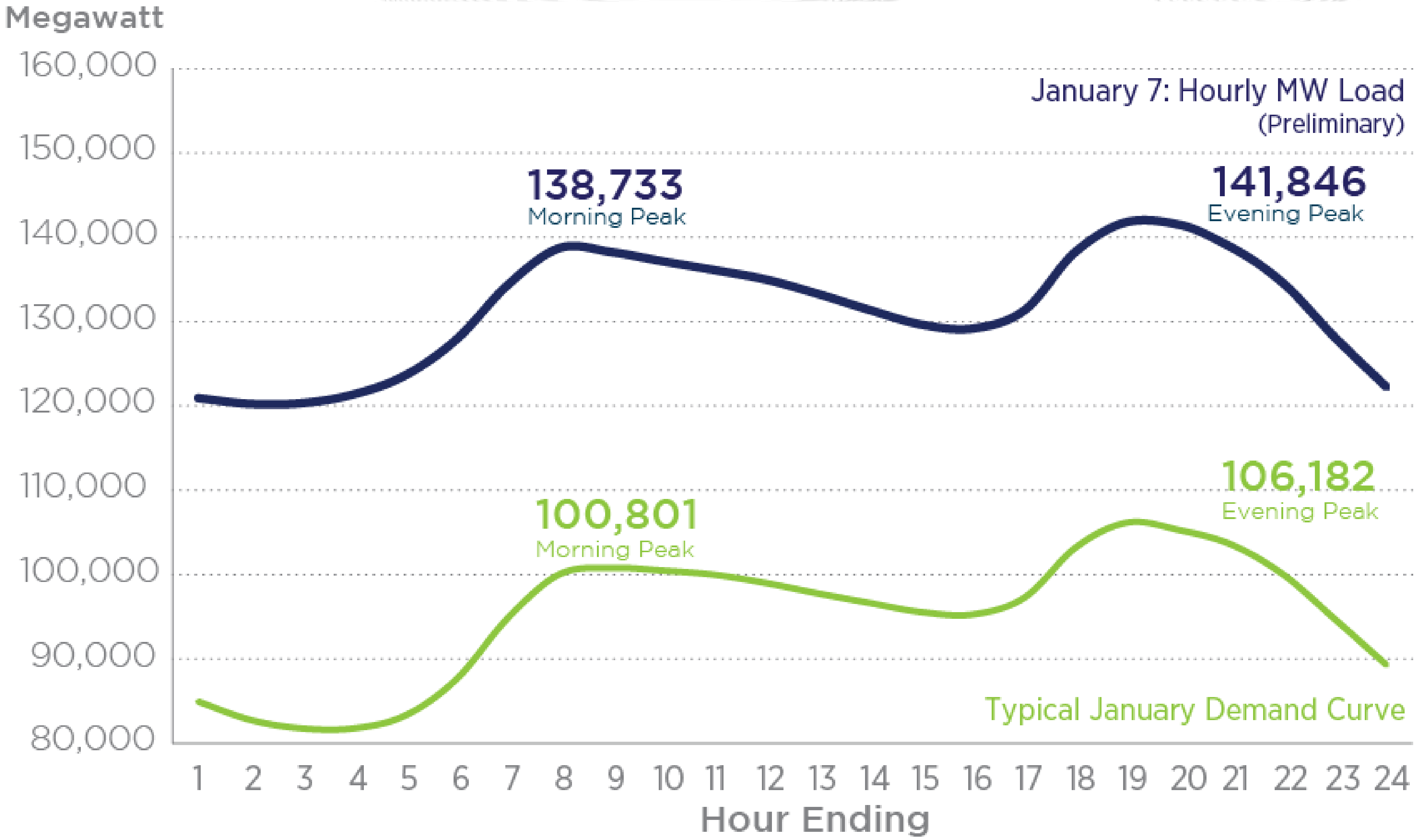
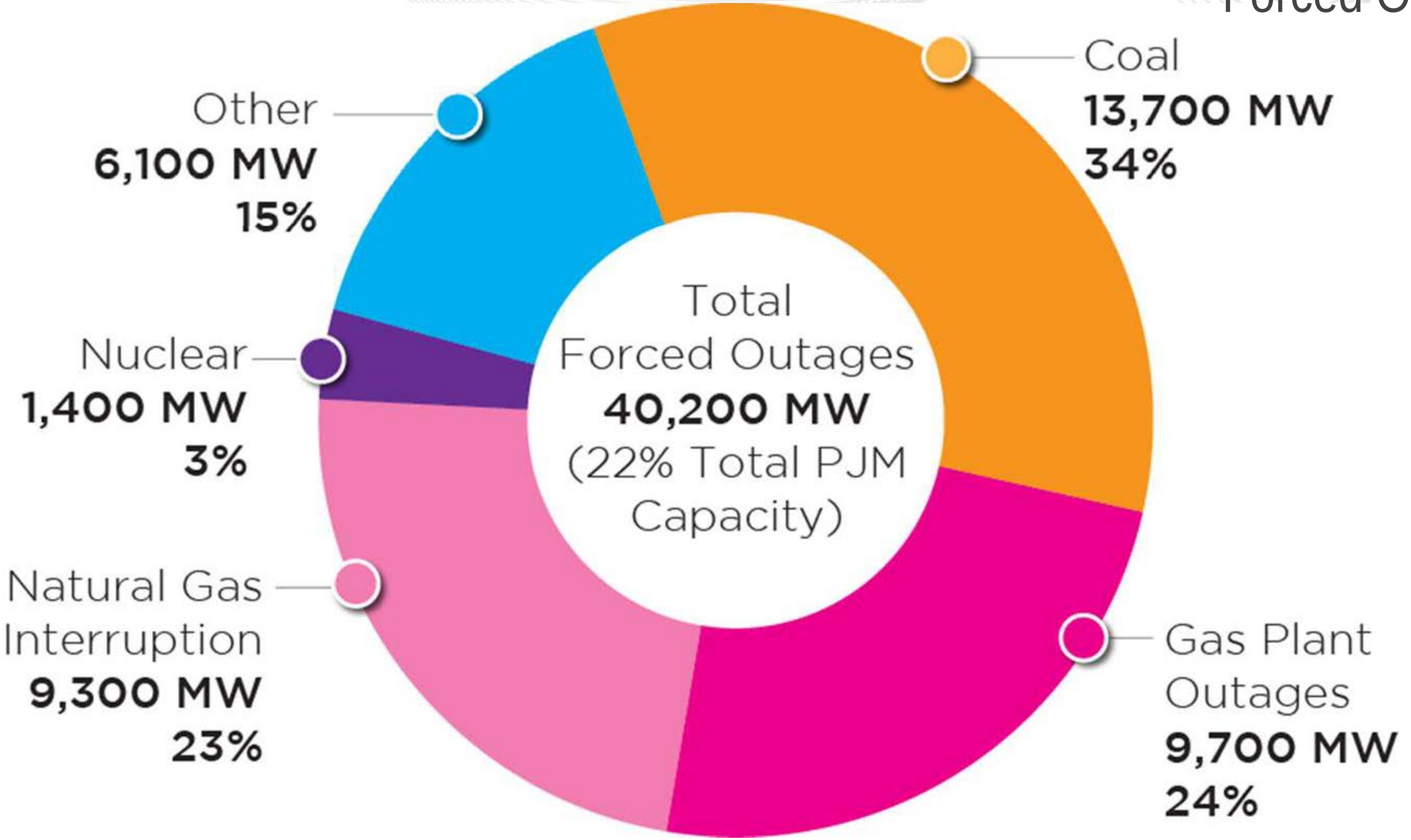


Figure 2: January 2014 Minimum Temperatures: Columbus, Philadelphia, Chicago and Richmond

January 7 – Peak Load vs. Typical Load

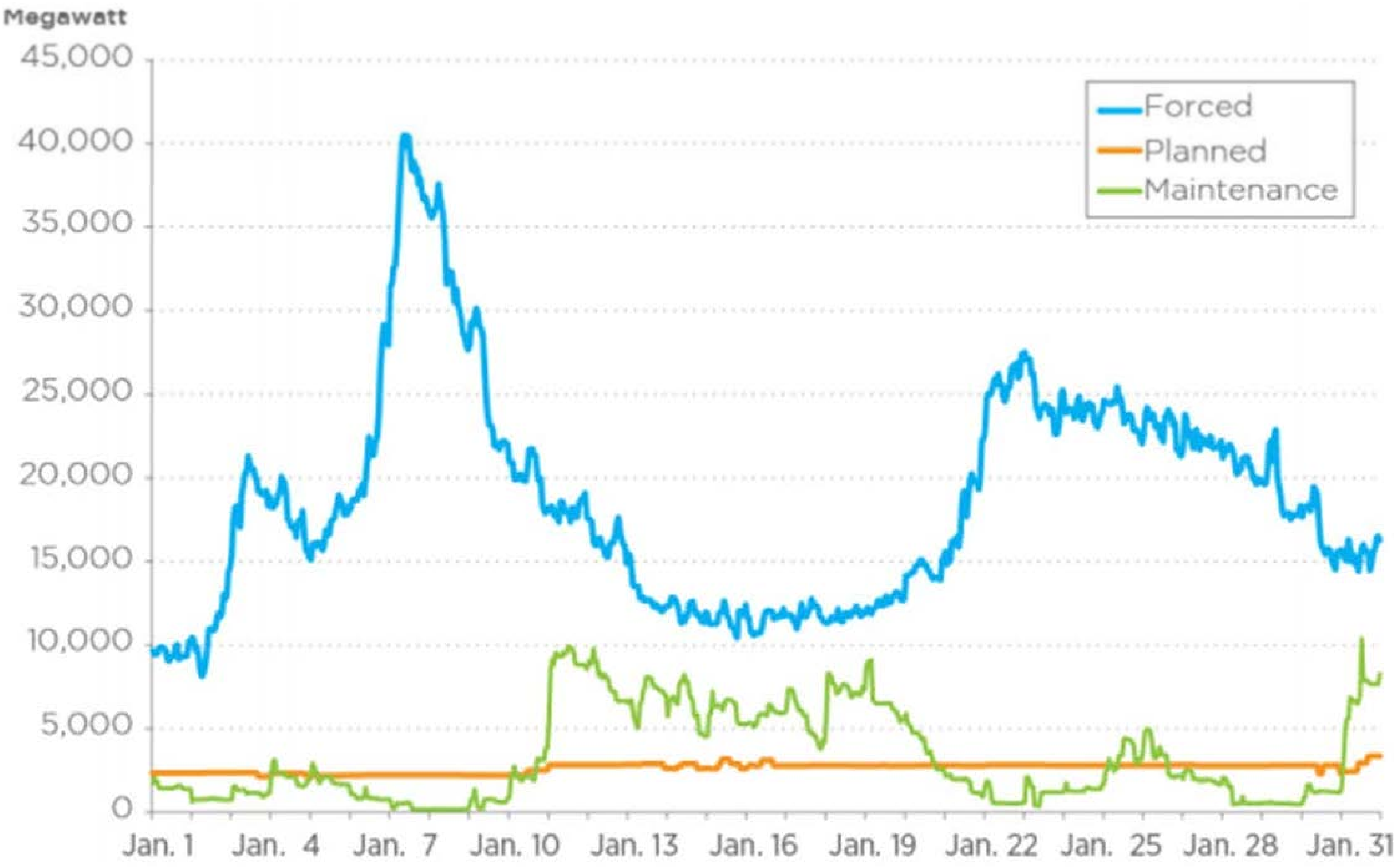


Jan. 7 Evening Peak, 7:00 p.m. Forced Outages



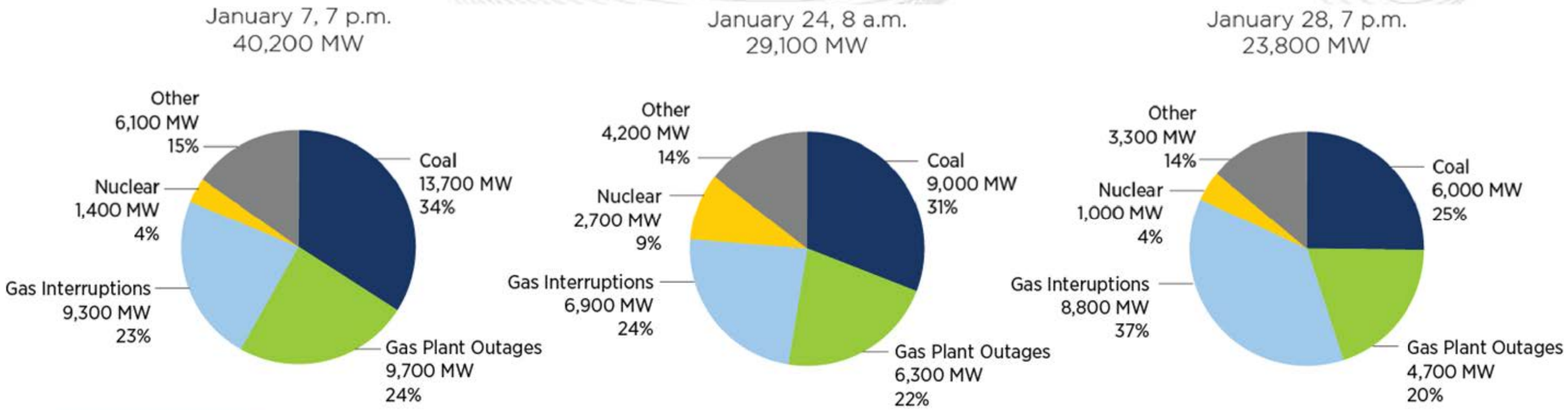
Increased Generation Outage Rates

Figure 4: Generator Outages – January 2014



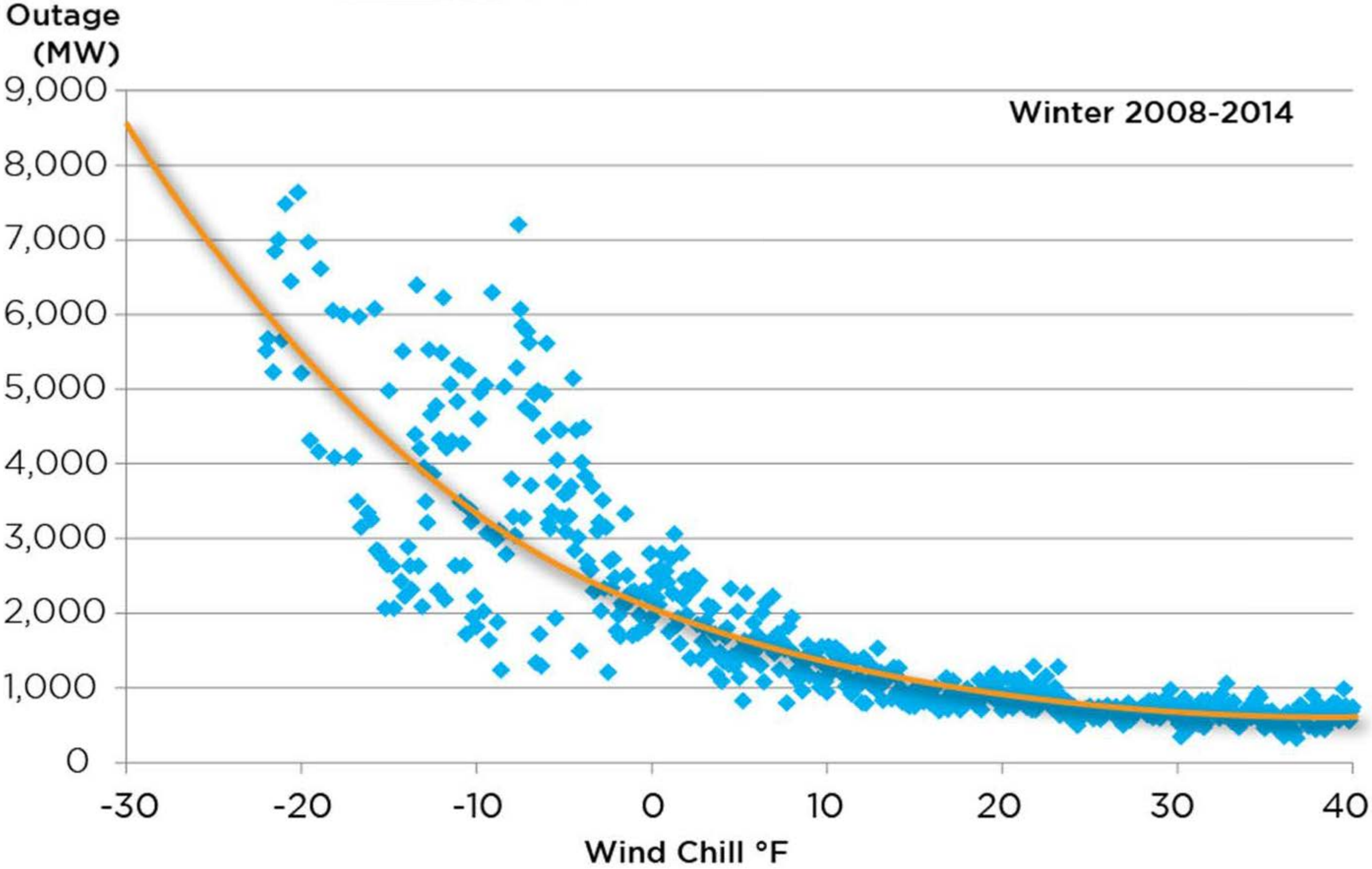
Increased Generation Outage Rates

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

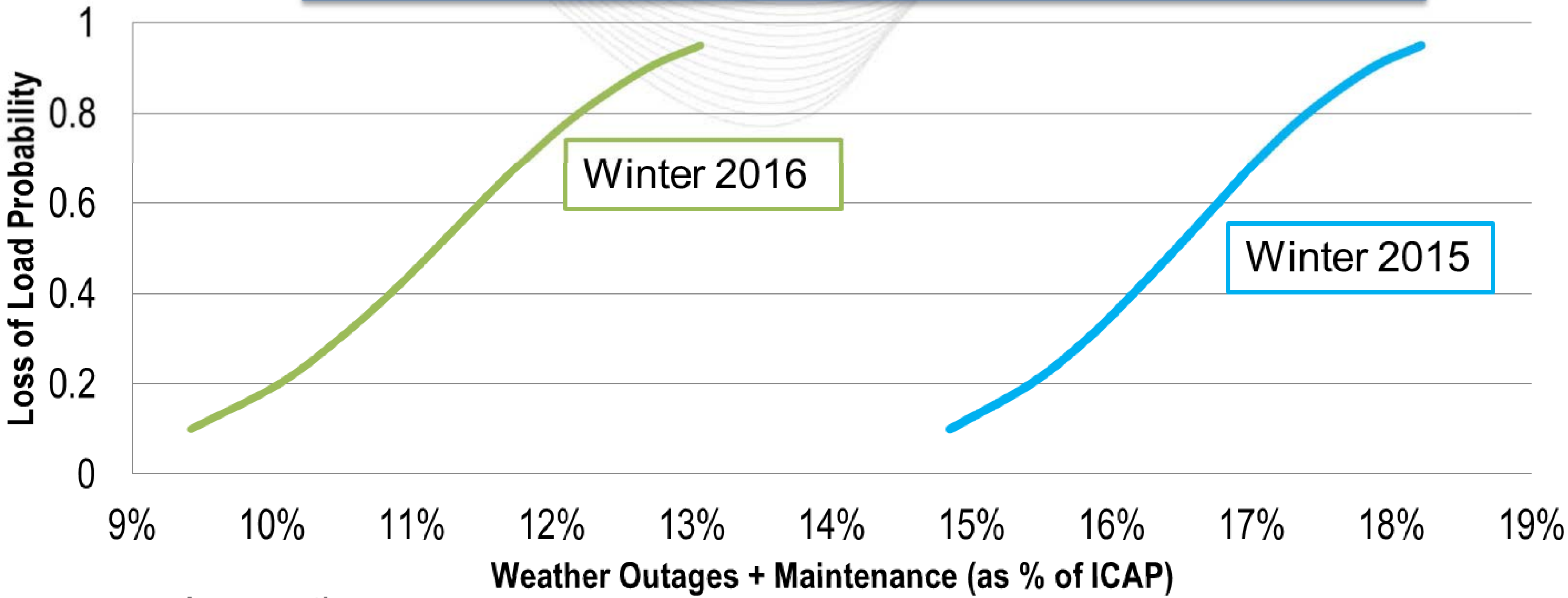
Wind Chill vs. Forced Outage – Western PJM



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

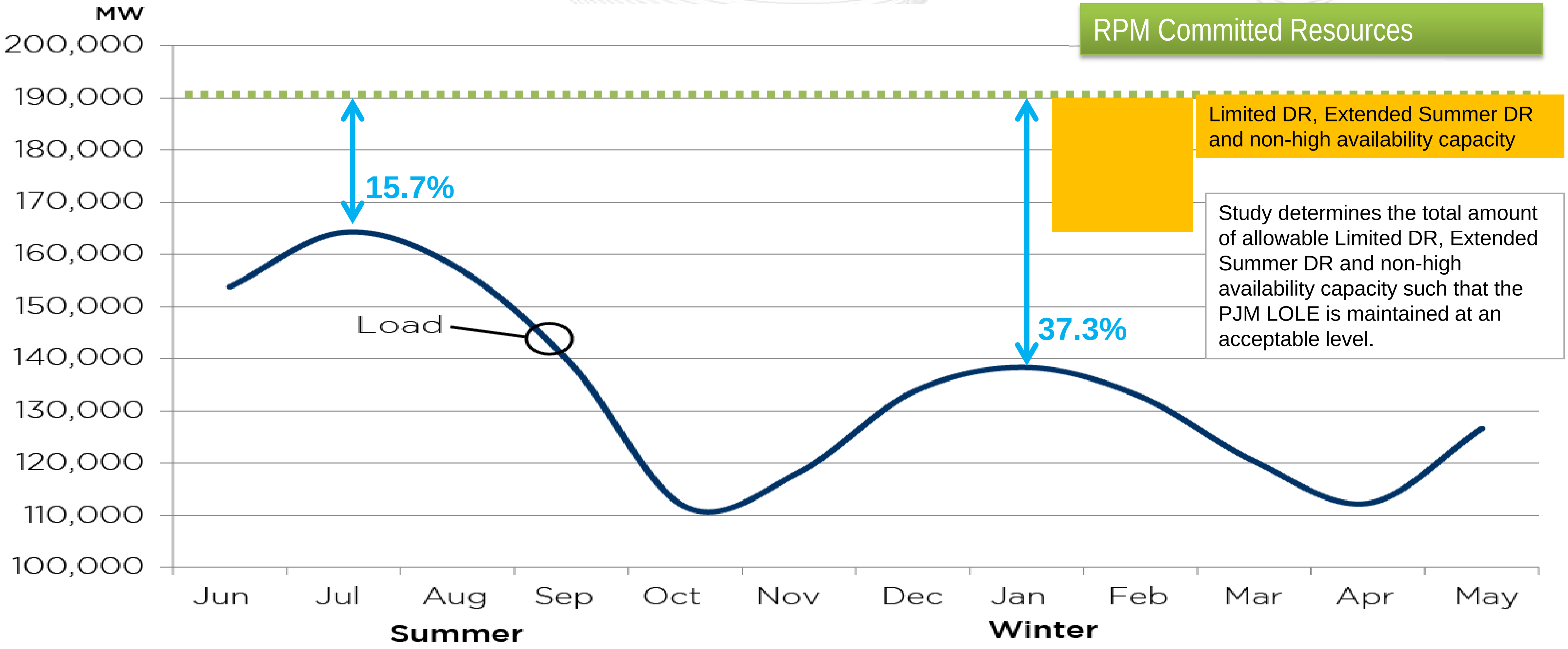
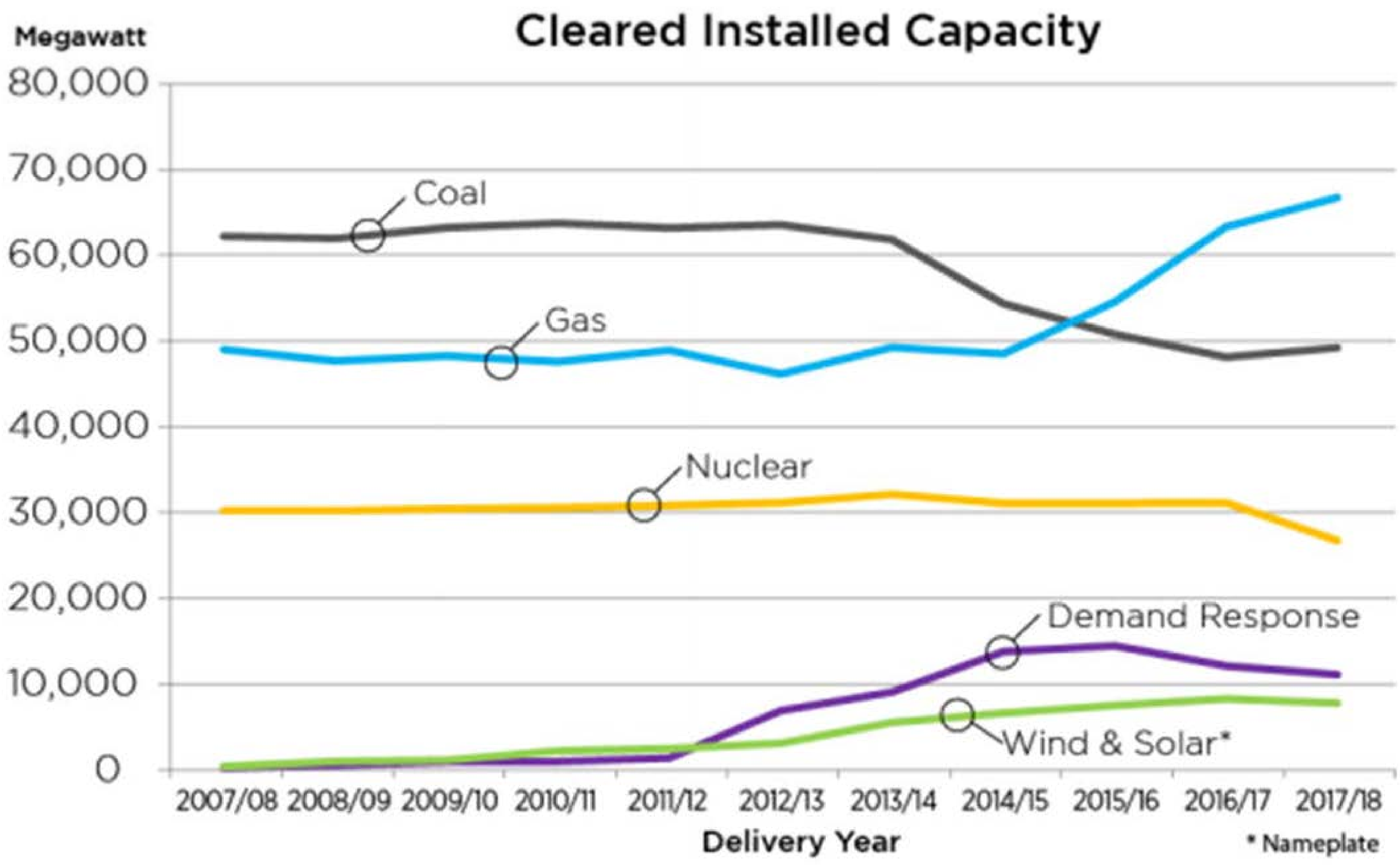
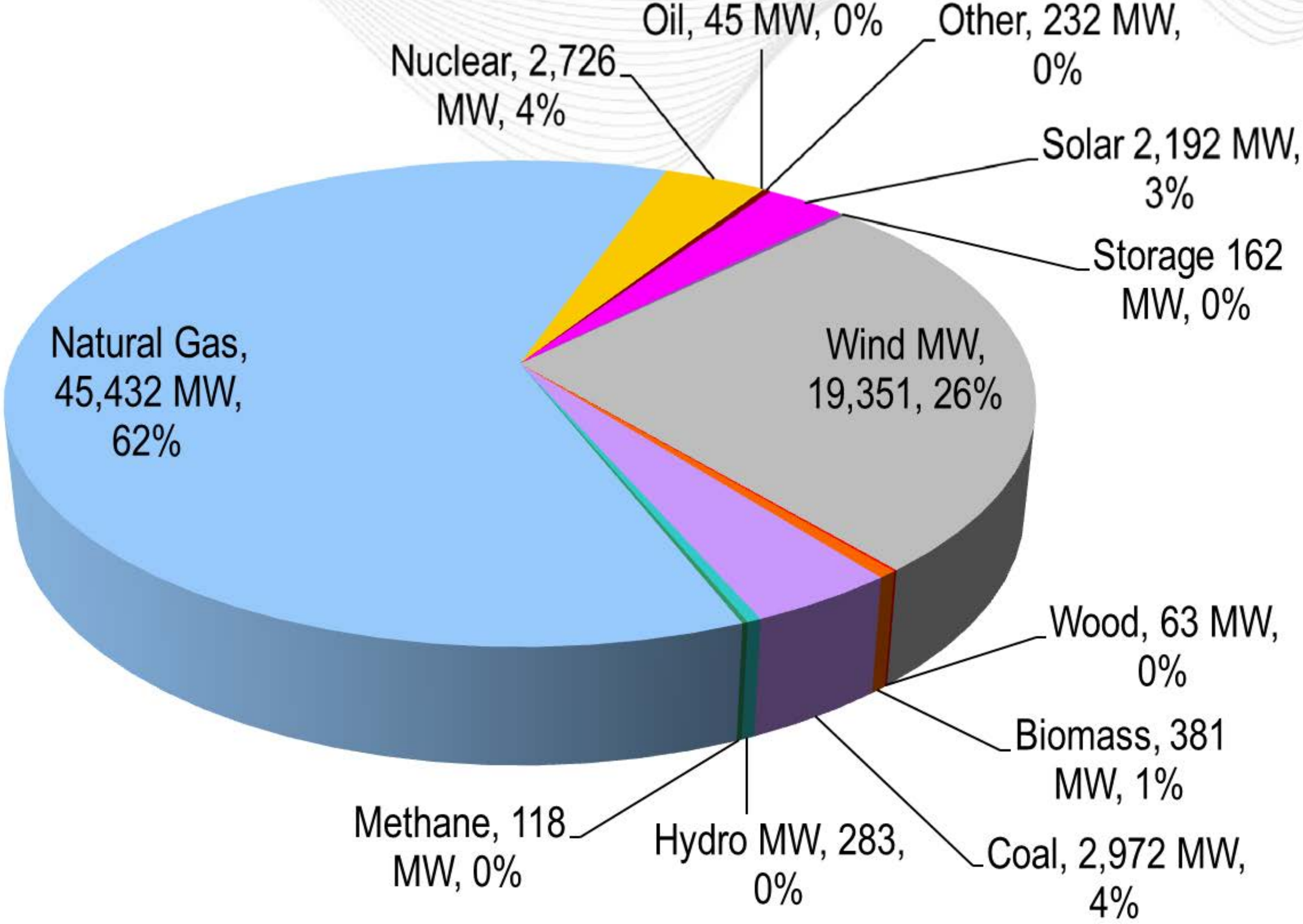


Figure 10: Cleared Installed Capacity



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

Natural Gas and Electricity Markets Issues

- 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

Other Cold Weather Initiatives

- 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.

AQs

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

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

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

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

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

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

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

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

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

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

[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.

[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

[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.

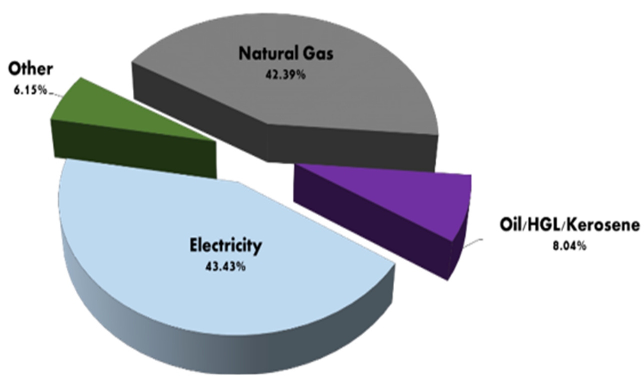
[20] *Id.*, page 8, lines 18-20. *See also id.*, page 4, lines 9-17 & page 15, lines 20-21.

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.

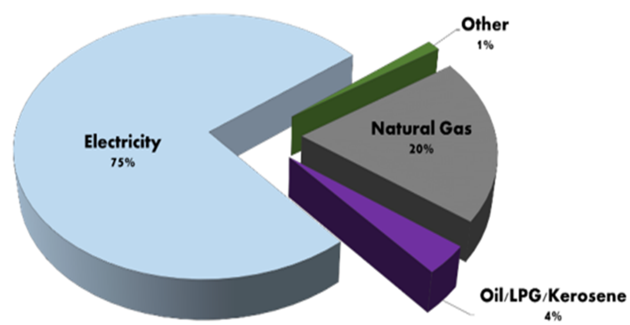
Q. CAN YOU DESCRIBE THE TYPICAL ENERGY CONSUMPTION PRACTICES OF ALABAMA RESIDENTS?

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



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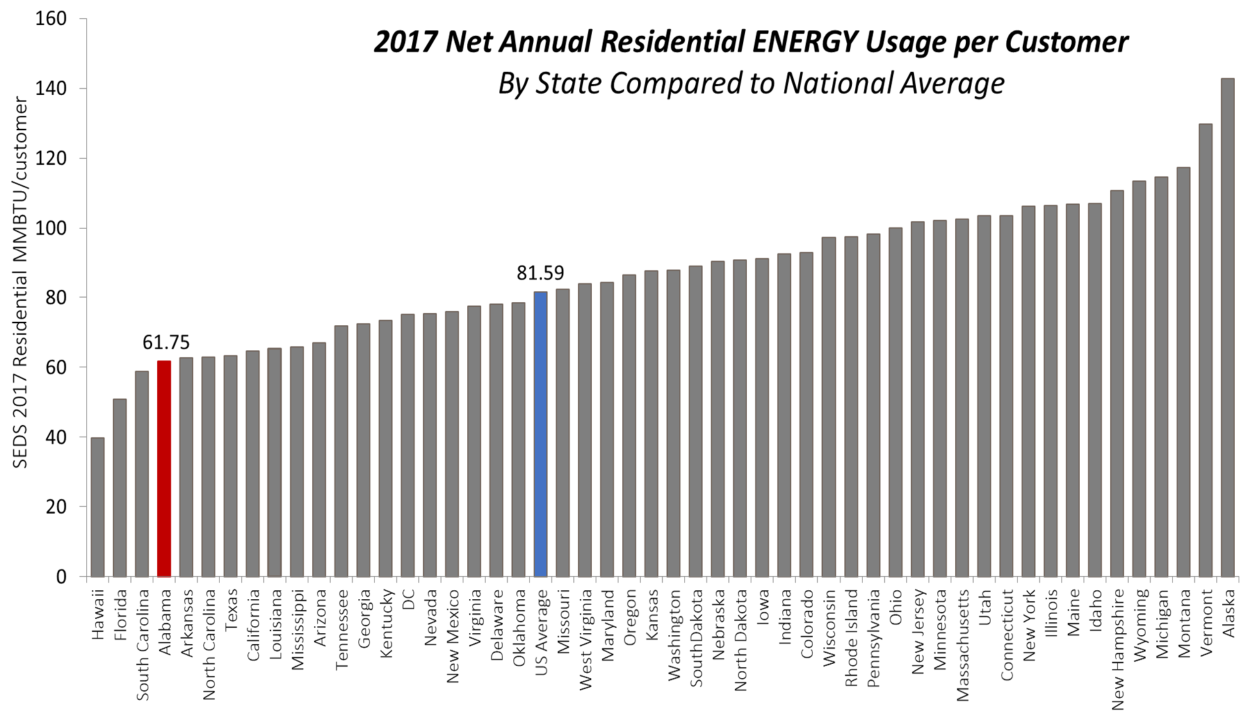
[21] *See* U.S. Energy Info. Admin., *Residential Sector Energy Consumption Estimates, 2017*, https://www.eia.gov/state/seds/sep_sum/html/sum_btu_res.html (attached as Reb. Ex. MJB-5).

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

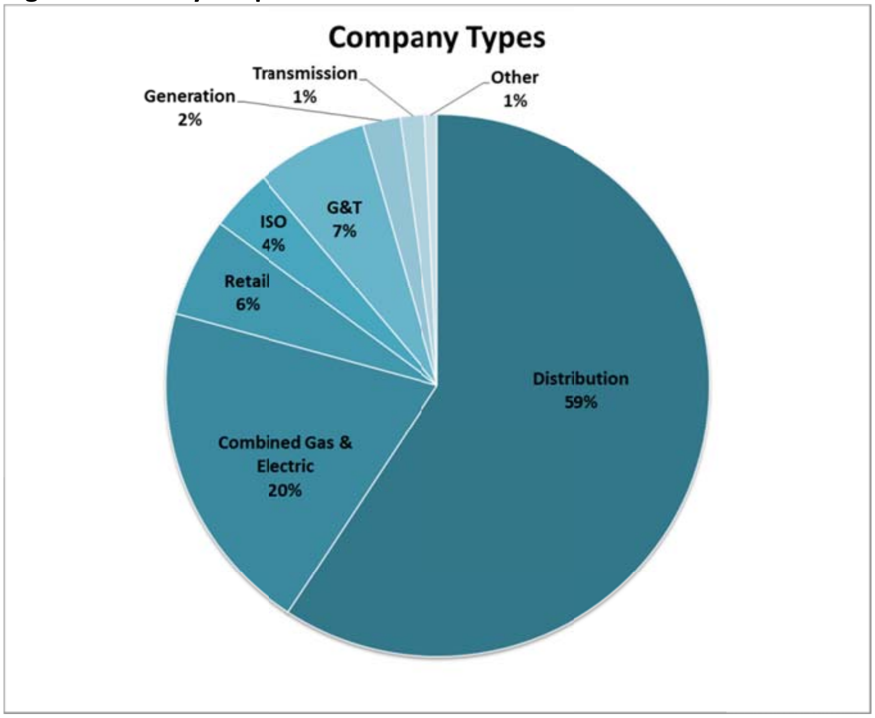


Figure 2: Survey Respondents by Size and Classification

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.

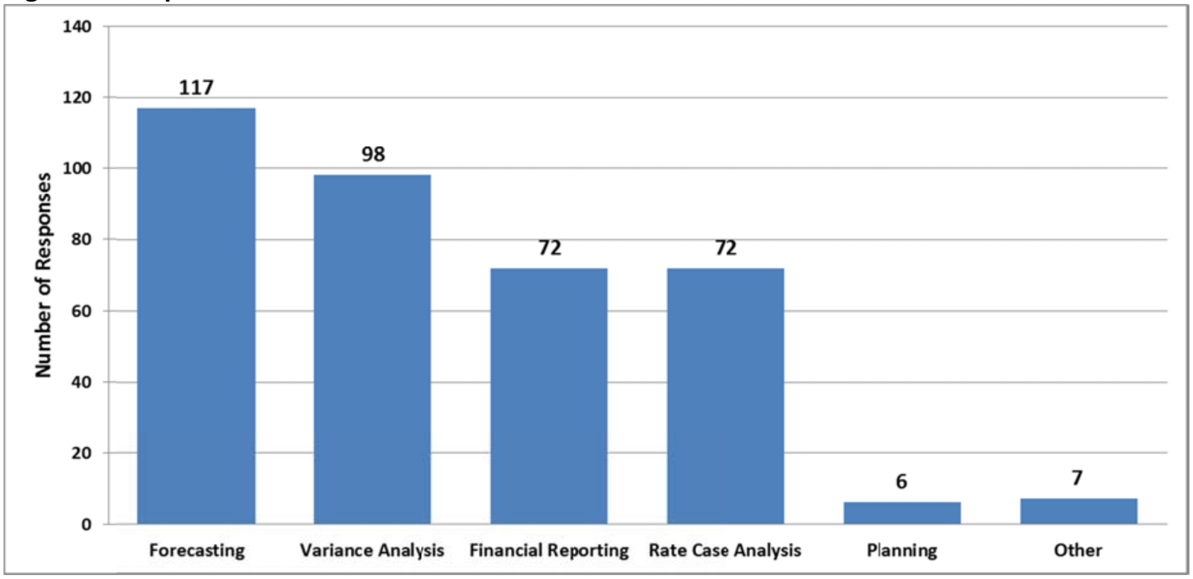
- **Distribution**. Distribution companies include both gas and electric companies that deliver service to an end-use customer. While these companies may include transmission and generation components, these components are not necessary for including a company into this category. Within this category, 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

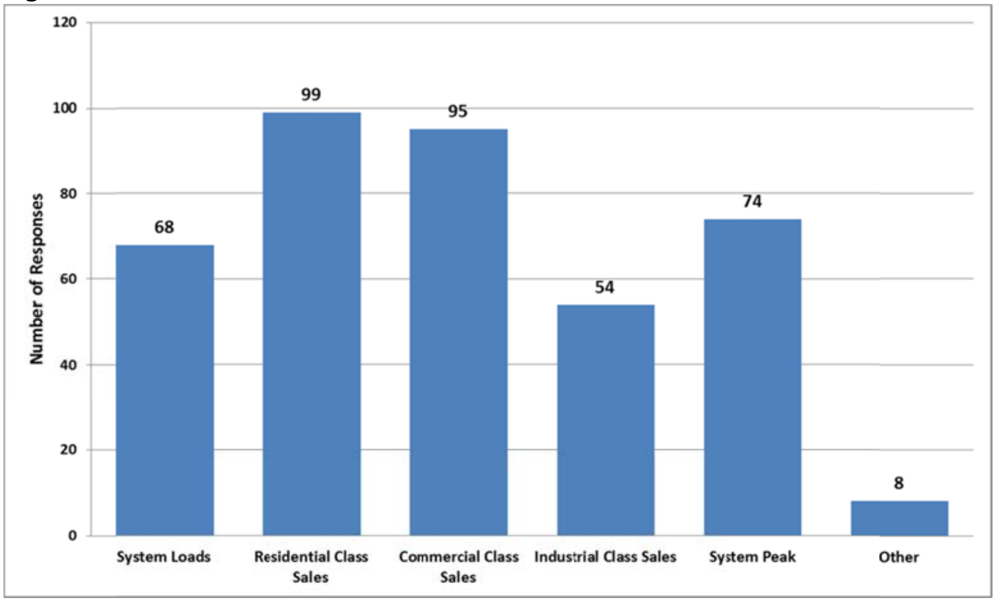
Questions 9 through 22

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.

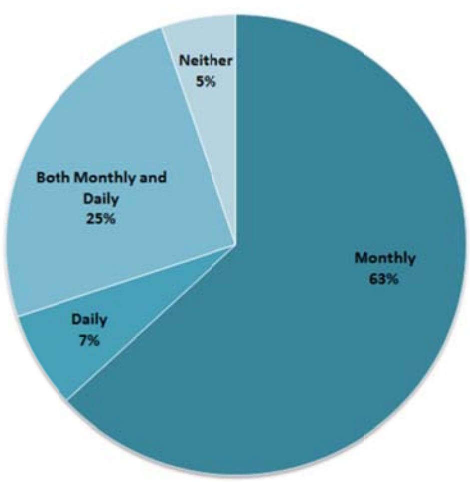
Figure 4: Weather Normalization Classes



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.

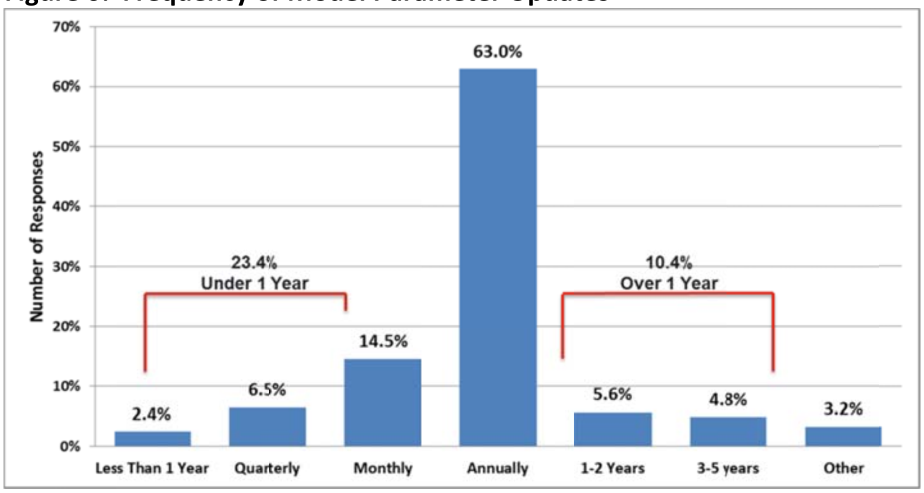
Figure 5: Data Frequency of the Model



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

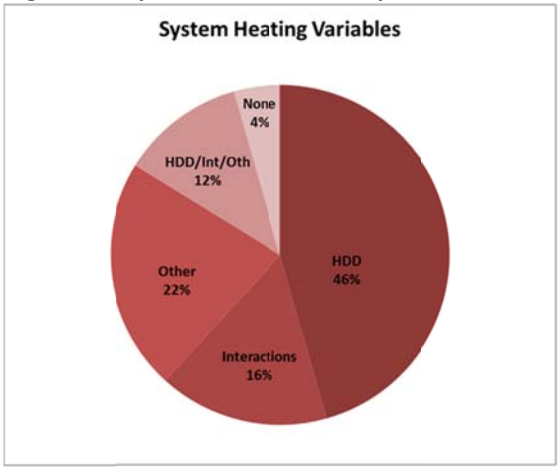
Cooling Variable Category	Description
CDD	Model includes cooling degree day (CDD) and/or CDD spline variables. No other weather variables are used.
Interactions	Model interacts CDD or CDD splines with another variable. Model may include CDD or CDD spline variables separately.
Other	Model includes additional 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.

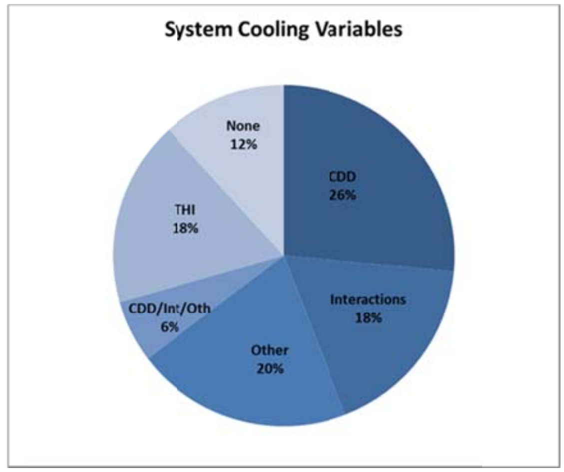
System Model Description

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

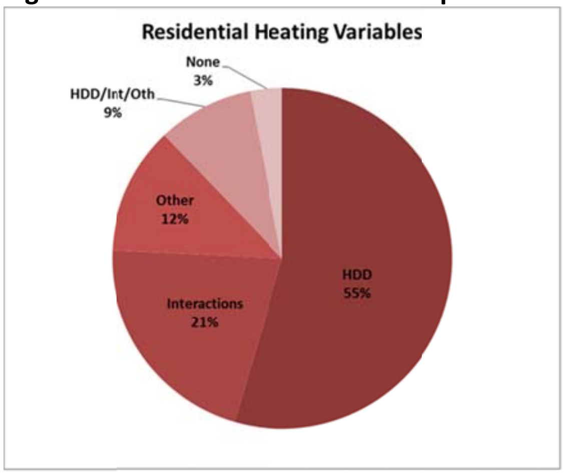
Heating Interactions	Cooling Interactions
Daytypes (9) End Use Trend (2) Economic Trend (1) Lag Temperatures (1) Deviations from Normal (1) Peak Temperature (1)	Daytypes (11) End Use Trend (3) Economic Trend (1) Hours of Light (1) Peak Temperature (1)

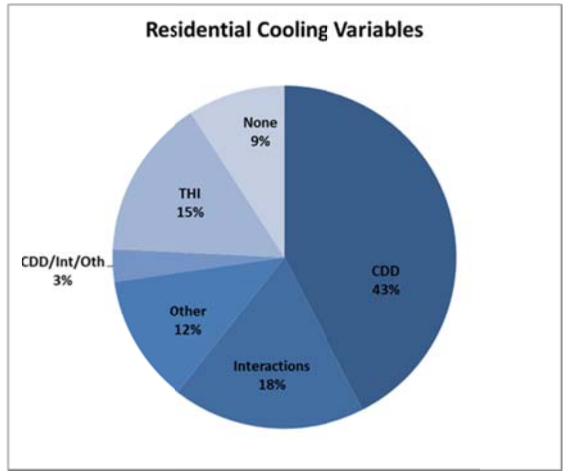
Residential Model Description

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

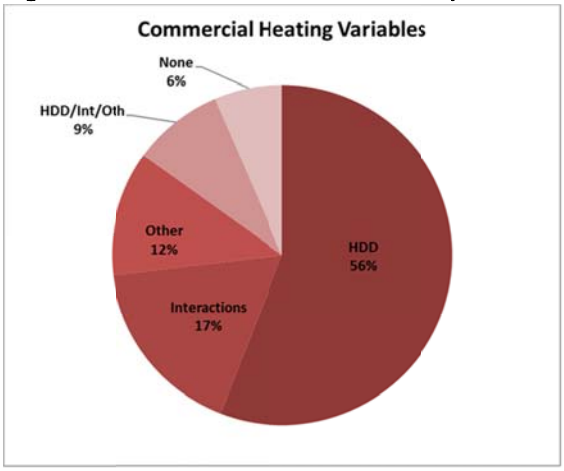
Heating Interactions	Cooling Interactions
Daytypes (12)	Daytypes (14)
End Use Trend (6)	End Use Trend (4)
Economic Trend (2)	Economic Trend (3)
Customer Counts (2)	Daylight Hours (1)
Daylight Hours (1)	Customer Counts (1)

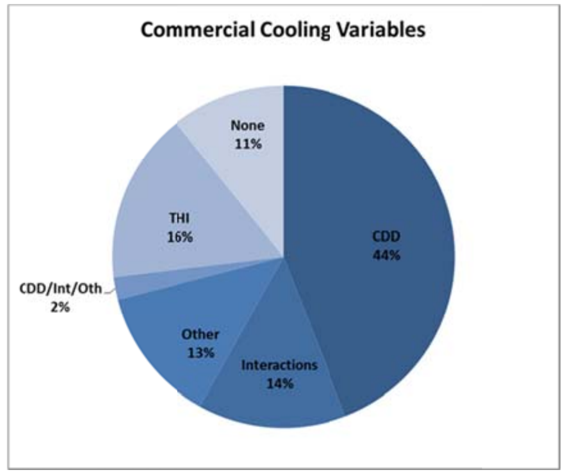
Commercial Model Description

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

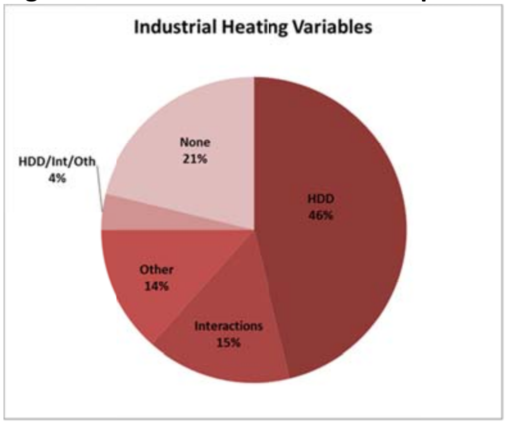
Heating Interactions	Cooling Interactions
Daytypes (11)	Daytypes (12)
Economic Trend (2)	Economic Trend (2)
End Use Trend (1)	Customer Counts (2)
Customer Counts (1)	End Use Trend (1)
Daylight Hours (1)	Day Light Hours (1)

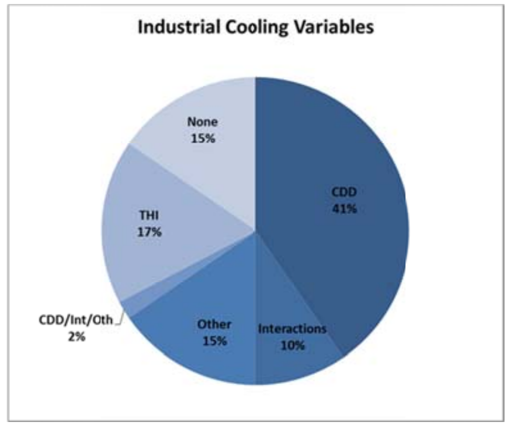
Industrial Model Description

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)

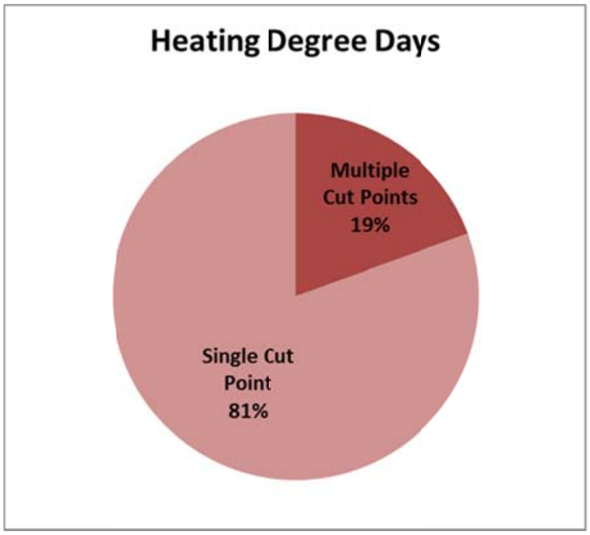
Figure 20: Industrial Interactive Variables

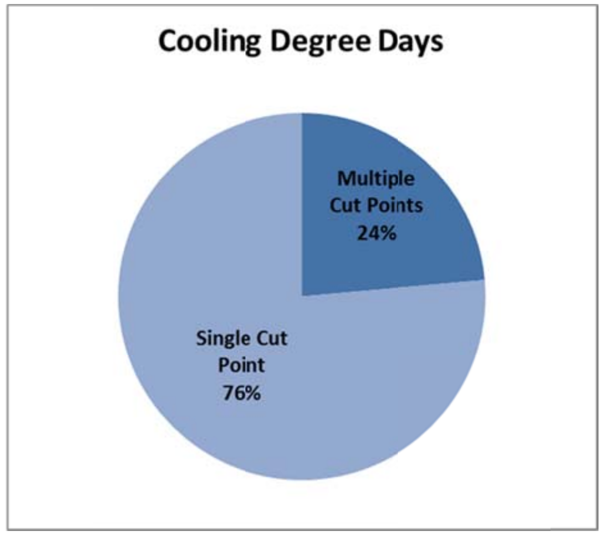
Heating Interactions	Cooling Interactions
Daytypes (4) Economic Trend (1)	Daytypes (4) Economic Trend (1)

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

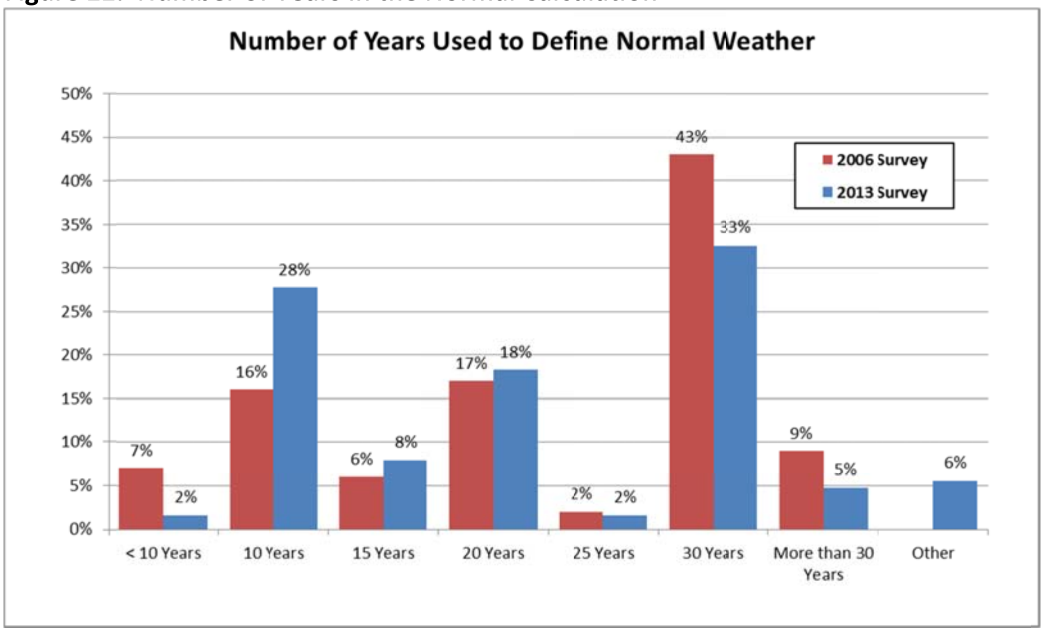
Questions 23 through 30

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

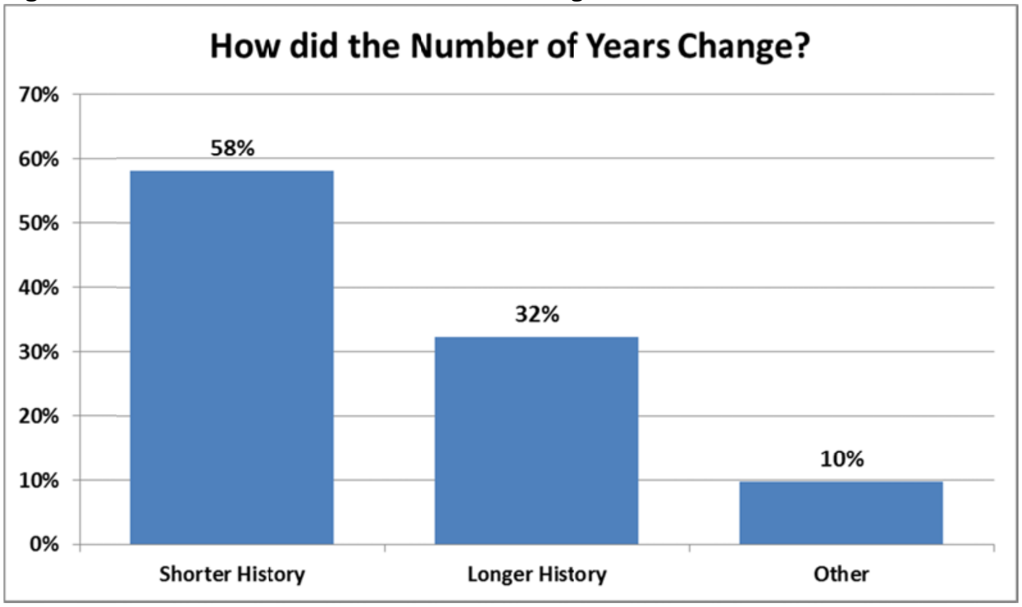
Changing the number of years used in the normal weather calculation has been a common technique for handling climate change. In 2006, 25% of survey respondents indicated that they had changed the number of years recently. In 2013, the same question was asked with 32% indicating a recent change. These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

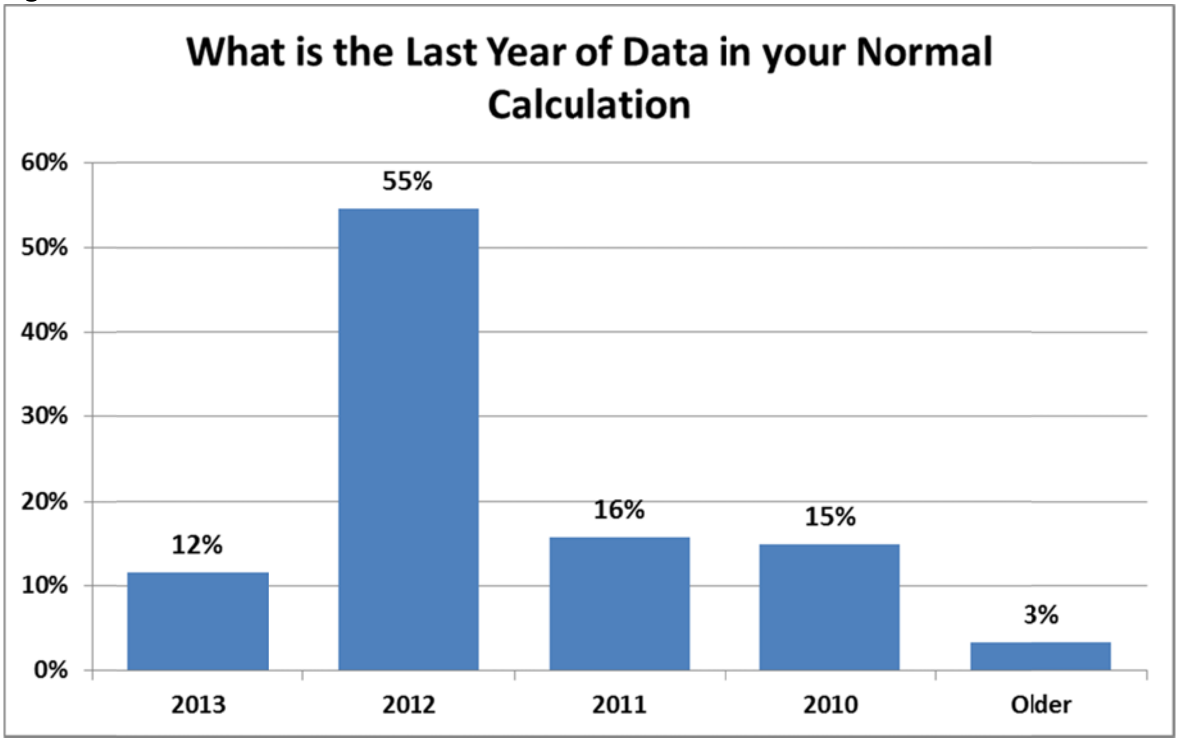
Each year, the availability of new weather data creates the opportunity to recalculate normal weather. Figure 25 shows that 81% of respondents update their normal weather each year compared to 69% from the 2006 Survey.

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

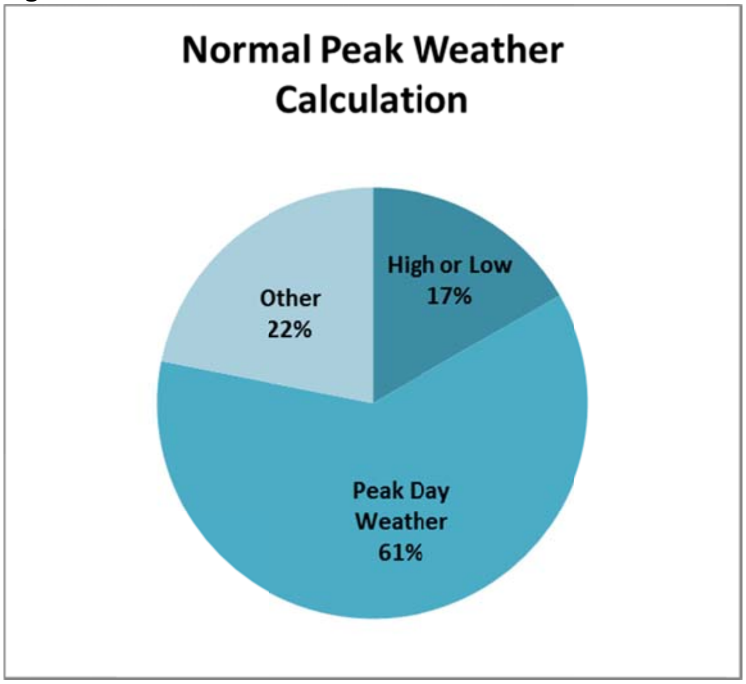
Normal peak weather is used to normalize peak weather events. Two types of normal calculations are typically used in the normal peak weather calculation. These calculations are defined below.

- **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

Rebuttal Testimony for Michael A. Bush

Reb. Ex. MAB-1

Reb. Ex. MAB-1

FPL Okeechobee Clean Energy Center
Fact Sheet

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.

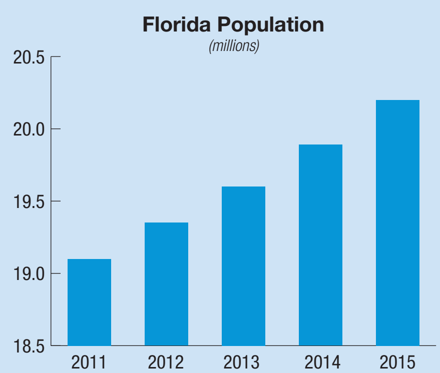
Why more power is needed

There are several reasons why additional power is needed:

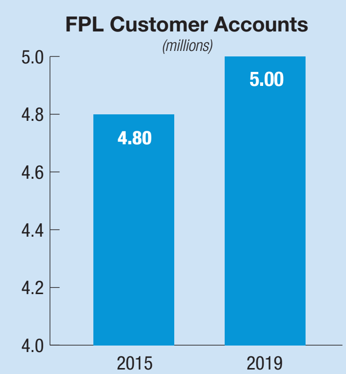
- **Growing population** – FPL serves approximately 4.9 million customer accounts in the state, a number expected to increase by 2019 to 5 million accounts serving approximately 10 million people. Florida's population is now the third largest in the nation, adding more than 300,000 people annually in 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.

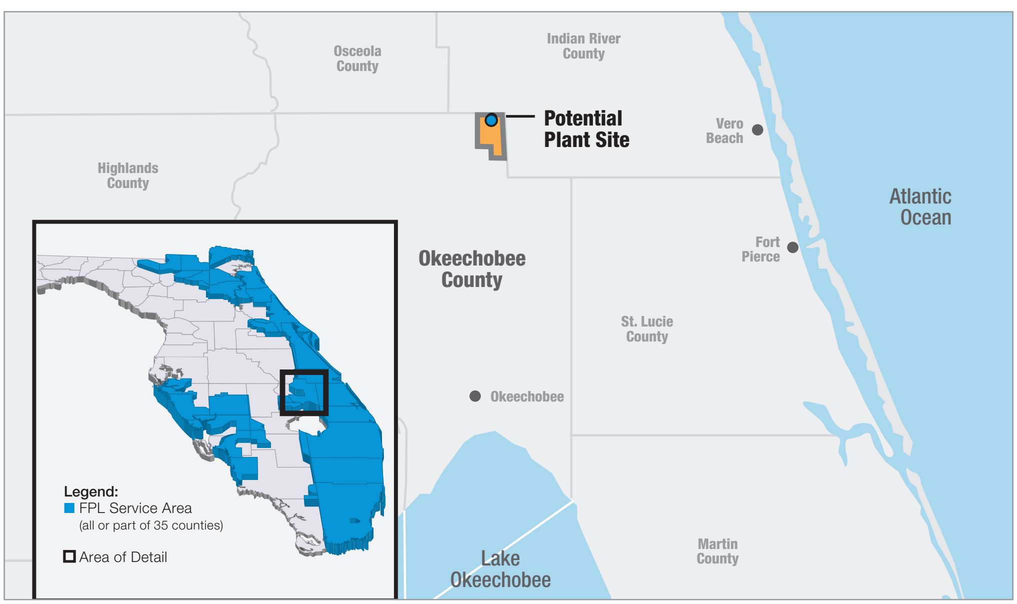
A comprehensive review and licensing process, which was completed in 2016, involved the Florida Public Service Commission, Florida Department of Environmental Protection and numerous other state, county, regional and federal agencies.

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

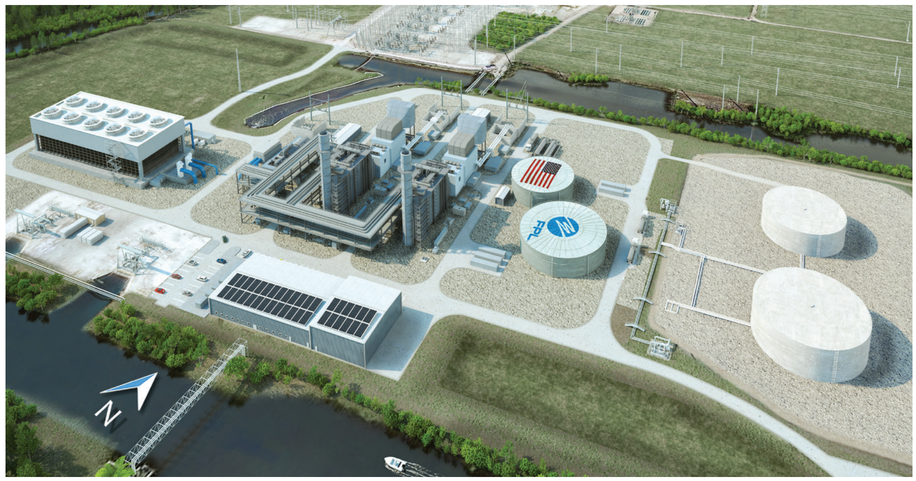
Modernizing FPL's power generation facility in Dania Beach

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.

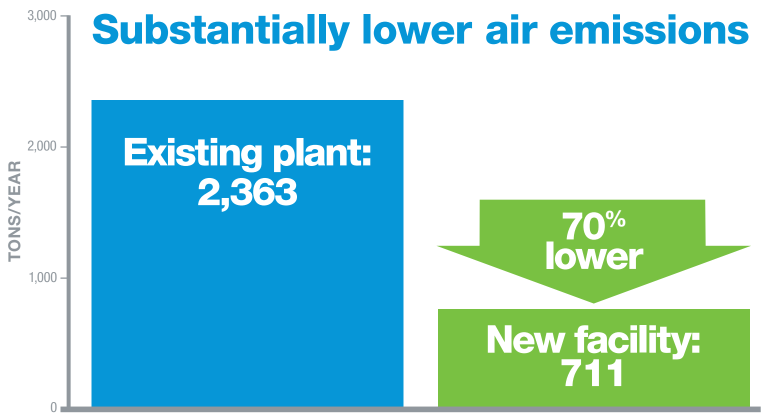
$13.47 million
Future plant
First-year tax (2023)

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

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

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."

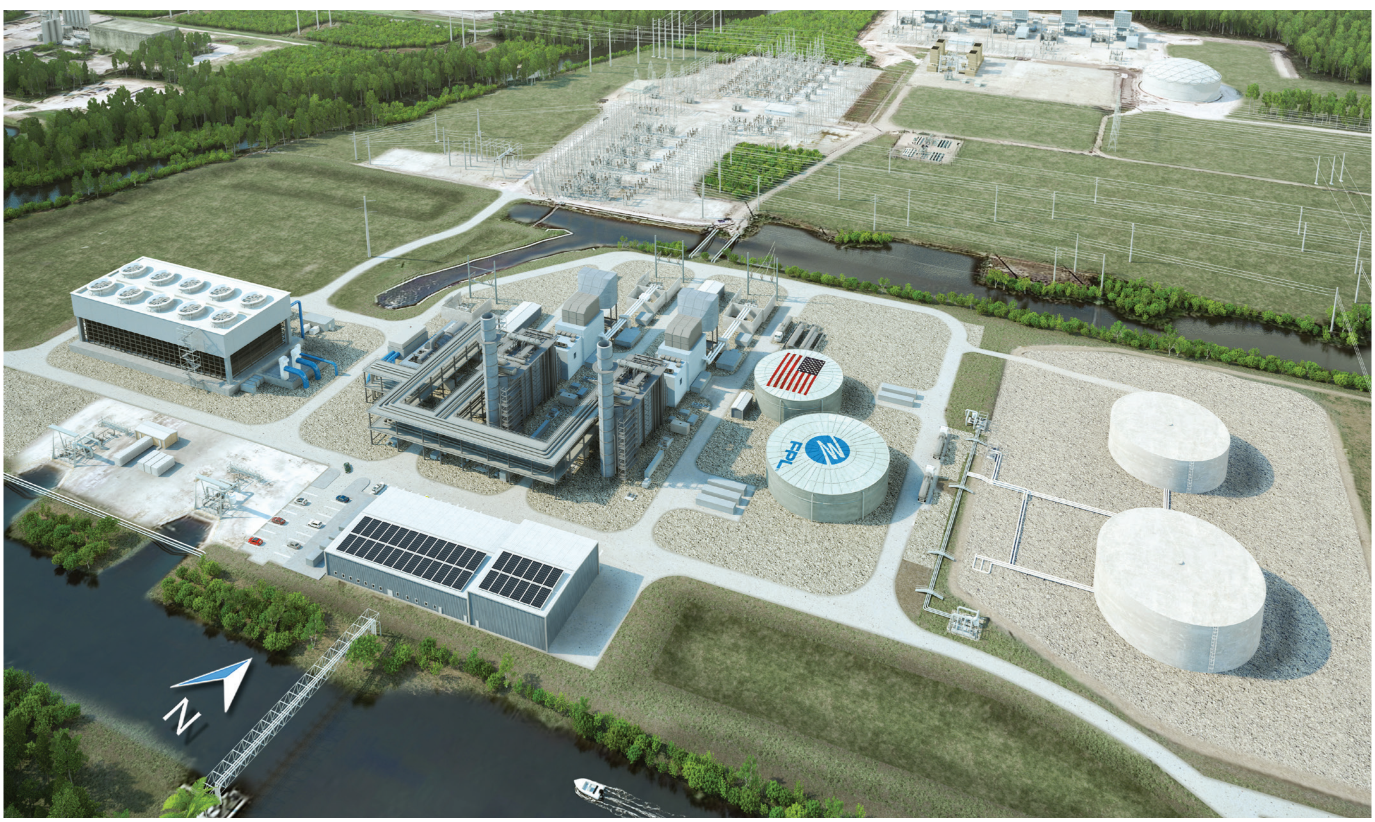
Bob Swindell, President and CEO, Greater Fort Lauderdale Alliance

Reb. Ex. MAB-2

Current FPL Power Plant in Dania Beach

Rendering of existing plant.

Future FPL Dania Beach Clean Energy Center



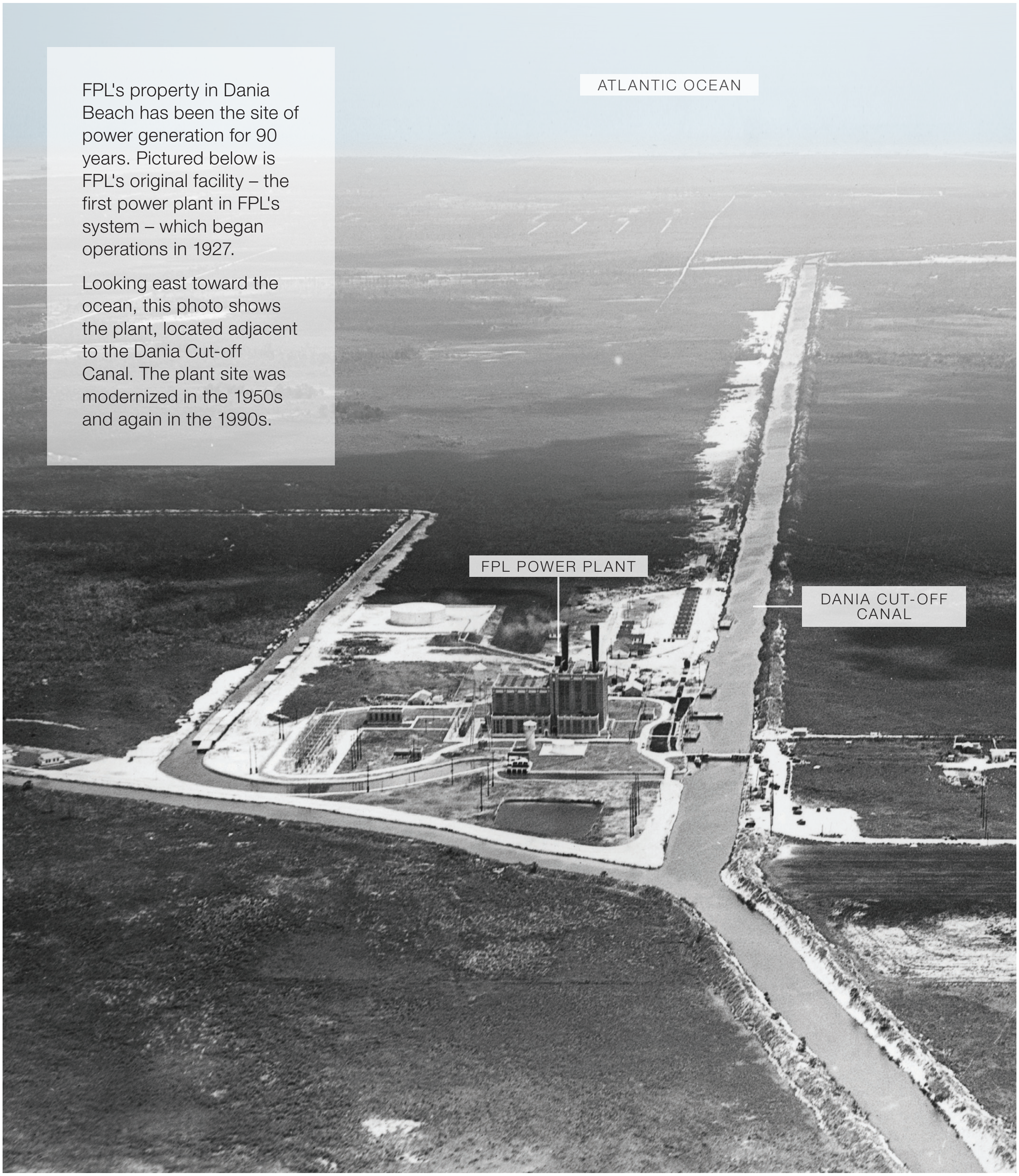
Conceptual rendering of proposed facility. Subject to final engineering.

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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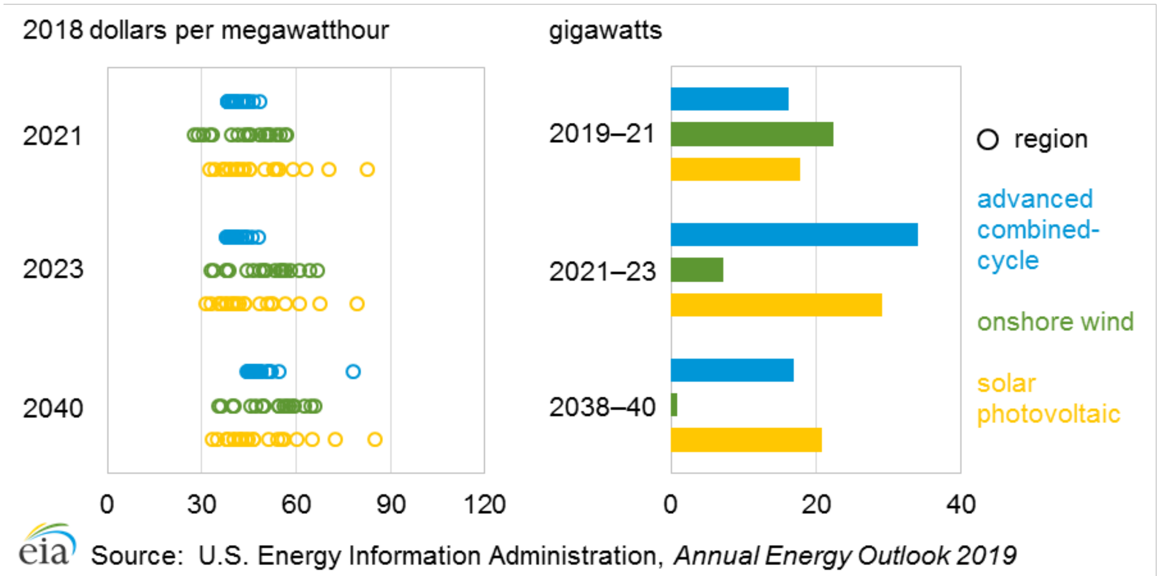
[1] Given the long lead-time and licensing requirements for some technologies, the first feasible year that all technologies are available is 2023.
[2] AEO2019 are available online (http://www.eia.gov/outlooks/aeo/).
[3] Appendix A shows LCOE and LACE for the subset of technologies available to be built 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.

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

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March 2014

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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

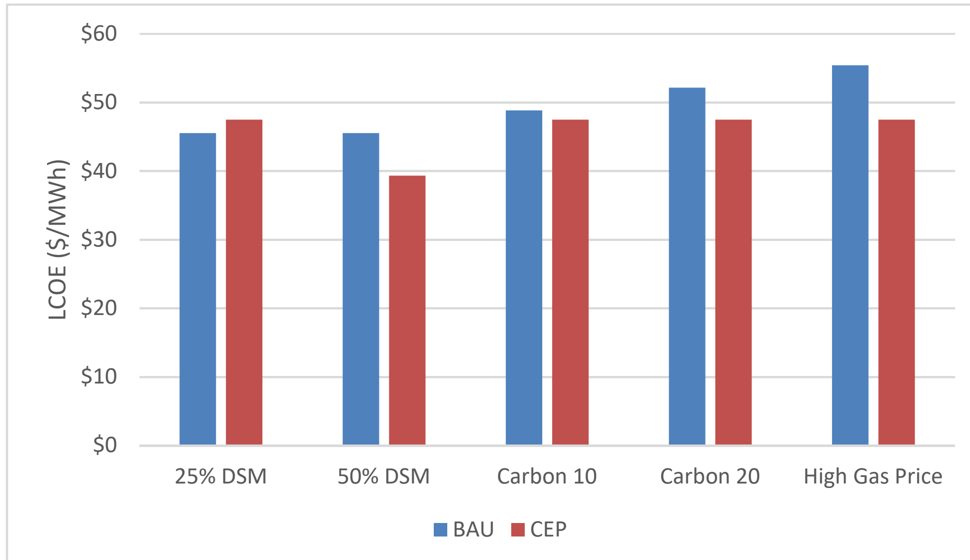
25% DSM
50% DSM
Carbon 10
Carbon 20
High Gas Price

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

[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

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[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

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[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

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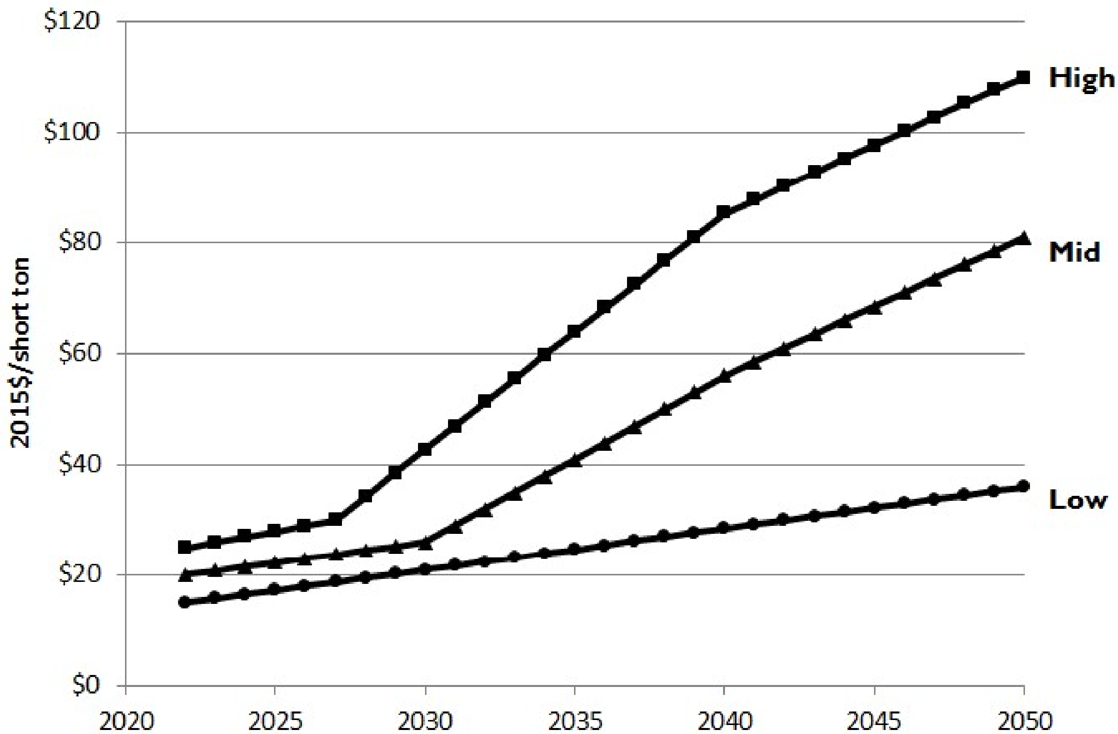
cooperation. As a result, we provide a single national-level CO_2 price and do not attempt to provide state-level forecasts. Figure 1 and Table 1 present Synapse's forecasts over the 2022-2050 period.[3]

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

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

Rebuttal Testimony for M. Brandon Looney

Reb. Ex. MBL-2

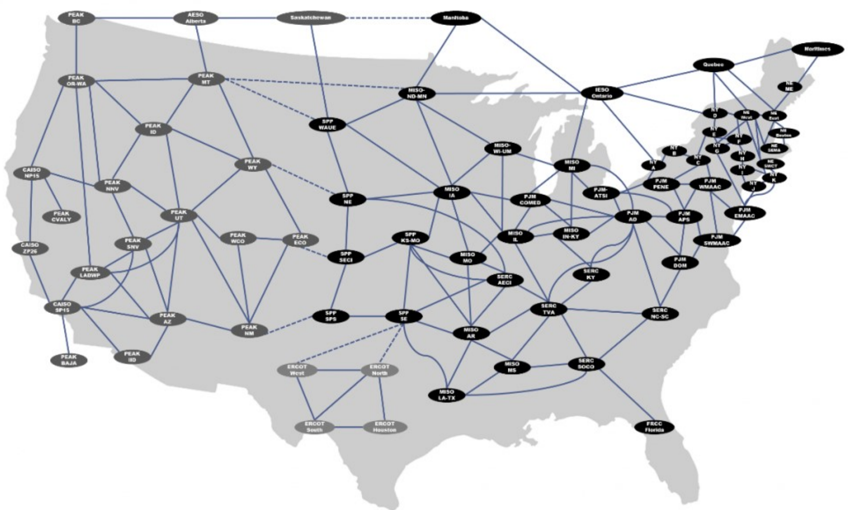
The Price of Emissions Reduction: Carbon Price Pathways through 2050

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

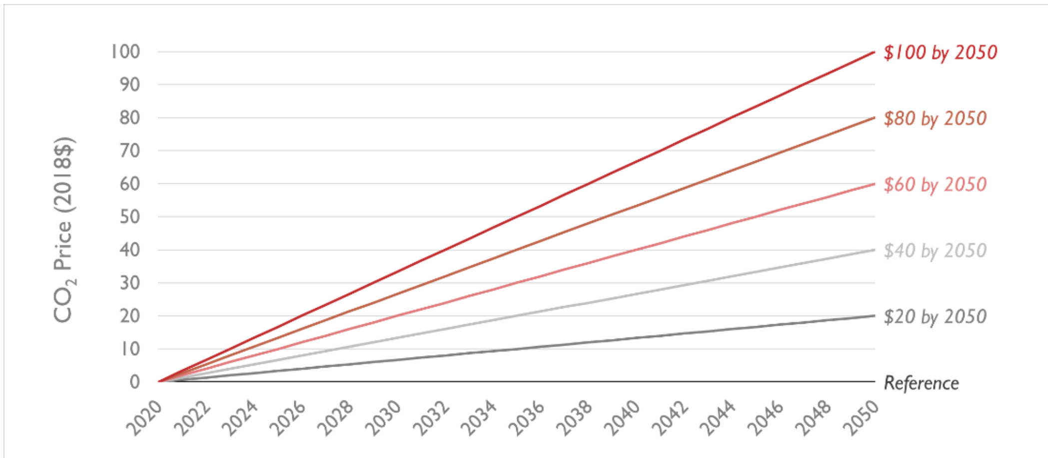


For this exploratory analysis, we used the following parameters:

- **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

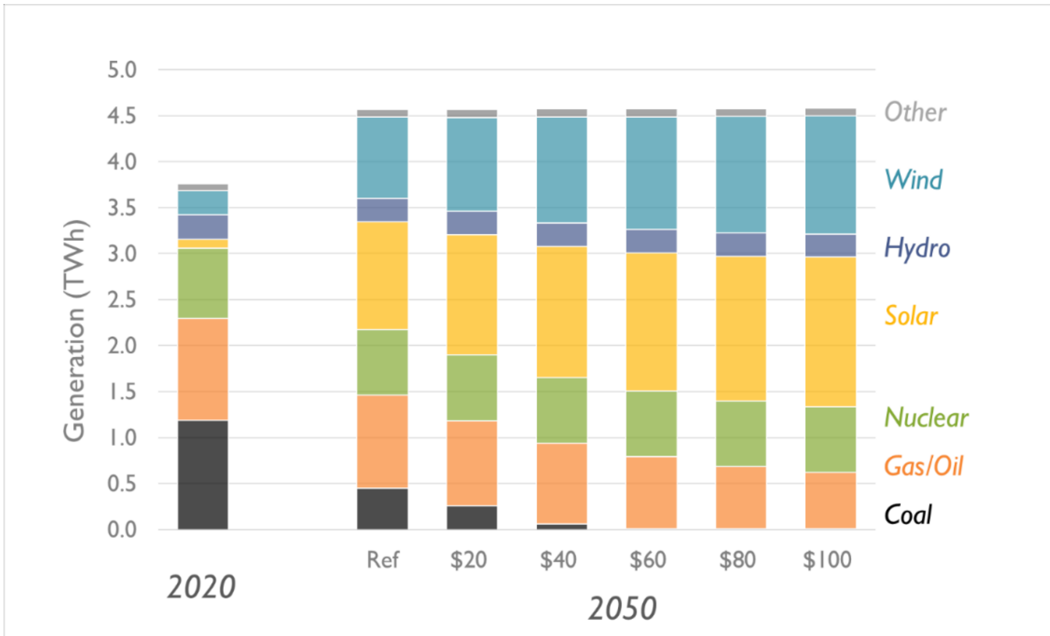
We modeled six scenarios with different linear CO_2 price projections through 2050, shown in Figure 2.

Figure 2. Modeled CO_2 price trajectories



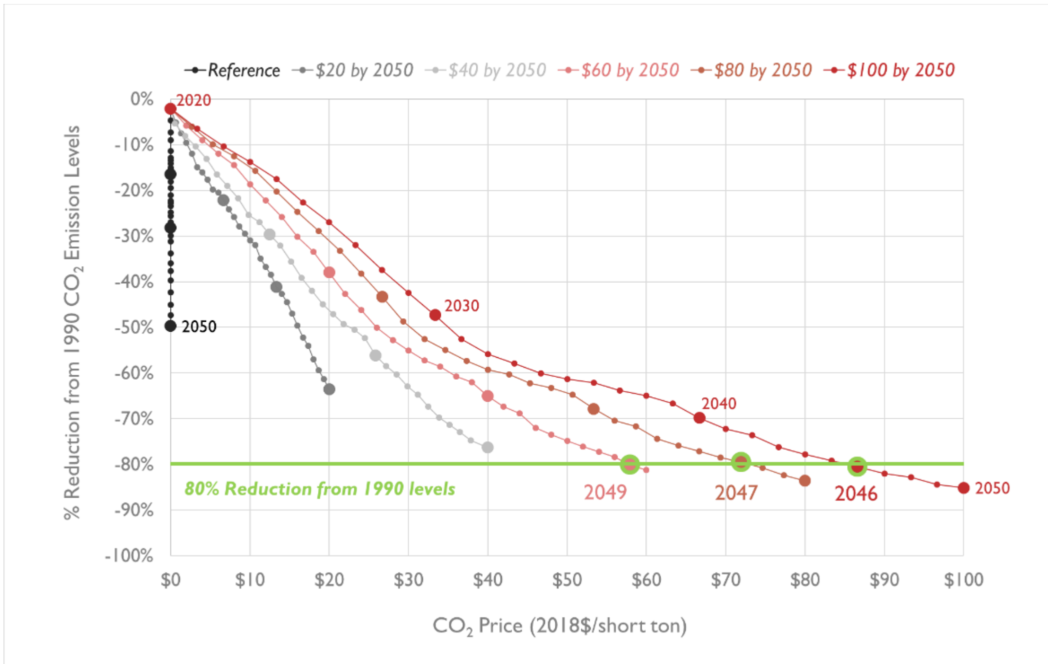
By 2050, our Reference case (featuring no carbon price) sees 36 percent less fossil generation and 278 percent more renewable generation (2 TWh) compared to estimated 2020 levels. This represents a 331 percent increase in U.S. renewable capacity, driven purely by reasonable renewable cost assumptions, 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

[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]

[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.

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[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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