STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 165

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans	)))))	ORDER ACCEPTING INTEGRATED RESOURCE PLANS, REPS AND CPRE PROGRAM PLANS WITH CONDITIONS AND PROVIDING FURTHER DIRECTION FOR FUTURE PLANNING

HEARD: March 9, April 14, and 19; May 5, 12, 17, and 26; September 30; and October 1, 2021, remotely via Webex.

BEFORE: Commissioner Daniel G. Clodfelter, Presiding; Chair Charlotte A. Mitchell, and Commissioners ToNola D. Brown-Bland, Lyons Gray, Kimberly W. Duffley, Jeffrey A. Hughes and Floyd B. McKissick, Jr.

BY THE COMMISSION: Pursuant to N.C. Gen. Stat. § 62-110.1, the integrated resource planning (IRP) process is intended to identify electric resource options that will ensure adequate and reliable electric service, can be obtained at least cost, and are in harmony with the environment. Specifically, under § 62-110.1(c) the Commission is required to “develop, publicize, and keep current an analysis of the long-range needs” for electricity in this State. The Commission’s analysis includes: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). Further, the statute requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly the following: (1) a report of the Commission’s analysis and plan for the future requirements of electricity for North Carolina; (2) the progress to date in carrying out such plan; and (3) the program of the Commission for the ensuing year in connection with such plan.

In addition, several other General Statutes and Commission Rules guide the Commission’s review of the electric utilities’ IRP processes. Pursuant to N.C. Gen. Stat. § 62-15(d) the Public Staff-North Carolina Utilities Commission (Public Staff) is required to assist the Commission in IRP analysis and planning. Moreover, N.C.G.S § 62-2(a)(3a) vests the Commission with the duty to regulate public utilities and their expansion in relation to long-term energy conservation and management policies. These policies include assuring that “resources necessary to meet future growth through the provision of adequate, reliable utility service include the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions.” As a result, in addition to electric generation and other supply-side alternatives, the utilities' IRPs consider conservation, efficiency and load management as resources for meeting the electric utilities' planning goals.

Finally, Commission Rule R8-60 defines an overall framework within which the Commission conducts its annual investigation into the electric utilities' IRPs. To meet the directives of N.C.G.S §§ 62-110.1 and 62-2(a)(3a), Commission Rule R8-60 requires that each of the electric utilities furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in that Commission Rule. In odd-numbered years, each of the electric utilities must file an update report updating its most recently filed biennial report. Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a Renewable Energy and Energy Efficiency Portfolio Standard compliance plan (REPS compliance plan) as part of its IRP report.

I. PROCEDURAL HISTORY

On May 1, 2020, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or Dominion) filed its 2020 biennial IRP and 2020 REPS Compliance Plan in this docket, in compliance with N.C.G.S. § 62-110.1(c) and Commission Rule R8-60. Likewise, on September 1, 2020, Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC, and collectively with DEP sometimes Duke or the Duke Utilities), each filed their IRPs and REPS Compliance Plans.

Petitions to intervene were filed by and were granted for the Commission for Broad River Energy, LLC (Broad River); Carolinas Clean Energy Business Association (CCEBA); Carolina Industrial Groups for Fair Utility Rates (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); City of Asheville and Buncombe County; City of Charlotte; jointly ElectriCities of North Carolina, Inc. (ElectriCities), North Carolina Eastern Municipal Power Agency (NCEMPA), and North Carolina Municipal Power Agency Number 1 (NCMPA1, collectively ElectriCities); jointly NC WARN, Inc., and Center for Biological Diversity (CBD, collectively NC WARN); North Carolina Sustainable Energy Association (NCSEA); jointly The Southern Alliance for Clean Energy (SACE), Sierra Club, and Natural Resources Defense Council (NRDC, collectively SACE/NRDC/Sierra); jointly Apple Inc., Facebook, Inc., and Google LLC (Tech Customers); and Vote Solar.

The participation of the Public Staff and the North Carolina Attorney General's Office (AGO) is recognized by N.C. Gen. Stat. §§ 62-15 and 62-20, respectively.

Extensive written comments on the IRPs have been filed by the Public Staff, AGO, CCEBA, City of Asheville and Buncombe County, City of Charlotte, NC WARN, NCSEA, SACE/NRDC/Sierra, Tech Customers, and Vote Solar. Replies to these comments have been filed by DENC, the Duke Utilities, Public Staff, AGO, CCEBA, CIGFUR, NC WARN, NCSEA; SACE/NRDC/Sierra, and Tech Customers.

On March 9, 2021, the Commission held a technical conference on Duke's initiative to develop and implement an Integrated Systems and Operations Planning (ISOP) project, and related ISOP topics (First Technical Conference). This technical conference was a follow-up to an ISOP technical conference held by the Commission in 2019 as part of the previous IRP process in Docket No. E-100, Sub 157.

Beginning on April 14, 2021 and continuing through May 26, 2021, the Commission held six public witness hearings in which it received testimony from 129 public witnesses. In addition to the witnesses who appeared at the public hearings, during the course of this docket the Commission has received several hundred written consumer statements of position from interested persons.

On June 29, 2021, the Commission issued an Order Waiving in Part Rule R8-60(h)(2) and Giving Notice of Additional Proceedings (the Additional Proceedings Order), suspending certain IRP filing requirements and stating the Commission's intention to address additional issues in further proceedings in the docket. In summary, the Additional Proceedings Order (1) relieved DEC and DEP of the obligation to file updated 2021 IRPs under Rule R8-60; (2) required DEC and DEP to file on or before September 1, 2021, their REPS Compliance Plans as required by Rule R8-60(h)(4) and Rule R8-67(b), their CPRE Program Plan update as required by Rule R8-71(g)(1), and any material modifications to the short-term action plans identified in their 2020 biennial IRPs as would be required by Rule R8-60(h)(3); (3) denied pending motions for further evidentiary hearings, and (4) required DENC to comply with all requirements for filing an updated 2021 IRP under Rule R8-60.

On September 1, 2021, DENC filed its 2021 IRP Update report. In addition, DEC and DEP each filed their 2021 Update to 2020 Short-Term Action Plan, REPS Compliance Plan, and CPRE Plan Update.

On September 30 and October 1, 2021, the Commission held a technical conference (Second Technical Conference) to hear further presentations from the two Duke Utilities on the following three topics: (1) the proper methodology for evaluating economic retirement of coal-fired generating units, (2) potential use of an all-source procurement process, and (3) grid impacts of different resource portfolios.

Appearances of counsel were made for Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Virginia Electric and Power Company d/b/a Dominion Energy North Carolina, the Public Staff, the North Carolina Attorney General's Office, and several intervenors, with all such appearances noted in the official records of the hearings.

II. STANDARD OF REVIEW

The IRPs are first and foremost planning tools. The IRP statute, N.C. Gen. Stat. § 62-110.1(c), establishes a planning process that is an exercise of the Commission's legislative function, as opposed to an exercise of the Commission's judicial function. In *State ex rel. Utilities Commission v. North Carolina Electric Membership Corp.*, 105 N.C. App. 136, 412 S.E.2d 166 (1992), addressing the character of proceedings relating to utilities' integrated resource plans, the Court of Appeals, stated: "…[W]e believe that the least-cost planning proceeding should bear a much closer resemblance to a legislative hearing, wherein a legislative committee gathers facts and opinions so that informed decisions may be made at a later time." *Id.* at 144, 412 S.E.2d at 170.

In addition, N.C. Gen. Stat. § 62-94 authorizes the Commission to consider the whole record when making its decisions. As a result, the Commission views the IRP information and data received through public witness testimony, comments and reply comments, consumer statements of position, and technical conferences to be information and data to be considered by the Commission and used in its IRP investigation and decision-making process. The Commission is the sole judge of the weight to be given to any particular piece of information or data presented during its review and consideration of the utilities' IRPs.

III. THE UTILITIES' INTEGRATED RESOURCE PLANS

DEC's and DEP's IRPs include what they call "base case" plans, not including any consideration of carbon policy, that represent existing policies under least-cost planning principles. To show the impact potential new policies may have on future resource configurations the 2020 IRPs also introduced a variety of alternative resource portfolios that evaluate more aggressive carbon emission reduction targets. As described throughout the two IRPs, these portfolios have trade-offs between the pace of emission reductions weighted against both associated cost and operational considerations. The 2020 IRPs project potential pathways for how the resource portfolios may evolve over the 15-year period through 2035 based on current data and assumptions across a variety of scenarios. The analyses developed compare the carbon emission reduction trajectory, cost, operability and execution implications of each portfolio to support the regulatory process and inform public policy dialogue. The 2020 IRPs include two resource portfolios that illustrate potential pathways to achieve by 2030 a 70% reduction in carbon dioxide emissions, measured against a base year of 2005. All portfolios keep the Duke Utilities on a trajectory to support the carbon-reduction goal of at least 50% by 2030 and long-term goal of net-zero by 2050, an enterprise-wide goal declared by their common parent, Duke Energy Corporation.

Dominion's operations in North Carolina are very different from those of the Duke Utilities. Dominion's North Carolina territory has a small amount of generation and only approximately 5% of Dominion's total electric load. The remaining load, and most of the generation, is located in Virginia. In addition, Dominion is part of the PJM Regional Transmission Organization (RTO). In April 2020, the Virginia Clean Economy Act (VCEA) became law in Virginia, and among other things, requires Dominion to produce 100 percent of its electricity from renewable sources by 2045. In July 2020, Virginia joined the Regional Greenhouse Gas Initiative (RGGI), which is a market-based program implemented by several Northeast and Mid-Atlantic states to reduce greenhouse gas emissions. RGGI is a state-implemented program, not a utility-implemented program, and requires its member states to cap CO_2 emissions and buy allowances for any CO_2 that is emitted. Dominion modeled the effects of RGGI in all plans but Plan A. The effect of RGGI on future Dominion operations is uncertain, and the future establishment of mandatory federal CO_2 compliance could influence the RGGI market. Similarly to the Duke Utilities, Dominion has committed to achieve net zero CO_2 and methane emissions by 2050. The

VCEA and Virginia's membership in RGGI is a clear mandate for CO_2 reduction and renewable energy. For its IRP, Dominion developed a Plan A, which is a pure least-cost scenario but is not compliant with the VCEA. Dominion's Plan B includes significant development of solar, wind, and energy storage resources, and is compliant with the VCEA renewable energy requirements within the study period (2021 to 2045).

IV. SUMMARY AND GENERAL CONCLUSIONS

The written comments and reply comments of the parties, accompanied by reports, analyses, studies, and compilations, run to several thousand pages. The Commission has read and given due consideration to all these written submissions. In this Order, however, the Commission will not attempt to provide summaries or recitations of each of the points made by the parties in their filings. As noted earlier, the purpose of the IRP process is to inform the report required by N.C.G.S. § 62-110.1(c) and to serve as a guide to Commission decisions in other dockets.

The Commission's Additional Proceedings Order revised this year's IRP process with regard to the Duke Utilities by eliminating the requirement that they file an updated IRP in September 2021. Instead, the Commission expanded its analysis of DEC's and DEP's 2020 IRPs by delving more deeply into several issues that were presented by those IRPs. The Commission is satisfied that the revised procedure has enhanced the value of the 2020 biennial process as a planning tool. In particular, the Commission found the parties' presentations at the First and Second Technical Conferences to be informative and helpful to the Commission's understanding of issues.

Based on the entire record, the Commission's summary and general conclusions with respect to the 2020 biennial IRPs are as follows:

1. The 2020 biennial IRPs submitted by DEC, DEP, and DENC comply with the filing requirements of Commission Rule R8-60 and with the Commission's August 27, 2019, and April 6, 2020, orders relative to the preparation of the 2020 IRPs with respect to the topics and elements required to be contained in such plans.

2. DENC's 2020 biennial IRP is adequate and reasonable for planning purposes and for the Commission's use pursuant to N.C.G.S. § 62-110.1(c).

3. Except as may be discussed hereafter, DEP's and DEC's 2020 biennial IRPs are adequate and reasonable for planning purposes with respect to matters concerning system overview (Chapter 2); load forecasting methodologies and load forecasts (Chapter 3); energy efficiency, demand side management and voltage optimization (Chapter 4); energy storage and electric vehicles (Chapter 6); screening of generation alternatives (Chapter 8); resource adequacy and reserve margins (Chapter 9); nuclear and subsequent license renewal (Chapter 10); identification of first new resource need (Chapter 13); and ISOP (Chapter 15). While several commenters questioned the Duke Utilities approaches to some of these

topics, the Commission is not inclined at this time to revisit the conclusions it reached with respect to those issues in connection with its review of the two utilities' 2018 biennial IRPs and the 2019 updates. The Commission takes note that the Duke Utilities, in reply to suggestions made in the Public Staff's comments, have committed to continue to assess their load forecasting process in order to enhance the normalization of peak-weather forecasting during extreme cold winter peaks.

4. With respect to the modeling, analysis and results of the base case and alternative resource portfolios in the DEC and DEP 2020 IRPs, the Commission receives these as presented but declines to accept them for future planning purposes.[1] The Commission notes that the first new resource need identified in DEC's 2020 IRP is for the year beginning January 1, 2026, and that the first new resource need identified in DEP's 2020 IRP is for the year beginning January 1, 2025. Both these dates are beyond the timeframe of the short-term action plans contained in the two IRPs (Chapter 14), and neither utility anticipates a new supply resource will be required during that time period, notwithstanding the retirement of several existing generating units. The Commission's position on this point is based on the recent enactment of S.L. 2021-165. That new statutory directive establishes an explicit goal for carbon emission reductions by 2030 for the Duke Utilities' North Carolina generating assets and further establishes a requirement that the two utilities' North Carolina resource portfolio be net neutral as to carbon emissions by 2050. The present record in this docket does not permit a conclusion at this time as to whether these new directives will change the schedule for coal plant retirements proposed in either the base case or any of the alternative case scenarios in the DEC and DEP 2020 biennial IRPs and, further, whether they will require revision of the two utilities' technology screening and resource selection modeling for additional resources over the IRP planning period. The Commission wishes to be clear that this Order should not be interpreted as passing judgment on any of the resource scenarios presented in the 2020 IRPs; it should instead be understood as a recognition of the carbon emission reduction mandate and associated process created by the enactment of S.L. 2021-165.

5. On an interim basis and for immediate planning purposes only, the Commission finds that the short-term action plans (STAPs) contained in the DEC and DEP 2020 IRPs (Chapter 14) are reasonable and adequate, pending preparation by DEC and DEP of Carbon Plans, as is required by Section 1 of S.L. 2021-165.

[1] These matters are addressed primarily in Chapters 5, 11, 12, and 16 of the IRPs.

V. FURTHER DISCUSSION AND GUIDANCE

In addition to the Commission's general findings and conclusions set forth above the Commission has determined that it would be appropriate to provide additional guidance with respect to the preparation and submission of the Carbon Plan required by S.L. 2021-165 and future IRPs. The matters addressed here arise out of the comments and reply comments of various participants and have been deemed by the Commission to be of particular interest as they may affect the utilities' near-term and long-term planning for new or replacement resources. In its review and evaluation of the 2020 IRP Reports the Commission has given particular attention to five topics: (1) natural gas supply and pricing issues, (2) methodology for evaluating economic retirement dates for coal-fired generating units, (3) grid impacts of different resource portfolios, (4) potential use of all-source procurement process, and (5) energy efficiency and demand-side management. DEC and DEP should adhere to the guidance provided for each of these topics in developing their Carbon Plan and for future IRPs.

A. Natural gas issues

The availability and pricing of natural gas to fuel combustion turbine (CT) and combined cycle (CC) generating plants is a matter that strongly affects whether such technologies are selected relative to other alternatives to meet future resource needs. It is also a matter that has implications for the methodology by which the utilities determine their avoided cost rates for purposes of PURPA. For the period 2021 through 2030 DEC and DEP use ten years of monthly pricing from the observable market. This market pricing period is followed by four years of transition from market prices to fundamental prices by blending the forward natural gas prices for 2031 through 2034 with a fundamental forecast from I Markit, Inc. The full fundamental forecast is in effect starting in 2035. Dominion utilizes commodity price forecasts provided by ICF Resources, LLC (ICF) in all periods except the first 36 months of the Study Period. The forecasts used for natural gas prices rely on forward market prices as of December 31, 2019, for the first 18 months of the Study Period and then blended forward prices with ICF estimates for the next 18 months. Beyond the first 36 months, the Company used the ICF commodity price forecast exclusively.

In their comments NCSEA and CCEBA contend that the Duke Utilities' natural gas price forecasts and sensitivities are seriously flawed and significantly underestimate future gas prices. They posit that Duke's near-term forecast is well below the fundamentals-based models. They concede that while the Duke Utilities did perform a low and high natural gas fuel cost forecast sensitivity, they also assumed that sufficient firm capacity to deliver natural gas to its new CC units would be available from "new or upgraded [pipeline] capacity" at a constant price. However, given the recent cancellation of the Atlantic Coast Pipeline and the still-undetermined status of the Mountain Valley Pipeline project, they contend that it is increasingly unlikely that sufficient new or upgraded pipeline capacity will be available to provide firm supply to the proposed new CC units modeled in several of the Duke IRP resource portfolios.

Second, NCSEA and CCEBA observe that Duke does not plan to contract for firm natural gas delivery to its CT units, despite adding substantial amounts of new CT capacity. These proposed CTs will be utilized during cold winter mornings and evenings – the exact same time when the natural gas distribution system will be under stress from building heating loads. The parties stated that the recent events in Texas have highlighted this concern and emphasize the need for Duke to include firm natural gas delivery in its models.

Third, according to NCSEA and CCEBA, Duke's natural gas pricing assumptions can dramatically impact the capacity additions selected during the IRP modeling process. It is therefore essential for ratepayers that gas price projections be subjected to very close scrutiny. As detailed by Mr. Lucas, such scrutiny shows that Duke's forward market forecast, compared to a pricing forecast based more on fundamentals, provides less realistic and less reliable natural gas price projections for the mid-2020s through the mid-2030s, when the utilities' needs for new capacity first arise. Furthermore, they point out that that Duke locked in market price forecasts on April 9, 2020, in the midst of a period of major futures market volatility, and very near to the lowest price point in the market in several years. According to NCSEA and CCEBA, if pricing had been locked in on a different day, the natural gas prices for the first 15 years of the IRP would have been substantially different.

The Public Staff in its Comments also raised concerns regarding the natural gas availability and pricing forecasts utilized by DEC and DEP. Specifically, the Public Staff criticized the use of Dominion Southpoint (DS) hub prices for all future and existing combined cycle (CC) generating facilities, beginning in 2026. The Public Staff noted that it had raised this issue in its Initial Comments filed in the 2020 avoided cost proceeding, Docket No. E-100, Sub 167. Other intervenors note that "[n]atural gas fuel price forecasts [by Duke] are lower for the newest, most efficient units than for older units" and that "[u]nderstating future gas prices could wrongly skew DEC's financial analysis in favor of gas generation to the exclusion of investments in fuel-free renewable generation." The Public Staff agreed with these intervenors that artificially low natural gas prices and constrained pipeline capacity for new CC generation plants is a serious matter. According to the Public Staff, total portfolio costs and the selection of natural gas capacity are both highly sensitive to fuel costs: the 'High Fuel' sensitivity analysis has the largest increase in costs relative to the base case of any sensitivity for both DEC and DEP, and the amount of new gas generation selected is also influenced by fuel prices. Therefore, the Public Staff stated that it believes the accuracy of the natural gas price forecast – which is inherently linked to the ability to transport sufficient gas into North Carolina – is of utmost importance. Based upon its review of Duke's IRPs, the Public Staff made the following two recommendations in its Initial Comments regarding the use of DS trading hub gas:

1. For the 2021 IRP update, Duke should re-evaluate its prediction that additional interstate pipeline capacity will be available. If Duke continues to believe that adequate capacity will be available, Duke should provide the Commission and stakeholders with a detailed narrative that identifies a specific timeline for completion, as well as identification of major challenges

associated with potential new interstate pipelines, which require FERC approval. (See Recommendation # 21)

2. In 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 or less reliance on DS point gas. (See Recommendation # 22)

The Public Staff noted that while Duke has indicated it is willing to conduct the analysis recommended by the Public Staff, it believes the additional analysis is better suited for the comprehensive 2022 IRP filing. According to the Public Staff, this delay would result in the 2021 Avoided Cost proceeding utilizing a portfolio and natural gas price forecast that would be overly reliant on the assumption of DS trading hub gas being available in 2026. The overreliance on lower priced shale natural gas, sourced from the DS trading hub, would artificially distort the 2021 Avoided Cost proceeding's avoided energy cost rates, and PURPA standard offer contracts.

The Public Staff requested that based on the potential for limited availability of DS trading hub gas, the Commission order Duke to file a Limited DS Hub Gas Portfolio in its 2021 IRP Updates, or as a supplemental filing to Duke's 2020 IRPs, for potential use in calculating avoided energy rates in the 2021 Avoided Cost proceeding.

In reply, Duke stated that the use of ten years of market prices before transition to full fundamentals has been evaluated by the Public Staff in past IRP proceedings and has also been accepted by the Commission as reasonable for planning purposes since 2015. Duke points out that the Commission noted in its 2018 IRP Order Duke's comments that "using 10 years of forward market natural gas prices in their IRPs is appropriate for evaluating future generation needs and allows for an appropriate head-to-head comparison of long-term purchase power obligations from QFs required under PURPA" and that the Commission accepted the 2018 IRPs as reasonable for planning purposes. Further, Duke stated that the Public Staff's comments in this proceeding do not oppose the Companies' natural gas pricing forecast methodology, essentially finding that this aspect of the 2020 IRPs is again appropriate for IRP purposes in this docket.

The Companies disagreed with NCSEA and CCEBA's argument that the natural gas price forecast methodology is flawed and biased downward. In Section IV of the SEIA Lucas Report, Mr. Lucas is critical of the Companies' natural gas forecasts and claims that they are flawed because they incorporate actual market prices, despite the fact that this methodology has been previously reviewed and accepted by this Commission. Duke contended that the use of fundamental market prices that are in excess of actual market prices, as proposed by Mr. Lucas, is flawed and would result in significant risk of customer overpayments if the same logic was followed in the upcoming avoided cost docket.

Further, Duke stated that contrary to the SEIA Lucas Report's arguments, the use of near-term market prices that have a demonstrated liquidity is appropriate. Near term use of fundamental natural gas forecasts was thoroughly discussed in recent avoided cost Docket Nos. E-100, Sub 148 and Sub 158, and, in the last decade fundamental forecasts tend to lag the structural changes in the natural gas market. According to Duke, the lagging nature of these fundamental forecasts, which are only updated once or twice per year, have been demonstrated in recent history to overstate the forward market price of natural gas. Changes to the market as speculated by the fundamental forecasts can take longer to develop and are therefore more appropriate only in the absence of demonstrated liquid market-based pricing.

Finally, based upon discussions with the Public Staff since the filing of the Public Staff's Initial Comments in this docket, the Duke Utilities agreed to model in their 2021 IRP Updates a sensitivity portfolio, separate from the updates to the base planning cases, that would limit Dominion Southpoint Gas to levels that would only allow DEC to supply its existing gas combined cycle (CC) fleet plus one new CC with Dominion Southpoint trading hub gas and DEP to supply its existing 78 and future CC plants from Transco Zone 4 or Zone 5 gas, through 2030, as recommended by the Public Staff.

Conclusions – Natural gas issues

No party disputed that the availability and pricing forecasts used in DENC's 2020 IRP are reasonable, and accordingly the Commission finds them to be acceptable and reasonable for planning purposes by that company.

The Commission declines at this time to direct that the Duke Utilities abandon the use of actual market price information in their price forecasts. However, the Commission does agree that the natural gas price forecasts used by DEC and DEP should mirror those used by the Companies in the determination of avoided energy cost for PURPA purposes. Accordingly, DEC and DEP shall prepare their Carbon Plan for 2022 and their future IRPs to include no more than eight years of market-based forward natural gas prices before using fundamental forecast data for the remainder of the planning period, consistent with the Commission's Avoided Cost Order in Docket No. E-100, Sub 158. (Order dated April 15, 2020, Ordering Paragraph 20) [2]

Next, the Commission notes and accepts the agreement between the Duke Utilities and the Public Staff that it would be useful, not only for IRP purposes but also for purposes of the determination of avoided costs, to model at least one future resource portfolio in which the supply of natural gas at DS pricing is constrained. Cancellation of the Atlantic Coast Pipeline and the present status of the Mountain Valley Pipeline extension both counsel the need for consideration of such possibility. Accordingly, as a supplement to their 2020 biennial IRPs, DEC and DEP shall each prepare and shall file one additional iteration of their Base Portfolio with Carbon Policy portfolios that assumes limited DS Hub Gas, in the manner between Duke and the Public Staff, and also relies on no more than eight years of forward natural gas prices before using fundamental forecast data for the remainder of

[2] The Commission notes that in Docket No. E-100, Sub 167, in its Eighth Joint 45-Day Progress Report filed on October 22, 2021, Duke noted its agreement with the Public Staff to continue the use of forward natural gas prices for eight years before using fundamental forecast data for the remainder of the planning period in calculating avoided energy rates in the 2021 Avoided Cost Proceeding. (p. 10) Additionally, in Duke's Joint Initial Statement filed on November 1, 2021, in Docket No. E-100, Sub 175, Duke relied upon forward market price data for 8 years before transitioning to fundamentals forecast data in year nine in calculating its avoided cost energy rates. (p. 25)

the planning period. Such supplemental filing should be made promptly and, in any event, not later than February 9, 2022.

B. Methodology for evaluating economic retirement of coal-fired generating units

Based on the comments and reply comments of the parties, the Commission considered this topic to be appropriate for more extensive review and consideration as part of the Second Technical Conference, during which the Commission focused not directly on the dates selected in the Duke Utilities' IRPs for retirement of their remaining coal generating fleet but on the question of the best methodology for determining the optimum date for such retirements. Although the 2020 IRPs and the Second Technical Conference preceded the enactment of S.L. 2021-165, the Commission believes that the foundation laid in those IRPs and in the technical conference will substantially advance the parties' ability to respond to the carbon reduction mandates in that new legislation. In many respects, the work done in connection with the 2020 biennial IRPs and the review and analysis of those results is a predicate for the preparation of their Carbon Plan.

In their 2020 IRPs DEC and DEP conducted coal facility retirement analyses in compliance with the Commission's previous IRP Orders in Docket No. E-100, Sub 157. These analyses involved a multi-step process that identified the most economic coal retirement dates for each of the utilities' coal assets. The resulting retirement dates were used in the Base Case Portfolios (with and without carbon policy). In addition, the Companies also determined the earliest practicable coal retirement dates for each unit, which were used in three of the IRP Portfolios. Most commenters on this methodology criticized Duke's use of its multi-step "Sequential Peaker Process."

The AGO relied on a report from Strategen Consulting to inform its comments. Based on that report the AGO contended that Duke's multi-step Sequential Peaker Method for selecting coal unit retirements is overly complicated and should be replaced by computer modeling that selects units for retirement from within the model. The NCSEA, CCEBA and SACE joint intervenors asked that the Commission direct Duke to replace its coal retirement study with a more transparent and detailed analysis that reflects the true costs of operating its existing coal fleet. Their comments were informed by the modeling effort and report by Synapse. The Public Staff recommended that Duke employ its EnCompass modeling capability to endogenously select the economically optimal plant retirement dates in future IRPs. According to the Public Staff the EnCompass model to which Duke is migrating has this ability. Instead of specifying the retirement dates by a complex external analysis based on assumptions and variables selected independently of the model, the model itself could determine when to shut the plant down and replace it with new capacity.

Duke stated that although the utilities appreciated the conceptual idea of using the capacity expansion model to perform all resource optimization – both retirements and replacements -- in a single computational process, this approach was not practical due to limitations of the capacity expansion model, the complexity of analysis, and the magnitude of the coal retirements being contemplated. Furthermore, because the Duke Utilities are switching to the EnCompass model as discussed with interested parties in the stakeholder process, DEC and DEP will also continue to evaluate the capabilities and enhancements that the new modeling software will provide with respect to co-optimizing retirements of the Companies' coal fleet. To the extent the Duke Utilities determine that the EnCompass software can be leveraged to better optimize coal retirement dates and replacement options, the utilities will agree to perform that analysis in the comprehensive biennial IRP filings in 2022. The utilities believe given the capabilities of the current models, the approach used in the 2020 IRP yielded the most economic retirement dates. The Companies commit to further evaluating if EnCompass can provide the necessary functionality to accurately capture changing cost and value over time as done in the Companies' coal retirement analysis in the 2020 IRP.

Conclusions – Coal unit retirements

At the time of the Second Technical Conference the difference between the positions of the Duke Utilities on the one hand and the positions of the Public Staff, the Attorney General, and intervenors on the other hand centered on whether optimal plant retirement dates should be selected endogenously as part of the same model that also selected the most economic and appropriate replacement resources or whether plant retirement dates should be selected first and then the optimal replacement resources identified separately and sequentially through use of Duke's capacity expansion model. The Commission concludes that this dispute likely will be resolved by Duke's planned deployment of the EnCompass modeling system, which has the capability to determine both plant retirement dates and optimal replacement resources in a single modeling exercise.

The Commission concludes that the Duke Utilities should continue to refine their analyses of optimum coal plant retirement dates and incorporate the results of such refinement in their Carbon Plans and future IRPs by:

1. Leveraging the full capability of the EnCompass cost modeling and capacity expansion tools. If Duke continues to believe that the Sequential Peaker Method used for the 2020 IRPs is the most appropriate methodology for the Carbon Plan and for future IRPs, it shall nonetheless present an alternative coal unit retirement schedule using the capabilities of the EnCompass model to select the optimum retirement dates endogenously. The Commission notes that ultimately, the retirement dates for Duke's remaining coal generating plants must support achievement of a least cost path to compliance with the carbon emission reductions mandated by S.L. 2021-165.

2. Updating assumptions as appropriate (such as ordered for natural gas forecasts in Section V.A. above).

3. Developing coal unit retirement dates necessary to achieve the 2030 carbon reduction target established in Section 1 of S.L. 2021-165.

4. Finally, and indirectly related to the matter of the retirement of existing coal-fired units and the resulting replacement of those resources, the

Commission has taken note of the Duke Utilities' discussion in Chapter 8 and Appendix G of their 2020 IRPS of their evaluation of several new generating technologies in order to meet future Zero-Emitting Load-Following Resource (ZELFR) needs. Technologies considered typically fall under the broad categories of advanced nuclear, advanced renewables, advanced transmission and distribution, biofuels, carbon capture utilization and sequestration, fuel cells, hydrogen, long duration energy storage, and supercritical CO2 Brayton Cycle gas generating plants. All of these technologies could potentially help Duke meet future carbon reduction goals if they reach commercial status and are economically competitive. In light of the enactment of S.L. 2021-165, the Commission believes that it will be imperative that full consideration of the commercial viability and cost parameters of these technologies be given prominence in the Carbon Plan and in future IRPs. In particular, the Commission is interested in and would benefit from additional analysis of high pressure Brayton cycle technologies employing supercritical CO2 as the working fluid, which appear to be in early stages of commercialization and are showing some early promise as zero-emitting resources.

C. Grid impacts of different resource portfolios

Commission Rule R8-60(i)(5) states that each utility shall include in its biennial IRP a list of transmission lines and other associated facilities (161 kV or over) which are under construction or for which there are specific plans to be constructed during the planning horizon, including the capacity and voltage levels, location, and schedules for completion and operation. The utility shall also include a discussion of the adequacy of its transmission system (161 kV and above). Each of the utilities included the information required by Rule R8-60(i)(5) in their 2020 IRPs.

In its August 27, 2019, Order the Commission directed the Companies to include in their 2020 biennial IRPs a more extended discussion of the expected issues and impacts to the transmission grid arising from different resource portfolios modeled in the IRPs as alternatives to the base case. This material was contained in Chapter 7 of the 2020 IRPs. Several commenters on the 2020 IRPs focused on transmission issues, and this was also one of the topics selected for further investigation at the Second Technical Conference.

NCSEA and CCEBA filed as part of their comments a report entitled "Transmission Issues and Recommendations for Duke 2020 IRP" (Grid Strategies Report). According to the NCSEA and CCEBA, this report addresses inadequate and inappropriate assumptions in Duke's IRP regarding transmission planning, which the report asserts fail to capture the benefits of optimized and least cost transmission planning. In its comments the AGO stated that Duke's resource adequacy studies do not adequately investigate how neighbor assistance can reduce reserve margin and capacity costs. The AGO suggested that Duke should further examine the potential benefits of wholesale imports from neighboring utilities and contended that Duke has failed to pursue a number of promising options for transmission investments that would enhance the ability to rely on imported energy.

The Tech Customers emphasized a need to reevaluate the purported barriers to replacing coal plants with non-gas alternatives. Their comments suggested that the Duke Utilities offer unsupported estimates of enormous transmission costs associated with wholesale power imports and with the addition of distributed renewable generation. Finally, the Public Staff's comments acknowledged that the number of permutations of generation types, geographic locations, timing, and capacity within generation scenarios and between scenarios can be significant, making their study complex. According to the Public Staff, the capacity expansion models used by the utilities in their IRPs trade off transmission specificity for reduced model complexity. The Public Staff stated that it is simply not possible at this time to solve a long-term capacity expansion model with sufficient generator site specificity and the typical power flow analyses to support detailed proposed transmission investments. The Public Staff believes the utilities can continue to improve the planning process without becoming too granular and time intensive. Further, the Public Staff stated that it believes future IRPs can improve how costs for required imports and exports are assigned to each portfolio, which the utilities acknowledge may be necessary to accommodate some future resource mixes. According to the Public Staff, the generic interconnection costs that are included in the existing capacity expansion model do not fully capture required transmission investments, and the evaluation of larger scale system impacts is critical to ensuring that capacity expansion portfolios presented in the IRP represent optimal solutions. The Public Staff recognizes 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.

In reply to the Public Staff and intervenors Duke responded that the two utilities' future transmission investment requirements are dynamic and are highly correlated to the timing of planned coal unit retirements as well as the type and location of replacement generation. Duke further stated that as more certainty is known regarding the timing of replacement and incremental resources, the options considered with respect to type and location, as well as capability (Megawatts, MVA), definitive transmission studies can be performed resulting in more accurate network upgrade cost estimates. In addition, further refinements around cost estimates for off-system capacity purchases will be included in future IRPs to the extent off-system purchases are contemplated in the plan. Finally, Duke stated in reply comments that no action is needed in response to the NCSEA/CCEBA Grid Strategies Report today and that future policy support would be needed to promote significant transmission expansions outside of least cost resource planning. Further, Duke noted that the Grid Strategies Report comments on the critical importance of transmission assumptions in the Companies' 2020 IRPs and suggests the "optionality provided by a strong electric transmission network is significant and will not be captured to the benefit of customers with incremental, least cost expansion planning, especially if planning models are based on known commitments and do not reflect expected conditions for the future." Duke stated that the Companies do not dispute the importance of a strong electric transmission network but disagree with the Grid Strategies Report's assertion that the Companies should deviate from least cost planning for their native load customers in order to significantly expand their transmission systems to increase import capability or support large-scale new renewable generation. According to Duke, DEC and DEP are bound to adhere to least cost integrated resource planning under the Public Utilities Act and NCUC Rule R8-60 as a component of their IRPs' evaluation of resource options.

Conclusions – Grid impacts of different resource portfolios

The Commission recognizes and appreciates the expanded discussion by DEC and DEP in the new chapter on Grid Requirements included in the 2020 biennial IRPs, which was offered partly in response to the Commission's August 27, 2019 Order. Of particular interest is the discussion by DEC and DEP of transmission projects needed to facilitate carbon reduction targets and to support several of the alternative resource portfolios modeled in the IRPs. As noted in the IRPs, the portfolios presented included different assumptions for coal plant retirement dates along with a varying array of demand and supply-side resource requirements to reliably serve load over the planning horizon. DEC and DEP conducted high-level assessments to estimate the associated necessary transmission network upgrades for retiring the existing coal facilities and integrating each scenario's requisite incremental resources, including combinations of some or all of the following resources: solar, solar-plus-storage hybrid facilities, stand-alone battery storage, pumped-hydro generation/storage, onshore wind, offshore wind, increased off-system purchases, and dispatchable natural gas facilities. In addition, the Commission concludes that the information presented at the Second Technical Conference provided the transparency and education that the Commission intended to be the outcome of such a proceeding.

The Commission concludes that in developing their Carbon Plan for 2022 and for future IRPs DEC and DEP should:

1. Continue to follow the directive contained in the Commission's August 27, 2019, Order in Docket No. E-100 sub 157 that the IRPs contain an analysis of anticipated or likely grid impacts associated with each alternative resource portfolio modeled in the IRPs and continue to refine transmission network upgrade cost estimates for incremental resources to take into account the most recent system impact study results;

2. Determine the feasibility of providing a timeline for necessary critical transmission network upgrades required to enable interconnection of incremental resources identified in each alternative resource portfolio modeled in the IRPs;

3. Incorporate the results of the North Carolina Transmission Planning Cooperative (NCTPC) offshore wind study results and associated cost estimates;

4. Incorporate applicable results from the 2021 NCTPC Future Resource Scenario Study, as was referred to and discussed at the Second Technical Conference;

5. Refine import capability studies specifically for capacity purchase from PJM; and

6. Continue to assess costs, risks, and reliability aspects of potential off-system purchases.

Finally, the Commission expects that portfolios presented in the Carbon Plan and future IRP filings will reflect the transmission and distribution infrastructure investments that will be required to implement the capacity and additions contemplated in the plans. The Companies should also attempt to identify – with as much specificity as is possible in the circumstances - all major transmission and distribution upgrades that will be required to support the alternative resource portfolio(s) along with the best current estimate of costs of constructing and operating such upgrades. These estimates should include the costs to secure firm transmission.

D. Potential use of all-source procurement process

Commission Rule R8-60(g) states that the fundamental objective of resource planning is to identify a resource plan "… that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of … [the utility's] … system." Based on the experience of other utilities, all-source competitive solicitations (ASCS) are a tool that can support achieving this objective. ASCS selects the least-cost portfolio of resources that can meet the utility's overall need because it allows different technologies or combinations of technologies to compete to meet the overall need, rather than single solutions to discrete portions of it. A holistic view can find opportunities to meet need more efficiently. In addition, a competitively bid all-source procurement process permits the utilities, the Commission, and interested stakeholders to "market test" the planning assumptions relative to the maturity, commercial viability, and relative cost of new resource technologies and relative to whether existing resource assets continue to provide "least cost" solutions to capacity and energy requirements.

The value and feasibility of all-source procurements was most strongly advocated by intervenors SACE, et al. They argued that the Commission should adopt an all-source procurement approach to identifying the need for new resources and selecting the best resource mix to meet the need. The intervenors commissioned John D. Wilson of Resource Insight, Inc. to evaluate the feasibility of implementing all-source procurement in the Carolinas. Mr. Wilson is the lead author on a recent report on all-source procurement prepared for Energy Innovation and the Southern Alliance for Clean Energy. Mr. Wilson's report prepared for the instant proceeding illustrates the benefits of all-source procurement and offers a guide to implementing it in the Carolinas.

The Public Staff supported the use of all-source procurements and commented at the Second Technical Conference that:

1. The Commission could initiate a rulemaking proceeding to establish rules for all-source procurement

a. Could be modeled off of R8-71 (CPRE rules) but would require substantial modifications to meet the requirements of an all-source procurement

b. Would likely require modifications of R8-60 (IRP rule) as well

2. Facilitate any required stakeholder discussions or revisions to North Carolina Interconnection Procedures (NCIP) in order to integrate with queue reform Resource Solicitation Clusters (NCIP Section 4.4.2)

Duke stated in reply comments that the all-source procurement proposal is a solution in search of a problem that would require enabling legislation, not regulatory approval in an IRP docket, and therefore should be rejected. At the Second Technical Conference Duke advocated continued reliance on the competitive procurement practices the utilities' currently use, even though such existing competitive procurements are employed only after a particular technology solution has been selected through other decision-making processes.

Conclusions – All-source procurement

The Commission appreciates the comments and participation of the parties in the Second Technical Conference where this subject was vetted. In addition, the Commission reviewed the report entitled *All-Source Competitive Solicitations: State and Electric Utility Practices* published in March 2021 for the Lawrence Berkeley National Laboratory (LBNL). The report points out that all-source competitive solicitations require significant investments in process design and implementation, and their design involves consideration of trade-offs in stakeholder participation, transparency, time, flexibility, and discretion. At this time and in recognition of the substantial commitment of resources that will be required to fulfill the requirement of S.L. 2021-165 that the Commission develop a Carbon Plan no later than December 31, 2022, the Commission declines to reach any conclusions regarding how, if at all, and in what ways all-source procurement might be incorporated into the utilities' future planning processes. The Commission may revisit this topic, as appropriate, once the initial Carbon Plan has been approved and is put in place.

E. Energy efficiency (EE) and demand-side management (DSM)

In 2019 the Duke Utilities retained Nexant, Inc. to conduct a comprehensive assessment of EE/DSM potential for DEC and DEP. Nexant's methods are industry-leading and its analysis relied on the best data available at the time to support the study. Its results were specific to the DEC and DEP service territories and were not generalizations drawn from other territories. The Nexant Market Potential Study (MPS) includes currently known technologies, estimated costs, and energy and demand reduction impacts for these EE and DSM measures and determines the Technical, Economic, and Achievable Potential of EE/DSM programs applicable to DEC and DEP customers.

In mid-2020 the Duke Utilities engaged Tierra Resource Consultants (Tierra) to perform a deeper analysis into the winter peak loads which are driving system capacity planning for DEC and DEP. Following the initial winter peak analysis, Tierra collaborated with Dunsky Energy Consulting to identify a range of potential winter peak focused DSM solutions for the DEC and DEP service territories. The Public Staff recognized in its comments, that "these reports incorporate traditional DSM/EE measures, non-traditional measures, and rate schedule and tariff-based DSM opportunities to provide increased winter peak reduction opportunities."

Several participants in this proceeding took issue with the conclusions drawn from the MPS and the Tierra and Dunsky studies and then embodied in DEC's and DEP's 2020 IRPs. The NCSEA, CCEBA, and SACE intervenors contended that Synapse's modeling corrects significantly flawed and inaccurate assumptions and inputs in Duke's modeling and demonstrates that a very different resource plan than those developed by Duke is in the best interest of Duke ratepayers. With respect to energy efficiency, Synapse in its modeling assumed a higher but achievable level of energy efficiency savings than Duke. Synapse assumed that Duke would ramp up energy efficiency programs starting in 2022 from the 5-year EE plan levels and increase first year savings by 0.15% per year to 1.5%, and that this level of savings will persist through the study period. According to the intervenors, reaching a 1.5% annual savings level is a reasonable scenario for Duke, given that the American Council for an Energy Efficient Economy found that the implementation of energy efficiency policies and measures could increase energy efficiency savings by nearly double by 2030 over a business as usual case and that leading states in energy efficiency such as Massachusetts and Rhode Island have been achieving much higher savings ranging from 2% to 3% per year over the past decade. In contrast, Duke's own savings have been at about 1% per year or less during that time frame.

The AGO's expert witness, Strategen, applauded Duke for pursuing utility energy efficiency programs, as they are generally among the least-cost resources and can significantly reduce the need for more costly generation. However, Strategen also contends that Duke's level of planned energy efficiency, while above average for the Southeast, could still be improved given the savings other utilities have achieved nationwide. Likewise, the Tech Customers also commended Duke for regional leadership in energy efficiency performance. Nonetheless, they recommended that Duke and this Commission look to and consider adopting examples set in other states and prioritize greater utilization of efficiency and advanced energy technologies to shave winter peak demand and build a more responsive grid. Finally, Appalachian Voices, relying on the modeling produced by Synapse Energy Economics, stated that it believes the Companies intentionally limited the potential impact of energy efficiency investments in order to argue a need for more new gas generation and to falsely claim that their scenarios that achieve the greatest carbon reductions would result in the highest cost to customers.

The Duke Utilities responded to these comments, replying that the current modeling methodology identifies the maximum achievable potential for utility-based DSM/EE based on the detailed analysis represented in the Market Potential Study and, going forward, additional innovative programs identified in the Winter Peak Study. Customer adoption of DSM/EE measures is not something that can be forced. The purpose of developing the Achievable Potential estimates in multiple scenarios in the MPS is to identify the amount of DSM/EE that can be reasonably included in resource planning where system reliability and resource adequacy are overriding requirements. Duke suggested that the intervenors are seeking to add additional, selectable DSM/EE above and beyond the Achievable Potential, presumably at an understated cost, in the hopes that the model would select this additional DSM/EE rather than other supply side resources. According to Duke, this methodology would completely disregard the fact that modeling outcomes do not affect customer adoption decisions and could result in a plan that artificially overstates the potential future of DSM/EE savings, and thereby understates the net load forecast and amount of traditional supply side resources required to reliably serve customer load.

Further, Duke stated that direct comparisons of EE savings as a percentage of load is of limited value across disparate service territories due to significant differences in factors influencing the cost effectiveness and adoption of EE programs including climate, age and type of housing stock, fuel types for space and water heat as well as other energy end uses, retail energy prices, avoided energy costs, EE program maturity, opt-out rules, and average usage per retail customer.

Conclusions – EE/DSM

The Commission recognizes the significant role that cost-effective EE and DSM programs must continue to play in North Carolina. In order to ensure that the Companies can reliably serve customers' future energy needs, it is critically important that EE assumptions utilized in system planning through an IRP be grounded in a market potential study or other credible and realistic analysis, especially in the near-term, because any overstatement of EE potential will directly result in an understatement of the load forecast, potentially leading to inadequate resources to serve load. For this reason, the Duke Utilities' reliance on the Nexant MPS, supplemented by the Tierra and Dunsky studies, is reasonable. No other party in these proceedings has provided information that calls into serious question the conclusions of that work. The Commission determines it useful for Duke to file the Tierra and Dunsky studies in this instant docket.

Accordingly, the Commission concludes that:

1. Duke's Market Potential Study produced reasonable results for long-range planning purposes for DEC and DEP.

2. DEC and DEP should continue to study the recommendations of the Winter Peak Study to develop new and enhanced DSM programs in conjunction with the Collaborative and other stakeholders.

3. Use of the Total Resource Cost (TRC) test for cost effectiveness screening continues to be appropriate.

Going forward, DEC and DEP's 2022 Carbon Plan and future IRPs shall include consideration of key trends observed and emerging technology or program developments that may have a meaningful impact on future EE/DSM forecasts, regardless of the 10% threshold previously ordered by the Commission.

VI. REPS AND CPRE PROGRAM PLANS AND MISCELLANEOUS MATTERS

North Carolina General Statute § 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and energy efficiency. The total amount of renewable energy that must either be generated by an electric power supplier, or must be evidenced by purchased renewable energy certificates (RECs) or energy efficiency certificates (EECs), for 2020, 2021, and 2022 is equal to 10% of its North Carolina retail sales for the preceding year.

Commission Rule R8-67(b) provides the requirements for REPS Compliance Plans. Electric public utilities must file their plans on or before September 1 of each year as part of their IRPs and explain their plans to meet the requirements of N.C. Gen. Stat. § 62-133.8(b)-(f) for the year of filing and the two calendar years thereafter, in this case 2020, 2021, and 2022 (the planning period). An electric power supplier may have its REPS requirements met by a utility compliance aggregator as defined in R8-67(a)(5).

The record in this proceeding shows that DEC, DEP, and DENC have each contracted for or procured sufficient resources to meet the general requirement and solar energy set-aside for the Planning Period, both for the utility and for the utilities' Wholesale Customers. DEC and DEP each intend to use the EE program to meet up to 25% of their REPS requirements in 2020, and up to 40% of REPS requirements in 2021 and 2022. DENC plans to use EE, purchased in-state and out-of-state RECs, and company-generated RECs to meet the general requirement for its retail customers. For the town of Windsor (Windsor), Dominion will use biomass RECs and Windsor's Southeastern Power Administration (SEPA) allocation. Dominion has purchased or plans to purchase solar RECs to meet the solar energy set-aside and has executed contracts with in-state solar facilities to satisfy Windsor's portion of the in-state solar energy set-aside.

DEP plans to meet a significant portion of the general requirement using RECs from solar facilities, including RECs acquired from its net-metered customers. A portion of the general requirement will be met through various biomass resources, including landfill gas to energy, combined heat and power, and direct combustion of biomass fuels. Hydroelectric facilities will also provide RECs for DEP's retail customers. DEP will continue to evaluate the use of wind energy for future REPS compliance. To meet the solar energy set-aside provided in the REPS statute, DEC will obtain RECs from its self-owned solar photovoltaic (PV) facilities and from other solar PV and solar thermal facilities.

DEC, DEP, and DENC each anticipate that its REPS compliance costs for the Planning Period will remain below the cost caps contained in N.C.G.S. § 62-133.8(h)(3) and (4). The state's electric power suppliers have encountered continuing difficulties in their efforts to comply with the swine and poultry waste requirement. In each year from 2012 through 2017, the electric power suppliers moved the Commission to delay the swine waste requirement until the following year, and the Commission granted each request. The requirement for all electric power suppliers is currently set at 0.07% in 2021 and 0.14% in 2022. With respect to poultry waste, the electric power suppliers annually requested from 2012 through 2019 that the requirement be delayed and modified. The Commission granted these motions. The requirement increased to 700,000 MWh in 2020 and increases to 900,000 MWh in 2021 and 2022.

In its annual orders granting delays or reductions in the swine and poultry waste requirements, the Commission has required the suppliers to file reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, on a semiannual basis in Docket No. E-100, Sub 113A. The Commission has further required the suppliers to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in obtaining contract approval and interconnecting facilities. Additionally, the Commission has directed the Public Staff to hold periodic stakeholder meetings to facilitate compliance with the swine and poultry waste set-asides. In response, the Public Staff organized bi-annual stakeholder meetings beginning in June of 2014. The attendees have included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, bankers, state environmental regulators, and the electric power suppliers. The state's electric power suppliers have been able to comply only to a limited extent with the poultry waste set-aside, and to an even lesser extent with the swine waste set-aside. Nevertheless, the REPS statute has served as a stimulus for several important advances in waste-to-energy technology.

Pursuant to Commission Rule R8-71(g) and the Additional Proceedings Order, DEC and DEP submitted their respective CPRE Plan Updates on September 1, 2021. The CPRE Plan Updates presented each Company's current plans for implementing its CPRE program. The Commission finds and concludes that the CPRE Plan Updates fulfill the requirements of Rule R8-71(g) and that they should, therefore, be accepted as filed.

CONCLUSIONS

The Public Staff in its comments noted that overall, the three utilities are better positioned to comply with all the requirements of the REPS statute, including the set-asides, than has been the case in previous years, and that none of the three utilities appears likely to exceed the cost caps for the planning period. No other party to this proceeding has taken issue with the compliance plans filed by the three utilities. Accordingly, the Commission concludes that the REPS Compliance Plans filed by DEC, DEP, and DENC contain the information required by Commission Rule R8-67(b). As such, and based on the recommendation of the Public Staff, the Commission accepts the REPS Compliance Plans filed in this docket.

Finally, the Commission takes note of the suggestion by the Public Staff, to which the Duke Utilities concur, that it would be appropriate and useful for the Commission to initiate a proposed rulemaking proceeding concerning the circumstances, if any, under which certificates of public convenience and necessity (CPCNs) should be required for battery-based energy storage facilities and, if it is determined that CPCNs should be required in at least some circumstances, the appropriate processes and standards for applying for, reviewing, and granting or denying CPCNs. The Commission appreciates this suggestion, will take it under further advisement, and will address the suggestion by separate order at a later time.

IT IS, THEREFORE, ORDERED as follows:

1. That the 2020 biennial IRP filed by Dominion Energy North Carolina is reasonable for planning purposes, and the Commission hereby accepts DENC's IRP, subject to adjustments based on its 2021 IRP Update;

2. That DEC's and DEP's 2020 biennial IRPs are adequate to be used for short-term planning purposes as discussed in the Companies' Short-Term Action Plans (STAPs);

3. That the 2020 REPS Program Plans filed by DENC, DEC and DEP are hereby accepted; and

4. That the 2020 CPRE Plan Updates filed by DEC and DEP are hereby accepted.

ISSUED BY ORDER OF THE COMMISSION.

This the 19th day of November, 2021.

NORTH CAROLINA UTILITIES COMMISSION

Erica N. Green

Erica N. Green, Deputy Clerk