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May 28 2021

May 28, 2021

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Raleigh, NC 27603

Re: Docket No. E-100, Sub 165
2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans
Joint Reply Comments of the North Carolina Sustainable Energy Association and the Carolinas Clean Energy Business Association

Dear Ms. Campbell,

Please find enclosed the Joint Reply Comments of the North Carolina Sustainable Energy Association and the Carolinas Clean Energy Business Association in the above-caption docket. Please let me know if you have any questions or if there are any issues with this filing.

Respectfully yours,

/s/ Peter H. Ledford

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 165

In the Matter of:	)	
2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans	)	**JOINT REPLY COMMENTS OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION AND THE CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION**

JOINT REPLY COMMENTS OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION AND THE CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION

Pursuant to the North Carolina Utilities Commission's ("Commission") orders[1] issued in this docket, the North Carolina Sustainable Energy Association ("NCSEA") and the Carolinas Clean Energy Business Association ("CCEBA") (NCSEA and CCEBA, collectively, "Joint Commenters") hereby submit these joint reply comments to initial comments previously submitted by various intervenors on the biennial integrated resource plans (the "IRPs") filed in this proceeding on September 1, 2020 by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (DEC and DEP, collectively, "Duke").[2]

[1] *Order Granting Extensions of Time* (January 8, 2021); *Order Granting Second Extension of Time* (February 26, 2021); *Order Granting Extension of Time* (April 19, 2021); *Order Granting Further Extension of Time* (May 11, 2021).

[2] Joint Commenters note that they do not respond to all issues or statements in other intervenors' initial comments. Any portion of another intervenor's initial comments to which Joint Commenters do not respond in these reply comments should not be construed as support for or agreement with those comments.

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I. THE COMMISSION MUST REQUIRE DUKE TO CORRECT IDENTIFIED FLAWS IN ITS IRPS IN THIS PROCEEDING

As discussed in detail below, the Joint Commentors, the Public Staff, the Attorney General's Office ("AGO"), and other intervenors have all identified serious flaws in modeling methods, inputs, and assumptions utilized by Duke in preparing its IRPs. These flaws have a significant and material bearing on the cost and operational impacts of the various resource scenarios evaluated by Duke in the IRPs – and thus on any determination of which portfolio (potentially including a portfolio not yet evaluated by Duke) is in the best interests of Duke's ratepayers and the state as a whole. These flaws also have a significant and material bearing on the decision that the Commission is required to make *this year* pursuant to N.C. Gen. Stat. § 62-110.8 regarding additional renewable energy resources that should be procured by Duke through competitive procurement. This decision by the Commission will be the first implementation of this provision of 2017's House Bill 589 ("H.B. 589").[3] It is critical that the Commission has accurate, robust, and up-to-date information and analysis upon which to make this important decision. In addition, Governor Cooper has adopted a comprehensive Clean Energy Plan for the state that calls for a 70% reduction in carbon emissions from the utility sector by 2030.[4] As Duke's IRPs demonstrate, that goal cannot be achieved unless planning and implementation begins immediately to replace Duke's existing bulk coal fleet with large volumes of renewable and other clean energy resources. The outcome of this proceeding will determine whether North Carolina moves forward now toward the goals set forth in the Clean Energy Plan or

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[3] Competitive Energy Solutions for NC, Sess. L. No. 2017-192 (2017).

[4] North Carolina Department of Environmental Quality. October 2019. *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System*. Available at: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

delays its implementation. It is therefore essential that the Commission require Duke to correct identified flaws in Duke's IRPs and to resolve disputed issues now rather than kicking the can down the road to some future proceeding.[5]

The Commission has historically found IRPs with identified flaws or disputed issues to be adequate "for planning purposes" and accepted them with direction that such issues be addressed in a future proceeding.[6] However, the General Assembly's mandate to the Commission in N.C. Gen. Stat. § 62-110.8(a) no longer allows that approach.

N.C. Gen. Stat. § 62-110.8(a) was enacted by H.B. 589 and establishes the Competitive Procurement of Renewable Energy ("CPRE") program. The initial CPRE program established a procurement process for renewable energy

> over a term of 45 months beginning when the Commission approves the program. . . . In addition, at the termination of the initial competitive procurement period of 45 months, the offering of a new renewable energy resources competitive procurement and the amount to be procured shall be determined by the Commission, based on a showing of need evidenced by the electric public utility's most recent biennial integrated resource plan or annual update *approved by the Commission* pursuant to G.S. 62-110.1(c).[7]

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[5] As discussed below, although the Public Staff identifies many flaws in Duke's IRPs, in all cases it proposes that they be corrected in a future proceeding rather than in this one.

[6] See, e.g., *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses*, pp. 91-92, Docket No. E-100, Sub 157 (August 27, 2019) ("IT IS, THEREFORE ORDERED as follows: That the IRPs filed herein by Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, are *adequate for planning purposes* during the remainder of 2019 and for 2020, subject to DEC's and DEP's 2019 IRP Updates, and *the Commission hereby accepts the IRPs*, subject to the questions raised in this Order concerning the underlying assumptions upon which the IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020.") (emphasis added).

[7] N.C. Gen. Stat. § 62-110.8(a) (emphasis added).

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The Commission approved Duke's CPRE program on February 21, 2018[8] and thus the initial CPRE program will expire in November 2021. Pursuant to N.C. Gen. Stat. § 62-110.8(a), any CPRE procurements after November 2021 will be based on Duke's most recently "approved" IRPs. While Commission Rule R8-60 requires Duke to file an IRP update report on September 1, 2021, the procedure set forth in the rule establishes that the Commission will not be able to render a decision on the IRP update report prior to November 2021. Thus, the Commission must establish "the offering of a new renewable energy resources competitive procurement and the amount to be procured" based on the results of this current proceeding. If it does not require identified flaws in Duke's IRPs to be corrected now, that critical decision will necessarily be informed by error and inaccurate information. The Commission cannot make an informed and rational decision about future renewables procurement if the document it is required to reference in making such determination is riddled with flaws. Thus, the Commission should identify the errors and deficiencies in Duke's IRPs and require Duke to make a compliance filing in which these matters are corrected.[9] [10]

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[8] *Order Modifying and Approving Joint CPRE Program*, Docket Nos. E-2, Sub 1159 and E-7, Sub 1156 (February 18, 2018).

[9] As discussed below, Joint Commenters acknowledge that certain identified flaws in Dukes IRPs cannot reasonably be addressed in a compliance filing in this proceeding and that Duke should be required to address those matters in its next IRP proceeding.

[10] An argument may be made that the relief request by the Joint Commenters is required because the Commission cannot approve an IRP, as required by N.C. Gen. Stat. § 62-110.8, that contains manifest flaws and errors. Joint Commenters acknowledge that the relevant language in N.C. Gen. Stat. 62-108(a) is poorly worded and the exact intended effect of that language is somewhat unclear. Specifically, the language references approval by the Commission of a utility's most recently approved IRP pursuant to N.C. Gen. Stat. § 62-110.1(c), but that section of the General Statutes makes no mention of a utility integrated resource plan, much less Commission approval of such a plan. Rather, it requires the Commission to prepare its own resource plan, considering input from electric public utilities and to submit that plan to the General Assembly and the Governor. Nevertheless, in light of the statutory language and the Commission's prior statement that

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The Joint Commenters recognize the challenges that Duke would face if it were to be required to both file a compliance IRP and an IRP update in the upcoming months.[11] The Joint Commenters therefore recommend that the Commission utilize the authority given to it by N.C. Gen. Stat. § 62-31 and waive the requirements of Rule R8-60(h)(2), (j), and (l) so as to relieve Duke of its obligation to file an IRP update and instead direct Duke to file a corrected, biennial IRP as a compliance filing.

The Joint Commenters' request that Duke be required to correct identified errors in its IRPs through a compliance filing is consistent with the initial comments of other intervenors. In their initial comments, the Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council ("SACE et al.") stated that "[w]hile they are non-binding planning documents, utility IRPs have major implications for important decisions that the Commission will face in the future"[12] including forming the basis for a utility's decision to build or acquire a new capacity or energy resource, providing support for an application for a certificate to build a new power plant, providing assumptions used in the calculation of avoided cost rates used to determine cost-effectiveness testing of demand-

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"House Bill 589 was intended to evolve the State's energy policy[,]" *Order Modifying and Approving Green Source Advantage Program, Requiring Compliance Filing, and Allowing Comments*, p. 41, Docket Nos. E-2, Sub 1170 and E-7, Sub 1169 (February 1, 2019), the Joint Commenters believe that N.C. Gen. Stat. § 62-110.8 should be read to require Commission *approval* of Duke's IRP and that such approval would be arbitrary and capricious if conspicuous and highly material errors are not corrected.

[11] While there is nothing in the General Statutes requiring integrated resource plans to be filed annually, the regulated utilities are required by rule to *update* their integrated resource plans annually. The filing of IRPs is governed by Commission Rule R8-60. Pursuant to Rule R8-60(h)(2), Duke is required to file an IRP update report on September 1, 2021.

[12] *Partial Initial Comments of Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council*, p. 2 (March 1, 2021) ("SACE et al. Initial Comments").

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side management and energy efficiency programs, as well as rates available to small qualifying facilities and the bid cap for CPRE projects.[13]

Similarly, the AGO also acknowledges and discusses in its initial comments the significance of the IRPs and the importance of addressing and correcting flaws in Duke's IRPs now. The AGO states that "Duke's 2020 IRP contains a variety of methodological flaws that, if not corrected, will likely increase ratepayer costs."[14] Additionally, these flaws "will also likely bias the State's resource portfolio in favor of fossil fuels", are "inconsistent with the North Carolina Clean Energy Plan" and "contrary to the climate objectives of Duke Energy's net zero goal."[15] The AGO addresses at length flaws in Duke's IRPs related to coal retirement modeling. As described by the AGO, in response to the 2019 IRP Order[16] directing coal retirement modeling "Duke has identified what it believes are the earliest practicable retirement dates for its 9,182 [MW] of coal." However, because "Duke's four-step retirement analysis appears to conflict with sound resource planning principles" Duke has failed to adequately support its coal retirement analysis. These faulty assumptions "appear to unnecessarily delay retirement, to the detriment of ratepayers."[17]

The Public Staff also acknowledges in its initial comments the importance of IRPs and the urgency of improving IRP inputs and methodologies. The Public Staff states that "[o]ver the last decade or more, IRPs have taken on greater significance due to the influence

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[13] *Id.*

[14] *Attorney General's Office Initial Comments on Duke's Integrated Resource Plans*, p. 3 (March 5, 2021) ("AGO Initial Comments").

[15] *Id.*

[16] *Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans*, Docket No. E-100, Sub 157 (April 6, 2020) ("2019 IRP Order").

[17] AGO Initial Comments at 9.

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these plans have on directing and guiding public policies associated with energy consumption and the economy."[18] Additionally, [s]ince the most recent IRP update, there have been significant energy policy actions that influence the 2020 IRP"[19] and "[i]t is important that the issue of the necessity for accelerated coal unit retirement and corresponding replacement by other resources receive regulatory direction sooner rather than later."[20]

Unfortunately, despite the acknowledged critical importance of the IRPs, the Public Staff repeatedly takes the position in its initial comments that Duke should only be required to modify their IRP inputs or methodologies in *subsequent* IRP proceedings or that such changes should be left to Duke's discretion. For example, the Public Staff recommends that *"[i]n future IRPs*, Duke should present a portfolio that sets a carbon limit and allows the model to economically select the necessary resources to meet that limit[;]"[21] that "[t]he Utilities should use economically optimal endogenous plant retirement dates *in future IRPs* with the Encompass model[;]"[22] "*[i]n future IRPs*, the Utilities should continue to evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data[;]"[23] "Duke *should consider*

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[18] *Comments of the Public Staff on 2020 Biennial Integrated Resource Plans of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Dominion Energy North Carolina and 2020 REPS Compliance Plans of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Dominion Energy North Carolina*, p. 20 (February 26, 2021) ("Public Staff Initial Comments").

[19] *Id.* at 28.

[20] *Id.* at 109.

[21] *Id.* at 15 (emphasis added).

[22] *Id.* (emphasis added).

[23] *Id.* at 16 (emphasis added).

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implementing stochastic optimization in its capacity expansion model[;]"[24] "*[f]uture market potential studies* should consider a more comprehensive list of measures that can contribute and provide a more accurate picture of the achievable market potential for Duke's [demand-side management ("DSM")] and [energy efficiency ("EE")] programs, as described in the Market Potential Study section of these comments[;]"[25] "*[f]or the 2021 IRP update*, Duke should re-evaluate its prediction that additional interstate pipeline capacity will be available[;]"[26] and "[i]n order to assess the portfolio risk of Duke's natural gas pricing assumptions, *Duke should consider developing* an IRP portfolio that is similar to its base case but includes natural gas import restrictions."[27]

While Joint Commenters respond to, and agree with, certain of the Public Staff's substantive concerns and recommendations below, for the reasons discussed above Joint Commenters strongly disagree that changes to Duke's IRPs required by the Commission as a result of this proceeding should only be made in the next proceeding. Instead, given the near-term significance of Duke's IRPs, including the Commission's obligation under N.C. Gen. Stat. § 62-110.1(c) to develop and keep current a long-range planning document for North Carolina, the Commission should require Duke to make the changes recommended by the Joint Commenters as part of this proceeding through a compliance filing.

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[24] *Id.* (emphasis added).

[25] *Id.* at 18 (emphasis added).

[26] *Id.* (emphasis added).

[27] *Id.* (emphasis added).

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II. "LEAST COST" PLAN

The Joint Commenters recognize the challenge of reflecting a "least cost" plan when technology and regulation is changing quickly, but as set forth in the *Initial Comments of the North Carolina Sustainable Energy Association and the Carolinas Clean Energy Business Association on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Integrated Resource Plans* (the "NCSEA/CCEBA Initial Comments"), Joint Commenters believe it is clear that clean technologies and generation resources provide the best path for North Carolina ratepayers and, ultimately, are required to produce the least-cost plan. Delaying decisions now and approving Portfolio A or B, which are effectively the same in the short term, will lock in new natural gas resources and preclude the other solutions. It simply does not make sense to accept these IRP proposals and then also wait to see if Duke does better next time. As set forth below, the Joint Commenters believe the Public Staff's Initial Comments, while reflective of the complexity of the least cost analysis, are inconsistent and do not reflect the likeliest path forward for a least cost generation mix. The Tech Customers make several good points that Joint Commenters echo on this topic.

A. PUBLIC STAFF ON LEAST COST

The Public Staff correctly states that what "constitutes a 'least cost plan' has become clouded as a result of satisfying the initiatives of policies that are not yet required by law" and notes the Clean Energy Plan and Executive Order 80 as examples of things that influence the "method of modeling" for the Duke's IRPs.[28] Later in its Initial Comments, the Public Staff states:

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[28] *Id.* at 21.

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> It is the Public Staff's position that "least cost" must consider not only the factors that are known and present at the time of the IRP, but also potential future changes to the electricity industry, combined with their likelihood of occurrence and potential risk factors of pursuing a plan that does not account for these potential changes. This is consistent also with requirements of Commission Rule R8-60 that requires the utility to analyze the risk associated with the costs of complying with environmental regulation.
>
> The recommendation of a "least cost" plan has to, in part, consider the uncertainty around whether there will be carbon pricing in the future.[29]

The Joint Commenters agree with the Public Staff on this point. As noted in the *Partial Initial Comments of NCSEA, CCEBA, and SACE, et al. on Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's 2020 Integrated Resource Plans* ("NCSEA/CCEBA/SACE Initial Comments"),[30] modeling the IRP portfolios in a manner that is reflective of a least cost paradigm including likely carbon or carbon-related regulation is the most realistic path for Duke in planning its future generation portfolio. Furthermore, the Joint Commenters acknowledge the complexity of the task here and reassert the position that Duke should incorporate robust risk assessment and the need to view the generation mix from a long-term basis. The Joint Commenters stress that the takeaway here should be that under Rule R8-60, an IRP must account for the likelihood of carbon regulation.

However, despite acknowledging that an IRP filing under Rule R8-60 should consider the likelihood of future carbon or other environmental regulation, the Public Staff suggests that the IRPs' planning portfolio can simply be updated later: "[t]he Utilities file new IRPs every two years with updates in the intervening years; thus, the Utilities have

[29] *Id.* at 162-163.

[30] NCSEA/CCEBA/SACE Initial Comments, pp. 12-13, 24.

ample opportunities to modify their plan as the uncertainty surrounding carbon legislation is resolved."[31] The Joint Commenters do not agree that R8-60 allows for IRPs that effectively disregard the significant foreseeable risk of future carbon limits under the assumption that the plans will superseded by future plans once the contours of likely carbon regulation are finalized. Eventually, the Public Staff settles on approving two of the scenarios proposed by Duke.[32]

The Joint Commenters disagree in part with how the Public Staff treated the portfolio options other than A and B and their approval of Portfolios A and B without further scrutiny. The Public Staff states in pertinent part:

> The Public Staff considers Portfolios C, D, E, and F to be illustrative examples of what an expansion plan with aggressive carbon reduction goals might look like. The primary reason that the Public Staff does not believe these portfolios to be reasonable for planning purposes is that these portfolios were not optimized based on a carbon reduction restraint placed on the model. Instead, Duke forced various resources (wind, SMR, solar, and energy storage) into the model until the target CO2 reduction goal was met. Portfolios A and B were largely allowed to economically select the optimal resources to meet demand subject to system constraints and, in the case of Portfolio B, a carbon tax. In future IRPs, Duke should construct a portfolio that sets a carbon limit and allows the model to economically select the necessary resources to meet that limit. This would represent a least-cost carbon constrained portfolio, which would be preferable to the illustrative portfolios provided in this IRP.[33]

This argument is fair but incomplete. The Joint Commenters generally agree that better tools should be used for Portfolios C, D, E, and F and believe that Duke has these tools and they should implement them now. As noted above, what the Public Staff misses is that delaying decisions now and approving Portfolios A and B, which are effectively the

[31] Public Staff Initial Comments at 165.

[32] *Id.* at 168.

[33] *Id.* at 154-155.

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same in the short term, will lock in new gas resource planning and preclude the other solutions.

The Joint Commenters agree with the Public Staff that Duke should continue to evaluate the residential rate impacts of each proposed IRP portfolio against a carbon-free scenario[34] and present this information in a manner similar to that used by Dominion, which accounted for carbon limitations.[35] Similarly, the Joint Commenters agree with the Public Staff that Duke should construct a portfolio that sets a carbon limit and allows the model to economically select the necessary resources to meet that limit which would represent a least-cost carbon constrained portfolio, preferable to the illustrative portfolios provided in this IRP.[36] The Joint Commenters only object to the idea of waiting for these two items and see no reason that Duke cannot make the changes now at the behest of an order by the Commission. The Joint Commenters do not believe any further clarity from the Commission (or outside the Commission) is needed when alternative generation mixes, which do not include carbon-emitting resources that will likely be subject to future federal and state regulation and cost, are available now.

The Joint Commenters find it concerning that the Public Staff's carbon price analysis does not also include the likelihood of early retirement of natural gas resources. "The Public Staff notes that this analysis does not consider the impact of potentially retiring

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[34] Joint Commenters also note, with regard to modeling a carbon-free scenario, that the White House Executive Order on carbon reduction for the power sector targets 0% carbon emissions in the U.S. by 2035, which is a much more ambitious goal than Duke's current proposals. *See*, https://www.whitehouse.gov/briefing-room/statements-releases/2021/05/17/fact-sheet-biden-administration-accelerates-efforts-to-create-jobs-making-american-buildings-more-affordable-cleaner-and-resilient/#:~:text=The%20President%20issued%20an%20Executive,net%2Dzero%20economy%20by%202050.

[35] Public Staff Initial Comments at 19.

[36] *Id.* at 155.

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natural gas plants early in the face of future climate legislation, as explored in a sensitivity analysis in Duke's IRPs."[37] While the Joint Commenters recognize that the carbon-price portfolio options presented in the Duke IRPs may reduce the cost of carbon tax on the utilities' respective generation mixes, the Duke IRPs fail to include the likely increased capital costs associated with early retirement of natural gas resources.

A common thread throughout the Public Staff's initial comments is the acknowledgement of changes to the industry, such as the likelihood of carbon regulation in some form at a state or federal level, or, as they remark on page 21, the changing marketplaces related to energy: "Energy storage and electric vehicles are expected to begin altering traditional load shapes in the near future as they become more widely adopted."[38] However, despite acknowledging the changing tide, the Public Staff refuses to take definitive positions reflective of the changing market and instead opts to wait and see. The Joint Commenters do not believe this is in the best interest of ratepayers in North Carolina.

B. Tech Customers on Least Cost

The Joint Commenters agree with the Tech Customers that the Duke IRPs do not adequately consider the benefits of renewable energy.[39] The Joint Commenters also agree that the cost of gas relied upon in the Duke IRPs does not adequately reflect exterior costs for carbon-based generation beyond even likely carbon regulation such as health benefits or climate concerns: "[Duke] is justifying the continuation of a traditional generation portfolio that, based on more realistic assumptions, might pose greater financial burdens

[37] *Id.* at 164.

[38] *Id.* at 21.

[39] *Initial Comments of Tech Customers*, p. 4 (March 1, 2021) ("Tech Customers Initial Comments").

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on ratepayers than a portfolio enhanced with more renewables."[40] Furthermore, the Joint Commenters agree that the Duke IRPs should consider a range of solar ownership options, including whether third-party ownership of utility-scale solar resources should also be considered. At the very least, these potential solutions to ratepayer costs should be modeled. Modeling purchases from third-party-owned generators, including solar generators, is consistent with the directive in Rule R8-60(e) to assess the potential benefits of reasonably available alternative supply-side energy resource options. As discussed in the NCSEA/CCEBA Initial Comments, Duke's IRPs have not adequately modeled the potential for energy purchases from third-party resources—even before Duke's first capacity need—to result in cost savings for ratepayers. This analysis is particularly relevant and significant in the context of the Commission's determination of a "showing of need" for additional competitive procurement under CPRE.

III. NATURAL GAS PRICING

Both the Public Staff[41] and the Tech Customers[42] appropriately question Duke's assumptions regarding pipeline capacity and availability. The Public Staff specifically notes that Duke's IRPs rely on pipeline capacity and availability figures that assume that both the Atlantic Coast Pipeline ("ACP") and the Mountain Valley Pipeline ("MVP") would be constructed.[43] Specifically, the Public Staff notes that Duke had contracted for nearly half of the ACP's capacity.[44] However, as noted by the Tech Customers, the

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[40] *Id.* at 5.

[41] Public Staff Initial Comments at 89-93.

[42] Tech Customers Initial Comments at 7-8.

[43] Public Staff Initial Comments at 91-93.

[44] *Id.*

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cancellation of the ACP constrains Duke's ability to transport natural gas to its planned generation facilities.[45] Similarly, the Public Staff notes that "the growth of natural gas production in the Appalachian basin is constrained by the lack of available takeaway pipeline capacity to move it to the Southeast demand markets."[46] While the MVP has not yet been cancelled like the ACP, its construction remains in limbo due to litigation, and the permit application for its North Carolina spur has been rejected.[47] Given the dynamics regarding the construction of new pipeline capacity, as noted by both the Public Staff and the Tech Customers, it is simply unreasonable to assume for planning purposes – let alone for making a decision about the need for additional renewables procurement – that the ACP and MVP will be available to provide natural gas to Duke's generating fleet. However, despite repeatedly questioning Duke's assumptions and methodology regarding natural gas pipeline capacity,[48] the Public Staff recommends that Duke re-evaluate its assumptions regarding natural gas pipeline capacity in its 2021 IRP updates.[49] The Public Staff's position is untenable: Duke's IRPs cannot be reasonable for planning purposes with these fundamental errors, and thus cannot be accepted or approved by the Commission.

Due to questions about natural gas pipeline capacity and availability, as well as other factors, the Public Staff[50] and the Tech Customers[51] both express concerns that Duke

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[45] Tech Customers Initial Comments at 7.

[46] Public Staff Initial Comments at 91-93.

[47] See, North Carolina Department of Environmental Quality, State Reissues Denial of Water Quality Certification for MVP Southgate Pipeline, April 29, 2021, available at https://deq.nc.gov/news/press-releases/2021/04/29/state-reissues-denial-water-quality-certification-mvp-southgate.

[48] See, e.g., Public Staff Initial Comments at 13-14, 89-93.

[49] *Id.* at 94.

[50] *Id.* at 89-90.

[51] *Id.* at 7-8.

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is underestimating the costs of new natural gas generation. As a result, both the Public Staff and the Tech Customers agree that Duke's IRPs exaggerate the role of new natural gas generation in meeting Duke's needs at the expense of new renewable energy generation. The Public Staff notes that, for DEP, this causes the IRPs to select more new natural gas generation during the planning period than new renewable energy generation.[52] This failing should be addressed in the current proceeding, and not in future proceedings, because there is a cost incurred by the issue.

The Public Staff did not oppose Duke's use of a 10-year market forward methodology for determining natural gas prices.[53] The Public Staff's acceptance of Duke's use of a 10-year market forward methodology for determining natural gas prices is inconsistent with positions taken elsewhere in their initial comments and should be disregarded by the Commission. Specifically, "While the Public Staff agrees that there is lower priced gas available at DS, it has reservations regarding Duke's assumptions of transporting those large volumes of natural gas daily from the DS hub to its gas fired units, mainly due to the recent regulatory landscape for the permitting of natural gas pipelines and the lack of pipeline takeaway capacity from the Appalachian region to the Transco Zone 5 region."[54] While Duke currently purchases a relatively small amount of natural gas on long-term contracts, the concerns expressed by the Public Staff and the Tech Customers make clear that it is unreasonable for Duke to assume there will be sufficient pipeline capacity and availability for 10-year market forwards to supply enough fuel for Duke's planned natural gas generation fleet. The Commission should therefore reject Duke's use

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[52] *Id.* at 125.

[53] *Id.* at 14.

[54] *Id.* at 91.

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of a 10-year market forward methodology for determining natural gas prices, as it is unreasonable even for planning purposes, and instead require Duke in its compliance filing to update its natural gas forecasts consistent with the recommendations made in the NCSEA/CCEBA Initial Comments.[55]

IV. RESOURCE ADEQUACY

As discussed in the NCSEA/CCEBA Initial Comments, it is critical that reliability planning and resource adequacy analysis be fully and appropriately incorporated into the IRP modeling process.[56] Duke's resource adequacy analysis includes its Resource Adequacy Studies, the Solar ELCC study and Storage ELCC studies, as well as the planning reserve margins that are derived from these studies.

A. PUBLIC STAFF COMMENTS

With respect to updates to the Resource Adequacy Studies that Duke has made after previous IRP proceedings, the Public Staff states that after the 2018 IRP proceeding, "Duke reached out to interested stakeholders and began a series of stakeholder meetings to discuss the inputs, methodology, and underlying assumptions for the 2020 Resource Adequacy Report. Participants in the stakeholder meetings included the Public Staff, the South Carolina Office of Regulatory Staff, and the North Carolina Attorney General's Office"[57] and "The Public Staff notes the efforts made by Duke to include the perspective of other stakeholders in updating its Resource Adequacy Study."[58] Although Joint Commenters

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[55] See NCSEA/CCEBA Initial Comments, Exhibit 3 at 4.

[56] NCSEA/CCEBA Initial Comments, pp. 23-25.

[57] Public Staff Initial Comments at 70. The Joint Commenters note that, while Duke reached out to state agencies that participate in proceedings before the Commission and the South Carolina Public Service Commission, Duke did *not* reach out to either NCSEA or CCEBA.

[58] *Id.* at 75.

agree that stakeholder engagement regarding a highly technical and significant issue like this is important and productive, Joint Commenters note that they were not included in the stakeholder group described by the Public Staff and therefore did not have the opportunity to participate in that process.

The Public Staff also states that the assumptions in the Resource Adequacy Study are adequate for planning purposes but notes that the effect of extremely low temperatures on load is still not well understood and recommends that Duke continue to utilize AMI data to improve this predicted relationship.[59] Joint Commenters agree that the Resource Adequacy Studies have not sufficiently modeled load resulting from extreme cold events, as discussed in the report by Brendan Kirby attached to the NCSEA/CCEBA Initial Comments.

The Public Staff also discusses the discrepancy between using the full installed capacity of traditional thermal resources while using effective load-carrying capability ("ELCC") values for intermittent resources.[60] In estimating the amount of existing generation and reserves necessary to meet load and account for uncertainty, the full installed capacity of traditional thermal resources are counted towards the necessary generation capacity, but forced outages are not considered, despite the fact that forced (i.e. unplanned) outages may prevent thermal resources from meeting a utility's load during peak periods. Conversely, the ELCC method does account for such outages. Joint Commenters agree that this results in a "mismatch" between the methods used to calculate the capacity contribution of thermal resources and ELCC used to calculate the capacity

[59] *Id.*

[60] *Id.* at 75-76.

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contribution of renewable resources. As discussed in the NCSEA/CCEBA Initial Comments, a more appropriate comparison of the capacity contribution of thermal resources to renewable resources would be the utility would use the unforced capacity (or "UCAP") method, rather than using the installed capacity (or "ICAP") method for thermal resources as Duke has done. Using the UCAP method for thermal resources and the ELCC method for intermittent resources would help to address the "mismatch" discussed by the Public Staff.

B. TECH CUSTOMER COMMENTS

In their initial comments the Tech Customers address Duke's use of a firm 17% reserve margin in its IRPs and question whether Duke's modeling approach is consistent with the expectations articulated by the Commission in its most recent IRP order.[61] Specifically, the Tech Customers note that in the Commission's order on Duke's 2019 IRP Update, the Commission stated:

> [I]t is important when applying the principle of long-term least cost planning for generation assets that the Companies avoid near term investments in long-lived generating assets that may, due to market forces and technological change, become economically stranded over the course of the longer planning period. Prudent investments in additional generating capacity in the short term must take this longer term risk into account, and an absolute insistence on a single fixed and unvarying planning reserve margin does not . . . permit sufficient flexibility to do so.[62]

The Tech Customers emphasize that "some flexibility in DEC's reserve margin could avoid large capital expenditures on generation plants that could become stranded

[61] Tech Customers Initial Comments at 10-13.

[62] *Id.* at 11 (citing 2019 IRP Update Order, at 11).

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assets."[63] Additionally, Tech Customers note that applying the inflexible 17% reserve margin, DEC forecasts that it must construct a 402-MW natural gas plant to stay above its 17% reserve margin, but that if DEC chose not to build the new plant, its reserve margin would decrease to only 16.3%.[64] Tech Customers state that "DEC's inflexibility in its reserve margin is, by its own admission, unnecessary and appears to result in massive investments in carbon-emitting plants that risk becoming stranded, rather than incremental construction of renewable generation that avoids such risks."[65]

Joint Commenters agree that Duke's use of its 17% reserve margin fails to consider the Commission's discussion of reserve margins in the 2019 IRP Update Order. Rather than build a new natural gas plant to maintain the 17% reserve margin, Duke should instead model—using appropriate inputs and modeling tools—the ability of carbon-free resources such as renewables and storage to meet required load, which can be constructed and deployed in smaller capacity increments. This is only amplified by the continued evaluation and optimization of EE and DSM programs, as well as the broader ISOP on the distribution grid, all of which will be critical to "permit sufficient flexibility" to consider "market forces and technological change" that makes traditional generation infrastructure like natural gas riskier than alternative supply-side and demand-side resources.

C. AGO COMMENTS

Discussing Duke's Storage ELCC study, the AGO states that Duke should include 2-hour battery storage in its IRPs, as "many storage durations provide comparable capacity values to those of firm resources" and "although 2-hour storage has less capacity value

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[63] *Id.*

[64] *Id.* at 12.

[65] *Id.*

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than longer duration options, the converse is that it is much cheaper."[66] The AGO notes that despite this, "Duke has excluded 2-hour storage as an IRP resource option." Joint Commenters agree that it would be appropriate for Duke to include 2-hour storage as a resource option in its IRP modeling and—assuming Duke applied appropriate inputs and modeling tools—see what combination of resources the model selects.

The AGO also states that Duke has failed to consider potential synergies between winter DSM and solar, noting that "increased winter DSM can help address winter peak demand" and "shift some of the risk of outages from the winter to the summer." This indicates that "increased winter DSM may make solar more valuable, as it will produce more power during high demand periods." The Joint Commenters strongly agree with this assessment, as discussed in detail in the expert reports of Brendan Kirby and E3 attached to the NCSEA/CCEBA Initial Comments. It is critical that Duke adequately consider the capacity contributions of individual resources as well as the potential synergies between different resources that can increase the total capacity contribution of those resources to Duke's system and in Duke's IRP modeling.

D. SACE ET AL. COMMENTS

SACE et al. state that the reserve margins used in the 2020 IRPs were improperly inflated, and Duke's forecasts for winter peak loads should be carefully scrutinized to ensure that they are not unduly driven by rare, extreme weather events. SACE et al. argue that Duke's claim that it needs capacity to meet over-estimated winter peaks, coupled with Duke's under-estimate of the contribution that DSM can provide to mitigate winter peaks,

[66] AGO Initial Comments at 24-25.

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could lead to costly overbuilding of gas plants that will need to be retired before the end of their useful lives.[67]

Joint Commenters agree with these concerns. In particular, SACE et al. expert James Wilson critiques Duke's approach to estimating historical winter loads using historical temperatures. Due to lack of historical winter load data at very low temperatures, Duke extrapolates load associated with low temperatures based on an algorithm. However, this extrapolation method was significantly flawed, resulting in Duke's model assuming higher winter loads. These extrapolated winter loads are a substantial factor in Duke's conclusion that the vast majority of loss of load risk is during winter months. Joint Commenters experts Brendan Kirby and Justin Sharp address these issues in the NCSEA/CCEBA Initial Comments and draw very similar conclusions as that of Mr. Wilson and SACE et al. This is a critical flaw in Duke's Resource Adequacy analysis that must be corrected.

V. Demand-Side Management and Energy Efficiency

A. Public Staff Comments

The Public Staff questions Duke's DSM and EE projections as being too low.[68] Public Staff's analysis shows more DSM measures could have been included, especially measures to meet winter/summer peaks.[69] Public Staff's analysis of the Economic Potential and Achievable Potential of Duke's DSM and EE forecasts both show the savings appear

[67] SACE et al. Initial Comments at 3.

[68] Public Staff Initial Comments at 56-59.

[69] *Id.* at 56-59, 62-63.

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to be lower than other studies, which is likely due to the DSM and EE projections being too low.[70]

More EE savings are possible: the Public Staff cites Dominion Energy's forecasted EE savings drastically increased from 2018, while DEC's projected EE savings decreased by 16.7% from 2018 and DEP's projected EE savings decreased by 8.2% from 2018.[71] This demonstrates increased EE savings are possible if the incentives are correct.

Public Staff notes that the IRPs do not include any residential DSM programs to meet winter peak.[72] However, the Commission granted approval to DEC and DEP for a new winter-focused residential DSM programs that were not included in the IRP forecasts.[73] Further, Public Staff notes DEC or DEP did not use any DSM to meet winter and summer peaks in 2020.[74] DSM could be used in these situations to lower peak demand.

Overall, Public Staff questions Duke's DSM and EE projections as being too low and Duke's lack of DSM for winter and summer peaks. However, Public Staff recommends "that future market potential studies consider a more comprehensive list of measures that can contribute and provide a more accurate picture of North Carolina's Achievable Potential. The Public Staff believes that the results of this Study should be considered acceptable and reasonable for purposes of inclusion into DEC's and DEP's IRP filings[.][75] The Joint Commenters disagree with Public Staff on timing of more robust studies

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[70] *Id.* at 58-59.

[71] *Id.* at 50.

[72] *Id.* at 54-55.

[73] *Id.* at 54-55.

[74] *Id.* at 62-63.

[75] *Id.* at 59-60.

regarding DSM and EE. The Joint Commenters believe Duke should be required to conduct those more robust analyses now and implement them into its IRPs.

B. AGO Comments

Overall, the AGO comments that Duke did not consider DSM and EE correctly, similar to the Public Staff and other parties. The AGO believes the Commission should order Duke to "[r]evisit the cost, value, and deployment assumptions that appear to constrain the integration of additional, alternative resources."[76] Further, the AGO states that "the Commission should direct Duke to revisit its clean energy assumptions and re-examine the interplay between winter DSM and solar."[77] Specifically, the AGO recommends:

> Duke should include 2-hour storage as an IRP resource option, examine potential synergies between winter DSM and solar, and reconsider its wind and solar interconnection assumptions. Furthermore, the Commission should consider the additional alternative resource recommendations set forth in Strategen's memorandum. As a whole, Duke's clean energy assumptions should be revisited. … Duke has failed to consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options and take into account, as applicable, system operations, environmental impacts, and other qualitative factors.[78]

Lastly, the AGO notes that "[t]hese flaws in clean energy valuation, if not addressed in this proceeding, will lead to a self-fulfilling prophecy that hinders proper consideration of cleaner energy resources."[79] The Joint Commenters also agree that these issues need to be addressed in this current IRP proceeding instead of the following one.

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[76] AGO Initial Comments at 6.

[77] *Id.* at 27.

[78] *Id.* at 27-28 (internal quotes omitted).

[79] *Id.* at 6.

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The AGO notes that Duke does not value DSM correctly and how DSM could increase the value of solar.[80] Specifically, the AGO states:

> Detailed modeling results provided by Duke suggest that an increase in winter DSM might reduce the loss of load expectation or outage risk in the winter, and could therefore increase the capacity value of solar and other summer peaking resources. Said another way, combining winter DSM and solar may increase solar's capacity value and contribution to resource adequacy. Accordingly, the capacity value for solar should be revisited to consider the interplay between winter DSM and solar.[81]

The AGO further states "increased winter DSM may make solar more valuable, as it will produce more power during high demand periods. This in turn could reduce the risk of summer outages."[82] Thus, the AGO recommends reassessing the capacity value of solar given potential synergies with winter DSM.[83]

Regarding EE, the AGO states:

> Duke appears to be (1) assuming that savings from "rolled off" energy efficiency measures will persist due to market improvements and (2) accounting for these continued savings by reducing its energy demand forecasts. However, it is not readily apparent that Duke's forecast for gross retail sales actually reflects this. In fact, the year over year increase in gross retail sales appears to change very little in the latter part of the planning period. Strategen recommends that Duke provide more quantitative detail on how naturally occurring end-use efficiency is incorporated into its load forecast model as energy efficiency program roll off occurs. Additionally, the steep roll off of energy efficiency measures later in Duke's forecasts suggests that Duke's energy efficiency portfolio is comprised of many short-lived measures. Strategen recommends that Duke identify steps it could take to incorporate more long-lived measures into its portfolio, such as new energy efficient construction, energy efficiency upgrades to building envelopes, and energy efficient HVAC equipment.[84]

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[80] *Id.* at 5.

[81] AGO Initial Comments, Strategen Report Attachment, pp. 15-16 ("Strategen Report").

[82] AGO Initial Comments at 26.

[83] *Id.* at 26.

[84] Strategen Report at 16.

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The Joint Commenters agree that Duke should be required to consider additional longer-term EE measures.

C. SACE ET AL. COMMENTS

Similar to concerns raised by other parties, SACE et al. believe Duke should optimize DSM resources in its modeling and implement EE as a resource in future IRPs using the EnCompass model.[85] Further, SACE et al. commented that Duke's Market Potential Study underestimated cost-effective DSM and EE.[86] For example, SACE et al. mentioned that the study failed to consider emerging technologies, evaluate variety of known measures, and consider new or enhanced customer engagement strategies.[87] SACE et al. also commented that Duke used improper cost-effectiveness tests.[88] Finally, similar to the AGO and the Public Staff, SACE et al. addressed Duke's lack of DSM and EE to address winter peaks. The Joint Commenters agree with these comments.

VI. COAL RETIREMENT

The Joint Commenters share the concerns expressed by other intervenors that Duke's coal retirement analysis is significantly flawed and must be corrected. The AGO has identified a variety of flaws with Duke's coal retirement analysis, including that Duke's multi-step process for selecting coal unit retirements is "overly complicated," "lacks objectivity," and "is not fully transparent."[89] The AGO notes that other utilities use computer models that determine the generation needed for grid reliability while

[85] SACE et al. Initial Comments at 8.

[86] *Id.* at 8-13.

[87] *Id.* at 9.

[88] *Id.* at 10-11.

[89] AGO Initial Comments 4.

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simultaneously selecting coal retirement; in contrast, Duke's process "uses flawed assumptions" and "subjective decision-making" to select the most economic retirement dates and then "incorporates these pre-selected dates into the model."[90] The AGO recommends that "Duke should use a computer model to retire its coal units economically" and concludes that "Duke has failed to compellingly demonstrate that its four-step [coal retirement date selection] process reflects the rigor of the IRP process" and that "Duke's approach does not appear to be based 'on reasonable assumptions and best available current knowledge concerning implementation considerations and challenges'."[91]

The Public Staff states that with respect to coal plant retirement dates, Duke's current model requires asset retirement dates to be determined externally and manually entered into the model.[92] The Public Staff recommends that Duke instead use economically optimal endogenous plant retirement dates in future IRPs resulting from the EnCompass model.[93] The Public Staff also notes an "identified concern with the sequential planning approach" that because a resource other than a CT was not allowed to be selected in Duke's model, the cost savings used to establish the retirement dates are not necessarily reflective of actual cost savings.[94]

The Joint Commenters agree with the assessment and critique presented by the AGO and the Public Staff regarding Duke's coal retirement analysis. Similar to the discussion of inadequate modeling that Joint Commenters addressed in the context of

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[90] *Id.* at 4, 12.

[91] *Id.* at 12, 13 (citing 2019 IRP Order at 8).

[92] Public Staff Initial Comments at 26.

[93] *Id.* at 110.

[94] *Id.* at 103.

capacity contribution calculations, Joint Commenters agree with the AGO that Duke's coal retirement analysis is significantly flawed and must be revised in order to meaningfully comply with the Commission's directive for Duke to model coal retirements as part of this IRP proceeding.

VII. RISK OF STRANDED ASSETS

Multiple intervenors identified and discussed the risk that new natural gas generation constructed by Duke could become uneconomical before the asset was fully depreciated due to carbon restrictions that would make those plants much more expensive or unacceptable to operate. As a result, ratepayers could be required to pay for replacement resources while still paying for the replaced assets, creating a "stranded asset" risk with respect to those natural gas plants.[95]

The Public Staff acknowledges this issue, stating that it "has concerns that Duke's anticipated buildout of natural gas in Portfolios A and B could result in the forced early retirement of natural gas assets if carbon legislation is enacted in the future" and that even if Duke reduced the life of natural gas assets from 35 years to 25 years "ratepayers could be required to pay for service from replacement resources while still paying for the replaced assets."[96]

The AGO observes that "Duke's failure to consider the long-term costs of fossil fuel generation, such as the risk that natural gas generating plants will create 'stranded'

[95] *Id.* at 7-8.

[96] *Id.* at 12.

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costs if natural gas plants, like coal plants, are required to close before the end of their expected lives due to climate legislation or policy."[97]

The Tech Customers discuss the fact that natural gas "faces the risk of obsolescence as the cost of renewables continues to decline, carbon emissions are penalized, and policy (whether federal, state, or Duke-internal policy) moves closer to a zero-emissions standard."[98] The Tech Customers state that Duke's logic that investments in future stranded assets are better than investments in renewable generation calls into question Duke's assumptions about the costs of renewable generation. The Tech Customers further state that "it is troubling that DEC's strategy for future generation is built on a belief that wasteful investment…could be in ratepayers' best interests."[99]

Vote Solar presented the study by the Energy Transition Institute entitled "Carbon Stranding: Climate Risk and Stranded Assets in Duke's Integrated Resource Plan." (the "ETI Study")[100] The ETI Study discussed that emergent climate-related risks are material to Duke's assets and operations in the Carolinas, that Duke has an obligation to demonstrate management of climate-related risks in its IRPs, and that Duke's 2020 IRPs do not adequately assess or manage climate-related risks.[101] The ETI Study demonstrated that "[s]hutting these plants down early to meet carbon commitments could result in $4.8 billion of stranded asset costs to ratepayers or $900 per residential Duke Energy customer in the Carolinas."[102] Additionally, the ETI Study points out that "[a]lthough the Duke plans

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[97] AGO Initial Comments at 27.

[98] Tech Customers Initial Comments at 6.

[99] *Id.*

[100] Initial Comments of Vote Solar, Attachment 3 (February 26, 2021) (the "ETI Study").

[101] Initial Comments of Vote Solar, pp. 1-2 (February 26, 2021) ("Vote Solar Initial Comments").

[102] *Id.* at 9 (citing ETI Study, p. ii).

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include a high-level discussion of carbon-neutral retrofits to their gas-fired assets, including green hydrogen and carbon capture and storage, the IRPs do not include any plans to deploy these technologies or discuss any costs they might incur to ratepayers."[103]

The Joint Commenters strongly agree that Duke's massive buildout of natural gas proposed in its IRPs fails to adequately consider and evaluate the risk that a substantial portion of those assets will be stranded and either paid for by ratepayers after the plants have been retired or be depreciated under an accelerated schedule at unnecessarily higher costs to customers. It is essential that such risk be sufficiently considered and accounted for in the risk analyses that Duke and the Commission perform as part of the IRP process. As discussed in NCSEA/CCEBA's Initial Comments, Duke should adopt a more robust risk analysis to better account for such risks.

VIII. TRANSMISSION

The Public Staff notes that "Transmission planning and investment is taking on greater significance than seen in previous IRPs for a variety of reasons[.]"[104] In their initial comments, various intervenors addressed the adequacy of the transmission systems within the DEC and DEP balancing authorities, the adequacy of the transmission ties between DEC and DEP and neighboring balancing authorities, and upgrades necessary for DEC and DEP's transmission systems to accommodate new generation.

[103] ETI Study at vi.

[104] Public Staff Initial Comments at 137.

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A. DUKE'S ANALYSIS OF TRANSMISSION NEEDS IS INADEQUATE

Several intervenors commented that Duke should conduct more robust transmission analysis.[105] The Joint Commenters agree that the Commission cannot determine whether Duke's IRPs are the most cost-effective long-term plans without more robust analysis of Duke's transmission system.

The Public Staff notes that "The Utilities have also presented the possible need for increased transmission import capability, but did not base their projection of costs on any formal study, evaluation, or analysis[.]"[106] While the Joint Commenters have concerns about the Public Staff's recent attempts to shift costs to developers of renewable energy for grid upgrades that benefit all ratepayers, the Joint Commenters agree that Duke's lack of transmission analysis is highly problematic. However, while the Public Staff believes that the lack of transmission analysis should be addressed in future IRPs,[107] The Joint Commenters believe that the IRPs filed by Duke are not reasonable for planning purposes with this fundamental lack of transmission analysis, and thus that Duke should be directed to perform the necessary analysis in its 2022 IRPs.

The Tech Customers also critique Duke's use of rough estimates for transmission costs, which departs significantly from industry norms, specifically noting that Duke's estimates do not even comply with AACE International's lowest level of cost estimation.[108] Accordingly, the Tech Customers argue that Duke's estimates are inadequate to analyze

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[105] *Id.* at 143-145; Tech Customers Initial Comments at 9-10.

[106] Public Staff Initial Comments at 143.

[107] *Id.* at 145.

[108] Tech Customers Initial Comments at 9.

the potential benefits that transmission upgrades could provide.[109] The Tech Customers note that the Commission has previously indicated that the IRP process is the appropriate venue for discussing the benefits associated with transmission investments.[110] The Joint Commenters agree with the Tech Customers "that this proceeding is the appropriate venue for exploration of such issues[,]"[111] and the Joint Commenters request that the Commission direct Duke to more fully analyze the potential costs and benefits associated with transmission investments in revised IRPs.

B. SMART TRANSMISSION INVESTMENTS BENEFIT RATEPAYERS

In their initial comments, the Public Staff expresses concerns that the costs of transmission upgrades, especially those associated with importing power from neighboring balancing authorities, do not yield benefits for ratepayers.[112] However, smart, targeted transmission investments benefit ratepayers by allowing utilities to move electricity from low-cost generation resources to load centers. Similarly, smart, targeted transmission investments that tie Duke to neighboring balancing authorities can allow Duke to access low-cost electricity produced by neighboring utilities.

Similarly, a well-planned transmission system would not require coal to support the grid. The AGO notes "that at least two of [Duke's] coal plants provide 'support to the transmission system' and thus cannot be retired without additional transmission

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[109] *Id.* at 9.

[110] *Id.* at 10.

[111] *Id.* at 10.

[112] Public Staff Initial Comments at 145.

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upgrades."[113] However, the AGO rebuts Duke's assertion that coal plants are necessary to support the transmission system. The Joint Commenters agree with the AGO's analysis and believe that this is an example of why Duke's earliest practicable coal retirement scenario fails to comply with the Commission's directive in its 2019 IRP Order.

Smart transmission planning requires an adequate analysis of the costs of transmission upgrades. The Public Staff and the Tech Customers both note that Duke failed to perform a robust analysis of the costs of transmission upgrades. The Public Staff notes that Duke's estimated network upgrade costs for new generation resources were based on historical network upgrade costs for similar projects.[114] However, the Tech Customers note that such costs are likely artificially inflated, as they fail to consider savings generated by independent development of solar generation or economies of scale associated with large-scale renewable energy development.[115]

C. INTEGRATED SYSTEMS OPERATION PLANNING

As discussed above, smart transmission investments can benefit ratepayers. However, the ability to make smart transmission investments requires a robust grid planning process that North Carolina currently lacks. The Public Staff notes that planning the grid of the 21st century "may require new modeling and analysis methodologies that

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[113] AGO Initial Comments at 14. The exact "support" provided by the coal plants has been marked by Duke as confidential. However, there does not appear to be a rationale for such confidentiality. Disclosing why the coal plants are necessary for the transmission system would provide the public with a better understanding of alleged issues related to coal retirement, and would provide independent businesses the opportunity to develop solutions to address the needs of the transmission system that could be less costly to ratepayers than running expensive coal generation units. The Joint Commenters respectfully request that the Commission rule that the support provided by the coal plants is not confidential pursuant to G.S. 132-1.2 and make the rationale publicly available.

[114] Public Staff Initial Comments at 138.

[115] Tech Customers Initial Comments at 8-9.

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have not been part of previous IRPs."[116] Similarly, the AGO notes that new technologies may be cheaper and faster to construct than traditional, wires-based grid upgrades.[117] Duke's Integrated Systems Operation Planning ("ISOP") process has the potential to provide the necessary planning sophistication, but the lack of transparency and Commission oversight associated with ISOP means it is currently of little use.

The Public Staff notes "that it would be too complex to include detailed power flow analyses associated with future capacity expansion plans, and is open to input from the Utilities and intervenors on how to address this concern in future IRPs."[118] The Joint Commenters respond to this request by noting that this is something that can, and should, be integrated into the ISOP process. However, given the lack of transparency, neither intervenors nor the Commission know whether power flow analysis is a component of ISOP. The Public Staff further notes that Duke's transition to the EnCompass modeling software will allow Duke's IRPs to better incorporate ISOP considerations.[119] However, the lack of transparency about ISOP undermines its value as a grid planning tool. The Joint Commenters believe that the Commission should develop a process, and if necessary rules, addressing how ISOP should be transparently integrated into the IRP process.

D. NEIGHBORING BALANCING AUTHORITIES

The Public Staff notes in their initial comments that Duke's Joint Planning Scenario reduces the need for Duke to build new natural gas generation resources.[120] However, the

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[116] Public Staff Initial Comments at 137.

[117] AGO Initial Comments at 21-22.

[118] Public Staff Initial Comments at 146.

[119] *Id.* at 26.

[120] *Id.* at 130.

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Public Staff does not recommend that the Commission investigate the benefits that would accrue to ratepayers of combining the DEC and DEP balancing authorities, despite the fact that Duke's IRPs indicate that there would be significant cost savings. The Joint Commenters request that the Commission further investigate the costs and benefits of combining the DEC and DEP balancing areas, including directing Duke to include a scenario in its 2022 IRPs that examines a combined balancing area.'

In addition, Duke's relationships with neighboring balancing authorities, and how those relationships impact the need for generation and transmission investments, received extensive discussion by intervenors. The Public Staff notes that Duke's IRPs do not allow imports from or exports to neighboring balancing authorities to meet energy and capacity needs, but that Duke's Resource Adequacy Study allows imports for determining the target reserve margin.[121] At a minimum, the Commission should direct Duke to correct this discrepancy to ensure both the IRPs and the Resource Adequacy Study are based on the same assumptions.

Power pooling and larger geographic service territories make it easier for utilities to integrate variable generation such as solar and wind. The AGO notes the benefits of allowing imports from and exports to neighboring balancing areas, stating:

> These utilities may not encounter reliability issues at the exact same time as Duke. They may not need to shut down their plants for maintenance at the same time as Duke. Therefore, these neighboring utilities could enter into exchange agreements to provide Duke with power from their existing power plants. Neighbor assistance would ensure Duke has sufficient power for grid reliability. If enough utilities could share their power with Duke, Duke could potentially avoid needing to build new fossil fuel plants. Therefore, increased neighbor assistance could potentially reduce the amount of new

[121] *Id.* at 143-144.

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fossil fuel generation needed for grid reliability. This would have the added benefit of decreasing capital costs.[122]

However, as discussed by various intervenors, Duke failed to (1) adequately consider imports from neighboring balancing authorities and (2) adequately calculate the costs of transmission investments necessary to achieve these benefits of regionalization.

The Tech Customers note that Duke failed to model the costs associated with improving its transmission system to better accommodate imports from neighboring utilities.[123] Similarly, the AGO extensively discusses the benefits that accrue from improving transmission connections to neighboring utilities.[124] The Joint Commenters agree with the AGO that Duke's analysis is flawed because it fails to adequately examine whether improved interconnections with neighboring utilities would allow Duke to utilize a lower reserve margin, which would drive savings for ratepayers.[125] The AGO also notes that a lower reserve margin may allow Duke to retire coal generation sooner, but that Duke failed to examine this possibility.[126]

The AGO specifically examines Duke's interconnection to the neighboring PJM Interconnection ("PJM") market. They note that PJM's actual reserve margin is expected to be approximately 40% over the next ten years, meaning that PJM resources could be used to meet Duke's resource adequacy needs if there was sufficient transmission capacity

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[122] AGO Initial Comments at 5.

[123] Tech Customers Initial Comments at 9.

[124] The AGO refers to increased interconnection with neighboring utilities as "neighbor assistance" and "support." NCSEA and CCEBA wish to note that "neighbor assistance" and "support" do not imply freeloading or that Duke's system is somehow insufficient. On the contrary, and as Duke has acknowledged with its SEEM proposal, interconnection coordination between utilities generates mutual economic and reliability benefits.

[125] AGO Initial Comments at 17; Strategen Report at 11.

[126] AGO Initial Comments at 19.

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between the two networks.[127] Similarly, the AGO notes that recent outages in Electric Reliability Council of Texas ("ERCOT") and the California Independent System Operator ("CAISO") demonstrate the need for Duke to improve its transmission ties to neighboring utilities.[128]

The AGO notes that Duke has no plans to improve transmission interconnections with neighboring utilities.[129] The Joint Commenters agree with and support the AGO's recommendation to further study the benefits provided by improved interconnections with neighboring utilities. The AGO noted that Duke's analysis assumed that transmission solutions were too expensive without ever analyzing the costs and benefits.[130] Performing a sensitivity analysis that relaxes import constraints, as recommended by the AGO, would be an easy, cheap, and fast exercise.[131] If the analysis determines that increased imports would be beneficial, then the Commission could begin investigating transmission solutions that would allow for increased imports. The AGO notes that Duke plans to build expensive new fossil fuel generation facilities for grid reliability, which would incur significant capital costs that would be passed on to ratepayers, at a time when PJM and other neighboring utilities have excess generation.[132] There is simply no compelling reason not to examine improved interconnections with neighboring utilities, especially when Duke is proposing to participate in the SEEM multi-state energy market.

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[127] *Id.* at 21.

[128] *Id.* at 22.

[129] *Id.* at 21; Strategen Report at 12.

[130] AGO Initial Comments at 20.

[131] *Id.* at 20-21; Strategen Report at 2.

[132] AGO Initial Comments at 4-5.

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E. SEEM and Organized Markets

The Tech Customers and Vote Solar both point out that Duke did not incorporate the recently proposed Southeast Exchange Market ("SEEM") into its resource planning.[133] Although SEEM has not yet been approved by Federal Energy Regulatory Commission ("FERC"), the fact that Duke is proposing to participate in SEEM indicates that it is likely that Duke will participate in some form of exchange market. It would therefore be prudent for the Commission to require Duke to re-run its IRPs to capture the operational and cost benefits of SEEM claimed by Duke and other SEEM participants.[134] The Joint Commenters agree with the Tech Customers that SEEM *is likely to* impact reserve margins, transmission investments, and the integration of renewable energy resources.[135] However, the extent of these benefits cannot be known unless SEEM is modeled as a part of Duke's IRPs.

The Tech Customers and Vote Solar both view SEEM as a first step towards broader regionalization of Duke's grid. Both the Tech Customers and Vote Solar contend that broader regionalization, in the form of an energy imbalance market ("EIM") or regional transmission organization ("RTO"), would produce benefits such as allowing increased penetration of renewable energy resources,[136] reducing the curtailment of renewable energy resources,[137] mitigating against supply shortfalls,[138] reducing

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[133] Tech Customers Initial Comments at 14; Vote Solar Initial Comments at 9.

[134] See, *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Informational Filing*, Docket Nos. E-2, Sub 1268 and E-7, Sub 1245 (December 11, 2020).

[135] Tech Customers Initial Comments at 14.

[136] *Id.* at 16; Vote Solar Initial Comments at 9.

[137] Tech Customers Initial Comments at 17.

[138] *Id.* at 15.

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transmission congestion,[139] and reduce carbon emissions.[140] On top of these operational benefits, the Tech Customers and Vote Solar both note that Duke's participation in an EIM or an RTO would create significant economic benefits as well.[141] The Tech Customers argue that "DEC's failure to account for impending market reform undermines the value of the entire IRP[,]"[142] and further notes that N.C. Gen. Stat. § 62-110.1(c) directs the Commission to develop a long-term energy plan that "include[s] an assessment of, among other things, 'other arrangements with other utilities and energy suppliers' that will 'achieve maximum efficiencies.'"[143] The Commission has previously recognized the savings to consumers associated with Dominion's participation in PJM.[144] Accordingly, the Joint Commenters agree with the Tech Customers that the Commission cannot adequately evaluate whether Duke's IRPs represent least-cost resource planning unless the Commission can compare Duke's current plan for generation to the costs and savings associated with reorganized markets.[145]

IX. THE NEED FOR IMPROVED MODELING

The development of Duke's IRPs relies upon a number of different modeling tools that produce various portfolios based on the parameters established by the modeler and the inputs selected for use by the model. Specifically, Duke used the System Optimizer

[139] *Id.* at 16.

[140] Vote Solar Initial Comments at 9.

[141] *Id.* at 9; Tech Customers Initial Comments.

[142] Tech Customers Initial Comments at 13.

[143] *Id.* at 17-18.

[144] *Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions*, Docket No. E-22, Sub 532 (December 22, 2016).

[145] Tech Customers Initial Comments at 17-18.

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capacity expansion model to develop its IRPs. In their initial comments, the Public Staff and the AGO both address the modeling that Duke has conducted and the modeling tools that Duke has used in the development of the IRPs. They conclude that Duke should use a more advanced capacity expansion model, which would help address a number of deficiencies identified by intervenors. The Joint Commenters agree, and request that the Commission direct Duke to perform its 2022 IRPs using the EnCompass modeling software.

The Public Staff states in its initial comments that over the past fifteen years "the IRP process has changed significantly" and that rather than "determining the type of large, centralized, thermal generation unit to build" the IRPs must now "incorporate consideration of distributed energy resources, intermittent generation such as wind and solar, the complexities of modeling energy storage systems, and legislation that influences the type of generation that can be built." The Public Staff notes that "there are significant and novel challenges associated with modeling these various factors" and that "new tools will be required to manage these challenges going forward."[146]

The Public Staff makes a number of specific observations related to Duke's modeling techniques. First, the Public Staff states that "Duke should consider implementing stochastic optimization in its capacity expansion model."[147] In describing the "deterministic" method currently used by the System Optimizer capacity expansion model used by Duke, the Public Staff states that the model generates "sub-optimal" portfolios and that Duke should consider implementing stochastic optimization in its

[146] Public Staff Initial Comments at 23-24.

[147] *Id.* at 16.

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capacity expansion model which would "seek to optimize the expansion plan." Second, the Public Staff states that with respect to coal plant retirement date, Duke's current model requires asset retirement dates to be determined externally and manually entered into the model.[148] The Public Staff recommends that instead Duke use economically optimal endogenous plant retirement dates in future IRPs resulting from the EnCompass model.[149] The Public Staff also notes the benefits of "sub-hourly modeling, which may in the future improve the IRP's' ability to integrate high levels of renewable energy" but which is not possible with Duke's current model.[150]

The Public Staff also notes that Duke is currently transitioning from System Optimizer to the EnCompass model. The Public Staff states that the "EnCompass model provides additional abilities that can aid in the ISOP process, including the modeling of climate goals, detailed ancillary service modeling, improved optimization of energy storage resources, endogenous retirement of generation assets, and improved dispatch of dual-fuel resources."[151] The Public Staff also states that EnCompass is capable of producing endogenous plant retirement dates.[152]

In its initial comments, the AGO also addresses shortcomings in the model Duke has used to develop its IRPs. First, the AGO states that "Duke should use a computer model to retire its coal units economically." The AGO states that Duke's multi-step process for selecting coal unit retirements is "overly complicated," "lacks objectivity" and "is not fully

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[148] *Id.* at 26.

[149] *Id.* at 110.

[150] *Id.* at 26.

[151] *Id.* at 25.

[152] *Id.* at 110.

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transparent."[153] The AGO notes that other utilities use computer models that determine the generation needed for grid reliability while simultaneously selecting coal retirement; in contrast, Duke's process "uses flawed assumptions" and "subjective decision-making" to select the most economic retirement dates and then "incorporates these pre-selected dates into the model."[154] The AGO states that since the System Optimizer model could not modify ongoing costs in real time, Duke could have used another model with that capability.[155]

The AGO concludes that "Duke has failed to compellingly demonstrate that its four-step [coal retirement date selection] process reflects the rigor of the IRP process" and that "Duke's approach does not appear to be based 'on reasonable assumptions and best available current knowledge concerning implementation considerations and challenges'."[156]

The Joint Commenters strongly agree with the Public Staff's characterization of the changing nature of the IRP process and believe that it is critical for utilities to use modeling tools that are designed for and capable of modeling a more diverse resource mix. As the Joint Commenters stated in their initial comments, IRP tools that utilities used in the past are poorly equipped to capture the economic, operational, and reliability complexities of today's resources. The Joint Commenters agree with the critiques of the Public Staff and the AGO concerning the need for Duke to adopt and properly use a more advanced capacity expansion model. This critique is consistent with the recommendation by Joint Commenter

[153] AGO Initial Comments at 4.

[154] *Id.* at 4, 12.

[155] *Id.* at 13.

[156] *Id.* at 12-13 (citing 2019 IRP Order at 8).

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expert consultant E3 that Duke should be required to use a capacity expansion model that is capable of "single-step optimization," or modeling all available resources simultaneously so that any benefits of certain combinations of resources on the grid (e.g. solar and storage) may be accurately captured and incorporated into the model.

As discussed by the Public Staff, Duke is in the process of moving to the EnCompass model, which is capable of both capacity expansion and production cost modeling. The Joint Commenters are supportive of Duke using EnCompass and are of the understanding that the newest version of EnCompass is capable of the single-step optimization recommended by E3 and the Joint Commenters. However, it is important to note that simply having access to the EnCompass model does not ensure that Duke will optimally apply the model and its capabilities, and the Joint Commenters do not suggest that the adoption of EnCompass will be a cure-all for the issues identified by the parties. Instead, as Duke begins to use the new model leading up to the 2022 IRP filings, the Joint Commenters request that the Commission require Duke to engage stakeholders to discuss the adoption and implementation of EnCompass, including Duke's planned application of the model as it applies to the specific critiques and recommendations of the parties. This type of process should help to decrease the number of contested issues in future IRP proceedings and will provide Duke valuable input as they continue to revise and update their IRP process to plan for and incorporate the variety of resources and tools available to utility planners.[157]

[157] The Joint Commenters note that the South Carolina Public Service Commission recently required Dominion Energy South Carolina to conduct a stakeholder process regarding the adoption of a capacity expansion model for future IRP development. South Carolina Public Service Commission, Order No. 2020-832, pp. 29, Docket No. 2019-226-E (Dec. 23, 2020).

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X. CONCLUSION

For the reasons set forth in the NCSEA/CCEBA Initial Comments, the NCSEA/CCEBA/SACE Initial Comments, and as set forth above, the Joint Commenters respectfully request that the Commission decline to approve or accept Duke's IRPs as reasonable for planning purposes. Instead, the Joint Commenters request that the Commission direct Duke to make a compliance IRP filing that incorporates the feedback provided by the Joint Commenters and other parties regarding natural gas pricing, resource adequacy, DSM and EE, coal retirement, and stranded asset risk to create an IRP that is truly least-cost. Furthermore, the Joint Commenters request that the Commission direct Duke to incorporate the feedback provided by the Joint Commenters and other parties regarding transmission analysis and improved modeling in their 2022 IRPs.

Respectfully submitted, this the 28th day of May 2021

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing filing by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

Respectfully submitted, this the 28th day of May 2021

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