STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 157

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2019 Integrated Resource Plan Update Reports and Related 2019 REPS Compliance Plans	))))	ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS

HEARD: Monday, March 9, 2020, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina:

Nicholas A. Dantonio, McGuireWoods LLP, 434 S. Fayetteville Street, Suite 2600, Raleigh, North Carolina 27603

For Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, 410 South Wilmington Street, NCRH 20, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Lucy E. Edmondson, Staff Attorney; Layla Cummings, Staff Attorney; and Nadia Luhr, Staff Attorney; Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to N.C. Gen. Stat. § 62-110.1 is included in the Rule as a part of the IRP process.

N.C.G.S. § 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis should include: (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, N.C.G.S. § 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. In addition, N.C.G.S. § 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of its: (1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. N.C.G.S. § 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to N.C.G.S. § 62-110.1.

Pursuant to N.C.G.S. § 62-2(a)(3a) it is a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of 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. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills....

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended N.C.G.S. § 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which N.C.G.S. § 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[1]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[2] Energy Efficiency measures do not include DSM.

To meet the requirements of N.C.G.S. §§ 62-110.1 and 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of its individual power supply resources,[3] furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60. In odd-numbered years, each of the electric utilities must file an annual 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 REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports, and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2019 Update Reports

This Order addresses the 2019 Update Reports (2019 Update Reports) filed in Docket No. E-100, Sub 157, by Duke Energy Progress, LLC (DEP); Duke Energy

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[1] N.C.G.S. § 62-133.9(c).

[2] N.C.G.S. § 62-133.8(a)(2) and (4).0

[3] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the electric membership cooperatives (EMCs) from the requirements of N.C.G.S. §§ 62-110.1(c) and 62-42, effective July 1, 2013. As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

Carolinas, LLC (DEC); and Dominion Energy North Carolina (DENC) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the IOUs.

The following parties have been allowed to intervene in this docket: Alevo USA, Inc. (Alevo); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); Grant Millin; Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Nucor Steel-Hertford (Nucor); and jointly, Southern Alliance for Clean Energy, Sierra Club, and the Natural Resources Defense Council (SACE, NRDC, and the Sierra Club). The Public Staff's intervention is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). The Attorney General's intervention is recognized pursuant to N.C.G.S. § 62-20.

Procedural History

On August 27, 2019, the Commission entered its order in this docket accepting the 2018 biennial IRPs filed by DENC, DEC and DEP and directing the parties to file responses to certain questions relating to the 2018 IRPs. In addition, the order gave notice of an oral argument in this docket scheduled on Wednesday, January 8, 2020.

On August 29, 2019, DENC filed its 2019 IRP Update Report and 2019 REPS compliance plan.

On September 3, 2019, DEC and DEP filed 2019 IRP Update Reports and related REPS compliance plans.

On October 4, 2019, DEC and DEP filed notice that the stakeholder meeting to review their 2019 IRPs had been scheduled for November 19, 2019 in Raleigh.

On October 25, 2019, the Public Staff filed a motion requesting that the Commission: (1) authorize the Public Staff to make one filing that combines a report on the electric utilities' 2019 IRP updates and comments on the electric utilities' REPS compliance plans, and (2) designate Thursday, October 31, 2019, as the deadline for filing the combined report and comments. The motion was approved by Order of the Commission on October 28, 2019.

On October 28, 2019, DENC filed a 2019 IRP Update Supplemental Filing that included a rate impact analysis of the Alternative Plans contained in the 2019 Update and information regarding savings projections.

On October 29, 2019, DEC and DEP refiled IRPs and REPS Compliance Plans to correct certain missing page numbers and descriptive headers.

On October 30, 2019, the Public Staff requested an extension of time to file the combined report and comments. The extension request was granted by the Commission on October 30, 2019, with a revised due date of November 7, 2019.

On November 7, 2019, the Public Staff filed a report concluding that, based on its review, the IRP update reports submitted by DENC, DEP and DEC meet the requirements of Commission Rule R8-60(j). Also, on November 7, 2019, the Public Staff filed a report concluding that, based on its review, the Commission should approve the 2019 REPS Compliance Plans.

On December 23, 2019, the Commission issued an Order Providing Notice of Hearing Topics for the oral argument in this docket on Wednesday, January 8, 2020.

On January 30, 2020, the Commission issued an Order Scheduling Public Hearing on 2019 IRP Update Reports and Related 2019 REPS Compliance Plans. The order set the required public hearing for the night of March 9, 2020.

Oral Argument

The Commission held an Oral Argument on January 8, 2020 to discuss load forecast and reserve margin issues for DEC and DEP. As ordered, the Public Staff, NCSEA, and the Natural Resources Council, Southern Alliance for Clean Energy, and the Sierra Club participated in the proceeding with presentations and responses to Commission questions.

Public Hearing

Pursuant to N.C.G.S. § 62-110.1(c) the Commission held a public hearing in Raleigh on March 9, 2020. Testimony was provided by six public witnesses at the hearing. The witnesses testified on various topics, including climate change, the role renewable energy technologies and EE/DSM programs might play in reducing greenhouse gases, North Carolina's Clean Energy Plan (published October 2019), and Duke Energy's goals for reducing carbon dioxide emissions.

Discussion

In its review and evaluation of the 2019 Update Reports the Commission has given particular attention to four topics: (1) carbon dioxide emissions, (2) resource adequacy, expressed in terms of reserve margins for DEC and DEP, (3) the integrated systems and operations planning (ISOP) effort now underway for DEC and DEP (Duke utilities), and (4) utility statement of need. The Commission's observations on these topics are set forth in the following sections of this order.

Reduction of Carbon Dioxide Emissions

Dominion Energy

DENC's 2019 Update Report reflects the Company's belief that regulation of carbon dioxide emissions from electric generating plants is imminent, whether through federal or state initiatives, or both. At the federal level the U.S. Environmental Protection Agency released the final version of the Affordable Clean Energy (ACE) rule on June 19, 2019. The ACE rule, which supplants the earlier Clean Power Plan, requires heat rate efficiency improvements at existing coal-fired units based on a range of candidate technologies.

At the state level the Virginia Department of Environmental Quality (DEQ) published a final rule on May 27, 2019, that establishes a state cap-and-trade program for electric generating units in Virginia. The final rule includes a provision that accounts for delayed implementation based on language in the state budget bill signed by Virginia Governor Ralph Northam on May 2, 2019. Specifically, implementation of most elements of the program, including requirements for holding and surrendering carbon dioxide allowances, will likely be delayed to the calendar year following authorization for funding to implement the program. Nevertheless, the final regulation became effective on June 26, 2019. The regulation includes a starting (baseline) statewide carbon dioxide emissions cap of 28 million tons in 2020. The cap is reduced by about 3% per year through 2030, resulting in a 2030 cap of 19.6 million tons.

Because of the uncertainty regarding the final form of carbon emission regulations, DENC's 2019 Update Report presents options (Alternative Plans) representing plausible future long-term paths for meeting the energy needs of the Company's customers. The Company also offers a strategic plan for the next five years in its Short-Term Action Plan (STAP).

Between 2000 and 2018 the carbon dioxide emissions from the Company's units declined by 32% while power production from these units increased 12%. On March 25, 2019, the Company committed to an 80% reduction in greenhouse gas emissions by 2050. Simultaneous with that announcement the Company also put forth a five-year plan that includes development of offshore wind, a new pumped hydroelectric storage facility, additional solar photovoltaic resources, and distribution system modernization.

The Commission concludes that the Alternative Plans presented in DENC's Update Report are reasonable for planning purposes. The Commission finds useful the rate impact analysis and savings projections included in the Company's 2019 Integrated Resource Plan Update Supplemental Filing.

Duke Energy

The Commission recognizes Duke Energy Corporation's publicly announced systemwide goal to reduce carbon dioxide emissions by 2030 to at least 50% below 2005 levels. For DEC and DEP the Base Cases in both the 2018 IRPs and the 2019 IRP Update plans achieve at least a 50% reduction in carbon dioxide emissions by 2030, measured from 2005 baseline levels. This is aligned with Duke Energy Corporation's current climate strategy.[4]

As set forth in both the DEC and DEP 2019 IRP Update Reports, the two utilities present Base Cases assuming a tax on carbon emissions beginning in 2025. However, remaining consistent with the Commission's Order to plan for scenarios that both include and exclude costs associated with carbon regulation, the current assumption of a carbon tax is intended to serve as a placeholder for some form of potential future carbon regulation.[5] An additional case assuming no carbon legislation was also developed in both Companies' 2018 IRPs and carried forward to the 2019 Update Plans. While the timing and form of potential future carbon legislation is unknown, it is prudent to continue to plan for a scenario in which carbon emissions are taxed or otherwise regulated, as well as other potential future scenarios. Furthermore, a primary focus of the 2019 IRP Updates are the Short-Term Action Plans (STAP), which cover the period 2020 to 2024. DEC and DEP note that including a case which assumes a tax on carbon emissions beginning in 2025 thus does not have any significant impact on their STAPs.[6] The Commission finds the two Base Case Plans (i.e. Base CO_2 Future and Base No CO_2 Future) and other portfolios evaluated under multiple sensitivities to be appropriate for planning and encourages the Companies to carry forward both alternatives for their next IRPs due for 2020.

The Commission continues to support a focus on the STAPs but also recognizes the importance of properly vetting the longer-term components of the IRP, as those components might develop to support Duke Energy's carbon dioxide reduction goals. The Commission notes that for the long-term, past 2030, Duke Energy Corporation's corporate goal is to achieve a level of zero carbon dioxide emissions by 2050, measured on a net basis systemwide across all affiliated Duke Energy operating companies. This goal has thus far not been further refined at the individual operating company level, and the 2018 IRPs for DEC and DEP were developed and presented before the corporate goal had been established. The 2019 IRP Updates, which are based on the 2018 IRPs, accordingly and understandably do not analyze or present specific resource planning options for achieving the Duke utilities' systems longer-term goal. The Commission believes that meeting this longer-term target will likely require aggressive restructuring of the Companies' resource portfolios and that it is appropriate that DEC and DEP in their

[4] *See* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to Commission Questions in August 27, 2019 Order in Docket No. E-100, Sub 157, pp. 29-30.

[5] Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket No. E-100, Sub 147, p. 35.

[6] *See* DEC 2019 IRP Update Report, pp. 10-11 and DEP 2019 IRP Update Report, pp. 11-12.

2020 IRPs identify alternative resource portfolios that offer prospects for supporting and advancing the stated Duke Energy corporate goal.

On November 4, 2019, the Companies filed in this docket a joint response to certain questions posed in the Commission's August 27, 2019 Order accepting the Companies' 2018 biennial IRPs. In that response the Companies presented two potential scenarios for achieving reductions in carbon emissions beyond the 50% target announced for 2030. The Commission acknowledges that these two scenarios were offered as "illustrative" only and that they were not based on the same scope and depth of analysis as would occur if they were being modelled for the IRP. One of the scenarios presented in this filing included retirement of all coal generating units by 2030. This would require replacement of approximately 10,415 MW of existing capacity for the two Companies.

With respect to these "illustrative scenarios" the Companies cautioned that:

> The scenarios presented do not fully account for the real-world challenges that would be faced in adding a significant number of new grid resources in a short amount of time. Issues not addressed, but required to implement this pace of system transformation, include physical and regulatory challenges affecting the time to construct new assets and their associated interconnection and system upgrade requirements. Implementation would require addressing issues in the areas of supply-chain, siting, permitting, right-of-way acquisition, transmission queue studies, comprehensive network upgrades, gas pipeline expansion and acquiring facility certificates of public convenience and necessity (CPCN) for all new facilities. At a minimum, existing legislative and regulatory processes governing resource additions (including but not limited to, siting, permitting, and CPCN processes), may be needed to be modified to accommodate the pace of transition outlined in the scenarios studied.

Acknowledging these factors and the high level nature of the November 4, 2019, submission, the Commission nonetheless finds good cause to direct that for their 2020 IRPs DEC and DEP present one or more alternative resource portfolios which show that the remainder of each Company's existing coal-fired generating units are retired by the earliest practicable date. The Commission contemplates that the Companies will build upon the work that formed the basis of the November 4, 2019 submission, and the objective is to further develop the "illustrative" scenarios in that filing by subjecting them to the more rigorous IRP process. The "earliest practicable date" shall be identified based on reasonable assumptions and best available current knowledge concerning the implementation considerations and challenges identified in the quoted passage above.[7] In the IRPs the Companies shall explicitly identify all material assumptions, the procedures used to validate such assumptions, and all material sensitivities relating to those assumptions. The Companies shall include an analysis that compares the

[7] Among other inputs, the Companies should include the updated Market Potential Study for Energy Efficiency referenced in their November 4, 2019, submission, p. 33 note 6.

alternative scenario(s) to the Base Case with respect to resource adequacy, long-term system costs, and operational and environmental performance.

DEC and DEP stated in their November 4, 2019 submission that the "illustrative scenarios" did not identify or include the costs of network transmission upgrades and other major grid investments necessary to support an alternative resource portfolio in which all coal-fired generating units have been retired and the replacement resources that will include a much larger number of geographically dispersed renewable energy and energy storage resources, many of which will not be under direct control of the grid operator. The Commission expects that the "earliest practicable date" chosen by the Companies when developing their alternative portfolio(s) and the replacement resources included in the portfolio(s) should reflect the transmission and distribution infrastructure investments that will be required to make a successful transition. 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.

The Commission recognizes the significant effort needed to undertake this work but determines that such an effort is essential for properly vetting any alternative scenarios and for comparing the alternatives to the Companies' proposed Base Case plans. Finally, the Companies should note that the directive in this order supplements and does not supersede the directive in the Commission's August 27, 2019 Order in this docket (at p. 31), requiring that the Companies in preparing and modeling their Base Case plans remove any assumption that existing coal-fired units will be operated for the remainder of their depreciable lives and, instead, include such existing assets in the Base Case resource portfolio only if warranted under least cost planning principles. In this Order the Commission's directive that the Companies present one or more "earliest practicable date" retirement portfolios is not constrained by least cost principles, and the Companies will be expected to discuss cost differences, if any, between such alternatives portfolios and the resource portfolios selected for their Base Cases.

DEC and DEP Resource Adequacy Issues

The Commission finds that the information developed during the January 8, 2020, Oral Argument was particularly helpful to the Commission's understanding of resource adequacy and reserve margin issues. Several participants in this docket and in the Oral Argument raised concerns, variously expressed, that DEC and DEP were using a flawed metric (LOLE.1) to characterize the risk of resource inadequacy. These participants suggested that there was insufficient support for the target reserve margins and/or errors affecting the underlying data and projections used to calculate the risk of a loss of firm load due to resource inadequacy. Finally, these participants suggested that the Companies' IRPs and supporting filings contained no information from which parties could evaluate the economic costs and benefits to customers and ratepayers of accepting levels of risk different from that embodied in the 17% planning reserve margins established in the IRP Base Cases.

At this point the Commission is disinclined to direct that in their 2020 IRPs DEC and DEP use some alternative measure of resource inadequacy other than the LOLE.1 standard. The information presented to the Commission at the hearing indicates that no single metric is unquestionably superior to all others but, instead, that each alternative metric reveals or discloses different considerations that bear on the question how much reserve generating capacity a utility should maintain.[8]

Physical reliability, which for purposes of long-term planning for generating assets is expressed in terms of resource adequacy, is of critical importance to utility planning, and the Commission would never suggest otherwise. Resource adequacy, however, is neither a concept that can be reduced to absolute mathematical precision nor, more importantly, can it be captured by a single metric to which all other resource planning values must necessarily be subordinate. To state the obvious example of this point, it might be possible to design a system with sufficient redundancies and excess facilities to offer 100% assurance that a load shed event due to inadequate resource capacity would never occur, but it is scarcely imaginable that such a system would prove to be "least cost" over the long term. A system may be considered reliable within a range of values and resulting reserve margins; the important matter is that the levels of risk or volatility and the costs associated with various points within a range of reserve capacity levels be understood and evaluated and that the tradeoffs between higher and lower reserve capacities and other system values be clearly and transparently discussed and explained.

As noted, the metric used by the Companies to quantify the risk of resource inadequacy – LOLE .1 – is a measure of physical risk only. The Commission believes that the most important conclusion to be drawn from the evidence and argument presented at the hearing is that for purposes of resource planning it is imperative that the economic costs of maintaining different levels of reserve capacity and the economic value of potentially unserved energy (lost load) be fully analyzed and transparently presented. On this point the Commission finds that the 2016 Astrapé Resource Adequacy Studies for DEC and DEP are useful in understanding the Companies' targeted reserve margins for planning. Particularly useful is the summary provided in Section VII relative to Base Case Economic Results. For example, Figure 13 presents a comparison of expected "Total System Costs" for various winter reserve margins and confidence levels. According to the report, Total System Energy Costs include Fuel Burn, O&M, Purchase Costs, Sales Revenues and the Cost of Unserved Energy. In addition, the carrying cost of capacity added to achieve various level of reserve capacity is included in Figure 13. The "bathtub curves" shown in this figure illustrate where Total System Costs are minimized based on the modeling. The Companies state that the reserve margin that optimizes Total System Costs, at an 85% confidence level, is approximately 17%. See Duke's response to

[8] From the information presented to the Commission at the hearing it could be concluded that setting reserve margins based on a risk neutral economically optimized analysis best balances the incremental costs of additional reserves against the benefit of reduced risk of loss of firm load. But the participants in the hearing confessed that finding the economically optimal level of reserves was a very difficult practical exercise, if it were possible at all. See for example economist James Wilson's discussion of economically optimal reserve margin where he states that "[t]he problem with the Economically Optimal Reserve Margin, is it rests on a lot of assumptions that, you know, are really kind of troubling." Hearing Transcript, pp. 19-20.

questions contained in the Commission's August 27, 2019 Order in Docket No. E-100, Sub 157, at p. 7.

Based on a review of the study results presented in the 2016 Astrapé Resource Adequacy Studies, the Commission recognizes that the differences in Total System Costs are not significant, especially around the central tendency and away from the tails of the cost curves, when compared to a typical annual spend by the utility. For example, based on Figure 13 in the DEC Report the difference in Total System Costs between an 18% winter reserve margin and a 13% winter reserve margin is approximately $18 million. This compares to DEC Power Production Expenses (O&M, Fuel, and Purchased Power) in 2018 of $2.8 billion. In terms of risk or volatility, the Commission does not view the differences in Total System Costs are enough to warrant a "hard and fast" minimum reserve margin for planning. This is not to say that the minimum reserve margins supported by the 2016 Astrapé Study are not valid for planning. Rather, the Commission's guidance is that the Companies should not be constrained in their planning to produce resource plans that meet the indicated minimum target reserve margin in each and every one of the plan years.[9]

The 2016 Resource Adequacy Studies should thus best be understood as supporting a range of values for the recommended minimum reserve capacity that cluster around a central point rather than as calculating a fixed and inflexible single point. This is an especially important consideration with respect to the STAPs in the IRPs. The Commission observes that all parties agree that the near and intermediate term periods will be marked by rapid technological change accompanied and reinforced by potentially dramatic changes in the costs of new generating technologies and compounded by an increasing emphasis on reduction in greenhouse gas emissions from electric power generation. The Commission's view is no different. For this reason it 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, especially during the period covered by the STAP, permit sufficient flexibility to do so.

For example, the decision to include short-term market purchases in DEP's STAP should be fully vetted and evaluated relative to the probability and impact of alternative options that might provide for less physical reliability but would do so at lower cost to ratepayers and without unreasonably increasing the risk of a loss of load event. In other words, clarity around the risk or volatility which the plan hopes to address is important.

[9] This point is implicit in Commission Rule R8-60(i)(3) which requires the utilities to provide an explanation in the IRP for any year in which the planned reserve margin will vary – up or down – by more than 3% from the established target. Note that R8-60(i)(3) does not address actual reserve margins achieved over the course of operations but speaks instead to the planned or targeted margins shown in the IRP.

A number of participants in this docket offered critiques of the economic and weather inputs used to forecast system loads and capacity needs for the IRPs. The Commission notes with interest that the Companies appear to acknowledge that it is possible that short-term[10] reserve capacity could fall below the long-term target of 17% without posing a significantly increased risk of resource inadequacy. Duke stated in its response to questions contained in the Commission's August 27, 2019 Order that:

> DEP used an 11%-13% summer capacity margin target, rather than reserve margin target, prior to completion of the 2012 studies. This level of capacity reserves corresponds to reserve margins ranging from 12.4% to 14.9%. DEP determined that an 11% capacity margin (12.4% reserve margin) may be acceptable in the near term when there is greater certainty in forecasts; however, a 12%-13% capacity margin (13.6%-14.9% reserve margin) is appropriate in the longer term to compensate for possible load forecasting uncertainty, uncertainty in DSM/EE forecasts, or delays in bringing new capacity additions online.

Duke's Responses, Docket No. E-100, Sub 157, at p.19.

Further, in response to questions about short-term reserve margins during the hearing, Duke witness Snider stated that "I think it's reasonable to say you have a short-term reserve margin that you could potentially have slightly less because you're not exposed to that economic uncertainty to the extent you are in the long run, and so, you know, I think there is some merit in considering that." Hearing Transcript, p.166.

As stated in the DEC and DEP 2019 IRP Update Reports, the Companies are committed to the development of new resource adequacy studies to support their 2020 IRPs. See for example DEC's 2019 IRP Update Report, p. 77. The Commission directs that these updated resource adequacy studies be filed along with the Companies' 2020 IRPs, together with all supporting exhibits, attachments and appendices subject to such confidentiality designations as the Companies deem warranted.

The Commission finds that in documenting the updated Resource Adequacy Study for 2020, the Companies should provide additional detail and support for both the study inputs and outputs. The Commission applauds the joint efforts of the Companies and Public Staff to delve into the details of the Resource Adequacy evaluation. Even though the 2016 Astrapé Resource Adequacy Study report provides great insights to the study's development, the Commission is limited in some regard by the information to which it has access. Therefore, the Commission will direct DEC and DEP to more fully explain and detail the study results. For example, so far as can be gleaned from the 2016 Study, it would appear that the costs of unserved energy are not significant to the determination of Total System Costs, but this is based solely on the single statement that "because

[10] The Commission will not define "short-term" for this purpose but rather defer to the Utilities to evaluate short-term planning reserve margins as they impact Short-Term Action Plans which, according to the IRPs, identify actions to be taken over the next five years. *See* for example DEC's 2019 IRP Update Report starting at p. 71.

expected unserved energy costs are so low near the economic optimum reserve margin, this value, while high in magnitude, is not a significant driver in the economic analysis." The updated Resource Adequacy Study should provide additional clarity around outputs such as these. At a minimum the Commission finds it helpful for results to be displayed in a graphic that clearly shows the various components to the Total System Costs such as included in the "Bathtub Curves." See for example Figure ES-1 included in the Brattle Group and Astrapé Consulting report for FERC, Resource Adequacy Requirements: Reliability and Economic Implications, by J. Pfeifenberger and K. Carden (2013), Executive Summary, p. v. As another matter, but evidence of the need for additional clarity in the study results, it is not clear in the Astrapé Resource Adequacy Study whether the Total System Energy Costs represent an annual figure or something else (such as the net present value of costs across the planning horizon.)

Finally, based on the Resource Adequacy Study report, the Commission recognizes that unlike typical production cost models, the SERVM model utilized by Astrapé does not use an Equivalent Forced Outage Rate (EFOR). Instead, historical Generating Availability Data System (GADS) data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. The Commission directs the updated Resource Adequacy studies to address the sensitivity of modeling inputs such as Equivalent Forced Outage Rates (EFOR). For example, in developing the portfolio ordered by the Commission above that will reflect 100% of coal units retired, will the reliability of the fleet be improved overall and therefore result in reduced reserve margins for planning?

Integrated Systems and Operations Planning

The Commission finds the information on the ISOP effort included in DEC and DEP's 2019 IRP Update Reports useful and understands that the Companies will be in a position to report on further developments of this effort in their 2020 IRPs. The Commission recognizes the Companies' efforts to involve stakeholders in the multi-year process to advance the ISOP. As noted in the joint report summarizing the December 10, 2019, workshop facilitated by ICF, "stakeholders supported the need to implement ISOP and integrate planning tools and processes. They expressed appreciation for Duke proactively addressing this initiative with them and believe there are additional opportunities to more directly define how ISOP will create value." The Commission supports the ISOP effort as discussed to date.

The Commission expects the Companies to continue to involve stakeholders in a meaningful way as the ISOP process advances. In particular, the Commission recognizes that there could be significant benefits to involving North Carolina's electric membership cooperatives and municipally owned and operated electric utilities in this effort. One stated goal of the ISOP process is to improve coordination of load forecasting, project and systems planning, and operational effectiveness between the transmission system operator and the distribution system operator. In North Carolina the transmission system operator is, in the main, either DEC and DEP, but in many parts of the State the distribution system operator will be an EMC or a municipally owned utility. The

Commission views the ISOP program and stakeholder involvement in that program as an important opportunity to strengthen effective communication and interaction both in planning and in operations between the Companies and the non-regulated distribution system operators that serve a significant portion of the State.

The Commission determines that the 2020 IRPs should continue to report on the progress of the ISOP effort. As a minimum, the IRPs should communicate with some specificity the project plan and dates for the ISOP effort. In addition, the Commission will direct the utilities to discuss the expected outputs of the ISOP process and how they will be utilized in the IRP process.

Utility Statement of Need

As discussed in the Commission's 2018 IRP Order dated August 27, 2019, the Public Staff noted the fundamental link between each IOU's IRP and avoided costs, formalized with the passage of HB 589, which provided that a "future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] filed with the Commission . . . has identified a projected capacity need to serve system load . . ." *See* amended N.C.G.S. § 62-156(b)(3). The Public Staff pointed out that a number of assumptions used by the IOUs in the avoided cost proceeding have not been clearly specified by each utility. To remedy this issue and mitigate the potential for paying for more capacity than what is needed, the Public Staff recommended that the utilities, in their IRP Update to be filed in 2019 and all future IRPs and updates, include a new Utility Statement of Need section. Duke agreed with the Public Staff's recommendations and stated that it will include a Statement of Need section to more clearly identify the undesignated capacity needs for each utility in DEC's and DEP's 2019 IRP Updates and in future biennial IRP filings. *See* 2018 IRP Order, at p. 65.

The Commission determines that the "First Resource Need" section of DEC's and DEP's 2019 IRPs is an appropriate output of the integrated resource planning processes and adequate to support future avoided cost calculations.

Conclusion

Based upon the record in this proceeding, the comments of the Public Staff regarding the IRP Update Reports and REPS compliance plans submitted by DEC, DEP and DENC, the Companies' written submissions in this docket dated November 4, 2019, and the materials and testimony presented at the January 8, 2020 hearing, the Commission hereby accepts the 2019 IRP Update Reports filed by the utilities as complete and fulfilling the requirements set out in Commission Rule R8-60. The Commission further accepts the REPS compliance plans submitted by DEC, DEP and DENC, as recommended by the Public Staff. In preparing their 2020 biennial IRPs the utilities shall follow the applicable guidance and directives set forth in this order and in the Commission's August 27, 2019 Order addressing the 2018 biennial IRPs.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.

This the 6th day of April, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Janice H. Fulmore, Deputy Clerk

Commissioner Lyons Gray did not participate in this decision.