Technical Review Committee's Review of Duke Energy's Solar Integration Service Charge (SISC)

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AUGUST 31, 2021

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I. Overview of the Technical Review Committee (TRC) Process

On April 15, 2020, the North Carolina Utilities Commission ("NCUC") issued a final Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, directing Duke to organize and coordinate an independent technical review of the "Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge Study" to be undertaken by Astrapé Consulting in 2021 (referred to herein as the "Astrapé Study"). The purpose of the Astrapé Study is to analyze and quantify the costs of the ancillary service impact associated with integrating existing and future solar generation on both the DEC and DEP systems. This solar integration cost is then applied by Duke as Solar Integration Service Charge ("SISC") to intermittent solar generation facilities requesting to sell power to Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (jointly "the Companies").

The NCUC Order specifically stated that:

> . . . the Commission directs Duke to assemble a technical review committee to provide a review of the Astrapé Study. The technical review committee shall be comprised of individuals, not otherwise affiliated with Duke or any of its affiliates or organizations in which Duke is a member, who have technical expertise, knowledge, and experience related to the integration of solar generation as well as the development of complex research, development, and modeling. The committee should include personnel employed by the National Laboratories with relevant experience and expertise. The purpose of the work with a technical review committee is to provide an in-depth review of the study methodology and the model used for system simulations. The technical review committee should provide specific comments or feedback to Duke in the form of a report, which report is to be included in the initial filing made in Duke's 2020 biennial avoided cost proceeding.

Pursuant to NCUC guidance provided in Docket E-100, Sub 158, the TRC "should include personnel employed by the National Laboratories with relevant experience and expertise." The Companies have thus retained the following individuals from National Laboratories as members of the TRC ("TRC Technical Leads"):

- Nader Samaan: Chief Engineer and Team Lead (Grid Analytics), Electricity Security Group at Pacific Northwest National Laboratory (PNNL)
- Gregory Brinkman: Researcher V-Model Engineering and Member, Grid Systems Group in the Strategic Energy Analysis Center at National Renewable Energy Laboratory (NREL)

- Andrew Mills: Staff Scientist, Electricity Markets and Policy Group, Lawrence Berkeley National Laboratory (LBNL)

The Public Service Commission of South Carolina ("PSCSC") similarly directed Duke to undertake "an independent technical review of the underlying modeling, inputs, and assumptions of the Integration Services Charge prior to the next avoided cost proceeding" (PSCSC Order No. 2019-881-A, at 31, 121). Duke agreed with certain interveners to complete the independent technical review in a Partial Settlement Agreement filed with the PSCSC on October 21, 2019, in Docket Nos. 2019-184-E and 2019-185-E. That Partial Settlement Agreement, which was approved by the SCPSC in Order No. 2019-881-A, provided, in pertinent part, that:

> The Astrapé Study used to calculate the SISC presents novel and complex issues that warrant further consideration. Duke shall submit the study methodology and inputs to an independent technical review and include the results of that review and any revisions in its initial filing in the next avoided cost proceeding. To the maximum extent practicable the independent review of the study methodology shall take into consideration the South Carolina Integration Study called for by S.C. Code Ann. § 58- 37-60. This process shall be subject to Commission oversight and comment from interested stakeholders.[1]

The Companies, with input from the NC Public Staff and SC Office of Regulatory Staff ("ORS"), have retained The Brattle Group ("Brattle") as the TRC Principal Consultant to coordinate the TRC meetings, incorporate feedback from the TRC Technical Leads, and author the TRC Report for the Companies to incorporate into their 2021 regulatory filings.

The Brattle Group has substantial expertise in understanding the intra-hour impacts of renewable energy and the impacts of its associated intermittency on a regulated electric utility's system operations. Additionally, through various past consulting engagements, Brattle has demonstrated experience in collaborating with various entities in the development and presentation of technical studies related to renewable energy integration.

The NC Public Staff and the SC ORS have designated the following individuals to participate in the TRC as "regulatory observers" subject to substitution if needed:

- NC Public Staff Primary Regulatory Observer: Jeff Thomas

[1] S.C. Code Ann. § 58- 37-60 provides in pertinent part that "[t]he commission and the Office of Regulatory Staff are authorized to initiate an independent study to evaluate the integration of renewable energy and emerging energy technologies into the electric grid for the public interest. An integration study conducted pursuant to this section shall evaluate what is required for electrical utilities to integrate increased levels of renewable energy and emerging energy technologies while maintaining economic, reliable, and safe operation of the electricity grid in a manner consistent with the public interest. Studies shall be based on the balancing areas of each electrical utility." At this time, no South Carolina Integration Study has commenced.

- NC Public Staff Alternate Regulatory Observer: Dustin Metz
- SC Office of Regulatory Staff Observer: Robert Lawyer
- SC Office of Regulatory Staff Observer: O'Neil Morgan

Starting in March 2021, Brattle consultants (the "TRC Principal") have coordinated regular meetings of the TRC and Astrapé to review the SISC study methodology and modeling assumptions with the Technical Leads, participation by the Regulatory Observers (as available), and Duke technical staff (as needed to address the specific questions raised by the TRC). During these meetings, Astrapé consultants have presented the proposed SISC study methodology and initial draft results to the TRC and the Regulatory Observers for review in biweekly meetings.

In our role as the TRC Principal, we (the named Brattle consultants) have now compiled this TRC Report for the Companies, who will then present the TRC's findings to stakeholders. This TRC Report will also be included in the Companies' South Carolina Act 62 PURPA filing.

II. Public Stakeholder Meeting and Comments

On March 19, 2021, also hosted a public stakeholder meeting to introduce the TRC, discuss plans for completing the scope of study required by the NCUC and PSCSC, and solicit any comments for consideration by Astrapé and the TRC to inform the ongoing study. The presentation slides used for this meeting are attached as Appendix A.

The public comments received in response to the March 19 stakeholder meeting—submitted on March 30 by the Southern Environmental Law Center (SELC) on behalf of Southern Alliance for Clean Energy, North Carolina Sustainable Energy Association, and the Carolinas Clean Energy Business Association—are attached as Appendix B. These comments have been reviewed by the TRC and reflected in the refined SISC study methodology as applied by Astrapé in the current SISC study effort (as reflected the next section of this report).

III. The TRC Review of the SISC Study Methodology

During the TRC meetings, conducted from early March 2021 through the beginning of July 2021, the TRC members discussed several methodological and modeling questions with the Astrapé team. The Astrapé team implemented the recommendations from the TRC, which are reflected in the preliminary report published by Astrapé. In making its recommendations, the TRC also considered the comments provided by the SELC, many of which aligned with the TRC's perspective and have been incorporated in Astrapé final modeling effort.

This section of this TRC Report summarizes the main topics discussed by the TRC during its meetings with Astrapé, provides the TRC's recommendations on each topic, and discusses how Astrapé incorporated the recommendations. The topics include:

A. **Modeling the DEC and DEP Joint Dispatch Agreement (JDA):** The JDA between DEC and DEP allows for joint unit commitment and dispatch between the two utilities (subject to certain limitations). The TRC believes that the JDA allows the two utilities to provide load following reserves at a lower cost than under strictly separate ("islanded") balancing area operation. The TRC recommended that Astrapé model a case that reflects the JDA, and the results of that case were included in the preliminary report ("the Astrapé Report").

B. **The Proposed Southeast Energy Exchange Market (SEEM):** The TRC discussed the possibility of modeling Duke's membership in the proposed SEEM, which would entail modeling some intra-hour imports and exports from Duke's two utilities with the neighboring utilities that plan to join SEEM. In the end, the TRC recommended not modeling the SEEM in this iteration of the SISC estimate, but that it should be considered for the future as operational experience in the SEEM becomes available.

C. **Representation of Solar Volatility and Geographic Diversity:** The TRC and Astrapé discussed the methodology used to model solar profiles, including improvements Astrapé made since their previous effort to estimate the SISC to incorporate the geographic diversity of solar resources. The TRC finds that Astrapé's currently modeling approach to capture solar volatility, including the benefit of decreased volatility due to geographic diversity as more solar resources come online, is a significant improvement compared to their methodology in the 2018 study.

D. **The Level of Solar Curtailments:** The TRC raised questions about the fact that Astrapé assumes no cost for curtailing solar in the model, and recommended that Astrapé conduct a sensitivity that imposes a cost for curtailments to observe how this would change the estimated SISC. The results of that sensitivity suggest that imposing a cost on curtailments does not materially change the SISC, or the overall level of curtailments. The sensitivity results also documented that only a small portion of the simulated curtailments relate to flexibility limits.

E. **Operational Flexibility of Duke Generation Resources:** The TRC explored whether the modeled operational flexibility of some of Duke's combustion turbine (CT) resources and their pumped storage hydro facilities accurately reflected constraints on those resources. The TRC discussed the topic with subject matter experts at Duke. The TRC concluded that, while some of Duke's CTs and pumped storage facilities are less flexible than similar resources owned by other utilities, the modeling assumptions reflect the current operational restrictions on these generation resources.

F. **The Addition of Flexible Generation Resources to Duke's Fleet:** The TRC observed that Duke may be able to provide the load following necessary to integrate new solar at a lower cost by investing in or contracting for additional flexible resources. The TRC, working with Astrapé, conducted a back-of-the-envelope estimate to compare how much it would cost to provide the same level of load following reserves determined by SERVM with new battery resources. The TRC found that under the solar penetration levels studied in Tranche 2 it is unlikely that building new battery storage resources would be cheaper than providing load following with Duke's current generation fleet. However, the TRC recommends that the Commissions should continue the discussion regarding Duke's investment in new flexible resources in the context of Duke's resource planning efforts, especially as solar penetration levels increase beyond those modeled in Tranche 2 and as the cost of new flexible resources change over time.

G. **Methodology for Modeling the Addition of Load Following Reserves:** Astrapé implemented a new methodology for determining how load following reserves are added by the model to accommodate new solar. The new methodology is more targeted to specific times of day (compared to an all-hours approach used in the 2018 SISC study), which reduces the amount of load following and the cost needed to integrate new solar. The TRC finds that the new approach is an improvement compared to the 2018 study, results in a lower solar integration cost, and better represents the actual solar integration cost.

H. **Benchmarking the Estimated Cost of Reserves:** The TRC compared the estimated cost of load following reserves with similar reserve products in PJM. The estimated cost of load following for DEC and DEP are higher than they are in PJM, which is expected and reasonable given the size of Duke's footprint relative to PJM and given the relative inflexibility of Duke's generation resources.

I. **Consideration of Comments from the SELC:** The TRC reviewed and discussed all the comments submitted by the SELC, many of which aligned with the TRC's own view on how to improve the estimate of the SISC. Where the TRC agreed with comments from SELC, it recommended that Astrapé implement those changes in its model.

J. **Interpretation of Solar Tranches:** The TRC reviewed the modeling assumptions for the three Tranches of solar penetration studied by Astrapé. Tranche 1 represents a level of solar penetration slightly lower than the currently planned solar additions in DEC and DEP and Tranche 2 models a level of solar that is slightly higher than the currently planned solar additions. Tranche 3 analyzes much higher levels of solar penetration than expected during the time when the SISC estimated in this proceeding will be in effect. The TRC recommends that the Commissions not rely on the results of Tranche 3 in setting the SISC in the current proceeding.

The remainder of this section provides a more in-depth review each of these topics, including details of the TRC's recommendations.

A. Modeling the DEC and DEP Joint Dispatch Agreement

After the merger of Duke and Progress, the combined company implemented the JDA between DEC and DEP to provide generation at a lower cost for customers of both utilities. Under the JDA, Duke performs a joint unit commitment and minute-by-minute energy dispatch subject to transmission availability between the two utilities. The JDA allows lower fuel and operational costs for both utilities. Although each BA must have sufficient capacity to meet their respective planning reserves and operating reserves, the transfer of economic energy between the two BAAs allows for lower-cost load following, than would be achieved under separate unit commitment and dispatch.

In its previous estimate of the SISC, Astrapé modeled independent unit commitment and dispatch for the DEC and DEP generation resources. The previous Astrapé study also assumed that there was no transmission interconnection between the two utilities and no exchange of economic energy for the purpose of intra-hour load following. Similar assumptions are reflected in the "islanded" cases presented in the Astrapé Report in this estimate of the SISC.

To reflect the operation of the JDA, the TRC requested that Astrapé simulate a scenario for the current study where DEC and DEP areas perform joint unit commitment and minute-by-minute dispatch subject to applicable transmission limitations. Astrapé and the TRC discussed the operation of the JDA with subject matter experts at Duke to ensure that the model reflects the true operation of the JDA as best as possible. In the combined case, resources in DEC and DEP are jointly committed and dispatched, but the BA's must satisfy their individual operating reserve requirements, and the model respects the transmission constraint between DEC and DEP. The Astrapé Report presents the results of this case as the "combined" case.

The TRC recommended modeling the combined case because it better reflects Duke's current operations than the islanded cases.

B. The Proposed Southeast Energy Exchange Market (SEEM)

Within the last year, Duke and several other utilities in the Southeast region have proposed creating the Southeast Energy Exchange Market (SEEM). As proposed, the SEEM will facilitate 15 minute trading between Duke and its neighbors, such as TVA and Southern Company, without the need for paying transmission wheeling fees between the areas. In the SEEM, schedules would be locked in five to ten minutes before the 15 minute trading period, implying that the SEEM could respond on a 20 to 25 minute basis to help balance solar volatility between SEEM members. As of the writing of this report, that proposed market rules are still in front of FERC for approval and the SEEM has not begun operation.

The TRC decided that it is premature at this point to include potential effects of the SEEM in the estimate of the SISC. This recommendation was made because the design, implementation, and actual operations of SEEM are still uncertain, making any modeling assumptions used to represent the SEEM at least partially speculative. The TRC made this recommendation in light of the fact that the proposed start date for the SEEM is January 2022, which is during the time period when the currently estimate of the SISC is likely to be in effect. However, the effects of the SEEM can be considered in the next estimation of the SISC after the exchange is implemented and operational experience has been gained.

In addition, the TRC is not certain that the SEEM will be helpful in balancing solar volatility given the 20 to 25 minute lead time needed to lock in schedules prior to real-time operation. The TRC raises the question of how much solar uncertainty is resolved 20 to 25 minutes before real-time. There is some evidence from studies done in other jurisdictions related to wind volatility that even a 30-minute prior to real-time update to schedules can reduce integration costs.[2] However, that study is almost 10 years old, is from a different region of the country, and does not address solar volatility, which has different characteristics then wind. This uncertainty is another reason why the TRC recommends waiting until the SEEM has been in operation for some time before it is represented in the modeling done to estimate the SISC.

The TRC recommends including SEEM in next update of the SISC when more is known about SEEM operations and there is historical data on SEEM intra-hour energy trades.

[2] See the 2012 Bonneville Power Administration Study accessed here: https://www.bpa.gov/Finance/RateCases/InactiveRateCases/BP12/Final%20Proposal/BP-12-FS-BPA-05.pdf

C. Representation of Solar Volatility and Geographic Diversity

The TRC reviewed the methodology utilized by Astrapé in the SERVM model to capture solar profiles in line with historical volatility. The hourly solar profiles used in the model come from the National Renewable Energy Laboratory's (NREL) National Solar Radiation Database for the last 39 years for each county in Duke's service territory.[3] On top of the hourly profiles, Astrapé adds 5-minute volatility to represent real-time solar output. The 5-minute volatility is determined from historical data.

Unlike in their previous estimation of the SISC, Astrapé accounted in this study for the decline in unitized volatility of Duke's aggregate solar portfolio due to the addition of new solar resources. The decline in solar volatility as a decreasing function of solar capacity is due to the increasing geographical diversity of Duke's solar resources, as new facilities come online in different parts of the Carolinas. The Astrapé team analyzed the decline of aggregate solar volatility by observing the historical 5-minute volatility of solar for DEC, DEP, and the combined DEC-DEP footprint. This provided three historical data points of 5-minute solar volatility as a function of installed solar capacity. The Astrapé team fitted a curve to the 95th percentile in solar volatility at those three levels of solar deployment, and then extrapolating that trend to greater levels of solar deployment.[4]

The TRC raised several questions during the discussion with the Astrapé team. First, the TRC pointed out that it will be more difficult to forecast solar volatility on certain types of days (e.g., partially cloudy days), and asked how day-ahead forecasts are generated in SERVM. The Astrapé team explained that the model compares the realized output for the day in question and compares it to other days with similar profiles. Next, the model randomly samples those similar days to use as a forecast (e.g., if a day's realized solar output is highly variable, corresponding to a partially cloudy day the model will select a profile from a similarly cloudy day).

In addition to the difficulty in forecasting solar volatility on a day-ahead basis, the TRC commented that intra-hour solar volatility would be larger on a day that is partially cloudy. The Astrapé team responded that the model accounts for this implicitly by sampling volatility profiles as a function of hourly solar production, so an hour with 50% of nameplate output will stochastically draw its volatility profile from a historic hour that also has approximately 50% nameplate output.

The TRC discussed the inclusion of behind-the-meter solar in the historical data used to determine the intra-hour volatility of solar. The Astrapé team indicated that the historical solar data is from SCADA and does not include behind-the-meter solar, so ramps in solar generation could actually be larger than

3 Carden, K., Wintermantel, N., and Patel, P., "Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study," Preliminary Draft, p. 23.

4 *Id.*, pp. 27-28

modeled. The modeling effort may thus underestimate the integration cost of new solar resources. Behind-the-meter solar is included in the historical load data and affects the load volatility, but increased adoption of behind-the-meter adoption is not modeled, implying that the load volatility is fixed during the forecast period.

The TRC finds that Astrapé has significantly improved the modeling of solar volatility, including the benefits from a decline in volatility as new solar resources come online in DEC's and DEP's service territories.

D. The Level of Solar Curtailments

The TRC raised questions about the level of solar curtailments observed in the results, and regarding how curtailments effect the integration cost of new solar resources. The TRC noted that solar curtailments reached very high levels in the "island" case, where DEC and DEP perform independent unit commitment and dispatch, and cannot trade with each other. For example, in the island case, solar curtailment in DEP ranges from 6.8% in Tranche 1 to 14.1% in Tranche 2.[5] In the combined case, which reflects the JDA, curtailment levels are significantly lower and range from 0.3% in Tranche 1 to 3.0% in Tranche 2 for the combined DEC and DEP footprint.[6]

The Astrapé model does not include a penalty for solar curtailment, though curtailing solar does impose an increase in fuel costs in the model as fossil generation replaces curtailed solar. The lack of penalty for curtailments is consistent with state regulations for PURPA contracts. Even during non-emergency conditions, Duke does not pay a penalty for curtailments unless curtailed energy over the year is greater than 5% of expected annual output in DEC and 10% expected annual output in DEP for North Carolina; and 5% of expected annual output in South Carolina.

The TRC, in discussion with Astrapé, noted that the high levels of curtailments estimated in the simulations might actually reduce the SISC. This is because only a small fraction of the simulated curtailments relate to intra-hour load following needs. This also means that the model can use curtailments as load following reserve, and the ability to curtail solar without a penalty may make them a low-cost way to provide the additional load following reserves needed to integrate new solar resources. This is consistent with a recent study on solar integration costs in Arizona, which found that integration costs increased when solar curtailments were reduced by applying a penalty.[7]

[5] *Id.,* p. 48

[6] *Id.,* p. 53

[7] See https://www.osti.gov/biblio/1164898/

To explore the impact of solar curtailments on integration costs, the TRC requested that Astrapé conduct a sensitivity that includes an economic penalty for curtailing solar resources. The results of that sensitivity demonstrated that curtailments and the estimated SISC remain relatively the same even with the penalty on curtailments included in the model. In fact, the SISC increases by a small amount given the penalty, which confirms that curtailments reduce overall integration costs.[8]

The TRC finds the treatment of curtailments in the model is conservative in terms of its impact on the SISC and is consistent with policy related to PURPA contracts.

E. Operational Flexibility of Duke Generation Resources

The TRC reviewed the modeling assumptions used to represent the operational parameters of DEC's and DEP's conventional generation fleet, including max output, min output, minimum downtime, minimum uptime, 10 minute ramping capability, and startup time. This review led the TRC to raise questions about the modeling assumptions used for two particular resource types: combustion turbines (CTs) and pumped storage hydro resources. The modeling assumptions used to represent these two resource types indicated that the resources were less flexible than TRC members expected. In light of the fact that CTs and pumped storage hydro are typically ideal resources for providing load following, the TRC requested additional information from Duke on the operational characteristics of these resources.

The TRC noted that a number of block-loaded CTs (e.g., Lincoln and Mill Creek) are modeled without any flexibility, meaning the minimum output on the units is equal to maximum output. Duke confirmed that these units cannot be put on Automatic Generation Control (AGC) because of air permit restrictions. Upon further review, the TRC concluded that the lack of ramping capability for these CTs might not have substantial impact on the SISC, as the units are relatively small capacity that can be committed in less than an hour. In fact, the SERVM model is able to commit or de-commit the CTs unit-by-unit to help ramp up generation as solar production declines. Astrapé confirmed that the CTs can be used this way by SERVM, as the model has the ability to start and shutdown units intra-hour even though commitment is determined only on an hourly basis.

The TRC requested a detailed explanation of the capabilities of Duke's Bad Creek and Jocassee pumped storage hydro units. The modeling assumptions suggested that both resources have a very narrow window between minimum generation and maximum generation. Duke provided the following operational information about pumped storage:

8 This sensitivity was conducted before the final version of the model and results were completed. Given the results, the TRC did not recommend that this assumption be applied to the final version of the model.

- When in generation mode, the Bad Creek units can operate between 320-420 MW, and the Jocassee units can operate between 170-195 MW.
- When in pumping mode, the units have no ramping capability because they are single-speed motors (fixed load).
- The units are often in pumping mode during periods of peak solar generation, to utilize the low variable cost energy provided by solar resources. Therefore, the pumped storage units are typically not available to provide load following in the hours when solar volatility is most severe.

The TRC discussed with the Duke the feasibility of upgrading the pumps to variable frequency drive, which would enable them to provide more flexibility. Duke indicated that the company has considered that in the past, but that the new machines did not fit within the existing physical structure. Given that an upgrade to the two pumped storage hydro resources is currently not planned, the TRC concluded that the resources should be modeled based on the existing operational capabilities.

TRC concludes that the CT and pumped storage units in DEC and DEP are less flexible than in other systems. However, barring potentially expensive upgrades to the units, their limited flexibility appears to reflect legitimate constraints on their operation and are correctly represented in the simulations to estimate the SISC.

F. The Addition of Flexible Generation Resources to Duke's Fleet

The TRC observed that as the total estimated integration cost grows large enough—particularly under Tranches 2 and 3—it may be less expensive to provide the necessary load following reserves by investing in or contracting for new flexible resources, such as battery storage. The current assumption in the Astrapé study is that all load following reserves will be supplied through the operation of Duke's current generation fleet, implying increased fuel and operating expenses to provide the load following needed to integrate the new solar. The TRC suggested that it may be possible to provide the same level of load following reserves at a lower cost by having additional battery storage resources on the system.

For example, the Astrapé study found that the annual integration cost in the combined case under Tranche 2 is $24.3 million per year.[9] The TRC and Astrapé conducted a back-of-the-envelope calculation to test whether new batteries could provide the needed load following at a lower cost. This would require enough battery capacity to cover the maximum increase in load following reserves for any hour

[9] Carden, K., Wintermantel, N., and Patel, P., "Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study," Preliminary Draft, p.51.

estimated by Astrapé's modeling. Astrapé estimated that the maximum load following would be 472 MW, implying that the system would require 472 MW of 1-hour battery resources to provide the same result as modeled by Astrapé.[10] Lazard's 2020 Levelized Cost of Storage Analysis estimates a range of costs for 1-hour in-front-of-the-meter battery resources of $55-$87/kW-year.[11] Applying those numbers to the estimated 472 MW of needed batteries produces a cost estimate of $26.9 million per year to $41.1 million per year. Therefore, the TRC found that it is unlikely that new battery resources could provide the same integration at a lower cost than Duke's existing resource fleet, based on the Tranche 2 level of solar penetration.

However, the TRC recognizes that the cost of battery storage has been declining in recent years and the level of solar penetration on Duke's system continues to climb, and will likely be above the levels analyzed in Tranche 2 within the time horizon used for integrated resource planning. Moreover, the TRC recognizes that battery storage resources provide additional benefits to Duke customers through inter-hourly energy arbitrage opportunities, and that battery resources may imply additional costs not accounted for in the estimate conducted by the TRC. Therefore, the TRC raises the issue for the Commissions to consider during Duke's future resource planning processes.

The TRC finds that it is unlikely that battery storage alone would provide a cost effective integration solution based on the solar penetration levels studied under Tranche 2. However, the TRC raises this question for the Commissions to consider during Duke's future resource planning efforts if they were to determine that is appropriate.

G. Methodology for Modeling the Addition of Load Following Reserves

In the current Astrapé study, additions of load following reserves additions made only to maintain the intra-hour reliability level that the Duke systems are able to achieve in the absence of solar generation. This is a less stringent criterion than the absolute level of loss of load events (LOLE) that was used in the 2018 study. In addition, the current study increases load following reserves on a monthly basis and only during the hours of the day when solar-related flexibility violations are likely to occur each month. This is a different approach than that employed I the 2018 study, which increased reserve requirements by the same amount for all hours of the year. Maintaining no-solar reliability levels and targeting the load following reserves additions to the months and time of day when needed reduces integration costs.

[10] The results from SERVM in the Astrapé study provide an average realized increase in load following needed to integrate new solar over the entire year (204 MW), but not the maximum increase in load following needed for this calculation. Therefore, we use the ratio of the maximum targeted increase in load following (1,047 MW) to the average targeted increase (452 MW) to scale up the average realized increase. See Figures 16 and 21 in the Astrapé Report for the targeted load following amounts. The resulting estimate is as follows: (1,047/452)*204 = 472.

[11] See Lazard's Levelized Cost of Storage Analysis, Version 6.0, accessed at https://www.lazard.com/perspective/lcoe2020

The TRC noted that the reserve levels might be adjusted further depending on each the day's volatility forecast. For example, required reserves could be higher on partially-cloudy days when volatility is the greatest. However, this forecast-based approach is still in the research stages and, thus, not standard practice among system operators. It is consequently not necessary to include it in this study of the SISC.

The TRC finds Astrapé's approach to be reasonable, representing a significant improvement over the 2018 study and consistent with how most system operators determine their load following requirements.

H. Benchmarking the Estimated Cost of Reserves

To benchmark and validate the results of the Astrapé model, the TRC compared the implied cost of load following reserves from the simulation to the cost of reserves in PJM, the neighboring organized RTO market. The TRC determined the implied price of Duke load following reserves based on (1) the simulated increase in ancillary service costs: the ancillary service cost impact ($/MWh) multiplied by the renewable generation (MWh); divided by (2) the additional load following MWh needed to integrate the renewable energy. The TRC and Astrapé found that the implied cost of load following reserves from the simulation is $17.25/MWh to$20.45/MWh in the combined case for Tranche 1 and Tranche 2, respectively.

Publicly available data from the PJM market indicates that the cost of regulation reserves was $13.55/MWh in 2020, $16.27/MWh in 2019.[12] Therefore, the estimated prices in Duke's service territory are slightly higher than in the PJM. However, the higher cost of reserves for DEC and DEP than PJM is expected, due to the much smaller footprint relative to PJM and the more limited flexibility of Duke's generation fleet. Therefore the TRC finds that the estimated cost of load following reserves is within the expected range.

The TRC finds that the estimated cost of additional load following reserves is reasonable given the size of DEC's and DEP's footprint relative to PJM and given the relative inflexibility of Duke's generation fleet (specifically the CTs that are block loaded and the narrow operating range of the two pumped storage resources).

[12] Monitoring Analytics, Independent Market Monitor for PJM, "2020 State of the Market Report for PJM," Section 10, p. 464, accessed here: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-sec10.pdf. The Regulation Ancillary Services product in PJM is not an exact benchmark for the 10-minute load following reserves modeled in the Astrapé study, because the PJM Regulation product requires 5-minute response. However, there is no exactly comparable product in PJM's market, as there is no market in PJM for load following reserve similar to the load following deployed by Duke. The 5-minute Regulation product in PJM is likely more expensive than a hypothetical 10-minute product in PJM that would be more directly comparable to the 10-minute load following reserves used in the study.

I. Consideration of Southern Environmental Law Center Comments

The TRC considered all the topics raised by the SELC, several of which align with the TRC's own views on how to improve the estimation of the SISC. The list of topics raised by the SELC and the TRC recommendations for each are:

1. **The flexibility balancing requirement should be based on NERC standards, not historical 5-minute flexibility violations.**

   The model is set up to replicate the historical operation of Duke's system. The methodology matches simulated 5-minute flexibility violations in the added solar cases with 5-minute violations in the no solar case, which is calibrated to match the historical 60-minute ramping capability of the DEC and DEP systems. The TRC found that this is a significant improvement over the approach used in the previous Astrapé study. The previous approach determined the additional load following reserves necessary to maintain 0.10 expected flexibility violations per year ($LOLE_{FLEX}$). The new approach adds load following reserves as needed, and lets the model calculate the flexibility violations. The additional load following will free the capacity of units on AGC to provide system regulation and avoid violations of NERC standards. Astrapé iterates the simulation by reducing or adding more load following reserves to match historical 5-minute flexibility violations. Therefore, this new approach calculates the cost of integrating solar resources due to the need for additional load following reserves to maintain the historical 5-minute flexibility violations.

   It is possible that historical operations have resulted in higher reliability than is necessary to avoid NERC violations, creating a "cushion" of added reliability that could be lost without violating NERC standards. The TRC did not study if such a reliability cushion exists, because the TRC believes it is out of scope for this study. One may make an argument that Duke has historically over-provided reliability compared to what is necessary to achieve the NERC standards, and that it may be possible for Duke to provide less reliability and lower system costs while maintaining NERC standards. The TRC did not study what optimal operation would look like, as that is a separate issue from estimating the SISC.

   Moreover, adjusting the modeling assumptions to reduce the level of reliability to exactly the amount needed to avoid NERC standards implies eliminating any potential reliability cushion that has historically been provided to customers and giving all the benefit of eliminating that cushion entirely to solar resources.

   The TRC and Astrapé discussed additional modeling considerations related to this topic:

- The model has perfect foresight 5 minutes ahead. Therefore, the number of 5-minute flexibility violations found by the model is less than what would occur in reality, implying that the estimate of integration costs in conservative in this.
- The TRC raised technical concerns about how to fully model the NERC BAAL standards without modeling the frequency on the entire Eastern Interconnection. Modeling the entire interconnection would require a much larger modeling effort than was provided for in this study, with uncertain additional benefits from the added modeling effort.
- Astrapé provided information on the length of flexibility violations (5-min vs. 10-min) to inform whether having the model match historical 10-min flexibility violations, instead of 5-min violations, would significantly alter the results. The addition of solar resources increases the share of longer flexibility violations, which implies the integration costs would be higher if the modeling was forced to match historical 10-minute flexibility violations. Therefore, the approach used by Astrapé results in a lower SISC relative to using a longer flexibility violation.

2. **Non-spinning reserves should be allowed to provide load following.**

   Astrapé's model allows non-spinning reserves to provide load following, including the quick start resources.

3. **Account for aggregation benefits and reduced variability and uncertainty as more solar resources come online.**

   The TRC finds that Astrapé has made several adjustments for this study relative to the 2018 study to better capture solar variability, as well as adjustments to capture some of the aggregation benefits and reduced variability/uncertainty as new solar resources. See discussion in Section III.C.

4. **Validate the model results against historical reserve data.**

   The TRC discussed this suggestion and concluded that historical data likely does not provide a good comparison to the model results for the estimate of the future SISC. Historical data would be based on lower solar penetration and different system conditions (e.g., fuel prices, coal retirements, water conditions, load levels, etc.) that will affect the quantity and cost of load following reserves historically held by Duke.

5. **Incorporate the SEEM.**

   The TRC recommended not including a representation of the SEEM in the model for this iteration of the estimation of the SISC, as the final market structure has not been approved and implemented. In addition, it is unclear how much the SEEM will help provided lower-cost load following reserves, given the requirement to lock in schedules 20 to 25 minutes ahead of real-time. The TRC suggests that the Commissions should consider this for future updates of the SISC. See discussion Section III.B

6. **Model DEP and DEC with unified commitment and dispatch.**

The TRC recommended that Astrapé conduct a sensitivity that includes the JDA. The results of that sensitivity are presented in the Astrapé Report as the "combined case." The TRC finds that the combined case better represents actual operation of DEC and DEP with the JDA relative to the islanded case. The TRC recommends that the Commissions consider those results when setting the SISC. See discussion Section III.A

7. **The high cost of conventional generator inflexibility.**
   The TRC requested additional information from Duke to confirm the modeling assumptions related to the operational flexibility of Duke's CTs and its pumped storage hydro resources. The TRC finds that these resources are relatively inflexible compared to similar resources in other parts of the country, but the modeling assumptions represent legitimate operating restrictions on Duke's system. See discussion Section III.F

J. Interpretation of Solar Tranches

The Astrapé study estimates the SISC for a wide range of potential solar penetration. Tranche 1 represents a level of solar penetration that is slightly less than the currently planned solar additions in DEC and DEP. Tranche 2 models a level of solar that is slightly higher than the currently planned solar additions. Lastly, Tranche 3 analyzes much higher levels of solar penetration than expected during the time when the SISC estimated in this study will be implemented. By the time solar penetration reaches the levels analyzed in Tranche 3, DEC's and DEP's conventional resource mix will likely be considerably different, which means that the cost of integrating solar will be significantly different than Tranch 3 estimates.

Given the level of solar development analyzed in each Tranche, the TRC found the Commissions do not consider the results of Tranche 3 in determining the current SISC. The TRC recommended that the Tranche 3 results be placed in an appendix of the Astrapé Report and only be relied upon for illustrative purposes, as the estimates are unlikely to reflect the cost of solar integration during the time when this SISC will be in place. Moreover, the composition of the Duke generation fleet will likely change before the levels of solar penetration studied in Tranche 3 on the DEC or DEP systems are achieved, which would result in different integration costs than determined for Tranche 3 in this study.

The TRC recommends that the Commissions do not rely on the results of Tranche 3 in setting the SISC in the current proceeding.

IV. TRC Conclusions and Recommendations

The TRC engaged with Astrapé to understand the modeling approach employed to estimate the SISC, and the underlying assumptions. Where appropriate the TRC asked for information from subject matter experts at Duke to inform discussions regarding the modeling assumptions. During this process, the TRC made two recommendations to the modeling approach, both of which were adopted by Astrapé for this iteration of the estimate of the SISC:

- The TRC recommended modeling the JDA between DEC and DEP to better reflects Duke's current operations and any reduction in the integration costs provided by the joint unit commitment and dispatch that occurs under the JDA. Astrapé modeled a sensitivity that includes the JDA and included those results in their report, as the "combined case."
- The TRC recommended not modeling the proposed SEEM in this estimate of the SISC. The TRC recommends including it in the model for subsequent updates to the SISC when more is known about SEEM operations and there is historical data on SEEM energy trades.

In addition to the two specific recommendations related to the modeling approach and scope, the TRC reached several conclusions related to the study approach that may be informative for the Commissions in their review of the estimated SISC:

- The TRC finds that the Astrapé made significant improvements in the study methodology and assumptions since the previous SISC study:
  - Astrapé applied a new approach to determine how many load following reserves are necessary to integrate new solar resources. The new approach calibrated the modeled 60-minute ramping capability (ramping capability is provided by operating reserves) with historical ramping capabilities in the no solar case.[13] The modeled 60-minute ramping capability resulted in a specific number of 5-minute flexibility violations for the no solar case. The cases with added solar are simulated to match the number of 5-minute flexibility violations to the number of violations in the no solar case. The TRC found that this is a significant improvement over the approach used in the previous Astrapé study. The previous approach determined how many additional load following reserves are needed to maintain 0.10 expected flexibility violations per year ($LOLE_{FLEX}$) due to the new solar resources. The new approach adds load following reserves in a targeted manner and the model calculates the flexibility violations. The simulation is then iterated with adjustments to the added load following reserve amounts to match historical 5-minute flexibility violations.

[13] Carden, K., Wintermantel, N., and Patel, P., "Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study," Preliminary Draft, p. 35.

  - Astrapé implemented a new approach for reflecting solar volatility, including the benefits due to the geographic diversity of new solar resources coming online in Duke's service territories. The new approach accounts for the diversity between solar production profiles in different counties throughout the Carolinas, which capture the fact that new solar facilities will come online in different locations.
  - Astrapé implemented a targeted approach to only add additional load following reserves in hours when they are most likely needed (i.e., whenever volatility is the highest). This is an improvement over the previous study, which added load following reserves in all hours. The targeted approach reduces the overall estimated integration cost.

  The TRC agrees with both improvements, and believes the improvements better represent actual system conditions and operations. In both instances, the improved approach will likely reduce the overall integration cost of new solar and result in a lower SISC.

- TRC concludes that the CT and pumped storage resources owned by DEC and DEP are less flexible than similar resources owned by other utilities. However, barring upgrades to the units, the modeling assumptions used to represent their flexibility appear to reflect legitimate constraints on their operation. The TRC believes that the addition of more flexible resources to Duke's generation will likely reduce the integration cost of solar. However, the TRC determined that this question is out of scope for Astrapé's estimate of the near-term SISC.
- The TRC finds Astrapé's treatment of curtailments to be conservative in terms of impact on the SISC. The ability to freely curtail solar to manage flexibility issues on the system, lowers the integration cost of new solar resources and leads to a reduced SISC. The TRC asked Astrapé to run a sensitivity with an economic curtailment penalty, and the results of that sensitivity confirmed that the penalty slightly increases the SISC. Although overall system costs may be higher with additional solar curtailments, due to the increase in fuel costs needed to replace curtailed solar production. The TRC discussed this issue with subject matter experts at Duke, and confirmed that no penalty on curtailments is consistent with PURPA contract rules and historical system operation.
- The TRC finds that the estimated cost of reserves is reasonable given the size of DEC's and DEP's footprint relative to PJM (the competitive market the TRC benchmarked against), and given the relative inflexibility of Duke's generation fleet.
- The TRC recommended that the results for Tranche 3 of Astrapé's study be reported in an appendix as likely does not reflect current or near-term solar integration costs for DEC and DEP. The TRC advises that the Commission consider both the Tranche 1 and Tranche 2 results in setting the SISC, potentially interpolating between the two results to set the current SISC.

Appendix A: March 19, 2021 Stakeholder Meeting Presentation

Technical Review Committee for the Solar Integration Service Charge (SISC)

PRESENTED BY

Stephanie Ross

Hannes Pfeifenberger

MARCH 19, 2021

Brattle

About the Brattle team

The Brattle team assists electric utilities, independent system operators, generation and transmission developers, electricity customers, regulators, and policymakers with planning, regulatory, and market design challenges in the electricity industry. Relevant experience also includes addressing renewable integration challenges, power system simulations, applications of the SERVM simulation tool, and collaborations with national labs.

Hannes Pfeifenberger
Principal, Boston

Stephanie Ross
Associate, Boston

Technical Leads on the TRC

Three technical leads from the National Labs with relevant experience and expertise are serving on the TRC.

- Nader Samaan – Chief Engineer and Team Lead (Grid Analytics), Electricity Security Group at Pacific Northwest National Laboratory (PNNL)
- Gregory Brinkman – Researcher V-Model Engineering and Member, Grid Systems Group in the Strategic Energy Analysis Center at National Renewable Energy Laboratory (NREL)
- Andrew Mills – Research Scientist, Electricity Markets and Policy Group at Lawrence Berkeley National Lab (LBNL)

Regulatory Observers on the TRC

- Observers from the NC Public Staff
  - Jeff Thomas (primary)
  - Dustin Metz (alternate)
- Observers from the SC Office of Regulatory Staff
  - Robert Lawyer
  - O'Neil Morgan
  - Gretchen Pool

- The participation of the NC Public Staff and SC ORS Regulatory Observers is designed to encourage **open dialogue and ensure the transparent nature** of the TRC review process.

- The positions or perspectives raised by the Regulatory Observers in those discussions do not, however, limit the ability of those agencies to ultimately agree or disagree with the findings of the TRC or to take positions in later proceedings that do not align with the TRC's findings and recommendations.

TRC Work Plan

Conduct independent technical review of the methodology and assumptions used byAstrapé to develop the SISC, with substantial input from technical experts and regulatory observers

- Provide technical review of the SISC analysis' inputs, methodology, and outputs
  - Review input assumptions. For example:
    - Intra-hour renewable generation uncertainty
    - Changes since the 2020 Duke IRP, particularly early generation retirements (e.g., Allen Unit 3 which will be retired nine months early on March 31, 2021)
  - Review methodology. For example:
    - Compare Astrapé's approach with similar methodologies developed by the National Labs
    - Ensure consistency with changes in market fundamentals (e.g., natural gas prices, wholesale power markets, Southeast Energy Exchange Market (SEEM))
  - Review results
- Provide input and feedback to Astrapé throughout the review process so that it can be incorporated into the analysis in a timely manner
- Prepare TRC report with input from technical experts and regulatory observers

Timeline

March – June 2021

- TRC will meet bi-weekly through June 25, 2021
  - TRC Kickoff Meeting: March 2, 2021
  - TRC Meeting #2: March 12, 2021
  - TRC Meeting #3: March 26, 2021
  - Bi-weekly meetings thereafter

Milestones

- March – Astrapé develops draft set of results by end of March / early April to TRC
- April – TRC reviews results and provides feedback
- May – Astrapé performs any additional analysis to finalize study
- June – TRC finalizes recommendations and Brattle compiles final report

Revised SISCs for DEC/DEP will be included in both states' 2021 Avoided Cost filings

- July 2021: South Carolina – Filed with the Companies' Avoided Cost proceeding
- November 2021: North Carolina – Filed with the Companies' Avoided Cost proceeding.

Questions and Comments?

Duke has opened a channel for written comments to inform the TRC's review of the SISC

- sisctrc@outlook.com
- All comments due by April 2, 2021

Our Practices and Industries

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- Distributed Energy Resources
- Electric Transmission
- Electricity Market Modeling & Resource Planning
- Electrification & Growth Opportunities
- Energy Litigation
- Energy Storage
- Environmental Policy, Planning and Compliance
- Finance and Ratemaking
- Gas/Electric Coordination
- Market Design
- Natural Gas & Petroleum
- Nuclear
- Renewable & Alternative Energy

LITIGATION

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- Analysis of Market Manipulation
- Antitrust/Competition
- Bankruptcy & Restructuring
- Big Data & Document Analytics
- Commercial Damages
- Environmental Litigation & Regulation
- Intellectual Property
- International Arbitration
- International Trade
- Labor & Employment
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- Product Liability
- Securities & Finance
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Appendix B: Southern Environmental Law Center Comments

SOUTHERN ENVIRONMENTAL LAW CENTER

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CHAPEL HILL, NC 27516-2356 | Facsimile 919-929-9421

March 31, 2020

Via Email

Solar Integration Services Charge (SISC)
Technical Review Committee (TRC)
sisctrc@outlook.com

Ravi Mujumdar, Lead Planning Analyst
Duke Energy
Carolinas Integrated Resource Planning
ravi.mujumdar@duke-energy.com

Re: Comments for SISC TRC

Dear Members of the TRC and Mr. Mujumdar,

On behalf of the Southern Alliance for Clean Energy, North Carolina Sustainable Energy Association, and the Carolinas Clean Energy Business Association we submit the attached comments for the TRC prepared by Brendan Kirby, P.E.

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

Sincerely,

/s/ Nick Jimenez
Nicholas Jimenez, Staff Attorney
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SISC TRC Concerns

Brendan Kirby P.E. 31 March 2021

Flexibility Balancing Requirement Should Be Based on Mandatory NERC Reliability Rules

Duke first presented its proposed Solar Integration Services Charge ("SISC") in the North Carolina Utilities Commission ("NCUC") 2018 avoided cost proceeding (Docket No. E-100 Sub 158) and later filed the SISC in the South Carolina Public Service Commission ("PSCSC") 2019 avoided cost proceedings (Docket Nos. 2019-185-E and 2019-186-E). In those proceedings I submitted testimony and an accompanying report evaluating Duke's proposed SISC and appeared before the NCUC and PSCSC during evidentiary hearings on the SISC.[1] The partially updated methodology described in the March 19, 2021 Astrape "Ancillary Service Impact Study to Calculate Solar Integration Services Charge (SISC)" presentation is an improvement over the methodology presented in the November 11, 2018 "Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study" report but there are still significant concerns that we hope the TRC will carefully consider.

The fundamental concern is with both studies' focus on 5-minute ramping "flexibility violations". Astrape's slide 5 defines "Flexibility Violations" as the "Number of events where generators modeled in SERVM could not meet the next 5-minute net load." There is no mandatory NERC reliability rule requirement for a BA's generators to "meet the next 5-minute net load". Balancing requirements under normal, non-contingency[2], conditions are established in NERC's BAL-001-2 – Real Power Balancing Control Performance standard with its two reliability metrics: Control Performance Standard 1 (CPS1) and the Balancing Authority ACE[3] Limit (BAAL). Neither of these require balancing every 5 minutes. A brief summary of the BAL-001-2 balancing requirements is provided at the end of these comments but NERC allows 30 minutes to restore an imbalance under normal conditions, and only requires imbalances that are hurting interconnection frequency to be mitigated at all. In developing the mandatory BAL standards NERC found that excessive balancing beyond what is required by CPS1 and BAAL does not improve power system reliability.

Duke's current proposal to base the SISC on calculating the added following reserves that would be needed to maintain the same level of balancing with additional solar generation as was historically

[1] My testimony and report in NCUC Docket No. E-100 Sub 158 was filed on June 21, 2019 and is available at http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=afafa2e6-c755-4521-ae8e-16a9cbf90424. My testimony and report in PSCSC Docket Nos. 2019-185-E and 2019-186-E were filed on September 11, 2019 (Direct Testimony) and October 11, 2019 (Surrebuttal Testimony) and are available at http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=afafa2e6-c755-4521-ae8e-16a9cbf90424 and https://dms.psc.sc.gov/Attachments/Matter/71de8985-f38b-4e6d-bdab-f0b7607d704b.

[2] Balancing requirements during contingencies are established in NERC's BAL-002 – Disturbance Control Standard (DCS) which requires balancing within 15 minutes but which also allows for the use of contingency reserves to restore the balance.

[3] Area Control Error

required without solar generation is an improvement over the 2018 proposal, which calculated the reserves required to meet an arbitrary balancing requirement of 0.10 $LOLE_{FLEX}$ Events Per Year (Astrape slide 11). Still, neither calculation is based on meeting NERC reliability requirements.

The concern with applying a 5-minute balancing requirement is that it does not reflect the reliability requirements that actually apply to the utility. A purely hypothetical example may help to illustrate why this is a concern. Suppose a utility had a perfectly flat load. It would have no variability and no ramping requirements. It would have zero ramping shortfalls in one hundred years, let alone ten years. The utility's exemplary historic pre-solar following performance would not be based on holding sufficient reserves to meet NERC mandatory reliability requirements but instead would be an artifact of the utility's load characteristics. It would not make sense to add reserves sufficient to maintain a perfectly flat net-load when solar (or any other variable load or generator) was added. Instead, it would make sense to determine what reserves were needed to meet NERC mandatory reliability standards.

DEC and DEP do not have perfectly flat loads, so the hypothetical example is not perfectly applicable. Still, the concept is valid. Sufficient reserves should be added to maintain mandatory reliability performance. Excessive reserves beyond that amount impose unnecessary costs without improving reliability.

Not All Imbalances Are Equal

Simply counting imbalances with an LOLE metric is overly simplistic – as would be allowing 30-minute imbalances every hour just because they would not technically violate NERC mandatory reliability standards. Five- to 10-minute imbalances every hour would not threaten reliability. Similarly, 20-minute imbalances that occurred once a week or once a month would not be a reliability concern. Imbalance limits should reflect the imbalance frequency and duration. A suggested set of imbalance limits are: imbalances of 15 minutes or less are not limited, Imbalances longer than 15 minutes but no longer than 20 minutes are allowed once a week, Imbalances longer than 20 minutes but no longer than 25 minutes are allowed once a year.

Requiring All Following Reserves to be Spinning Reserves Is Inappropriate

Duke is requiring all SISC following reserves to be spinning reserves ("Load Following Up/Down Reserves – identical to spinning reserves", Astrape slide 7) provided by on-line generation operating at less than maximum capacity. This is not appropriate. Spinning reserves are typically much more expensive than non-spinning reserves provided by fast-start generation or demand side management or storage. It seems likely that modeling will show that small fluctuations are more common than large fluctuations. For events that happen hourly, spinning reserves are appropriate. For events which happen once a week or a few times a year, non-spinning reserves are probably much more appropriate. NERC mandatory balancing requirements provide ample time for fast-start generators, demand side management, and storage to respond to these more infrequent events.

Additional battery storage should also be considered to determine if it would be a lower cost option for supplying any needed additional following reserves. Fast battery response is an ideal resource for following reserves where extended response duration is not required. Batteries can typically be installed quickly, within the time frame required for implementing the SISC.

Updated Solar Volatility

The SISC is being calculated for higher penetrations of solar generation than currently exist. Astrape slide 7 states that the analysis will: "Update solar volatility based on most recent data – Include diversity benefit at higher solar tranches; Extrapolated from historical data." Fortunately, Duke now has operating data and experience with a larger solar fleet than when they first calculated a SISC. It is critical that the "Extrapolation from historical data" recognize the diversity benefits of aggregating larger amounts of solar generation. The extrapolation should not be linear but should instead reflect aggregation benefits that reduce the per-unit variability and uncertainty as solar penetration increases. Further, Duke should now have multiple historical data years of high penetrations of solar and should be able to compare costs actually caused by solar intermittency including specifically the associated costs built into the SISC against what the Astrape model shows. Essentially, the Astrape model, at this point, should be validated against historical data.

SEEM

Duke and regional utilities have filed with FERC to establish the Southeast Energy Exchange Market (SEEM) that will facilitate 15-minute energy trading. SEEM should assist balancing solar variability both by providing a fast regional outlet for excess solar generation (reducing solar curtailment) and a fast supply for solar shortfalls (reducing required reserves). It is a valid point that a filed SISC cannot be based on a regional energy exchange market that does not yet exist, but it is also a valid point that a pre-SEEM SISC will be immediately invalid once SEEM is operational. While doing the modeling necessary to establish the pre-SEEM SISC it seems prudent to include SEEM sensitivity analysis. Including preliminary SEEM results would inform the Commissions and stakeholders of potential SEEM benefits.

Modeling DEP & DEC as Separate BAs

It would also be informative to model the benefits of joint DEC and DEP dispatch on the SISC. The Two BAs could capture the aggregation benefits of operating with a single combined ACE for compliance with NERC BAL-001-02 while still operating independently otherwise. The savings for all rate payers, not just SISC customers, may justify the effort. It would be good to know.

The High Cost of Conventional Generator Inflexibility

While being more applicable to cost allocation/causation than to cost calculation, the inflexibility of Duke's conventional generators is a major concern because it results in an increased calculated SISC with Astrape and Duke's analysis method. Higher minimum loads, slower ramp rates, longer startup times, and higher cycling costs all increase the costs attributed to integrating solar generation by this analysis method. Arguably, the SISC could be allocated to conventional generators as an inflexibility integration charge. At a minimum, the methodology should consider allocating costs associated with the inflexibility of any new conventional generators to those generators rather than to solar generators. Similarly, existing conventional generators should be allocated inflexibility costs to the same extent that existing solar generators are assessed a SISC.

Applicable Mandatory NERC Balancing Requirements

NERC's reliability standard BAL-001-2 – Real Power Balancing Control Performance establishes two reliability metrics that apply during normal (non-contingency) operations: Control Performance Standard 1 (CPS1) and the Balancing Authority ACE Limit (BAAL).

CPS1 Reliability and Balancing Requirement

CPS1 limits the annual average 1-minute area control error deviations. ACE deviations result from difference between a BA's total instantaneous generation (plus scheduled imports) and total instantaneous load (plus scheduled exports) (plus the BA's instantaneous frequency support obligation).[4] While 100% compliance is required, this metric may be a bit deceptive. The CPS1 metric runs between 0% and 200%, meaning continuous perfect balancing would result in a CPS1 score of 200%, not 100%. Therefore, 100% compliance does not mean compliance during every minute. The CPS1 requirement is reflected in the following formula:

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \leq \epsilon_1^2$$

This formula is simpler than it at first appears. It says that the annual average of the instantaneous ACE values, times the instantaneous ΔF [frequency deviation from the scheduled frequency (usually 60 Hz)], must be less than 0.000324.[5] It is the multiplication of ACE times ΔF that makes balancing operations easier (and analysis harder). During times when frequency is exactly equal to 60 Hz then there is no CPS1 limit on ACE. When frequency is exactly equal to 60 Hz then ΔF is zero, which is multiplied by ACE and the result remains zero no matter how large ACE is. Physically this means that the BA can be far out of balance with no penalty when frequency is exactly 60 Hz. This makes sense for reliability because, if frequency is exactly equal to 60 Hz (ΔF is zero) the overall interconnection is not experiencing an overall imbalance and an individual BA's imbalance is not a reliability threat.

Further, not all imbalances are bad. If frequency is below 60 Hz (ΔF is negative) and the BA is over-generating (excess solar, for example) then the BA's imbalance is supporting reliability by reducing the interconnection's overall imbalance and helping to push frequency back up to 60 Hz. CPS1 calculation credits the BA for that help. The excess generation is a reliability benefit and there is no requirement to reduce ACE. Conversely, if frequency is above 60 Hz (ΔF is positive) and the BA is under-generating (excess load or solar is suddenly reduced, for example) the BA is again helping overall power system reliability by reducing the interconnection's overall imbalance and helping to push frequency back down to 60 Hz, and CPS1 again credits the BA.

---

[4] Because BA load cannot be measured directly it is determined indirectly by measuring the BA's generation and interconnection flows (imports and exports). NERC defines ACE as "The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias[.]" Reliability Standards for the Bulk Electric Systems of North America, NERC (updated July 3, 2018).

[5] ϵ_1 for the Eastern Interconnection is 0.018 Hz (Reliability Standards for the Bulk Electric Systems of North America, updated July 3, 2018) ϵ_1^2 is 0.000324.

Given that short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the 720,000 MW Eastern Interconnection, CPS1 does not require correction of imbalances about half of the time. This significantly reduces the balancing reserves that Duke must have available and reduces the times Duke must exercise those reserves.

BAAL Reliability and Balancing Requirement

Like CPS1, the Balancing Authority ACE Limit (BAAL) does not require perfect compliance. In fact, BAAL only limits ACE deviations that exceed 30 consecutive minutes. Further, like CPS1, BAAL only limits ACE deviations that hurt interconnection frequency. That is, over-generation is not limited when interconnection frequency is below 60 Hz and under-generation is not limited when interconnection frequency is above 60 Hz. BAAL limits are specific to each BA and depend on the actual interconnection system frequency at each time interval. As shown below, ACE limits are lax when frequency is close to 60 Hz and get progressively tighter as frequency deviates farther from 60 Hz.

Again, given that short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the very large Eastern Interconnection, BAAL does not require correction of imbalances about half of the time.

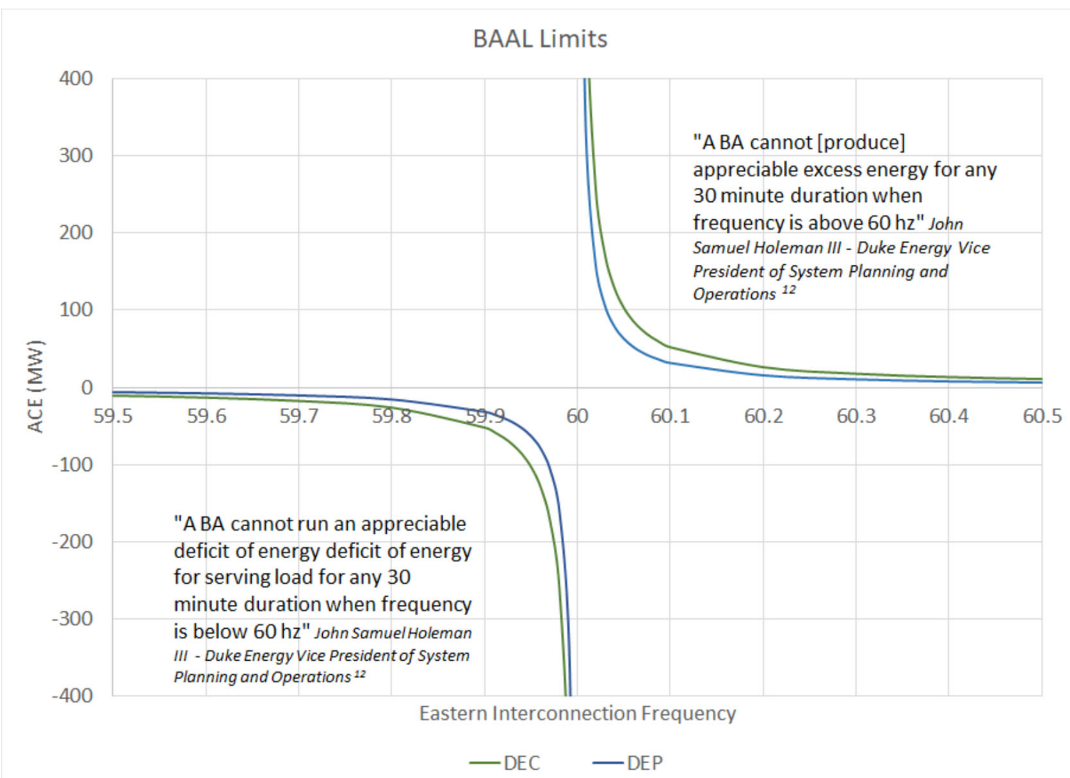

Figure 1 BAAL allows 30 minutes to restore balance.