STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

DOCKET NOS. 2019-224-E AND 2019-225-E

In the Matter of: South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC	))))))))))))	DIRECT TESTIMONY OF JAMES F. WILSON ON BEHALF OF NATURAL RESOURCES DEFENSE COUNCIL, SOUTHERN ALLIANCE FOR CLEAN ENERGY, SIERRA CLUB, SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND UPSTATE FOREVER[1]

I. INTRODUCTION AND QUALIFICATIONS

Q: Please state your name, position, and business address for the record.

A: My name is James F. Wilson. I am an economist and independent consultant doing business as Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, Maryland 20814.

Q: Please describe your experience and qualifications.

A: I have thirty-five years of consulting experience, primarily in the electric power and natural gas industries. Many of my assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved

[1] Sierra Club and Natural Resources Defense Council filed a petition to intervene out of time on February 3, 2021; as of the date of this filing, February 5, 2021, these petitions are still pending before the Commission.

resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients.

With respect to the resource adequacy issues I address in this testimony and the attached report, I have been actively involved in these issues in the PJM Interconnection, L.L.C. ("PJM") region for many years, participating in PJM stakeholder processes, performing and presenting analysis of these issues, and submitting affidavits in various regulatory proceedings. I have also been involved in these issues recently in New England, New York, Virginia, North Carolina, Georgia, and Alabama.

I have submitted affidavits and presented testimony in proceedings of the FERC, state regulatory agencies, and U.S. district court. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is attached as Exhibit A.

Q: On whose behalf are you testifying in the proceeding?

A: I am testifying on behalf of Natural Resources Defense Council, Southern Alliance for Clean Energy, Sierra Club, South Carolina Coastal Conservation League, and Upstate Forever.

Q: Have you previously testified before the South Carolina Public Service Commission?

A: Yes. In Docket Nos. 2019-185-E and 2019-186-E (the Duke Energy Carolinas, LLC and Duke Energy Progress, LLC 2018 avoided cost proceedings), I testified and submitted a report with regard to resource adequacy and capacity value issues.[2]

Q: Are you sponsoring any exhibits in this proceeding?

A: Yes. I am sponsoring a report, *Review and Evaluation of the 2020 Resource Adequacy Studies Relied Upon for the Duke Energy Carolinas and Duke Energy Progress 2020 Integrated Resource Plans*, attached as Exhibit B.

Q: What is the purpose and scope of your direct testimony in this proceeding?

A: Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Companies" or "Duke") filed their 2020 Integrated Resource Plans ("2020 IRPs", "2020 Plans") on September 1, 2020 in these dockets. The 2020 IRPs present load forecasts (Chapter 3 and Appendix C) and resource adequacy analysis and recommended reserve margins (Chapter 9 and Attachment III) that serve as the basis for each utility's determination of the total generating capacity required over the IRP planning horizon. The resource adequacy analysis and reserve margins for the 2020 Plans were based upon resource adequacy studies ("DEC RA Study", "DEP RA Study"; collectively

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[2] Wilson, James F., *Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing*, ("Wilson 2019 RA Report").

"RA Studies") prepared for DEC and DEP by Astrapé Consulting.[3] As explained in the RA Studies, their primary purpose was "to provide Duke system planners with information on physical reliability and costs that could be expected with various reserve margin planning targets."[4] In addition, in December 2020, the Companies released a Winter Peak Study that identifies the customers and end uses contributing to winter peak loads and evaluates demand-side management programs to mitigate winter peak loads.[5] My testimony and expert report review and evaluate the Companies' 2020 RA Studies.[6]

Q: What materials have you reviewed in order to prepare your report and testimony?

A: I reviewed the 2020 Plan filings, supporting files, and discovery responses, and also some filings and testimony in prior IRP proceedings.

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[3] Astrapé Consulting, *Duke Energy Carolinas 2020 Resource Adequacy Study*, Prepared for Duke Energy, September 1, 2020, DEC 2020 Plan Attachment III, and Astrapé Consulting, *Duke Energy Progress 2020 Resource Adequacy Study,* Prepared for Duke Energy, September 1, 2020, DEP 2020 Plan Attachment III. The analysis included in such RA Studies typically also serves as the basis for calculations of the capacity values of solar and other resources; however, a new solar capacity value study was not performed for the 2020 Plans (the Companies relied on their 2018 Solar Capacity Value Study). The 2020 Plans attach a study of the capacity value of storage resources that utilized the same model and the same load and resource assumptions as the 2020 RA Studies, Storage ELCC Study p. 19.

[4] DEC RA Study p. 3.

[5] Tierra Resource Consultants, Dunsky Energy Consulting, and Proctor Engineering Group, *Duke Energy Winter Peak Analysis and Solution Set, Duke Energy Winter Peak Demand Reduction Potential Assessment,* and *Duke Energy Winter Peak Targeted DSM Plan*, December 2020 (Winter Peak Study Task 1, Task 2 and Task 3 Report, respectively, and collectively "Winter Peak Study"). My report notes some aspects of the scope and content of the Winter Peak Study as they pertain to the topic of resource adequacy, but an evaluation of that work is beyond the scope of my testimony and report.

[6] I also reviewed and evaluated the Companies' peak load forecasts, however, I comment only briefly on those forecasts. My critique of the assumptions used in the 2020 RA Studies is equally applicable to the Storage ELCC Study which relies upon the same assumptions; however, an evaluation of the Storage ELCC Study is beyond the scope of my report.

II. Summary and Recommendations

Q: Please summarize your conclusions with regard to the RA Studies.

A: My main conclusion is that the RA Studies have substantially overstated winter resource adequacy risk. The primary flaw is the inaccurate approach to estimating the impact of extreme cold on loads, extrapolating based on observations at milder temperatures. In addition, the RA Studies used 39 years of temperature data (1980-2018), weighted equally, which includes many instances of very extreme cold that have not been seen in these areas, or only rarely, for decades. This overstates the likely frequency of such extreme cold going forward, amplifying the effect of overstating the impact of extreme cold on winter peak loads. Power plant forced outage rates under extreme cold have also been overstated.

My report also shows that the RA Studies model loads far in excess of the "Study Peak Day" adopted in the Winter Peak Study, and these extreme loads drive the RA Studies' results; however, the Winter Peak Study does not even acknowledge such loads are possible. Therefore, the RA Studies and Winter Peak Study are highly inconsistent.

While a number of other assumptions adopted in the RA Studies that impact the physical reliability results appear very conservative and could be questioned (such as, external region and market diversity and potential assistance, and demand response operational limits), my report focuses on the issues noted above.

Q: Please summarize your recommendations with regard to the RA Studies and the Companies' reserve margins.

A: Due to the overstatement of winter resource adequacy risk, I again conclude that the recommended increases in the DEC and DEP planning reserve margins (relative to IRPs before 2016) are unsupported and higher than necessary. If the flaws I have identified were even partially corrected, the 14.5% summer planning reserve margin that was in place until the 2016 IRP, which would provide a 16.5% winter reserve margin, would be more than adequate**.**

Due to the identified flaws in the RA Studies, I also recommend that the analysis and assumptions reflected in the 2020 RA Studies be rejected as the basis of the Storage ELCC Study, or of any future studies of the capacity value of solar or other resource types.

Q: Please briefly note other topics addressed in your report.

A: My report also critiques the economic reliability calculations, noting that they rest upon numerous highly questionable assumptions. I recommend that no weight be given to these calculations. My report also questions the use of multi-year economic load forecast error, and the approach to developing these assumptions.

Finally, my report also provides various recommendations for future IRPs.

III. RESOURCE ADEQUACY STUDIES AND WINTER RESOURCE ADEQUACY RISK

Q: What is "resource adequacy"?

A: Resource adequacy is the utility's ability to serve customer loads at all times, in particular during times of high summer or winter loads.

Q: What is the purpose of a resource adequacy study?

A: The purpose of a resource adequacy study is to identify the planning reserve margin that provides sufficient resource adequacy. Together with peak load forecasts, the planning reserve margins determine the capacity requirements for resource planning purposes.

To determine the planning reserve margin needed to achieve resource adequacy, RA Studies involve probabilistic simulations of load and resources. The objective is to find the planning reserve margin required to satisfy a "one day in ten years" ("1-in-10") resource adequacy criterion, equivalent to an annual Loss of Load Expectation ("LOLE") of 0.1 events per year.

Q: What were the results of the 2020 RA Studies?

A: The RA Studies identify a 16% winter planning reserve margin for DEC and 19.25% for DEP, based on separate analysis, and 16.75% for a "combined" case, ultimately recommending 17% for each utility.

Q: Did the Companies accept these recommendations?

A: Yes, the 2020 Plans adopt the recommended 17% winter planning reserve margin (DEC 2020 Plan pp. 66-67, DEP 2020 Plan pp. 68-69) based on the recommendations of the 2020 RA Studies.

Q: You stated that the RA Studies overstate winter resource adequacy risk. Please explain.

A: There are three flaws that lead to the RA Studies overstating winter resource adequacy risk:

1. The primary flaw is the inaccurate approach to estimating the impact of extreme cold on loads, extrapolating based on observations at milder temperatures.
2. In addition, the RA Studies used 39 years of temperature data (1980-2018), weighted equally, which includes many instances of very extreme cold that have not been seen in these areas, or only rarely, for decades. This overstates the likely frequency of such extreme cold going forward, amplifying the effect of overstating the impact of extreme cold on winter peak loads.
3. Finally, power plant forced outage rates under extreme cold have also been overstated.

Q: Please explain how the impact of extreme cold on loads was estimated.

A: The RA Studies generally associated loads with temperatures using a neural network approach.[7] However, for the most extreme temperatures (high or low) for which there are fewer observations, the neural network approach was considered inaccurate, so an additional step, based on regressions, was used to

[7] A neural network is a series of algorithms that endeavors to recognize underlying relationships in a set of data through a process that mimics the way the human brain operates.

"extrapolate the peaks." The approach, discussed on pages 10-21 of my report, entailed estimating the amount by which incremental cold apparently increased load in the 10 to 21 degree range through regression. The results of the regressions, expressed in MW/degree, were then used to extrapolate load levels to the very low temperatures found in the 39-year weather history used for the studies.

Q: Please explain why you consider this extrapolation approach flawed.

A: There are three flaws in this approach. First, this extrapolation approach assumes that when temperatures drop to extremely low temperatures (15, 10, 5 degrees and even lower), each additional degree will increase loads by the same amount as occurs at around 20 degrees. But for the lowest temperatures, the relationship between temperature and load is much weaker. This is logical -- once temperatures drop to the teens, customers are likely already operating space heating equipment at maximum levels; if temperatures fall even lower, few customers have additional equipment they can turn on. In addition, under the very rare extreme cold conditions, some schools, offices, and other commercial, government and industrial facilities may open late, remain closed, or operate at reduced levels, reducing loads during the early morning peak on such days.

The second flaw is in the regression approach itself, which employed a simplistic and flawed way to estimate the impact of incremental cold on loads. The most important flaw in the regression approach was to include observations for temperatures up to 21 degrees. The same regression analysis, but excluding the higher temperatures, provides a much lower and more reasonable estimate of the impact of incremental cold on load at lower temperatures.

The third flaw in the extrapolation approach was in the details of how the MW/degree results of the regressions were applied to determine the final loads used in the RA Studies. This led to some extreme and nonsensical load values.

Q: You stated that the RA Studies used 39 years of weather data, which overstates the likely frequency of such extreme cold going forward. Please explain.

A: The 39 years of temperature data (1980-2018) used in the RA Studies included many instances of extreme cold that have not been seen, or only rarely, for decades. This calls into question how likely we should expect such extreme cold to be going forward, and whether the RA Studies have overstated the frequency of such extreme cold (all years are equally weighted) and resulting high loads. Overstating the likely future frequency of extreme cold amplifies the effect of overstating the impact of extreme cold on winter peak loads discussed in the prior section.

Using 39 years, and equally weighting all years, overstates the likely frequency of extreme cold going forward, and amplifies the impact of overstating the load values under extreme cold.

Q: The region has seen extreme cold, "polar vortex" events in 2014, 2015, and 2018. Are you suggesting that such extreme cold events are not likely in the coming years?

A: No. Those recent events are included in the temperature data used for the RA Studies and given equal weight. However, the RA Studies also apply equal weight to instances of far lower temperatures that have not been seen at all, or only rarely, since the 1980s.

Q: Did overstating the likely magnitude and frequency of extreme winter loads have an impact on the RA Studies' results and recommendations?

A: Yes. The most extreme temperatures, and the extreme loads assigned to them, drive the results of the RA Studies. In the DEC RA Study simulation, 97% of the loss of load events in winter occur under scenarios with temperatures under 9 degrees. 76% of the winter loss of load occurs under scenarios with temperatures of 6.4 degrees or less, which has only occurred once since 1996. In the DEP simulation, 97% of the winter loss of load is under scenarios with 11 degree or lower temperatures. 96% of the winter loss of load is under 10.1 degrees, which has only occurred once since 1996.

The majority of the winter hours with loss of load are from scenarios under which the DEC load was 106% of the value on the Winter Peak Study's Study Peak Day or higher. Fully 94% of the loss of load in the DEC RA Study occurs on days with loads in excess of the Study Peak Day value. In the DEP RA Study, the majority of the load loss is in hours with load 114% of the Study

Peak Day peak load or higher. 99% of the loss of load in the DEP RA Study occurs under loads in excess of the Study Peak Day value.

Astrapé performed a sensitivity analysis under which temperature data from 1990 to 2018 was used (the data from the 1980s was dropped), while no other changes were made. Using data from 1990 to 2018 rather than 1980 to 2018 had a huge impact on the reserve margins to meet the 1-in-10 standard: 13.25% for DEC and 14.75% for DEP, compared to 16% and 19.25%, respectively, from the RA Studies.[8] Note that this is only due to dropping the 1980s temperature data; these reserve margins still reflect application of the flawed extrapolations that overstate the impact of extreme cold on load.

IV. RECOMMENDATIONS FOR FUTURE IRPS

Q: Please summarize your recommendations for future IRPs.

A: My report provides a number of recommendations for future IRPs at pages 38-41. My key recommendations are as follows:

a. The Companies should study the relationship between extreme winter weather and load, and develop more sophisticated methods for estimating the potential impact of extreme winter weather on load. This research would be useful for anticipating and preparing for such events. This research would also inform the assumptions for future resource

[8] Response to Data Request SELC 3-4 (referring to the file "AG Office Follow-up Items_062520_Final.docx," which is one of the 2020 RA Study support documents).

adequacy studies, and ensure consistency between load forecasting, resource adequacy modeling, and plans for managing winter peak loads.

b. If research into the impact of extreme winter weather on loads suggests peaks may far exceed what was evaluated in the Winter Peak Study, the Companies should engage with customers and develop tailored programs for shaving these rare and brief spikes.

c. The Companies should research the potential for load forecast errors due to economic forecast errors or other causes, and the realistic extent to which this could ultimately lead to less capacity than planned in a delivery year, also to inform future resource adequacy studies.

d. The Companies should prepare additional load forecast scenarios (such as high and low scenarios), as required by South Carolina regulations.[9] The Companies should also prepare forecasts of extreme or "90-10" summer and winter peak loads, that is, the peaks that are expected to occur only once in ten years.

e. The Companies should provide additional scenario analysis and sensitivity analysis of its RA studies, and allow stakeholders to request additional sensitivity analysis through discovery.

Q: Does this complete your direct testimony?

A: Yes.

[9] S.C. Code § 58-37-40 (2019) (B)(1) "An integrated resource plan shall include all of the following: (a) a long-term forecast of the utility's sales and peak demand under various reasonable scenarios…".

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I certify that the following persons have been served with one (1) copy of Testimony of James F. Wilson on behalf of South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, and pending intervenors Natural Resources Defense Council, and Sierra Club by electronic mail and/or U.S. First Class Mail at the addresses set forth below:

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February 5, 2021

s/ Robin Dunn

EXHIBIT A

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SUMMARY

James F. Wilson is an economist with over 35 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He also spent five years in Russia in the early 1990s advising on the reform, restructuring and development of the Russian electricity and natural gas industries.

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the *Energy Journal*, *Electricity Journal*, *Public Utilities Fortnightly* and other publications, and he often presents at industry conferences.

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.

EDUCATION

MS, Engineering-Economic Systems, Stanford University, 1982

BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Analysis of provisions to enhance resource fuel security in day-ahead and real-time wholesale electricity markets.
- Evaluated peak electric load forecasts and enhancements to load forecasting methodologies.
- Evaluated a probabilistic analysis to determine the electric generating capacity reserve margin to satisfy resource adequacy criteria.
- Evaluated the potential impact of an electricity generation operating reserve demand curve on a wholesale electricity market with a capacity construct.
- Developed wholesale capacity market enhancements to accommodate seasonal resources and resource adequacy requirements.
- Evaluation of wholesale electricity market design enhancements to accommodate state initiatives to promote state environmental and other policy objectives.
- Evaluation of proposals for natural gas distribution system expansions.
- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.
- Cost-benefit analysis of a new natural gas pipeline.
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.

- Panelist on a FERC technical conference on capacity markets.
- Affidavit on the potential for market power over natural gas storage.
- Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.
- Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
- Participated in a panel teleseminar on resource adequacy policy and modeling.
- Affidavit on opt-out rules for centralized capacity markets.
- Affidavits on minimum offer price rules for RTO centralized capacity markets.
- Evaluated electric utility avoided cost in a tax dispute.
- Advised on pricing approaches for RTO backstop short-term capacity procurement.
- Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
- Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
- Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
- Participated on a panel teleseminar on natural gas price forecasting.
- Affidavit evaluating a shortage pricing mechanism and recommending changes.
- Testimony in support of proposed changes to a forward capacity market mechanism.
- Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
- Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
- Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
- Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.

EARLIER PROFESSIONAL EXPERIENCE

LECG, LCC, Washington, DC 1998–2009.
<u>Principal</u>

- Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.
- Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
- Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
- Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism's design; prepared a detailed report. Evaluated the impacts of the mechanism's flaws on prices and costs and prepared testimony in support of a formal complaint.
- Analyzed impacts and potential damages of natural gas migration from a storage field.
- Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
- Prepared affidavit evaluating a pipeline's application for market-based rates for interruptible transportation and the potential for market power.
- Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
- Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.

- Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
- Evaluated market power issues raised by a possible gas-electric merger.
- Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under Federal Energy Regulatory Commission ("FERC") policy.
- Prepared an expert report on damages in a natural gas contract dispute.
- Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
- Prepared testimony evaluating natural gas procurement incentive mechanisms.
- Analyzed the need for and value of additional natural gas storage in the southwestern US.
- Evaluated market issues in the restructured Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
- Affidavit on market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
- Testimony on the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
- Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
- Testimony on the causes of California natural gas price increases during 2000-2001 and the possible exercise of market power to raise natural gas prices at the California border.
- Advised a major US utility with regard to the Federal Energy Regulatory Commission's proposed Standard Market Design and its potential impacts on the company.
- Reviewed and critiqued draft legislation and detailed market rules for reforming the Russian electricity industry, for a major investor in the sector.
- Analyzed the causes of high prices in California wholesale electric markets during 2000 and developed recommendations, including alternatives for price mitigation. Testimony on price mitigation measures.
- Summarized and critiqued wholesale and retail restructuring and competition policies for electric power and natural gas in select US states, for a Pacific Rim government contemplating energy reforms.
- Presented testimony regarding divestiture of hydroelectric generation assets, potential market power issues, and mitigation approaches to the California Public Utilities Commission.
- Reviewed the reasonableness of an electric utility's wholesale power purchases and sales in a restructured power market during a period of high prices.
- Presented an expert report on failure to perform and liquidated damages in a natural gas contract dispute.
- Presented a workshop on Market Monitoring to a group of electric utilities in the process of forming an RTO.
- Authored a report on the screening approaches used by market monitors for assessing exercise of market power, material impacts of conduct, and workable competition.
- Developed recommendations for mitigating locational market power, as part of a package of congestion management reforms.
- Provided analysis in support of a transmission owner involved in a contract dispute with generators providing services related to local grid reliability.
- Authored a report on the role of regional transmission organizations in market monitoring.
- Prepared market power analyses in support of electric generators' applications to FERC for market-based rates for energy and ancillary services.
- Analyzed western electricity markets and the potential market power of a large producer under various asset acquisition or divestiture strategies.
- Testified before a state commission regarding the potential benefits of retail electric competition and issues that must be addressed to implement it.

- Prepared a market power analysis in support of an acquisition of generating capacity in the New England market.
- Advised a California utility regarding reform strategies for the California natural gas industry, addressing market power issues and policy options for providing system balancing services.

ICF RESOURCES, INC., Fairfax, VA, 1997–1998.
Project Manager

- Reviewed, critiqued and submitted testimony on a New Jersey electric utility's restructuring proposal, as part of a management audit for the state regulatory commission.
- Assisted a group of US utilities in developing a proposal to form a regional Independent System Operator (ISO).
- Researched and reported on the emergence of Independent System Operators and their role in reliability, for the Department of Energy.
- Provided analytical support to the Secretary of Energy's Task Force on Electric System Reliability on various topics, including ISOs. Wrote white papers on the potential role of markets in ensuring reliability.
- Recommended near-term strategies for addressing the potential stranded costs of non-utility generator contracts for an eastern utility; analyzed and evaluated the potential benefits of various contract modifications, including buyout and buydown options; designed a reverse auction approach to stimulating competition in the renegotiation process.
- Designed an auction process for divestiture of a Northeastern electric utility's generation assets and entitlements (power purchase agreements).
- Participated in several projects involving analysis of regional power markets and valuation of existing or proposed generation assets.

IRIS MARKET ENVIRONMENT PROJECT, 1994–1996.
Project Director, Moscow, Russia

Established and led a policy analysis group advising the Russian Federal Energy Commission and Ministry of Economy on economic policies for the electric power, natural gas, oil pipeline, telecommunications, and rail transport industries (*the Program on Natural Monopolies,* a project of the IRIS Center of the University of Maryland Department of Economics, funded by USAID):

- Advised on industry reforms and the establishment of federal regulatory institutions.
- Advised the Russian Federal Energy Commission on electricity restructuring, development of a competitive wholesale market for electric power, tariff improvements, and other issues of electric power and natural gas industry reform.
- Developed policy conditions for the IMF's $10 billion Extended Funding Facility.
- Performed industry diagnostic analyses with detailed policy recommendations for electric power (1994), natural gas, rail transport and telecommunications (1995), oil transport (1996).

Independent Consultant stationed in Moscow, Russia, 1991–1996

Projects for the WORLD BANK, 1992-1996:

- Bank Strategy for the Russian Electricity Sector. Developed a policy paper outlining current industry problems and necessary policies, and recommending World Bank strategy.
- Russian Electric Power Industry Restructuring. Participated in work to develop recommendations to the Russian Government on electric power industry restructuring.
- Russian Electric Power Sector Update. Led project to review developments in sector restructuring, regulation, demand, supply, tariffs, and investment.
- Russian Coal Industry Restructuring. Analyzed Russian and export coal markets and developed forecasts of future demand for Russian coal.
- World Bank/IEA Electricity Options Study for the G-7. Analyzed mid- and long-term electric power demand and efficiency prospects and developed forecasts.

- Russian Energy Pricing and Taxation. Developed recommendations for liberalizing energy markets, eliminating subsidies and restructuring tariffs for all energy resources.

Other consulting assignments in Russia, 1991–1994:

- Advised on projects pertaining to Russian energy policy and the transition to a market economy in the energy industries, for the Institute for Energy Research of the Russian Academy of Sciences.
- Presented seminars on the structure, economics, planning, and regulation of the energy and electric power industries in the US, for various Russian clients.

DECISION FOCUS INC., Mountain View, CA, 1983–1992
Senior Associate, 1985-1992.

- For the Electric Power Research Institute, led projects to develop decision-analytic methodologies and models for evaluating long term fuel and electric power contracting and procurement strategies. Applied the methodologies and models in numerous case studies, and presented several workshops and training sessions on the approaches.
- Analyzed long-term and short-term natural gas supply decisions for a large California gas distribution company following gas industry unbundling and restructuring.
- Analyzed long term coal and rail alternatives for a midwest electric utility.
- Evaluated bulk power purchase alternatives and strategies for a New Jersey electric utility.
- Performed a financial and economic analysis of a proposed hydroelectric project.
- For a natural gas pipeline company serving the Northeastern US, forecasted long-term natural gas supply and transportation volumes. Developed a forecasting system for staff use.
- Analyzed potential benefits of diversification of suppliers for a natural gas pipeline company.
- Evaluated uranium contracting strategies for an electric utility.
- Analyzed telecommunications services markets under deregulation, developed and implemented a pricing strategy model. Evaluated potential responses of residential and business customers to changes in the client's and competitors' telecommunications services and prices.
- Analyzed coal contract terms and supplier diversification strategies for an eastern electric utility.
- Analyzed oil and natural gas contracting strategies for an electric utility.

TESTIMONY AND AFFIDAVITS

In the matter of the Application of DTE Electric Company for Reconciliation of its Power Supply Cost Recovery Plan for the 12-month Period Ending December 31, 2019, Michigan Public Service Commission Case No. U-20222, Direct Testimony on behalf of Michigan Environmental Council, October 27, 2020.

Virginia Electric and Power Company's 2020 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUR-2020-00035, Direct Testimony on behalf of Environmental Respondent, September 15, 2020; testimony at hearings, October 27, 2020.

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Review and Evaluation of the 2020 Resource Adequacy Studies Relied Upon for the Duke Energy Carolinas and Duke Energy Progress 2020 Integrated Resource Plans

James F. Wilson, Wilson Energy Economics

Prepared on behalf of Natural Resources Defense Council, Southern Alliance for Clean Energy, Sierra Club, South Carolina Coastal Conservation League, and Upstate Forever

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Contents

I. INTRODUCTION AND SCOPE OF THIS REPORT

1. Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Companies" or "Duke") filed their 2020 Integrated Resource Plans ("2020 IRPs," "2020 Plans") on September 1, 2020 in North Carolina Utilities Commission Docket No. E-100, Sub 165 and Public Service Commission of South Carolina Docket Nos. 2019-224-E and 2019-225-E. The 2020 IRPs present load forecasts (Chapter 3 and Appendix C) and resource adequacy analysis and recommended reserve margins (Chapter 9 and Attachment III) that serve as the basis for each utility's determination of the total generating capacity required over the IRP planning horizon.

2. The resource adequacy analysis and reserve margins for the 2020 Plans were based upon resource adequacy studies ("DEC RA Study," "DEP RA Study"; collectively "RA Studies") prepared for DEC and DEP by Astrapé Consulting.[1] The analysis included in such RA Studies typically also serves as the basis for calculations of the capacity values of solar and other resources; however, a new solar capacity value study was not performed for the 2020 Plans (the Companies relied on their 2018 Solar Capacity Value Study).[2] The 2020 Plans attach a study of the capacity value of storage resources[3] that utilized the same model and the same load and resource assumptions as the 2020 RA Studies.[4]

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[1] Astrapé Consulting, *Duke Energy Carolinas 2020 Resource Adequacy Study*, Prepared for Duke Energy, September 1, 2020, DEC 2020 Plan Attachment III, and Astrapé Consulting, *Duke Energy Progress 2020 Resource Adequacy Study,* Prepared for Duke Energy, September 1, 2020, DEP 2020 Plan Attachment III.

[2] Duke Energy Response to Data Request NCSEA 3-8.

[3] Astrapé Consulting, *Duke Energy Carolinas and Duke Energy Progress Storage Effective Load Carrying Capability (ELCC) Study,* Attachment III to the 2020 Plans, September 1, 2020 ("Storage ELCC Study").

[4] Storage ELCC Study p. 19.

3. In December 2020, the Companies released a Winter Peak Study[5] that identifies the customers and end uses contributing to winter peak loads and evaluates demand-side management programs to mitigate winter peak loads.

4. I reviewed and evaluated the previous (2016) DEC and DEP RA Studies in reports filed in 2019 and 2017,[6] raising a number of issues with the studies' assumptions and methodologies. I also reviewed the Companies' load forecasts, and discussed extreme winter peak load issues, in reports filed in the same dockets.[7]

5. This report reviews and evaluates the 2020 RA Studies relied upon for the 2020 Plans. I also reviewed and evaluated the Companies' peak load forecasts, however, I comment only briefly on those forecasts. My critique of the assumptions used in the RA Studies is equally applicable to the Storage ELCC Study which relies upon the same assumptions; however, an evaluation of the Storage ELCC Study is beyond the scope of this report. This report notes some aspects of

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[5] Tierra Resource Consultants, Dunsky Energy Consulting, and Proctor Engineering Group, *Duke Energy Winter Peak Analysis and Solution Set, Duke Energy Winter Peak Demand Reduction Potential Assessment,* and *Duke Energy Winter Peak Targeted DSM Plan*, December 2020 (Winter Peak Study Task 1, Task 2 and Task 3 Report, respectively, and collectively "Winter Peak Study").

[6] Wilson, James F., *Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing*, filed February 12, 2019 as Attachment 4 to Initial Comments of the Southern Alliance for Clean Energy in North Carolina Utilities Commission Docket No. E-100, Sub 157, also filed September 11, 2019 as Exhibit B to Direct Testimony on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy in South Carolina Public Service Commission Docket Nos. 2019-185-E and 2019-186-E ("Wilson 2019 RA Report"); Wilson, James F., *Review and Evaluation of the Reserve Margin Determinations for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans*, Attachment B to the Comments of Southern Alliance for Clean Energy, Natural Resources Defense Council and the Sierra Club, filed February 7, 2017 in North Carolina Utilities Commission Docket No. E-100, Sub 147 ("Wilson 2017 RA Report").

[7] Wilson, James F., *Review and Evaluation of the Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans*, filed February 12, 2019 as Attachment 3 to Initial Comments of the Southern Alliance for Clean Energy in North Carolina Utilities Commission Docket No. E-100 Sub 157 ("Wilson 2019 Load Forecast Report"); Wilson, James F., *Review and Evaluation of the Peak Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans*, filed February 7, 2017 as Attachment A to the Comments of Southern Alliance for Clean Energy, Natural Resources Defense Council and the Sierra Club, in North Carolina Utilities Commission Docket No. E-100 Sub 147 ("Wilson 2017 Load Forecast Report").

the scope and content of the Winter Peak Study as they pertain to the topic of resource adequacy, but an evaluation of that work is also beyond the scope of this report.

II. SUMMARY AND RECOMMENDATIONS

6. The RA Studies document probabilistic simulations of load and resources to find the planning reserve margin required to satisfy a "one day in ten years" ("1-in-10") resource adequacy criterion, equivalent to an annual Loss of Load Expectation ("LOLE") of 0.1 events per year.[8] The RA Studies identify a 16% winter planning reserve margin for DEC and 19.25% for DEP, based on separate analysis, and 16.75% for a "combined" case, ultimately recommending 17% for each utility (DEC RA Study pp. 17-18, DEP RA Study pp. 17-18). Both 2020 Plans adopt the recommended 17% planning reserve margin (DEC 2020 Plan pp. 66-67, DEP 2020 Plan pp. 68-69) driven by winter capacity needs, based on the recommendations of the 2020 RA Studies. The 17% winter planning reserve margin ensures at least a 15% summer planning reserve margin for both DEC and DEP.[9]

7. The Winter Peak Study adopted January 5, 2018, the recent day with the Companies' highest winter peak, as the "Study Peak Day,"[10] and the three-volume, 240-page study appears to be detailed and thorough with regard to demand response programs to address the loads that are expected to occur on the Study Peak Day. However, the RA Studies model winter peak loads over 13%, and over 4,400 MW, in excess of the highest load on the Study Peak Day,[11] and these extreme loads drive the RA Study results. The extreme loads represented

[8] For the purposes of the RA Studies, "The one day in 10-year standard (LOLE of 0.1) is interpreted as one day with one or more hours of firm load shed every 10 years due to a shortage of generating capacity." DEC RA Study p. 3.

[9] DEC RA Study p. 18, DEP RA Study p. 18.

[10] Winter Peak Study Task 1 Report p. 9.

[11] Duke Energy Response to Data Request SELC 5-1.

in the RA Studies are based on a simple arithmetic extrapolation, as this report will discuss; they not based on any analysis or theory of how loads greater than the Study Peak Day could occur (what customers or end uses). Nor did the Winter Peak Study discuss the possibility of winter peak loads higher than the Study Peak Day, evaluate what customers and end uses could contribute to loads higher than the Study Peak Day, or identify or evaluate programs tailored to mitigating loads greater than the Study Peak Day.

8. Based on the Winter Peak Study's scope (focusing on the customers and end uses that make up the Study Peak Day, and programs to reduce these loads) it appears that, contrary to the RA Studies, the Companies assign low likelihood to, and are not particularly concerned about, the possibility of winter peak loads substantially in excess of the Study Peak Day. If instead the Companies believe such extreme loads beyond the Study Peak Day are reasonably likely to occur (as assumed in the RA Studies), *how* such loads can occur (what customers and end uses cause them), and approaches to mitigating them, should have been major topics of the Winter Peak Study.

9. In addition, the RA Studies assigns relatively high likelihood to very extreme temperatures that have not been seen in the Carolinas, or only rarely, in past decades, and these very extreme conditions drive the RA Studies' results. The Winter Peak Study does not explicitly consider such extreme conditions or evaluate programs specifically designed to reduce loads under such conditions (such as inducements for facilities to open late or remain closed).

10. Accordingly, the Winter Peak Study and the RA Studies are highly inconsistent and contradictory – the RA Studies recommend a reserve margin driven by extreme conditions and extreme winter loads well in excess of the Study Peak Day, while the Winter Peak Study does not even acknowledge such conditions and loads are possible.

11. As I will explain in detail in this report, the extreme winter loads in the RA Studies result from a flawed extrapolation approach for associating loads

to extremely low temperatures that have not been seen for decades. In my 2019 Load Forecast Report, I recommended that the Companies develop a more sophisticated model of how extreme winter weather affects their loads.[12] This important work was not pursued.

12. The main conclusion of this report is that the RA Studies have substantially overstated winter resource adequacy risk. The winter resource adequacy risk was overstated largely due to the following flaws in the RA Studies' analyses:

a. The primary flaw is the inaccurate approach to estimating the impact of extreme cold on loads, extrapolating based on observations at milder temperatures.

b. In addition, the RA Studies used 39 years of temperature data (1980-2018), weighted equally, which includes many instances of very extreme cold that have not been seen in these areas, or only rarely, for decades. This overstates the likely frequency of such extreme cold going forward, therefore amplifying the effect of overstating the impact of extreme cold on winter peak loads.

c. Power plant forced outage rates under extreme cold have also been overstated.

13. While a number of other assumptions adopted in the RA Studies that impact the physical reliability results appear very conservative and could be questioned (such as, external region and market diversity and potential assistance, and demand response operational limits), this report focuses on the issues identified in the previous paragraph.

14. Overstating loads under extreme cold conditions had a substantial impact on the RA Studies' results and recommendations. Through discovery, the Companies provided data showing the specific scenarios within the RA Studies'

[12] Wilson 2019 Load Forecast Report p. 21.

simulations that led to lost load.[13] The majority of the winter hours with loss of load are from scenarios under which the DEC load was 106% of the value on the Winter Peak Study's Study Peak Day or higher. Fully 94% of the loss of load in the DEC RA Study occurs on days with loads in excess of the Study Peak Day value. In the DEP RA Study, the majority of the load loss is in hours with load 114% of the Study Peak Day peak load or higher. 99% of the loss of load in the DEP RA Study occurs under loads in excess of the Study Peak Day value.

15. In my 2019 RA Report I recommended that the Companies "research the drivers of sharp winter load spikes under extreme cold conditions" and "study the relationship between extreme cold conditions and load, taking into account other relevant factors such as likely facility closures and the impact of wind speeds, to inform future resource adequacy studies."[14] While the Winter Peak Study states that it was "initially pursued because of input from stakeholders . . ."[15] there is no evidence such research took place, or that the Companies have gained a better understanding of the relationship between extreme cold conditions and load. As I will explain in this report, the Companies and Astrapé use different and highly simplified approaches to this key question. To the extent the Winter Peak Study reflects such research, apparently the authors felt that under the most extreme conditions loads would not increase very much beyond the Study Peak Day level, due to factors such as the full deployment of space heating equipment and facility closures.

16. In my 2019 RA Report I had also recommended that the Companies "develop programs for shaving these rare and brief spikes" that occur under the most extreme cold. In my 2019 Load Forecast Report I recommended that the

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[13] Duke Energy Response to Data Request ORS AIR 2-35(k), which identifies the particular scenarios that lead to load loss. Note that this data was provided for reserve margins near, but not equal to the recommended reserve margins. See Duke Energy Response to Data Request SELC 6-2.

[14] Wilson 2019 RA Report p. 24.

[15] Winter Peak Study Task 3 Report p. 15.

Companies prepare a tailored plan to engage customers in mitigating extreme peak loads, to be activated if needed when extreme winter weather approaches.[16] Again, apparently the Companies, and the authors of the Winter Peak Study, do not actually anticipate loads much beyond the Study Peak Day with any frequency, for there is no evidence of plans to mitigate such loads.

17. Due to the overstatement of winter resource adequacy risk, I again conclude that the recommended DEC and DEP planning reserve margins are unsupported and higher than necessary. If the flaws I have identified were even partially corrected, the 14.5% summer planning reserve margin that was in place until the 2016 IRP, which would provide a 16.5% winter reserve margin, would be more than adequate.

18. Due to the identified flaws in the RA Studies' assumptions, I also recommend that the analysis and assumptions reflected in the 2020 RA Studies be rejected as the basis of the Storage ELCC Study, or of any future studies of the capacity value of solar or other resource types.

19. This report also comments on two other aspects of the RA Studies:

a. While the RA Studies' recommendations are based on physical reliability results, the reports also present economic reliability calculations. These calculations rest upon numerous highly questionable assumptions, and no weight should be assigned to them. To the extent any attention is given to these calculations, the focus should be on "risk neutral" values, rather than values that assume customers should pay more on average over the long run for additional capacity in order to potentially reduce infrequent high-cost outcomes.

b. The RA Studies also included assumptions about multi-year load forecasting errors ("economic load forecast error"). As in my

[16] Wilson 2019 Load Forecast Report p. 22.

previous reports, I again conclude that it is inappropriate to use multi-year load forecast uncertainty in a model that cannot represent short lead-time adjustments to unexpected load growth, and I again question whether historical Congressional Budget Office Gross Domestic Product forecasting errors are a reasonable basis for estimating the Companies' peak electric load forecasting errors.

20. I also reviewed the Companies' peak load forecasts and the underlying data and assumptions. Based on the information available at the time they were prepared, the load forecasts appear to fall within a reasonable range. However, these forecasts were prepared based on pre-pandemic economic projections (from January 2020), so "the potential impacts of COVID-19 are not incorporated in this forecast."[17] Economic forecasts have generally been lowered since January 2020, so peak loads in the coming years are likely to be somewhat lower than reflected in the Companies' forecasts.

21. The remainder of this report is organized as follows. Section III discusses the issues with the 2020 RA Studies that lead to overstating winter resource adequacy risk. Section IV discusses other concerns about the RA Studies. Section V provides a summary and recommendations for future IRPs. Appendix A summarizes the author's qualifications.

[17] DEC 2020 Plan p. 8.

III. THE RA STUDIES OVERSTATE WINTER RESOURCE ADEQUACY RISK

22. This section first explains that the RA Studies substantially overstate winter extreme peak loads due to a flawed extrapolation approach for estimating how loads would increase due to extreme temperatures. The second subsection reviews the temperature data, concluding that the impact of the flawed extrapolation was amplified by a data set that includes many instances of temperatures that have not been seen in decades and whose likely future frequency of occurring is therefore overstated. The third subsection explains that the frequency of cold-related forced outages was also overstated. These flaws drove the winter resource adequacy risk and reserve margins higher than they would otherwise be.

23. Nearly all of the resource adequacy risk in the 2020 RA Studies is in winter, and nearly all of the risk is in winter mornings, not evenings.[18] Because winter mornings drive the results, this report generally focuses on winter mornings.

A. THE IMPACT OF EXTREME COLD ON WINTER PEAK LOADS IS OVERSTATED

24. In the winters of 2014, 2015, and 2018 there were instances of very low winter temperatures in the DEC and DEP-East[19] service territories. Based on the temperature data used for the DEC RA Study,[20] 2014 and 2015 each had two days in which temperatures dropped below 10 degrees Fahrenheit. However, the 2020 RA Studies used 39 years of historical weather data, back to 1980, and far

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[18] Duke Energy Response to Data Request ORS AIR 2-35(k). In DEC, 96% of the LOLE is winter mornings, and the remainder is in summer. In DEP, 99% of the LOLE is winter mornings, the remainder is winter evenings.

[19] Some of the data in the RA Study workpapers distinguishes the eastern and (much smaller) western portions of the DEP service territory separately. As appropriate, this report will refer to DEP-East and DEP-West for the two portions. See DEC 2020 Plan p. 30 for a map of the service territories.

[20] RA Study support file "All Region Temps 1980-2018." The temperatures associated with each service territory are weighted averages of temperatures at multiple weather stations. See Duke Energy Response to Data Request NC Public Staff data request 1-1(g), attachment "PS DR 1 - Load Forecast - Part G.docx."

lower temperatures were seen in some years in the 1980s (in the DEC service territory, minus 5 degrees in 1985, and 3, 4, and 5 degrees in 1982, 1983, and 1986, respectively). The DEC 39-year data set includes 109 hours with temperatures below 9 degrees, but only 8 of these hours occurred since 1996; the DEP-East 39-year data set includes 67 hours with temperatures below 10 degrees, but this has only occurred once since 1996. Therefore, to use the 39 years of weather data to develop the synthetic load shapes for the RA Study simulations, Astrapé had to model loads under temperatures that have not occurred, or only rarely, in recent decades.

25. The RA Studies generally associated loads with temperatures using a neural network approach.[21] However, for the most extreme temperatures (high or low) for which there are fewer observations, the neural network approach was considered inaccurate, so an additional step, based on regressions, was used to "extrapolate the peaks."[22] The approach entailed estimating the amount by which incremental cold apparently increased load in the 10 to 21 degree range through regression.[23] The results of the regressions, expressed in MW/degree, were then used to extrapolate load levels to the very low temperatures found in the 39-year history. As discussed further below, the extreme loads resulting from these regressions account for nearly all of the load loss in the simulations, and drove the reserve margins higher than they would otherwise be.

26. There are three problems with this extrapolation approach that result in substantially overstating loads under extreme cold. These three flaws are discussed in the following subsections.

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[21] DEC RA Study p. 23. Under the neural network approach, algorithms are employed that endeavor to recognize the underlying relationships in a set of data (in this instance, the relationship of load to temperature) through a process that mimics the way the human brain operates.

[22] Duke Energy Response to Data Request NCSEA 3-3.

[23] Duke Energy Response to Data Request SELC 3-9.

i. The extrapolation approach is conceptually flawed: the incremental impact of extreme cold declines at the lowest temperatures.

27. First, this extrapolation approach assumes that when temperatures drop to extremely low temperatures (15, 10, 5 degrees and even lower), each additional degree will increase loads by the same amount as occurs at around 20 degrees. But for the lowest temperatures, the relationship between temperature and load is much weaker. This is logical -- once temperatures drop to the teens, customers are likely already operating space heating equipment at maximum levels; if temperatures fall even lower, few customers have additional equipment they can turn on. In addition, the winter peak loads under extreme temperatures typically occur in the 7 to 9 AM time frame;[24] under the very rare extreme cold conditions, some schools, offices, and other commercial, government and industrial facilities may open late, remain closed, or operate at reduced levels, reducing loads during the early morning peak on such days. Thus, extrapolating based on temperature-load relationships in the 10 to 20 degree range is conceptually flawed, and not a sound way to estimate what loads would be under the most extreme temperatures for which there is little or no recent data.

ii. The regressions, based on observations up to 21 degrees, overstate the impact of incremental cold on load at the lowest temperatures.

28. The second flaw is in the regression approach itself, which led to overstated estimates of the impact of incremental cold even for the 10 to 15 degree range. The regressions estimate how much load increases for each degree the temperature falls, based on the chosen set of historical observations. The RA Studies used daily minimum temperatures for the regressions, and included observations up to 21 degrees from recent years.[25] Most of the observations

[24] Winter Peak Study Task 1 Report p. 9.

[25] Duke Energy Response to Data Request SELC 3-9 attachment.

reflected in the regressions were in the 18 to 21 degree range for DEC, and in the 16 to 21 degree range for DEP-East. Based on these regressions, the RA Studies estimated the impacts of extreme cold on loads as shown in Table 1.

Table 1: RA Study Assumed Impact of Extreme Cold on Load[1]				
	Winter Mornings		Winter Evenings	
	MW/degree	Percent/degree	MW/degree	Percent/degree
DEC	216.6	1.2%	120.3	0.7%
DEP-E	263.2	1.9%	243.8	2.0%
DEP-W	13.2	1.1%	14.3	1.3%
Total	493.0		278.3	
[1] Duke Energy Response to Data Request SELC 3-9 attachment. Estimates based on regression of daily peak loads to daily morning/evening minimum temperatures, for temperatures 21 degrees and below, first averaging loads in one-degree increments.				

29. The value for winter mornings in the DEC service territory, 216.6 MW/degree, implies that for each additional degree the temperature falls, DEC's load is assumed to increase by 216.6 MW (roughly 1.2%). Ten additional degrees would increase loads by 2,166 MW, well over 10% of the peak load. Similarly, the extrapolation approach suggests that the DEP-East loads would increase 263.2 MW for each additional degree the temperature drops.

30. As noted earlier, in prior IRP dockets I have recommended research to develop a more sophisticated approach to estimating the impact of extreme weather on loads,[26] and this research has not occurred. Instead, the Companies and Astrapé continue to use various simple approaches for this very important relationship that drives RA Study results. For the 2016 RA Studies, Astrapé used the actual temperature in the hour of the peak load for such regressions, not morning minimums, and did not perform the averaging in one-degree

[26] Wilson 2019 Load Forecast Report p. 21.

increments.[27] Yet another very flawed approach to estimating the impact of extreme cold on loads, using "Peak Load Adjustment Factors,"[28] was recently applied in a resource adequacy study for Southern Company, on which Astrapé's role was to provide technical modeling guidance and confirm the technical accuracy of the inputs and methods.[29] The Companies use still another approach to estimating the impact of extreme weather on peak loads, based on very different regressions, to estimate historical weather-normal peaks.[30]

31. The 2020 RA Studies employed a simplistic and flawed way to estimate the impact of incremental cold on loads. First, daily minimum temperatures during morning hours were used to represent winter morning cold conditions. While this may be a reasonable measure for some days, it is a poor measure for other days, for instance on days when the minimum occurs several hours before or after the peak load.

32. However, the more important flaw in the regression approach was to include observations for temperatures up to 21 degrees. The same regression analysis, but excluding the higher temperatures, provides a more reasonable estimate of the impact of incremental cold on load at lower temperatures (although, again, using this estimate to extrapolate to very low temperatures is conceptually flawed and invalid). As I will show next, and also showed in my 2019 and 2017 RA reports, the impact is far lower when the analysis properly focuses on lower temperatures.[31]

33. I performed the same regressions, but excluded the observations at higher temperatures. The results are shown in Figures JFW-1 and JFW-2.

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[27] Duke Energy Response to Data Request SACE/NRDC/Sierra Club 3-1 attachment in Docket E-100, Sub 157.

[28] See *Direct Testimony of James F. Wilson on Behalf of Energy Alabama and GASP*, pp. 48-55, filed December 4, 2019 in Alabama Public Service Commission Docket No. 32953.

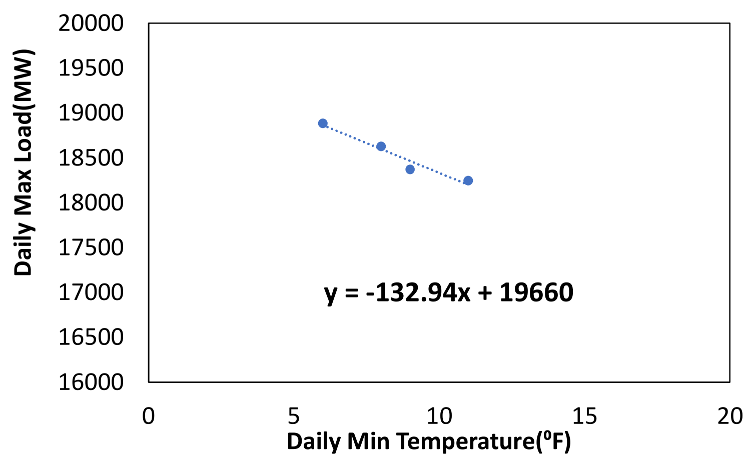
[29] See *Rebuttal Testimony of Kevin D. Carden on Behalf of Alabama Power Company*, p. 3, filed January 27, 2020 in Alabama Public Service Commission Docket No. 32953.

[30] Duke Energy Response to Data Request SELC 2-18.

[31] Wilson 2019 RA Report pp. 8-10, Wilson 2017 RA Report pp. 6-8.

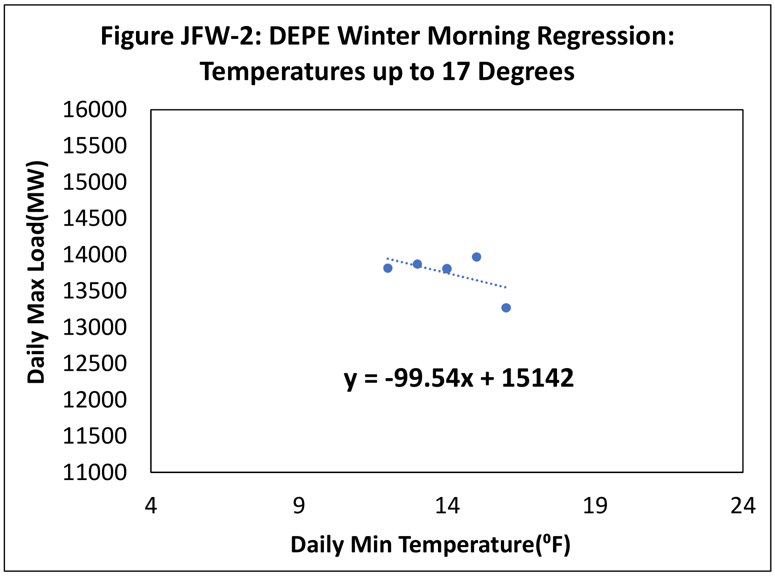
34. For DEC, across the entire temperature range up to 21 degrees, the relationship was 216.6 MW per degree, as shown in Table 1, above. When the regression is focused on temperatures 12 degrees and lower, the impact of cold is just 133 MW/degree. While the observations are few, they do fall in line quite well, as shown in Figure JFW-1.

Figure JFW-1: DEC Winter Morning Regression: Temperatures up to 12 Degrees



35. For DEP-East, the observations used for the regression have less cluster, with outliers at the coldest and also at more moderate temperatures. Just dropping the single observation in the 10-11 degree range changes the estimate from 263.2 MW/degree to 220.2 MW/degree; and additionally focusing the analysis on temperatures below 17 degrees further lowers the estimate to 99.5 MW/degree, as shown in Figure JFW-2. If the most moderate observation, at 16 degrees, is also dropped, the regression suggests further cold does not increase load at all.

36. While dropping the outlier in the 10-11 degree range, or the more moderate observation at 16 degrees, may or may not be justified based on the particulars of these events, the high sensitivity of the regression results to these choices demonstrates the arbitrary nature of the regression approach.



37. Again, it is likely that even the lower MW/degree values from the calculations shown in Figures JFW-1 and JFW-2 overstate the additional impact of the most extreme temperatures on loads, because, as suggested above, at the lowest temperatures, space heating appliances are already in full use and some facilities will open late or remain closed.

iii. THE REGRESSION VALUES WERE APPLIED IN A MANNER THAT LEADS TO SOME EXTREME AND NONSENSICAL RESULTS.

38. The third flaw in the extrapolation approach was in the details of how the MW/degree results of the regressions were combined with the neural network results to determine the final loads used in the RA Studies. While the exact approach is not documented and rather opaque, the values in Table 1 were

generally applied for temperatures below 20 degrees.[32] Apparently the MW/degree values shown in Table 1 were applied to the number of degrees below 20, with the resulting MW value added to the neural network results.

39. The 39-year data set used in the DEC RA Study includes temperatures as low as minus 5 degrees for DEC (on January 25, 1985).[33] Estimating loads at minus 5 degrees based on the 216.6 MW/degree value shown in Table 1 resulted in loads as high as 21,993 MW. Using instead the 132.9 MW/degree estimate shown in Figure JFW-1, this load would drop by over 2,000 MW ((216.6 – 132.9) x (- 5 – 20)), to under 20,000 MW. All other assumed loads under the most extreme temperatures would also be much lower, using a more moderate estimate of the impact of temperature on load. Again, even if a reasonable estimate of the MW/degree value were prepared, it would very likely overstate loads for the lowest temperatures, because the extrapolation approach is conceptually flawed.

40. Temperatures down to minus 2 degrees are modeled for DEP-East, however, the DEP RA Study states that for this particular, most extreme temperature, the regression result was not fully applied.[34] For plus five degrees, the 263.2 MW/degree value would result in adding almost 4,000 MW (263.2 x (5 - 20)) to the load estimate based on the neural network approach. If instead the 99.5 MW/ degree value from Figure JFW-2, the adder is 2,500 MW lower. The choice to use temperatures as high as 21 degrees in the regressions led to the high MW/degree values shown in Table 1, and greatly increased the most extreme loads used in the DEP RA Study.

41. The application of the regressions can also lead to some nonsensical load values. I note two examples.[35]

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[32] Duke Energy Response to Data Request SELC 7-2.

[33] RA Study support file "All Region Temps 1980-2018."

[34] DEP RA Study p. 25 (stating that the load for the negative temperature value was capped).

[35] Duke Energy Response to Data Request SELC 5-1.

42. In the early morning of March 3, 1980 in DEP-East temperatures fell to the high teens. The RA Studies' synthetic load shapes have a peak load for March 3, 1980 at 3 AM, 14,597 MW, with a temperature of 18.9 degrees. This is a very high load; it is the twelfth largest daily peak load in the entire 39-year database for DEP-East, and loss of load occurs in this hour under some of the DEP RA Study scenarios.[36] Why would such a high load occur at 3 AM, and under a relatively mild temperature? The neural network approach suggested a load of only 10,526 MW, but the regression result was applied to override this value, adding over 4,000 MW based on the regression to get the 14,597 MW value. As the morning of March 3, 1980 continued, temperatures continued to fall to a minimum of 13.8 degrees at 8 AM, the hour when winter loads typically reach their peak. But the RA Study shows a much lower load, 12,256 MW, at 8 AM. A huge load peak at 3 AM with mild temperatures, and much lower loads at 8 AM under colder temperatures, makes no sense.

43. As another example, in the DEC service territory, on January 20, 1985 temperatures were falling through the day, and the RA Studies show the peak load at 5 PM, 18,046 MW, with a temperature of 14.7 degrees. This is the highest winter evening load in the database; in fact, the next highest is over 1,600 MW lower. This again reflects a large override of the neural network result; over 2,200 MW was added to this hour based on the regression, and as much as 3,100 MW was added to other hours of this day. These huge adjustments based on the regression apparently result from the fact that temperatures continued to fall to very low levels by midnight. This reflects the flawed approach of using morning and evening peak loads and *minimum* temperatures in the regressions; in those instances where the minimum temperature occurred hours after the peak, the minimum clearly did not drive the peak.

[36] Duke Energy Response to Data Request ORS AIR 2-35(k).

44. Figure JFW-3 and JFW-4 show figures from the 2020 RA Studies illustrating how high winter peaks are assumed to go, relative to the winter peak loads in a "normal" year, based on the most extreme weather in each of the 39 years for which weather data was used. These figures also show the corresponding figures from the 2016 RA Studies. I offer the following observations based on these two figures.

a. First, note that the values for 2018 (the year of the Winter Peak Study's Study Peak Day) are well above (about 5% above) the normal winter peak for both DEC and DEP. The Study Peak Day is indeed an unusually high winter peak load.
b. Second, note some substantial differences in these values between the 2020 and 2016 RA Studies, despite the fact that the common historical data has not changed. For DEC, 2014 and 2015 were 6% to 8% above normal in the 2016 RA Study, but in the 2020 RA Study these years are now considered over 10% above normal. In the 2016 RA Study 1982 was 18% above normal; in the 2020 RA Study it is now 11%. In the 2016 RA Study 1985 was 13% above normal; in the 2020 RA Study it is now 18%. These substantial changes in both directions again reflect the rather arbitrary nature of the extrapolation approach used to assign extreme loads to extreme temperatures. The DEP figures also reflect substantial changes, though not as extreme as for DEC.

Figure JFW-3: Figure 3 from 2020 and 2016 DEC RA Studies

Figure 3. DEC Winter Peak Weather Variability (2020)

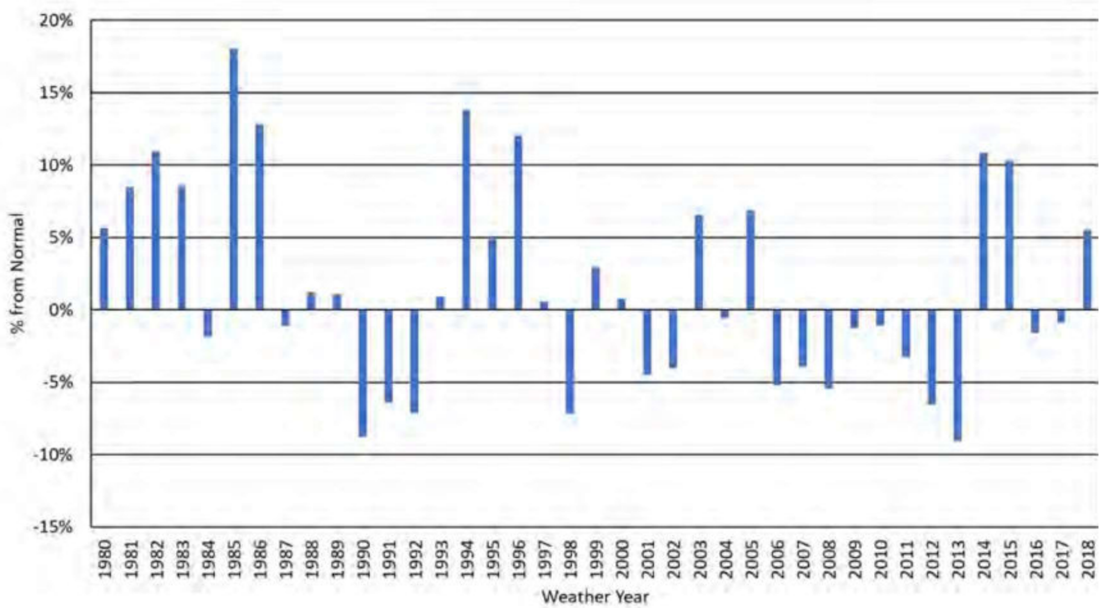


Figure 3. DEC Winter Peak Weather Variability (2016)

Figure 3. DEC Winter Peak Weather Variability

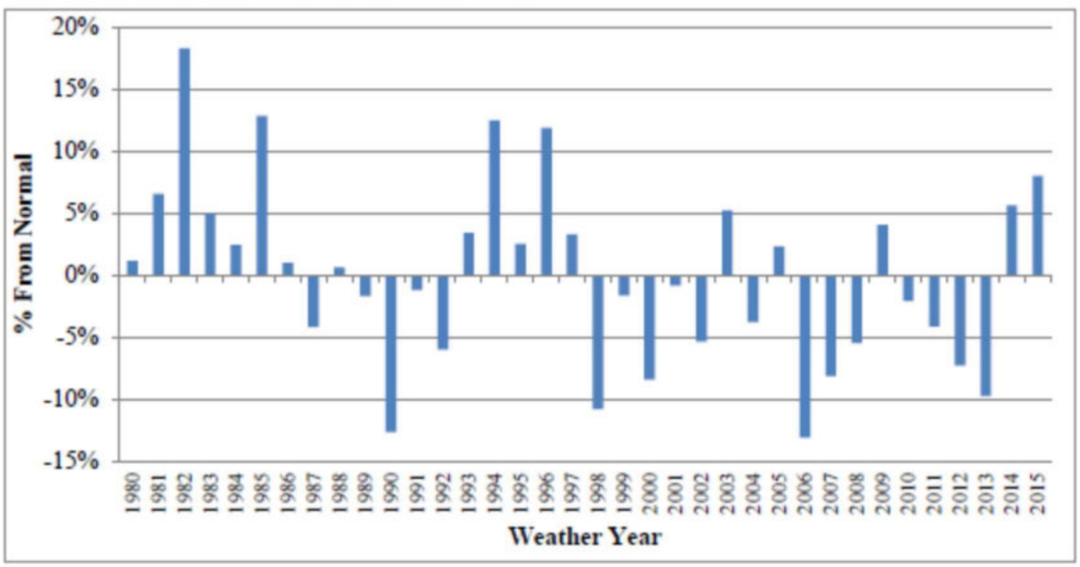


Figure JFW-4: Figure 3 from 2020 and 2016 DEP RA Studies

Figure 3. DEP Winter Peak Weather Variability (2020)

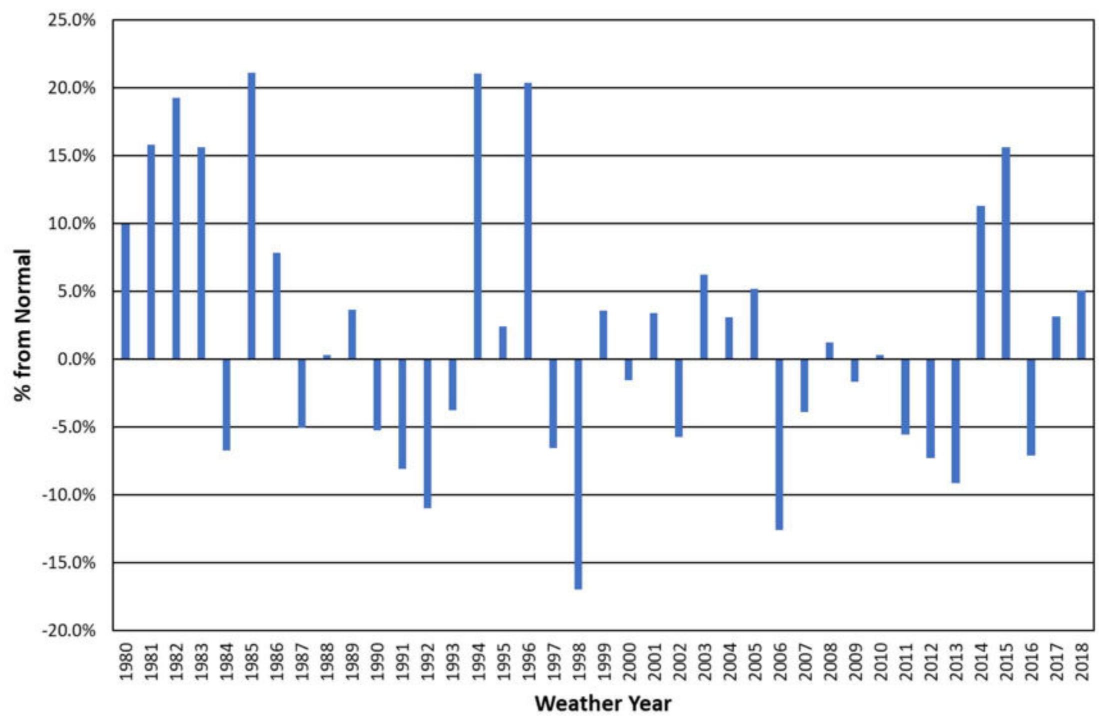
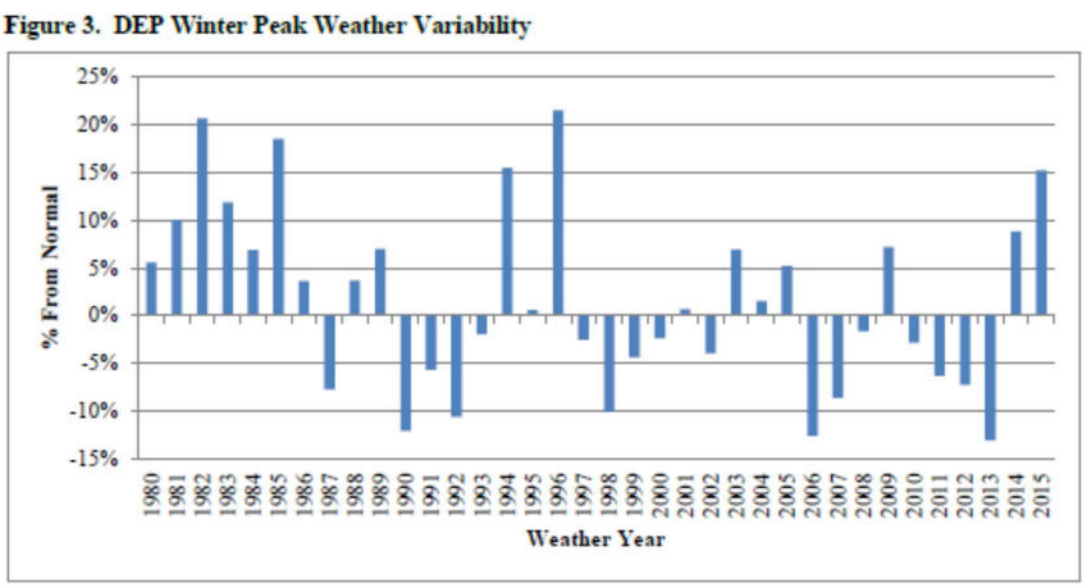


Figure 3. DEP Winter Peak Weather Variability (2016)



45. I conclude that the RA Studies greatly overstated loads under extreme cold conditions, due to the flawed extrapolation approach, as discussed

above.

46. Unfortunately, unlike in prior IRPs,[37] the RA Studies include no sensitivity analysis to the high winter load assumptions. However, these overstated loads had a substantial impact on RA Study results, as will be shown below.

B. The Likely Frequency of the Most Extreme Cold Is Overstated

47. The 39 years of temperature data (1980-2018) used in the RA Studies included many instances of extreme cold that have not been seen, or only rarely, for decades. This calls into question how likely we should expect such extreme cold to be going forward, and whether the RA Studies have overstated the frequency of such extreme cold (all years are equally weighted) and resulting high loads. Overstating the likely future frequency of extreme cold amplifies the effect of overstating the impact of extreme cold on winter peak loads discussed in the prior section.

48. In particular, for the DEC region:[38]

a. The 39-year data set includes 109 hours with temperatures below 9 degrees. But 101 of these instances were in the first 17 years of the period (1980 to 1996), and temperatures below 9 degrees have occurred only 8 times since 1996 (the last 22 years of the data). Two-thirds of these hours occurred in the 1980s.

b. The full data set includes 63 hours with temperatures below 7 degrees. But this has only occurred once since 1996 and only 16 times since 1989.

[37] See, for instance, Wilson 2019 RA Report p. 13.

[38] Duke Energy Response to Data Request SELC 5-1.

c. The full data set includes 44 hours with temperatures under 6 degrees, down to -4.7 degrees. But temperatures below 6 degrees have not occurred since 1996 and only 7 times since 1989.

d. There are 15 hours below 3 degrees, all of which occurred in 1982 and 1985.

49. Similarly, for the DEP-East region:

a. The 39-year data set includes 105 hours with temperatures below 12 degrees. But 97 of these occurred in only the first 17 years of the period (1980 to 1996), and this has occurred only 8 times since 1996 (the last 22 years of the data). Over 70 percent of these hours occurred in the 1980s.

b. The full data set includes 67 hours with temperatures below 10 degrees. But this has only occurred once since 1996 and only 16 times since 1989.

c. The full data set includes 33 hours with temperatures under 8 degrees, down to -1.9 degrees. But temperatures below 8 degrees have not occurred since 1996 and only 6 times since 1989.

d. There are 11 hours below 5 degrees, all of which occurred in 1982 and 1985.

50. The most extreme temperatures, and the extreme loads assigned to them based on extrapolation, drive the results of the RA Studies. In the DEC RA Study simulation, 97% of the loss of load events in winter occur under scenarios with temperatures under 9 degrees. 76% of the winter loss of load occurs under scenarios with temperatures of 6.4 degrees or less, which has only occurred once since 1996. 69% of the loss of load is on scenarios with temperatures below 6 degrees, which has not occurred since 1996. Of the over 14,200 weather days represented in the RA Studies (based on 39 years), two – January 11, 1982 and January 21, 1985 – account for 43% of the LOLE in the DEC RA Study.

51. In the DEC RA Study, the majority of the winter hours with loss of load are from scenarios under which the winter extrapolated DEC load exceeded 20,000 MW, even before load forecast uncertainty was applied (which leads to even more extreme loads).[39] This is 106% of the DEC RA Study's value for the Winter Peak Study's Study Peak Day, January 5, 2018, which is 18,820.4 MW. Fully 94% of the loss of load in the DEC RA Study occurs on days with loads in excess of the Study Peak Day value.

52. In the DEP simulation, 97% of the winter loss of load is under scenarios with 11 degree or lower temperatures. 96% of the winter loss of load is under 10.1 degrees, which has only occurred once since 1996. 79% of the winter loss of load is at 8 degrees or less, which has not occurred since 1996.

53. On the DEP system, the majority of the load loss is on hours with load in excess of 17,480 MW before application of load forecast uncertainty. This is 114% of the value associated with the Study Peak Day. 99% of the loss of load in the DEP RA Study occurs under loads in excess of the Study Peak Day value.

54. Some of these observations are summarized in Table 2.

Table 2: Frequency and Impact of Extreme Temperatures in RA Studies[1]

	Temperature threshold	# days with such temperatures		% of RA Study LOLE under such temperatures
		RA Studies (1980-2018)	Since 1996	
DEC	< 9 degrees	109	8	97%
DEP-E	< 12 degrees	105	8	97%

[1] Duke Energy Responses to Data Requests SELC 5-1 and ORS AIR 2-35(k).

55. As noted above, the RA Studies provided no sensitivity analysis that shows the impact of the assumed extremely high loads assigned to extremely low temperatures on RA Study results. However, Astrapé did perform a sensitivity

[39] Duke Energy Response to Data Request ORS AIR 2-35(k).

analysis under which the 29 years of temperature data from 1990 to 2018 was used (the data from the 1980s was dropped), while no other changes were made. Using data from 1990 to 2018 rather than 1980 to 2018 had a huge impact on the reserve margins to meet the 1-in-10 standard: 13.25% for DEC and 14.75% for DEP, compared to 16% and 19.25%, respectively, from the RA Studies.[40] Note that this is only due to dropping the 1980s temperature data; these reserve margins still reflect application of the flawed extrapolations that overstate the impact of extreme cold on load.

56. To summarize, the vast majority of the winter load loss in the 2020 RA Studies is based on a highly simplified and inaccurate assumption about how loads would increase under the most extreme temperatures, applied to temperatures that have not been seen, or only very rarely, in decades, and whose frequency of occurring is overstated. These assumptions drove the winter risk and reserve margins higher.

C. WINTER FORCED OUTAGE RATES UNDER EXTREME COLD ARE OVERSTATED

57. The RA Studies also exaggerated winter resource adequacy risk by including 400 MW of additional forced outages under all scenarios under 10 degrees:[41]

> "The 2014-2019 period showed more events than the 2016-2019 period which is logical because Duke Energy has put practices in place to enhance reliability during these periods, however the 2016 – 2019 data shows some events still occur. The average capacity offline below 10 degrees for DEC and DEP combined was 400 MW. Astrapé split this value by peak load ratio and included 260 MW in the DEC Study and 140 MW in the DEP Study at temperatures below 10 degrees."

[40] Duke Energy Response to Data Request SELC 3-4 (referring to the file "AG Office Follow-up Items_062520_Final.docx," which is one of the 2020 RA Study support documents).

[41] DEC RA Study p. 32.

58. It was correct to focus on 2016 to 2019, and to not use the data from 2014-2015, because the Companies have taken actions since the 2014 polar vortex event to prevent the high level of outages that occurred at that time. However, the description of this 400 MW for the 2016-2019 period is not correct and the 400 MW value is not supported.[42]

a. First, contrary to the quote above, there were no instances of temperatures below 10 degrees over 2016-2019. There was a single instance of 10.28 degrees.
b. Second, the 400 MW is not an "average"; it is based on the estimated cold-related forced outage on the single instance of 10.28 degrees, which occurred on the morning of January 2, 2018.
c. Third, note that this was a quite unusual date – the outage was very early Tuesday morning following a three-day New Year's weekend. Perhaps if this extreme cold had occurred under more regular circumstances the plant staff could have addressed the cold-related problems that arose without having to take a forced outage during the morning peak period of a day when extremely high loads were expected due to the extreme cold.

59. As DEC RA Study confidential appendix Figure CA3 clearly shows, cold weather outages during 2016-2019 were typically well below the 400 MW value across a broad range of low temperatures, with a few instances higher and other instances lower. If a larger set of instances of cold-related outages is considered, the average is considerably lower than 400 MW.

60. The cold weather outages assumption has a substantial impact on the RA Study results. According to the RA Studies' sensitivity analyses, removing

[42] 2020 RA Study support file "Feb 21 Follow-up Responses_032720_Confidential_Final cold weather outages."

the 400 MW of cold weather outages lowers the DEC and DEP reserve margins by 1.25% and 0.75%, respectively.[43]

61. While, as the RA Study recognizes, cold weather outages can be substantially higher or lower than 400 MW, it is important to keep in mind that the RA Studies perform probabilistic simulations, intended to estimate the likelihood of loss of load. Thus, all assumptions should either be probabilistic, or set at likely values rather than extreme values. Conservatism in planning is appropriate, but it should be transparent and based on unbiased analysis rather than baked into the underlying analysis through various conservative assumptions. I conclude that a value closer to 200 MW would be a better estimate of cold weather outages in future years for the purposes of the resource adequacy analyses.

62. The Companies should of course continue to strive to minimize the risk of outages under extreme cold when the capacity is needed the most. I also note that if the Companies were part of an RTO such as PJM or ISO New England, such outages would be subject to severe penalties, resulting in strong incentives to further improve power plant performance when it matters most.[44]

IV. OTHER CONCERNS ABOUT THE RA STUDIES

63. This section comments on a few other aspects of the RA Studies.

A. ECONOMIC RELIABILITY CALCULATIONS

64. While the focus of the RA Studies is on physical reliability calculations (to find the reserve margin that keeps LOLE below 0.1), and Astrapé recommends that the physical reliability metrics be used for determining planning

[43] DEC RA Study p. 54, DEP RA Study p. 54.

[44] See, for instance, PJM Interconnection, *Strengthening Reliability: An Analysis of Capacity Performance,* June 20, 2018, available at https://www.pjm.com/markets-and-operations/rpm.aspx.

reserve margins,[45] the RA Studies also present "economic reliability" calculations and results. The economic reliability calculations purport to reflect how expected customer cost varies based on planning reserve margins, and they result in the U-shaped curves shown in RA Study Figures ES1 and ES3.

65. This section explains why the economic reliability calculations are unreliable and no weight should be assigned to them. It further explains why, to the extent any attention is given to these calculations, the focus should be on "risk neutral" values, rather than values that assume customers should pay more over the long run to reduce potential high-cost outcomes.

i. Unlike physical reliability calculations, economic reliability calculations require numerous questionable price and cost assumptions.

66. The physical reliability calculations, focusing on loss of load, are typically driven by assumptions based on historical data (load shapes, power plant outage rates). The economic reliability calculations require numerous additional price and cost assumptions that are not needed and not used for physical reliability calculations:

a. Cost of unserved energy (aka Value of Lost Load, or "VOLL"): a price assigned to the MWh of unserved energy due to inadequate resources.
b. External assistance: the prices at which such assistance may be available.
c. Scarcity pricing: how high scarcity prices rise as operating reserves fall to low levels.
d. Demand response strike prices: at what prices demand response is invoked.

[45] DEC RA Study p. 11.

67. The RA Studies set quite high values for these prices, and this drives customer costs very high under low reserve scenarios. But there is no clear and sound basis for setting the values for these parameters, and cases can be made for values across wide ranges. Unfortunately, very little sensitivity analysis was provided for these assumptions (and of the sensitivity analysis that was provided, some show results highly sensitive to these assumptions.[46])

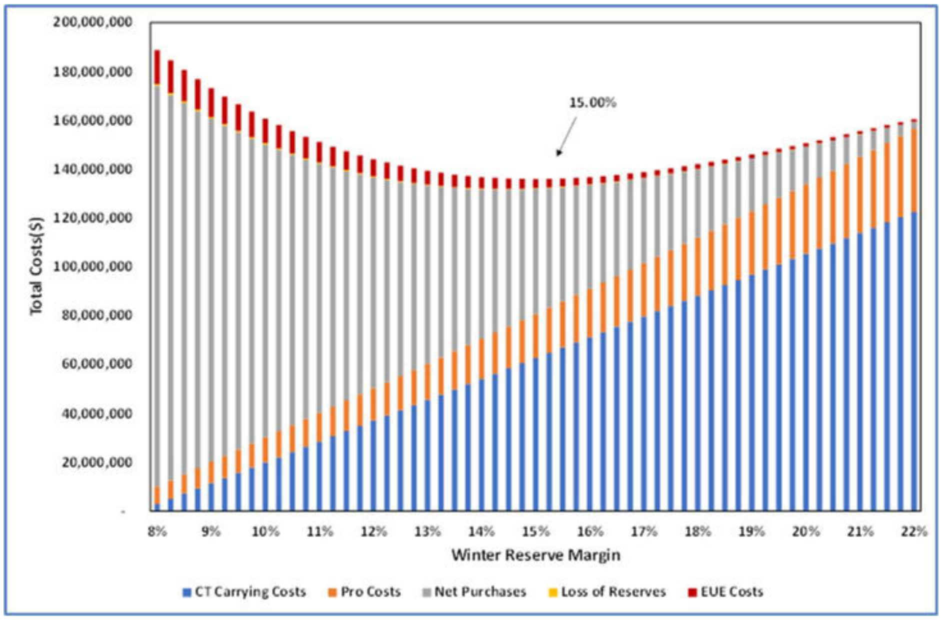
ii. HIGHER RESERVE MARGINS BASED ON PURPORTED CUSTOMER RISK AVERSION ARE NOT WARRANTED.

68. The lowest point on the U-shaped cost curves shown in the RA Studies' Figures ES1 (shown below, for DEC) and ES3, where customer cost is minimized, Astrapé usually calls the Economically Optimal Reserve Margin ("EORM").[47] However, as noted above, these cost curves are based on many rather arbitrary assumptions to which the results are sensitive. In addition, these curves are extremely flat; out of a total annual cost on the DEC system of approximately $1.5 *billion*, total cost only increases by about $3.5 *million* as planning reserves are reduced from 15% to 13%, or increased to 17%, according to the DEC RA Study's calculations.[48] Accordingly, the economic reliability analysis, whose results are summarized in these curves, provide only a weak basis for recommending the EORM, or any other specific reserve margin.

[46] See, for instance, DEP RA Study p. 60 Table 25 (showing a 4.75 % reserve margin difference depending upon whether VOLL $5,000/MWh or $25,000/MWh is used).

[47] See, for instance, The Brattle Group and Astrapé Consulting, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region*, prepared for ERCOT, October 12, 2018, p. 9.

[48] DEC RA Study p. 12 Figure ES1 and footnote 13, and workpapers to this figure.



69. Astrapé proposes focusing on reserve margins greater than the EORM, based on the 85th, 90th or 95th percentile of the calculated total system cost. The RA Studies suggest that this will "shield customers from extreme scenarios for relatively small increases in annual expected costs."[49] However, the higher reserves do not prevent or eliminate the extreme scenarios in the simulation; in fact, they have very little impact on those scenarios, according to the workpapers.

70. It is sometimes suggested that carrying additional reserve margin is analogous to paying for insurance. But this analogy also does not work. People pay for, say, home or auto insurance, because a car crash or home fire can have an extremely harmful impact on family finances. The insurance effectively removes the extreme impact, with the insured generally only paying a deductible, in addition to the insurance premiums. People are willing to pay for insurance, knowing they are likely to end up paying more on an expected value basis over the long term, because the potential impact of a crash or house fire can be so financially harmful.

[49] DEC RA Study p. 13.

71. Carrying a higher reserve margin is not at all like insurance. First, the extreme outcome due to a lower reserve margin would be a relatively high electric bill in a month when reserves fell to low levels. While such a bill might be high, it would not resemble the impact of losing a car or house. More important, carrying a bit more reserve margin, unlike insurance, would not eliminate the high bill, it would only reduce it somewhat. This is not at all similar to what insurance does.

72. The DEC RA Study also asserts (p. 15) that “Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEC is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1).” This is not correct. As the quote suggests, PJM incorporates its capacity market in order to achieve the one day in 10-year standard; but there is no assumption of risk aversion involved. And PJM would argue that its capacity market creates forward price signals that result in efficient capacity entry and exit decisions, and lead to its energy, ancillary services, and capacity markets together meeting customer needs efficiently.

73. The use of a higher percentile of cost rather than risk-neutral is based on the concept that customers should be willing to incur higher costs over the long term on average, in order to slightly reduce the magnitude of the very highest costs under the most unfortunate scenarios, should they ever occur. However, the RA Studies, in addition to exaggerating costs under the highest cost scenarios due to many questionable assumptions (as discussed above), also fail to account fully for the positive, indirect impacts of the high costs that occur under somewhat lower reserve margins.

74. Under the highest-cost scenarios, the very high costs are primarily a result of high unserved energy costs and high costs for purchases. The cost of purchases is dollars paid to purchase power from resources off the Companies’ systems when loads exceed production. But the dollars paid for such purchases

go to utilities, public power entities, merchant power plant owners, or other entities in neighboring regions. If the dollars flow to a utility or public power entity, it is likely that the amounts in excess of production cost reduce the utility's customers' bills, which would benefit those customers. If the Companies' customers and the neighboring utility's customers were to sit down and discuss such bilateral assistance, recognizing the benefits that flow to customers when there are such high-cost purchases, they would recognize that their costs are jointly minimized at somewhat lower reserve margins than if such benefits are ignored.

75. The purchased power dollars might also go to merchant generators. In this case, the dollars will also encourage merchant power plant owners to maintain resources, and to develop additional resources, at their own expense, in order to be able to take advantage of such sales opportunities in the future. This additional merchant capacity will benefit the Companies' customers by creating additional reserves at no cost to them.

76. In addition, the high costs will provide incentives for other types of resources and demand response capability, including price-responsive demand, that may not be sufficiently encouraged or deployed if such episodes of high prices occur less often. This will further draw forth resources and resource flexibility, increasing efficiency and providing indirect benefits to customers.

77. In light of these benefits from episodes of high prices that are ignored in the RA Studies' economic reliability calculations, if any attention is given to these results, the focus should be on the risk-neutral EORM values.

B. Representing Economic Load Forecast Error

78. If peaks loads grow faster than forecasted (for example, due to stronger than expected economic growth), and resource quantities are not increased, it would result in actual reserve margins lower than were anticipated in resource plans published years in advance. The 2020 RA Studies include

probabilistic "economic load forecast error," intended to represent the possible error in four-year-ahead load forecasts (DEC RA Study, p. 27, DEP RA Study p. 28).

79. In the prior (2016) DEC and DEP RA studies this assumption had a substantial impact on the reserve margins: using instead a lower estimated forecast error based on one-year ahead load forecasts, the reserve margin declined by about 1%.[50] For the 2020 RA Studies the representation of load forecast uncertainty was modified, and this assumption now has only a very small impact on the reserve margins.[51]

80. My 2019 and 2017 reports criticized the representation of economic load forecast uncertainty on two grounds.[52] First, I explained why it is not appropriate to include *multi-year* economic load forecast uncertainty in the RA Studies, because the model used (SERVM) is unable to represent the short-lead-time actions that the Companies and market participants would take if stronger-than-expected load growth were to materialize and continue year after year. Second, I explained that the probability distribution of economic load forecast error used in the 2016 RA Studies was not supported by the underlying data it was based upon, and greatly overstated the risk of large and unexpected peak load under-forecast errors.

81. The 2020 RA Studies again attempt to rationalize using multi-year economic load forecast uncertainty, stating as follows: "Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans."[53] In support of this claim, the Companies refer only to the full process of developing a new power plant, from

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[50] Duke Energy, *2016 Resource Adequacy Study – Outstanding Issues*, presentation in Docket E-100, Sub 157 December 12, 2017, slide 27.

[51] DEC RA Study p. 56, DEP RA Study p. 56.

[52] Wilson 2019 RA Report pp. 14-19, Wilson 2017 RA Report pp. 12-16.

[53] DEC RA Study p. 27.

"Develop an RFP for new capacity" through "startup and commissioning."[54] However, as explained in my 2019 and 2017 reports, this ignores the fact that there are many short lead time actions that can and very likely would be taken to expand resources or reduce peak load. If load grows faster than expected and raises concern about resource adequacy, the utilities (and customers and other market participants too) would have time to adjust their plans. To name a few potential actions, the development of some new resources might be accelerated; demand response or energy efficiency programs could be increased; a planned retirement could be delayed; firm purchases from adjacent regions could be increased; or wholesale sales contracts could be allowed to expire.

82. Using an estimate of four-year load forecast uncertainty in the RA Studies essentially assumes the reserve margin and resource plan must be chosen over three years in advance, and then the resource plan must remain frozen for three or four years, even if load growth is much stronger than expected year after year. This is not realistic, and is at odds with the Companies' business practices, including the biannual IRP planning cycle. The assumption that load can rise sharply and unexpectedly, but no adjustments to the resource mix can or would be made over three years, biases the planning reserve margins upward.

83. It is notable that PJM, in its resource adequacy analyses, acknowledges that resource plans can and would be adjusted as needed if load grows faster than expected. Accordingly, while PJM's resource adequacy analysis focuses on determining planning reserve margins for peaks over three years into the future, PJM represents only one year of economic load forecast error in its analyses.[55]

84. My 2019 and 2017 reports noted that it could be appropriate to represent multiple years of forecast uncertainty in a more sophisticated model

[54] Duke Energy Response to Data Request SELC 3-11.

[55] See, for instance, PJM, *2012 PJM Reserve Requirements Study,* p. 20 (explaining the rationale for using a forecast error factor representing one year of forecast error).

that is able to internally determine supply-side or demand-side adjustments over time as the load forecast and other resources change over time in the simulations. For instance, the Electric Power Research Institute's Over/Under capacity planning model, developed in the 1970s, had this capability.[56] Planning reserve margins for future years are somewhat smaller if it is recognized that supply plans can be adjusted over time if needed. However, the SERVM model that was used in the 2020 and 2016 RA Studies does not have the capability to represent any such contingent resource decisions. To represent multi-year load forecast uncertainty, but not the actions that would be taken to adapt resource planning over time as such uncertainty resolves, is a flawed methodology that can bias the result toward higher planning reserve margins. I again conclude that it was inappropriate to use multi-year load forecast uncertainty; it would be more appropriate to use one year of load forecast error.

85. Turning now to the load forecast error probability distribution, the 2020 RA Studies and 2016 RA Studies all used probability distributions for load forecast errors based on the historical forecasting errors reflected in the U.S. Congressional Budget Office ("CBO") U.S. Gross Domestic Product ("GDP") forecasts and applying a 0.4 elasticity of peak demand to economic changes.[57] My 2019 and 2017 reports questioned whether CBO GDP forecasting errors are a reasonable proxy for the applicable economic forecasting errors for the Companies' service territories, and also criticized the representation of economic load forecast error using a symmetric probability distribution.[58] The 2020 RA Studies now use a distribution that is a better fit to the underlying data, and this has reduced the impact of the load forecast uncertainty on the RA Studies' results.

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[56] Decision Focus Incorporated, *Costs and Benefits of Over/Under Capacity in Electric Power System Planning*, EPRI EA-927, Project 1107, October 1978.

[57] DEC RA Study p. 28, DEP RA Study p. 28.

[58] Wilson 2019 RA Report pp. 17-18, Wilson 2017 RA Report pp. 14-16.

86. It is also notable that economic forecasters now expect lower U.S. GDP growth than occurred over the past thirty years, which further shrinks the likelihood of large under-forecasting errors compared to the CBO history. According to the Federal Reserve Bank of Philadelphia's biannual Livingston Survey of approximately 25 economic forecasters, up until 2006, forecasters expected 3.2 percent per year GDP growth, but more recently the median expectation has been only 2.2 percent per year.[59]

87. While the economic load forecasting error assumption apparently had an insignificant impact in the 2020 RA Studies, I again conclude that it is inappropriate to use multi-year load forecast uncertainty in a model that cannot represent short lead-time adjustments, and I again question whether historical CBO GDP forecasting errors are a reasonable basis for estimating the Companies' potential load forecasting errors.

C. Demand Response Assumptions

88. Historically, the Companies were summer-peaking, with loss of load risk, and capacity value, concentrated in the summer period.[60] The Companies therefore have historically designed their demand response programs to reduce demand on the hottest summer days of the year, and, as a result, have substantially more demand response available in summer than in winter.

89. The DEC RA Study assumed 1,122 MW of summer demand response and 461 MW of winter demand response (p. 37). An additional 500 MW of winter demand response would eliminate 60% of the winter load loss events in the simulations; 1,000 MW would eliminate 85%, allowing a considerably lower

[59] Federal Reserve Bank of Philadelphia, *Livingston Survey*, December 2020; releases from 1991 to present are available at https://www.philadelphiafed.org/research-and-data/real-time-center/livingston-survey.

[60] See, for instance, *Duke Energy Carolinas 2012 Generation Reserve Margin Study*, p. 14; Duke Energy Response to Data Request SACE/NRDC/Sierra Club 4-1c in Docket E-100, Sub 157.

winter reserve margin and shifting resource adequacy risk toward summer.[61] The DEP RA Study assumed 1,001 MW of summer demand response and 442 MW of winter demand response (p. 37). An additional 500 MW of winter demand response on the DEP system would eliminate almost 70% of the winter load loss events in the simulations; 1,000 MW would eliminate over 90%.

90. On hot summer days, loads can remain at high levels for several hours. The Winter Peak Study observes that, compared to summer peak days, winter peak loads are typically "steep" (of brief duration), and suggests that peak shifting is not likely to pose a real problem.[62] This suggests that, other things equal, winter demand response should be relatively effective in reducing winter peak loads.

91. This shows that the conclusion that resource adequacy risk is concentrated in the winter is not only greatly exaggerated due to the flaws discussed earlier in this report, it is also highly sensitive to particular resource mix assumptions, such as demand response, that can and should be adjusted for the future. Furthermore, as noted in the summary section of this report, the Winter Peak Study did not discuss the possibility of winter peak loads higher than the Study Peak Day, and did not identify or evaluate demand response programs tailored to mitigating loads greater than the Study Peak Day.

D. Model Estimates of Seasonal and Hourly Capacity Value Are Highly Sensitive to Assumptions That May Change

92. The estimates of the particular seasons, months, and hours where the risk of load loss is highest, based on the modeling approach documented in the 2020 RA Studies and 2018 Capacity Value Study, will be highly sensitive to various model assumptions that can change over time. Assumptions about the

[61] Duke Energy Response to Data Request ORS AIR 2-35(k).

[62] Winter Peak Study Task 2 Report p. 5.

penetration of seasonal resources such as wind, solar and demand response can shift the seasonal balance, and also shift the particular hours in which capacity is likely to be scarce. Tailored demand response programs, or energy storage capacity (such as storage associated with solar resources) can shave peaks or shift them to adjacent hours. Load shapes may also change, due to the penetration of new end-use technologies, or changes in customers' habits, such as usage of programmable thermostats. Various scenarios of these assumptions might suggest very different seasonal and hourly patterns for the modeled load loss.

93. Correcting the flaws in the 2020 RA Studies that overstate winter resource adequacy risk would shift risk back toward summer, as would higher penetration of winter demand response or wind resources, which tend to have higher output during winter peaks than summer peaks.

94. A more balanced seasonal weighting of resource adequacy risk is also suggested by the simple fact that the majority of high load hours are in summer on both systems. According to DEC's load forecast, 92% of the highest load hours (top 1%) are in summer; for DEP's load forecast, 60% of the top 1% load hours are in summer. [63]

V. SUMMARY AND RECOMMENDATIONS FOR FUTURE PLANS

95. The evaluation in this report leads to the conclusion that the 2020 RA Studies have substantially overstated winter resource adequacy risk. I again conclude that the recommended DEC and DEP planning reserve margins are unsupported and higher than necessary. If the flaws I have identified were even partially corrected, the 14.5% summer planning reserve margin that was in place until the 2016 IRP, which would provide a 16.5% winter reserve margin, would be more than adequate.

[63] Duke Energy Responses to Data Request Public Staff 1-2. These values are based on the forecasts for 2025 with EE.

96. The following flaws in the 2020 RA Studies inflate the winter resource adequacy risk and planning reserve margins:

a. The extrapolation approach to associating loads to extreme cold conditions leads to substantially overstating the highest winter loads; more accurate regressions more focused on colder temperatures suggest a much more moderate impact of extreme cold on load.

b. The questionable use of 39 years of weather data, equally weighted, that over-represents extreme cold that has not been seen, or only rarely, for decades.

c. The additional power plant outages under extreme cold are also overstated.

97. The RA Studies also include economic reliability calculations that are unreliable, and no weight should be assigned to them. To the extent any attention is given to these calculations, the focus should be on "risk neutral" values, rather than values that assume customers should pay more on average over the long run for additional capacity in order to potentially reduce infrequent high cost outcomes.

98. The economic load forecast uncertainty assumption has little impact on the RA Study results this time around, but the approach remains flawed. The application of multiple years of economic load forecast uncertainty is inappropriate in a model that does not represent the contingent actions that could be taken if load grows more rapidly than expected. Even accepting the application of multiple years of economic load forecast uncertainty, the use of CBO GDP forecast error data, as a proxy for Duke load forecast error, is highly questionable.

99. The Companies' approach to estimating seasonal, monthly, and hourly resource adequacy risk, seasonal capacity values of solar resources, and recommended reserve margins, reflected in the 2020 RA Studies, will be highly sensitive to various assumptions that can change dramatically in just a few years'

time, such as load shapes during summer and winter peak periods, demand response, and penetration of seasonal resources such as wind and solar.

100. Finally, this evaluation leads to the following recommendations for future IRPs and supporting resource adequacy studies:

a. If the Companies believe winter peak load spikes well beyond the Winter Peak Study's Study Peak Day may be reasonably likely, the Companies should extend the Winter Peak Study work to understand the customers and end uses that could potentially contribute to such extreme loads. If such research suggests that peaks may far exceed what was evaluated in the Winter Peak Study, the Companies should engage with customers and develop tailored programs for shaving these rare and brief spikes.

b. The Companies should study the relationship between extreme winter weather and load, and develop more sophisticated methods for estimating the potential impact of future extreme winter weather on load. The methods should take into account relevant factors, such as wind speeds, and will likely entail multi-hour temperature measures rather than simply daily minimums. The methods should also take into account that the most extreme temperatures will likely result in maximum use of space heating equipment at many homes and businesses, and closure or delayed opening of some facilities. An enhanced method for estimating how extreme cold weather impacts loads would be useful in multiple ways:

    i. A model of how extreme weather affects loads would be useful for anticipating and preparing for the types of high-load events that have occurred in recent winters. Extreme cold weather does not arrive by surprise - it is generally predicted days in advance. An accurate model of how an anticipated weather event will impact loads would assist the Companies in planning for such events days and hours in advance, and determining which actions to mitigate the peak are warranted.

ii. An improved understanding of how extreme weather affects loads would also assist in developing a more effective method for estimating historical weather-normalized peak loads, and for improving the forecasting of future peak loads.

iii. This research would inform the assumptions for future resource adequacy studies, and ensure consistency between load forecasting, resource adequacy modeling, and plans for managing winter peak loads.

c. The Companies should research the potential for load forecast errors due to economic forecast errors or other causes, and the realistic extent to which this could ultimately lead to less capacity than planned in a delivery year, also to inform future resource adequacy studies. Resource adequacy studies must be internally consistent in their assumptions in this regard – if the potential for adjustments to the resource mix in a one- or two-year ahead time frame are not modeled, only one year of economic load forecast uncertainty should be modeled.

d. The Companies should prepare additional load forecast scenarios (such as high and low scenarios), as required by South Carolina regulations.[64] The Companies should also prepare forecasts of extreme or "90-10" summer and winter peak loads, that is, the peaks that are expected to occur only once in ten years.

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[64] SC Code § 58-37-40 (2019) (B)(1) "An integrated resource plan shall include all of the following: (a) a long-term forecast of the utility's sales and peak demand under various reasonable scenarios…".

e. The Companies should provide additional scenario analysis and sensitivity analysis of its RA studies, and allow stakeholders to request additional sensitivity analysis through discovery.

f. The Companies should consider defining an alternative metric for expressing and communicating target reserve margins, which might use, in the numerator, an aggregate capacity value measure (reflecting load carrying capacity rather than installed capacity). An alternative metric might also use, in the denominator, a 90-10 extreme (rather than weather normal) forecast peak load value. Reserve margin targets defined in such terms, which could be presented together with traditional installed reserve margin measures, would be more robust and stable over time as load patterns and the capacity mix change.

APPENDIX: QUALIFICATIONS OF JAMES F. WILSON

James F. Wilson is an economist and independent consultant doing business as Wilson Energy Economics, with a business address of 4800 Hampden Lane Suite 200, Bethesda, Maryland 20814. Mr. Wilson has 35 years of consulting experience, primarily in the electric power and natural gas industries. Many of his consulting assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. His experience and qualifications are further detailed in his CV, available at www.wilsonenec.com.