BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 157

In the Matter of:	)	**NCSEA'S INITIAL COMMENTS ON DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S INTEGRATED RESOURCE PLANS**
2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans	)	
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NCSEA'S INITIAL COMMENTS ON DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S INTEGRATED RESOURCE PLANS

Pursuant to the North Carolina Utilities Commission ("Commission") Rule R8-60(k) and the Commission's January 24, 2019 *Order Granting Extension of Time and Closing Discovery Period* and the Commission's February 8, 2019 *Order Granting Second Extension of Time*, the North Carolina Sustainable Energy Association ("NCSEA") submits the following comments on the 2018 integrated resource plans ("IRPs") submitted by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, Inc. ("DEP") (collectively, "Duke").

I. INTRODUCTION

In its closing comments in the *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans* issued on June 27, 2017 in the 2016 IRP docket, the Commission stated:

> Integrated Resource Planning 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. Potential significant regulatory changes, particularly at the federal level, and evolving marketplace conditions create additional challenges for already detailed, technical, and data-driven IRP processes. The Commission finds the IRP processes employed by the utilities to be both compliant with State law and

> reasonable for planning purposes in the present docket. The Commission recognizes that the IRP process continues to evolve.

In its 2018 IRPs, Duke failed to identify a generation resource mix that is least cost for both the utility and its ratepayers. As set forth in these Comments and the accompanying report, Duke's IRPs notably ignore a least cost alternative which would allow for the utilization of distributed generation resources including specifically renewable energy. Further, Duke's IRPs are inconsistent with their comments in other proceedings and also to the media.

Recently, Duke has spoken publicly about its plans to incorporate more distributed solar into its generation mix. In a February 28, 2019 news article, Duke employee Ken Jennings stated that Duke plans a new study to show how to significantly boost Duke's system capacity for renewable energy by 2050. Specifically, Mr. Jennings stated that Duke currently estimates that its grid systems will be able to handle about 20% of peak power generation from renewables in 2025 and the new study aims to make the grid capable of supporting as much as 50% of peak demand from renewables by 2050.[1] This study and the accompanying plans to substantially increase renewable generation are not discussed in Duke's IRPs. Instead, Duke forecasts increased centralized generation.

Duke previously introduced the idea of modernizing its grid as a means to incorporate more distributed generation in the 2017 DEC and DEP rate cases and has continued to pitch modernization investments to its investors. Duke has presented and is continuing to seek approval for substantial investment in the grid. Duke's purpose for

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[1] John Downey, *Duke Energy Study to Look at Expanding Renewables Capacity on the Grid*, CHARLOTTE BUSINESS JOURNAL, February 28, 2019, *available at* https://www.bizjournals.com/charlotte/news/2019/02/28/duke-energy-study-to-look-at-expanding-renewables.html.

investing in the grid is primarily to prepare the grid for the integration and utilization of an influx of demand-side resources, including new technologies that reduce peak costs and preparing for a future where demand and supply is largely met on the distribution system.

Yet, in these IRPs, that future is nowhere to be found as the grid improvement plans are ignored. The central question remains: why does the future of energy look different when Duke is seeking to spend billions of dollars on the electric grid to incorporate distributed generation than when Duke is seeking approval to spend billions of dollars in traditional, centralized generation? From NCSEA's perspective, Duke wants to make two massive capital expenditures when only one is necessary. Duke's continued spending on centralized generation resources should negate the need to upgrade its grid, ostensibly to accommodate distributed energy resources ("DERs"); conversely, Duke's spending to upgrade the grid to accommodate distributed energy resources should negate the need for continued spending on centralized generation resources. Investing such large amounts of capital in both will undoubtedly leave ratepayers responsible for stranded investments. Until it is clear which future Duke is actually committing to, no new supply-side resources should be approved.

NCSEA also has serious concerns as to whether the resource planning that Duke has presented is the most cost effective. NCSEA's analysis and the accompanying report from Synapse Energy Economics, Inc. ("Synapse") show that Duke's current operation fleet is not efficient and that the operations are dramatically restricting the use of renewables. The analysis also shows that Duke's proposed need to build new capacity resources is strictly a product of its failure to engage neighboring markets.

Finally, NCSEA believes that the future of utility scale solar power purchase agreements ("PPA") need to be addressed by the Commission. For the first time, a significant number of qualified facilities ("QFs") will be reaching the end of their PPAs within the planning horizon. These QFs have remaining life, and the Commission needs to decide how they should be addressed in the IRP process.

N.C. Gen. Stat. § 62-2(3a) states that the policy of the State of North Carolina regarding public utilities includes the following assertion regarding integrated resource planning:

> 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[.]

Commission Rule R8-60(a) further states regarding the "Purpose" of the Integrated Resource Planning and Filings Rule: "[t]he purpose of this rule is to implement the provisions of G.S. 62-2(3a) and G.S. 62-110.1 with respect to least cost integrated resource planning by the utilities in North Carolina." Rule 8-60 goes on to give the comprehensive requirements in North Carolina to prepare and submit a sufficient IRP. Duke has failed under the guidelines of the statute and as outlined in that rule to present the least cost integrated resource plan.

II. DUKE'S INTEGRATED RESOURCE PLANS ARE NOT THE MOST COST EFFECTIVE PLANS

Despite claims by Duke that these IRPs plan for future resource needs, "[i]n the most reliable and economic way possible while using increasingly clean forms of energy to meet those needs," these IRPs plan for an overly expensive resource mix that barely expands the use of clean energy beyond those that are legislatively mandated. These IRPs reflect the intentions of a utility that seems to still be planning for the electricity system of the past and not one that is taking steps towards creating the cleaner, cheaper, smarter, more reliable, and more resilient electricity system that North Carolina's future needs require. NCSEA believes that the Duke IRPs do not present a plan that will "[r]esult 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," therefor do not comply with the requirements of N.C. Gen. Stat. § 62-2(3a) or Rule R8-60(c)(2).

The Duke IRPs foretell an energy future for North Carolina that is inconsistent with current trends shaping the energy industry. With a heavy reliance on natural gas and other traditional generating resources, the plans fail to account for cost-effective clean energy alternatives to the increasingly uneconomic operations of Duke's existing coal plants. For example, Duke's IRPs call for an additional build out of over 9,000 MW of new natural gas plants, but less than 5,000 MW of new renewables (namely solar PV and battery storage), from 2019 to 2033. But especially with the advent of viable battery storage technologies, renewable resources can satisfy a far larger portion of the Duke's energy and capacity needs at a lower economic and environmental cost.

A. SYNAPSE'S REPORT

The report included as **Attachment 1** ("Synapse Report") details a rigorous, scenario-based analysis of alternative energy resource plans for Duke. It details a realistic clean energy future that provides both the energy and capacity to meet the needs of Duke's customers, while effectively meeting future reliability requirements as traditional generating resources are retired. The report was prepared by Synapse Energy Economics, Inc. ("Synapse"), a leading energy, economic, and environmental consulting firm whose clients include state utilities commissions, RTO/ISOs, local governments, and governmental associations including the National Association of Regulatory Utility Commissioners (NARUC).[2] The report was prepared using the EnCompass capacity expansion and production cost model, which is widely used for integrated resource planning and other forecasting and analytical purposes.

Key takeaways from the Synapse Report include:

- The Synapse Report models three distinct scenarios: the proposed Duke Integrated Resource Plan, a Clean Energy Scenario, and an Accelerated Coal Retirement Scenario.
- Duke's projected 2033 resource capacity mix includes 56% (27 GW) fossil fuels, nearly equal to its 2019 resource proportion, and just 23% renewables (11 GW).
- In the Clean Energy Scenario set forth in the attached report, by 2033 gas and coal would compose 32% of Duke's capacity mix, while renewable resources, including solar PV and battery storage, would make up 49% (27.5 GW) (with existing nuclear, hydro, and energy efficiency making up the rest).

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[2] Synapse has specifically provided consulting analysis and reports in numerous Commission Dockets, including: Docket No. E-100, Sub 158 (the 2018 Avoided Cost Docket); Docket No. E-7, Sub 1134 (Application of Duke Energy Carolinas, LLC for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County); Docket No. E-100, Sub 148 (the 2016 Avoided Cost Docket); Docket Nos. E-2, Sub 926 and Docket No. E-2, Sub 931; and Docket Nos. E-7, Sub 831 and Docket No. E-7, Sub 790. Synapse has also provided consulting services and/or analyses regarding other energy-related issues in North Carolina.

- Duke acknowledges that its current IRPs development tools are incapable of modeling the full value of renewable and distributed energy resources, including storage.[3] The Synapse model, by contrast, is capable of more accurately evaluating the costs and benefits of these resources.
- Duke's proposed IRPs add renewables barely above the amounts sufficient for the utility to comply with minimum legislative requirements, whereas the Clean Energy Scenario details how Duke can build more renewables at lower cost than traditional resources.
- Duke's must-run designations force coal plants to operate regardless of optimal cost considerations and require high levels of coal generation in 2033. When must-run designations are removed, economic signals dictate that coal generation drops significantly. Coal generation is markedly lower in 2019 in the Clean Energy Scenario than in the Duke IRP Scenarios.
- Total production costs of a Clean Energy Scenario are far cheaper than under the proposed IRP. With the removal of must-run designations and the build out of cheaper renewable resources, total production costs of a Clean Energy Scenario are over $1.5 billion less than the proposed IRPs in 2033.
- By 2033, Duke's plan emits almost 50 million tons of CO2 annually, while the Clean Energy Scenario emits just under 30 million tons. The removal of must-run coal designations leads to an immediate reduction of nearly 16 million tons of carbon in 2019.

[3] DEC IRP, p. 31, DEP IRP, p. 31.

- Under the Accelerated Coal Retirement Scenario, in which four additional coal units are retired early, EnCompass projects increased energy imports to make up for retiring generation. Production costs and emissions declines for the Accelerated and Clean Energy Scenarios are almost identical.
- The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, proving that the retirement of fossil fuels and build-out of renewables leads to no new system reliability issues.
- The Clean Energy Scenario provides significant health and cost savings to the people of North Carolina due to the increased utilization of existing low-pollutant nuclear and renewable resources to generate in the place of coal. By 2033, North Carolina residents could see up to $354 million in avoided health impacts due to a decrease in hospital room visits and lost work days.
- North Carolina ratepayers can expect to save between .24 cents/kWh and .48 cents/kWh through 2033, leading to a decrease in average annual electricity spending throughout the study period of 4 to 9 percent.
- Corresponding average annual electricity costs for residential customers decrease between $27 and $58 per year.

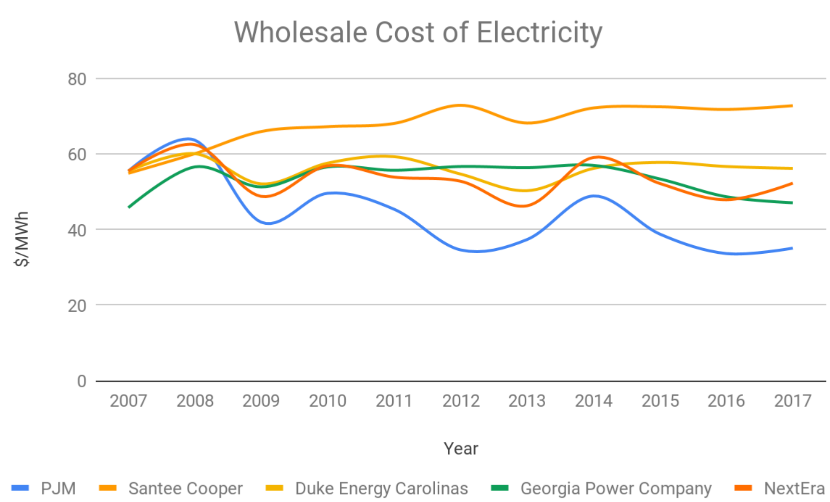
The Synapse Report clearly demonstrates that the Duke IRPs have significant limitations and at the very least fail to adequately consider a full range of scenarios with respect to the economic dispatch of coal units and the deployment of additional renewable and distributed energy resources. As the Synapse Report details, a clean energy future for

North Carolina customers will decrease energy costs, greatly reduce harmful greenhouse gas and other air pollutants, and drive the proliferation of new renewable resources.

B. <u>ADVANTAGES OF WHOLESALE MARKET COMPETITION</u>

Duke is working within an insular system which is bound to be inefficient. While Duke's wholesale cost of power is comparable for other IOU's with the region, its costs are not the most cost-effective in the region. The neighboring PJM marketplace wholesale costs continue to decline where DEC's costs have remained stagnant over the past ten years as shown below in Chart 1.

Chart 1: Recent Wholesale Costs of Electricity by Source[4]



As demonstrated in the Clean Energy Scenario presented in the Synapse Report, allowing system imports to make up a greater share of Duke's generation portfolio takes advantage of these lower out-of-system costs and lower overall operating costs.[5] Furthermore, the Commission has recognized that Dominion participation in PJM has lowered costs for their customers, stating that:

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[4] SNL Financial.

[5] See explanation on p. 5 of attached Synapse Report.

> The Commission finds the testimony of Public Staff witness McLawhorn persuasive. He concluded that DNCP's cost-benefit analysis methodology and assumptions were reasonable, and that even if the quantification was overstated, there has been a net economic benefit to DNCP's customers from PJM membership. Witness McLawhorn also stated, based on the most current projections of natural gas prices, capacity prices and other PJM-related costs, the Public Staff expects the net economic benefits of DNCP's membership in PJM to continue . . . The evidence presented in this case demonstrates that DNCP's integration into PJM has benefited its customers, and that those benefits can be expected to continue even if the Commission relieves the Company from compliance with most of the PJM Order conditions.[6]

Before approving their proposed IRPs as "least-cost," the Commission must adequately assess whether Duke's refusal to consider engaging in a competitive wholesale market is actually resulting in lower costs to customers.

III. DUKE'S INTEGRATED RESOURCE PLANS ARE INCONSISTENT WITH DUKE'S OTHER PLANS

A. POWER/FORWARD CAROLINAS A/K/A GRID MODERNIZATION PLAN A/K/A GRID IMPROVEMENT PLAN

Duke has presented limited grid plans in its 15-year IRP forecasts, but for reasons unclear it has failed to directly link its ongoing, massive grid modernization project known as Power/Forward Carolinas ("Power/Forward").[7] Power/Forward was introduced as a concept during the DEP's 2017 general rate case in Docket No. E-2, Sub 1142,[8] and DEC officially requested for approval of cost recovery measures during the DEC's 2017 general rate case in Docket No. E-7, Sub 1146 for its portion of the $13 billion bi-territory grid

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

[7] As Duke's plans have evolved over the past 18 months, the name has changed as well. Duke's proposal has, at times, been called "Power/Forward Carolinas," "Grid Improvement Plan," and "Grid Modernization." NCSEA uses these terms interchangeably in these comments.

[8] *Direct Testimony of David B. Fountain*, pp. 34-35, Docket No. E-2, Sub 1142 (June 1, 2017).

plan.[9] While the Commission ultimately rejected DEC's proscribed cost recovery rider mechanism, Duke still promotes grid modernization to its shareholders. Specifically, in its *Duke Energy Winter Update 2019*,[10] Duke claims to project an even larger $25 billion grid modernization effort as part of its future utility investment across all its service territories.

Duke's grid improvement/modernization plans are premised upon security, resiliency and, also, the idea that the grid needs to be flexible to allow for the integration and utilization of demand-side technologies, demand response, energy efficiency, and growing renewables. The new resources introduced to the grid to incorporate these guidelines will change load shape and have the potential to eliminate the need to build anymore supply-side resources. NCSEA supports a flexible grid that allows for the utilization of such demand-side technologies.

However, Duke's Power/Forward grid modernization plans do not appear in its IRPs. Despite comprehensive Rule R8-60 requirements regarding forecasting future generation investments, Duke's future scenario painted in its Power/Forward plan is not present when Duke seeks to receive approval for plans to utilize resources and funds for future generation. In fact, it appears that this future scenario only appears when Duke is seeking separate investment on its grid, despite the clear overlap in issues related to generation sources and other issues related to grid improvement. In fact, DEC Witness Robert M. Simpson III ("Witness Simpson") acknowledged the role of integrating distributed generation as an important factor in the Power/Forward plan. In his direct

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[9] *Duke Energy Carolinas, LLC's Application to Adjust Retail Rates and Charges, Request for an Accounting Order and to Consolidate Dockets*, p. 4, Docket No. E-7, Sub 1146 (August 25, 2017).

[10] *See generally*, *Duke Energy Winter Update 2019*, Slide 7, *available at* https://www.duke-energy.com/_/media/pdfs/our-company/investors/winter-2019-ir-update.pdf?la=en (last accessed March 6, 2019).

comments, he stated that the Power/Forward initiative will "primarily focus on projects that . . . [f]urther integrate and optimize intermittent distributed renewable generation[.]"[11] Witness Simpson went further in his Rebuttal Testimony in affirming the Power/Forward plan as a means to prepare the grid for decentralized, distributed generation:

> The primary goals of Power/Forward Carolinas are to significantly reduce the number and duration of outages the system experiences, and to transform the grid by enabling 21st-century performance capabilities Secondary [sic]—but also important—goals include improving the customer experience, by leveraging technology to make payment and usage information more easily accessible, and preparing the grid for the increased adoption of distributed energy resources ("DER").[12]

Witness Simpson further stated that the proposed ten-year scope of Power/Forward was found "to be the most practical time period to execute the intiative (sic) because that time-frame aligned with the Company's forecast of increased adoption of DER such a solar, storage, and microgrids."[13] Finally, Witness Simpson stated that NCSEA Witness Caroline Golin was "incorrect" in characterizing that the Power/Forward plan does not address "renewables."[14] Clearly, when DEC sought to recover costs for the Power/Forward plan, DEC intended for the pitch to be that the Power/Forward grid plan would utilize distributed generation.

Power/Forward also includes a voltage-management program entitled Integrated Volt/Var Control ("IVVC") which will allow the Duke utilities to "manage distribution circuits such that any impacts to customers with large motors sensitive to voltage control can be reduced," and also allow for the utilities to utilize peak shaving and emergency

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[11] *Direct Testimony of Robert M. Simpson III for Duke Energy Carolinas, LLC*, Docket No. E-7, Sub 1146, p. 24.
[12] *Rebuttal Testimony of Robert M. Simpson III for Duke Energy Carolinas, LLC*, Docket No. E-7, Sub 1146 ("Witness Simpson Rebuttal Testimony"), p. 4.
[13] Witness Simpson Rebuttal Testimony, p. 15.
[14] Witness Simpson Rebuttal Testimony, p. 38.

modes of operation.[15] Duke predicted that IVVC will enable 2% voltage reduction for energy conservation, an average roughly 1.4% load reduction in DEP territory and a corresponding and similar sized voltage reduction in DEC territory.

Power/Forward (or any other, later iteration of grid modernization) is not broached in Duke's IRPs, despite the fact that Power/Forward has the purpose, as advertised by Duke, of utilizing demand side resources, reducing peak costs, creating more efficiency within the system and flattening load. NCSEA believes these grid improvement plans, to the extent that they can demonstrably affect Duke's generation portfolio and any other express and implicit factors which are contained within the IRP rule and statute, should be accounted for in Duke's IRPs.

Over the past year, Duke has presented two very different futures to the Commission. The first requires substantial investment in the grid to allow for Duke to pursue the use of demand side management, flexible load, and other benefits associated with distributed generation. The other future, highlighted in these IRPs, outlines substantial investment in centralized generation while making no mention of efforts in the Power/Forward plan to utilize distributed generation and associated technologies. This practice of putting these two concepts in silos is not beneficial for the utilities or, more importantly, the rate payers. The IRP as codified was intended for scrutiny, by the Commission and by intervenors, to allow for the utility to present the best possible energy system for rate payers. NCSEA believes that the holistic approach to this question includes the afore-mentioned grid modernization plans.

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[15] *North Carolina Grid Improvement Plan Pre-Read Packet for Stakeholder Workshop*, p. 47; this document was attached as NCSEA Exhibit PB-2 to the Direct Testimony of Paul Brucke, P.E. on behalf of North Carolina Sustainable Energy Association filed in Docket No. E-100, Sub 101.

B. 50% Renewable Energy Penetration Study

As noted above, Duke has recently announced that it has retained the National Renewable Energy Laboratory to study how their grid can accommodate renewable energy penetration of 50% of peak demand.[16] Notably, neither DEC nor DEP's 2018 IRPs come anywhere near this threshold. If Duke genuinely believes that its IRPs represent the future of electricity generation in North Carolina, then such a study should be unnecessary.

The fact that Duke is undertaking such a study undermines the credibility of their own IRPs, and calls into question how Duke has modeled clean energy resources. As discussed above, the Synapse study shows that Duke has unfairly marginalized clean energy resources. Similarly, the Virginia State Corporation Commission rejected Dominion Energy Virginia's integrated resource plan because of its failure to adequately model clean energy resources, and particularly their cost.[17]

IV. Emerging Issues

A. Integrated Distribution Planning

Commission Rule R8-60(g) requires that:

> As part of its integrated resource planning process, each utility shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system.

[16] Downey, *supra* note 1.

[17] *Order In re: Virginia Electric and Power Company's Integrated Resource Plan Filing Pursuant to Va. Code § 56-597 et seq.*, Virginia State Corporation Commission Case No. PUR-2018-00065 (December 7, 2018), *available at* http://www.scc.virginia.gov/docketsearch/DOCS/4d5g01!.PDF.

Rule R8-60(g) goes on to make clear that the analysis to develop this plan should take into account the "sensitivity of its analysis to variations in future estimates of peak load energy requirements, and other significant assumptions, including, but not limited to . . . transmission *and distribution costs*[.]" (emphasis added). Additionally, the rule states that the utility's analysis "should take into account, as applicable, system operations, environmental impacts, and other qualitative factors." *Id*.

Historically, utilities in North Carolina have attempted to fulfill the requirements outlined in this rule by primarily identifying bulk power system needs and identifying the supply-side generation and transmission facilities needed to fill these needs. However, as Duke notes, "Technical advancements and declining cost trends in distributed energy resources such as battery storage, distributed solar generation and demand side management initiatives give rise to a future resource portfolio that is comprised of both centralized resources, as well as, a growing penetration of distributed resources."[18] In addition, the substantial growth of distributed solar in the state has already created many opportunities and challenges to North Carolina utilities and has been a key issue for the Commission to consider in several recent proceedings.[19] As noted by Lawrence Berkeley National Laboratory, the rapid increase in DERs has led to, "new challenges for utilities in planning their infrastructure investments and managing power quality at the level of the distribution system. The challenges are distinctly different from the large-scale generation and transmission challenges in regional planning processes."[20]

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[18] DEC IRP, p. 9; DEP IRP, p. 9.
[19] See generally, Docket No. E-100, Sub 101, E-100, Sub 158, Docket No. E-7, Sub 1146, Docket No. E-2, Sub 1142, Docket Nos. E-2, Sub 1159 & E-7, Sub 1156.
[20] Lisa Schwartz, *Overview of Integrated Distribution Planning Concepts and State Activity*, LAWRENCE BERKELEY NATIONAL LABORATORY (March 13, 2018), https://emp.lbl.gov/publications/overview-integrated-distribution.

NCSEA believes the traditional IRP approach employed by investor-owned utilities in North Carolina has not adequately planned for or addressed the challenges and opportunities with the increasing deployment of DERs. To better ensure that utilities are adequately planning for the opportunities created by DERs and for the electricity grid of the future, NCSEA requests that the Commission open a rulemaking docket for stakeholders to develop a framework and adequate requirements for Integrated Distribution Planning ("IDP").

B. BENEFITS FOR RATEPAYERS AND CLEAN ENERGY

NCSEA believes that IDP is a critical, and currently missing component of North Carolina's traditional IRP process that truly meets the future electricity needs of North Carolinas at the least cost and fulfills the provisions of N.C. Gen. Stat. § 62-2(3a). In Docket No. E-2, Sub 1142, NCSEA Witness Dr. Caroline Golin defined IDP as:

> Integrated distribution planning is a process that utilities undergo to map out their existing systems through a detailed engineering assessment, at the highest resolution, of the current and forecasted dynamics of the grid under multiple scenarios. The purpose of integrated distribution planning is to identify infrastructure changes that may be needed to achieve grid modernization goals. To properly plan for a grid of the future, and the impact of new technologies, integrated distribution planning must include forecasting and assessment of the role of DERs. Thoughtful integrated distribution planning is transparent and participative and can enable the inclusion of more effective investments as well as increase opportunities for third-party participation.[21]

Similar to the definition provided by Dr. Golin, the Regulatory Assistance Project identified three important tasks for IDP.

1. Recognize the capabilities of DERs so that the potential of low cost DER portfolio solutions are considered.
2. Determine how much investment is needed once one takes into account the DER portfolio effects.

[21] *Direct Testimony of Caroline Golin on Behalf of NCSEA*, pp. 20-23, Docket No. E-2, Sub 1142 (October 20, 2017).

3. Provide transparency to consumers and developers about where on a distribution system there is headroom, also known as hosting capacity, to accommodate more distributed generation, EVs, solar PV capacity, and other DERs, and where on the system there are opportunities to provide complementary DERs.[22]

Accomplishing these tasks requires significant data inputs that are currently unknown, or only available to the utility. As described by Dr. Golin, a thorough IDP process would require "high resolution" data from the utilities to fully consider the appropriate placement of DERs and distribution grid investments in ways that would reduce line losses and avoid the need for some of the expensive traditional generation included in the Duke IRPs. By establishing rules for an IDP process that results in the identification of hosting capacity limits and opportunities could help provide a constructive path forward on some of the more contentious issues related to DERs that have come before the Commission in recent years.

While the Clean Energy Scenario modeled in **Attachment 1** outlines a cleaner and cheaper generation portfolio than Duke's IRPs, it still bound by the relatively "low resolution" energy and capacity data publicly available. In the absence of this data and a clear IDP process for North Carolina, the Clean Energy Scenario modeled utility-scale battery and solar projects and did not specifically evaluate the distribution system needs and DER opportunities in the way that a thorough IDP process would.

In 2017, at least 15 states had proceedings planned or underway related to electric distribution planning.[23] While these states have a significant variation in approaches,

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[22] JIM LAZAR, REGULATORY ASSISTANCE PROJECT, ELECTRICITY REGULATION IN THE US: A GUIDE 112 (2nd ed. 2016), *available at* https://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.

[23] JULIET HOMER ET AL., U.S. DEPARTMENT OF ENERGY GRID MODERNIZATION LABORATORY CONSORTIUM, STATE ENGAGEMENT IN ELECTRIC DISTRIBUTION SYSTEM PLANNING (December 2017), *available at* https://emp.lbl.gov/sites/default/files/state_engagement_in_dsp_final_rev2.pdf.

safety, reliability, affordability, grid modernization, enabling greater customer control over energy costs and sources, and integrating higher levels of DERs were top objectives for seeking deeper state engagement in distribution system planning. These states are recognizing the opportunities enabled by IDP and the thoughtful preparations that are needed as increasing DER deployment continues to alter the traditional relationship between customers and the electric utility.

While there is a growing body of literature around the opportunities and best practices for IDP, Curt Volkmann with GridLab summarizes some of the primary benefits NCSEA believes IDP would provide to North Carolina utilities, customers, developers, and regulators.

> Utilities and their customers can derive substantial benefits from IDP, including lowering costs to reduce rate pressure in a low load growth environment, creating more cost-effective programs with better returns for customers and shareholders, and enhancing customer relationships as interest in DER continues to grow. Customers and developers will have the opportunity to propose, provide and be compensated for grid services, while experiencing more efficient and predictable interconnection processes. Regulators will benefit from increased transparency and data access for optimal solution identification, more efficient regulatory proceedings, and opportunities for more meaningful engagement with utilities and other stakeholders.[24]

These benefits are clear to NCSEA and many of its members and it now seems some of these benefits are becoming apparent to Duke in what it is currently referring to as Integrated System Operations Planning ("ISOP").

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[24] CURT VOLKMANN, INTEGRATED DISTRIBUTION PLANNING: A PATH FORWARD 8, *available at* https://static1.squarespace.com/static/598e2b896b8f5bf3ae8669ed/t/5b15ae6470a6ad59dcb92048/1528147563737/IDP+Whitepaper_GridLab.pdf.

C. DUKE'S INTEGRATED SYSTEM OPERATIONS PLANNING

NCSEA is glad to see that Duke is joining other utilities, consumers, and regulators across the country in, "recognizing that the traditional methods of utility resource planning must be enhanced to keep pace with changes occurring in the industry."[25] In both the DEC and DEP IRPs, Duke is proposing to address these shifting trends through an ISOP effort that is similar to what NCSEA and many others refer to as IDP. Duke's description of ISOP includes two of the three important tasks of IDP outlined by the Regulatory Assistance Project (namely recognizing the capabilities of DERs so they are considered in the portfolio and determine how much investment is needed once one takes into account the DER portfolio effects). However, they do not include any description similar to the critical third task of completing and publishing a hosting capacity analysis.

In addition to lacking this critical hosting capacity piece, the description of ISOP in the Duke IRPs is similar to the description included in their Smart Grid Technology Plans ("SGTPs"), which NCSEA criticized as lacking detail and not including any timeline for implementing this ISOP approach. In response to this criticism, Duke stated that:

> The Companies would show that ISOP, which is a planning process rather than a technology, is discussed in the IRP, is covered in the Grid Improvement Plan, and that it has been, and will continue to be, part of the Companies' ongoing stakeholder workshops. Further, DEC laid out the conceptual goals and timelines for ISOP development as part of the settlement agreement developed with NCSEA and filed in the DEC rate case, in Docket No. E-7, Sub 1146, and has been working on it as a baseline for stakeholder feedback.[26]

[25] DEC IRP, p. 31. DEP IRP, p. 31.
[26] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Reply Comments on 2018 Smart Grid Technology Plans*, p. 6, Docket No. E-100, Sub 157 (February 6, 2019).

In Attachment B of that proposed settlement agreement between DEC, NCSEA, Environmental Defense Fund, and the Sierra Club, there is a proposed timeline of commitments by DEC to include hosting capacity analyses with its 2020 IRP and will fully implement ISOP by January 1, 2022.[27] NCSEA appreciates the statement Duke made in its SGTP reply comments that it is still using this timeline of commitments as a baseline for stakeholder feedback, but notes that since that settlement was rejected by the Commission, there is currently no formal mechanism to hold Duke accountable to these commitments.

If Duke is still committed to the timeline for ISOP outlined in the proposed DEC 2018 Rate Case settlement, it is vital that the Commission initiate a directly related IDP Rulemaking Proceeding as soon as possible to assure Duke customers, stakeholders, and regulators that ISOP does not become a vehicle for the utility to justify routine/business as usual investments in the grid as "grid modernization" or in the worst case, justify excess investment. As GridLab noted in a recent South Carolina proceeding on grid modernization:

> GridLab believes that stakeholders are best served by having all grid investments — from reconductoring to smart meters to distribution automation — considered as part of a single IDP process. GridLab has found that such distinctions have proven meaningless in any event, as a capability one utility considers business as usual is considered by another utility as a policy/process/standard improvement, and by yet another utility as grid modernization. IOUs may be interested in preferred compensation for grid modernization, which leads to IOU interest in categorization. GridLab believes preferred compensation leads to excess investment, and recommends instead that preferred compensation be dedicated to exceptional performance on measured outcomes.[28]

[27] *Pilot Grid Rider Agreement and Stipulation Among Certain Parties*, Attachment B, Docket No. E-7 Sub 1146 (June 1, 2018).

[28] PAUL ALVAREZ, DENNIS STEPHENS, & RIC O'CONNELL, MODERNIZING THE GRID IN THE PUBLIC INTEREST: GETTING A SMARTER GRID AT THE LEAST COST FOR SOUTH CAROLINA CUSTOMERS 15 (January 31, 2019), *available at* https://ors.sc.gov/news/2019-02/gridlabs-releases-grid-modernization-report-south-carolina.

By initiating a rulemaking proceeding, NCSEA ultimately hopes that the Commission establishes a set of rules before Duke implements its ISOP process that ensure IDP by regulated North Carolina utilities is:

- Ongoing – A standardized, repeating IDP process like the IRP process has become.
- Integrated – IDP processes must consider and contribute to transmission plans and integrated resource plans. From DER forecasts to demand response programs, IDP processes must be integrated with other electric system component and capability plans.
- Transparent – Stakeholders should have a strong role in the IDP processes and should help determine the criteria used to evaluate proposed projects.
- Objective – Every proposed project identified should be evaluated and prioritized using the same criteria and weighting as every other proposed project in order to deliver collective goals at the lowest cost.
- Measurable – Stakeholders have the right to objective benefit forecasts and benefit measurement.
- Consequential – Utilities should agree to comply with outcomes of IDP processes and deliver the results promised from selected grid projects with utility incentives and consequences based on utility adherence to IDP priorities and outcomes.[29]

Establishing rules to enshrine these principles for IDP can "help address capital bias and associated business process, operating practice, and technology changes and choices of dubious value."[30]

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[29] *Id.*
[30] *Id.*

NCSEA believes these choices of dubious value are clear in the expensive overbuild and overuse of fossil fuel resources proposed in the Duke IRP. While we are encouraged by indications that Duke is also starting to acknowledge limitations to its current IRP process, we are not satisfied by the current lack of transparency and unenforceable timeline of commitments that they have currently proposed. Coupling the immediate opportunities for beneficial changes to Duke's planned generation portfolio that are identified in the Synapse Report with a robust IDP process and corresponding rules will help North Carolina take a big step towards a cleaner, cheaper, more resilient, and more reliable electricity system.

D. EXECUTIVE ORDER 80

On October 29, 2018, Governor Roy Cooper issued Executive Order No. 80 ("EO80") committing the State of North Carolina to support the 2015 Paris Agreement goals and honor the state's commitments to the United States Climate Alliance.[31] Broadly, EO80 sets an ambition goal for North Carolina to reduce its statewide greenhouse gas ("GHG") emissions to 40% below 2005 levels. In addition, EO80 sets additional goals including an increase in the number of registered zero-emission vehicles in the state to at least 80,000, reducing energy consumption in state-owned buildings, and directs the North Carolina Department of Environmental Quality ("DEQ") to develop a North Carolina Clean Energy Plan by October 1, 2019.

[31] Exec. Order No. 80 (2018), *available at* https://files.nc.gov/governor/documents/files/EO80-%20NC%27s%20Commitment%20to%20Address%20Climate%20Change%20%26%20Transition%20to%20a%20Clean%20Energy%20Economy.pdf.

In January 2019, DEQ published *North Carolina Greenhouse Gas Inventory (1990-2030)*.[32] The inventory presents an accounting of the state's GHGs emissions by source category from 1990 to 2017 and projects future emissions from 2018 to 2030. This inventory and projections of reasonably expected trends is an essential tool for tracking the state's progress towards achieving the goal of reducing statewide GHG emissions to 40% below 2005 levels. Based on the current projections included in the Inventory, North Carolina will reduce its net GHG emissions 31% by 2025 and will not achieve the 40% reduction goal without additional action.

As stated earlier, the generation portfolio presented in the Synapse Report's Clean Energy Scenario presents substantial additional reductions in GHG emissions compared to the Duke IRPs. In the analysis presented in the tables below, an NC allocation factor (to screen out emissions from SC customers) was applied to the emissions that were avoided in our Clean Energy Scenario compared to the Duke IRPs Scenario. These reductions in North Carolina GHG emissions were then incorporated into the projections in DEQ's GHG Inventory. This analysis shows that the Clean Energy Scenario produces enough of a reduction in overall GHG projections that North Carolina would reduce its net GHG emissions by 40.1% from 2005 levels by 2025 without doing anything altering any of the other GHG emissions projections included in the DEQ GHG Inventory.

[32] NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY, NORTH CAROLINA GREENHOUSE GAS INVENTORY (1990-2030) (January 2019), *available at* https://files.nc.gov/ncdeq/climate-change/ghg-inventory/GHG-Inventory-Report-FINAL.pdf.

Table 1: Status Quo GHG Emissions (MMT CO_2) from DEQ GHG Inventory[33]

Emissions Source	2005	2015	2020	2025	2030
Total Electricity Use	79.37	58.48	45.74	40.59	42.46
Gross Emissions from all Sectors	184.7	154.8	143.6	138.3	141.4
Net Carbon Sinks	-32.7	-34.2	-34	-34	-34
Net Emissions	152.1	120.7	109.5	104.3	107.3
Reduction in Net Emissions from 2005	-	20.7%	28.0%	31.5%	29.4%

Table 2: GHG Emissions (MMT CO_2) Projections Using Clean Energy Scenario Emissions from Synapse Report[34]

Emissions Source (Million Metric Tons)	2005	2015	2020	2025	2030
Total Electricity Use	79.37	58.48	33.8	27.5	28.8
Gross Emissions from all Sectors	184.7	154.8	131.6	125.2	127.7
Net Carbon Sinks	-32.7	-34.2	-34.0	-34.0	-34.0
Net Emissions	152.1	120.7	97.6	91.1	93.7
Reduction in Net Emissions from 2005	-	20.7%	35.8%	**40.1%**	38.4%

While the Duke IRPs present a pathway to a generation portfolio that likely reduces GHG emissions produced by the DEC and DEP systems by more than 40% compared to 2005 levels, they will not allow North Carolina to reach the statewide 40% reduction goal included in EO80. If Duke instead pursued the future generation portfolio presented in the Clean Energy Scenario of the Synapse Report, North Carolina would achieve this goal of reducing net GHG emissions by at least 40% compared to 2005. If the other sectors presented in DEQ's GHG inventory also pursue realistic opportunities for further GHG

[33] Analysis adapted from NORTH CAROLINA GREENHOUSE GAS INVENTORY (1990-2030), Table 1-1, *supra* note 29.

[34] Note: GHG emissions from the Synapse Report were converted to million metric tons of CO_2 in order to incorporate into the DEQ GHG Inventory projections

emissions reductions than are currently projected, North Carolina would likely exceed the GHG emissions goal in EO80.

E. Renewals of Power Purchase Agreements With Qualifying Facilities

Currently, DEC has 645 MW of capacity provided by qualifying facilities ("QFs") in its generation stack and DEP has 2,163 MW.[35] QFs provide this capacity to DEC and DEP pursuant to power purchase agreements ("PPAs") that typically have terms of 10 or 15 years. Despite the fact the PPAs with QFs will eventually expire, Duke assumes that the PPAs will "be either renewed or replaced in kind."[36] However, there is no guarantee, or requirement, that a QF will continue to provide the utility with capacity past the end of its initial PPA, even if the QF has remaining operational life.

Duke assumes for planning purposes that a QF's PPA will be renewed despite the fact that it has made numerous efforts in other proceedings to make it more difficult for a QF to renew a PPA. In Docket No. E-100, Sub 101, Duke has proposed changes to the Material Modification portion of the North Carolina Interconnection Standard that would make it more difficult for QFs to upgrade equipment when it reaches the end of its lifespan.[37] In Docket No. E-100, Sub 158, Duke has proposed that it have the unilateral authority to terminate a PPA if a QF upgrades equipment.[38] Also in Docket No. E-100, Sub 158, Duke has proposed that QFs that renew their PPA would not receive full payment for the capacity that they provide.[39]

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[35] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits*, p. 8, Docket No. E-100, Sub 158 (November 1, 2018).
[36] *See*, Duke Energy Carolinas, LLC's Response to Public Staff Data Request No. 6-4 and Duke Energy Progress, LLC's Response to Public Staff Data Request No. 4-12, included as **Attachment 2.**
[37] *Direct Testimony and Exhibit of Paul Brucke, P.E.*, pp. 14-16, Docket No. E-100, Sub 101 (November 19, 2018).
[38] *NCSEA's Initial Comments*, pp. 51-52, Docket No. E-100, Sub 158 (February 12, 2019).
[39] *NCSEA's Initial Comments*, pp. 10-11, Docket No. E-100, Sub 158 (February 12, 2019).

Other wholesale PPAs are removed from DEC and DEP's respective generation stacks when they expire and create capacity needs. However, Duke treats PPAs with QFs differently in its planning process. Accordingly, the Commission needs to decide how DEC and DEP's IRPs should treat QFs at the end of their initial PPAs. Duke's planning process, coupled with their proposal in Docket No. E-100, Sub 158 to restrict capacity payments to QFs that renew their PPAs, is wholly unfair to QFs. A QF with an expiring PPA is assumed in the IRP to remain in the generation stack, which means the IRP does not show a capacity need, which means that a QF would not receive a full capacity payment when it renews its PPA, despite being relied upon for capacity. The paradigm for renewing PPAs with QFs proposed by Duke is nonsensical, and needs to be resolved by the Commission.

V. CONCLUSION

The business as usual IRP process that Duke continues to employ in this proceeding is no longer working as intended for its North Carolina customers. Duke's current IRP process is producing a plan for a portfolio that is less clean and more expensive than other realistic portfolios like the Clean Energy and Accelerated Coal Retirement Scenarios in the Synapse Report. Implementing the portfolios outlined in the Synapse Report would not require drastic reforms to Duke's IRP process or business model.

Further, while we are encouraged by the statements Duke has made about its ISOP process, NCSEA believes that the Commission should initiate a rulemaking proceeding to implement rules so the ISOP process adheres to the principles for IDP identified in these comments. IDP will allow the utilities to identify new DER opportunities that have not yet been identified by Duke, Synapse, or any other party to this proceeding. Appropriate rules will guarantee that IDP maintains sufficient oversight and transparency so as to allow ratepayers, and their representatives, real opportunities to see whether the decisions being made with regard to distributed generation are in their best interests. NCSEA believes that establishing an IDP process for regulated North Carolina utilities will help address shortcomings of the traditional IRP process that is currently in practice.

For all the reasons set forth herein, NCSEA respectfully requests that the Commission reject the Duke IRPs and order Duke to refile new IRPs incorporating the recommendations made in the Synapse Report including, specifically, the least cost model incorporating additional renewable generation. Further, NCSEA requests that the Commission initiate a rulemaking proceeding to establish appropriate rules for integrated distribution planning and address the concerns contained within regarding the expiration of solar PPAs.

Respectfully submitted, this the 7th day of March, 2019.

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CERTIFICATE OF SERVICE

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

Respectfully submitted, this the 7th day of March, 2019.

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Attachment 1

North Carolina's Clean Energy Future

An Alternative to Duke's Integrated Resource Plan

Prepared for the North Carolina Sustainable Energy Association

March 7, 2019

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CONTENTS

FIGURES

1. INTRODUCTION

The Integrated Resource Plans (IRP) filed in North Carolina by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) in September 2018 reflect business as usual for the two utilities. The plans, which run through 2033 and include the Duke service territory in both North and South Carolina, rely heavily on new natural gas capacity. Together, they add more than 9,000 megawatts (MW) of new combined cycle and combustion turbine capacity over the 15-year analysis period from 2019 to 2033 to both meet anticipated increases in electricity demand and to replace certain retiring coal units. Renewable additions are comprised of solar photovoltaic (PV) and battery storage resources but are added in minimum amounts sufficient to comply with North Carolina House Bill 589.

Synapse performed a rigorous, scenario-based analysis to evaluate an alternative clean energy future compared to the more traditional portfolio of fossil-fueled resource additions included in Duke Energy Carolinas and Duke Energy Progress's (collectively Duke Energy) IRPs. The clean energy future analysis included resources such as solar, wind, energy efficiency, and battery storage. These resources were offered to the EnCompass electric sector model to provide both energy and capacity, and to meet future reliability requirements as coal resources in the Carolinas approach retirement. This report compares one such optimized Clean Energy scenario to a Duke IRP scenario. Synapse analyzed the benefits of this modeled clean energy future on the electric power system, emissions, public health, job creation, and electricity customer rates and bills.

Renewable resource options, in addition to those modeled by Duke Energy, are comparably cost-effective to new natural gas for North Carolina ratepayers and offer other benefits to the state.

In the Clean Energy scenario, the EnCompass model is allowed to select the most cost-effective future resource build. In contrast to the Duke IRP scenario, the model chooses to build out solar and storage resources to meet future capacity and energy needs with zero incremental natural gas-fired unit additions. Coal generation declines between the Duke IRP and Clean Energy scenarios, lowering the electric system production cost and reducing emissions of carbon dioxide (CO_2) while maintaining system reliability. Emissions reductions of additional air pollutants result in health benefits to North and South Carolina, avoiding hospital and emergency visits and lost work days. Total revenue requirements of the Clean Energy scenario are lower than in the Duke IRP scenario, and North Carolina consumers see lower electricity rates as a result. Under the Clean Energy scenario, North Carolina consumers also use less energy due to the increased energy savings associated with the High Energy Efficiency scenario from the Duke Energy IRPs. When coupled with the decrease in rates, residential consumers in the state see their average annual electricity expenditures decline by approximately 2.5 to 5.5 percent.

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2. Scenario Analysis

Synapse used the EnCompass capacity expansion and production cost model, licensed by Anchor Power Solutions, to examine two different future energy scenarios in the Duke Energy service territories from 2018 to 2033:

Duke IRP: The Duke IRP scenario reflects the anticipated energy resource future as outlined in the most recent Duke Energy IRPs. Specifically, the Duke IRP scenario assumes:

- The slate of planned resource additions already contracted or under construction, and the "optimized" natural gas combined cycle and combustion turbine plants selected during the IRP process. Duke Energy Carolinas and Duke Energy Progress were modeled as operating in a single Duke Energy service territory, but this does not assume the "capacity sharing" modeled by Duke in its IRPs as part of its Joint Planning scenario. Rather, the resource additions assumed by each utility in its individual IRPs are included and modeled as part of this scenario.

- Cost and operational data as outlined in Duke's discovery responses to North Carolina Utilities Commission Staff and other intervenors. In the absence of available data, Synapse relied on the Horizons Energy National Database (the primary data source for the EnCompass model) or other industry-recognized sources.

- Retirement dates for certain existing coal generators that are consistent with the utility IRPs.

- Must-run designations for coal units in the service territory, which force coal units to run regardless of price and reflect historical regional generation patterns.

Clean Energy: The Clean Energy scenario reflects an optimized view of the Duke Energy service territory with relaxed assumptions around operation and up-to-date renewable costs:

- The utility reserve margin is set at 15 percent (versus 17 percent in the Duke IRP scenario). This lower reserve margin was selected to be consistent with North American Electric Reliability Corporation (NERC) standards. It also reflects the assumption that as older units with higher forced outage rates retire and are replaced with new capacity, the reliability of the system is improved.

- Must-run designations for coal units are removed.

- Projected load includes the increased electric demand associated with the recent electric vehicle goal established in North Carolina Governor Roy Cooper's Executive Order Number 80.

- Energy efficiency is provided as a supply-side resource based on the High Energy Efficiency scenario in Duke Energy's IRPs.

- Renewable costs are based on the *2018 NREL Annual Technology Baseline*[1] or Lazard's *Levelized Cost of Storage Analysis.*[2]
- The Clean Energy scenario incorporates all planned resource additions outlined in the Duke IRPs that are currently under construction or necessary to comply with North Carolina's renewable procurement regulations but excludes the "optimized" natural gas combined cycle and combustion turbine units that were selected by the System Optimizer model to meet reserve margin constraints in and after 2025.
- The model can choose to build generic utility-scale solar, storage, wind, and paired solar-plus-storage resources in any amount (e.g. no restrictions were placed on either total or incremental renewable capacity), in addition to traditional natural gas-fired generating resources.

More information on the modeling structure, including detail on topology, load, fuel prices, and other assumptions, can be found in Technical Appendix A.

[1] National Renewable Energy Laboratory (NREL). 2018. *2018 Annual Technology Baseline*. Golden, CO: National Renewable Energy Laboratory. Available at: https://atb.nrel.gov/.

[2] Lazard. 2018. *Lazard's Levelized Cost of Storage Analysis: Version 4.0*. Available at: https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2018/.

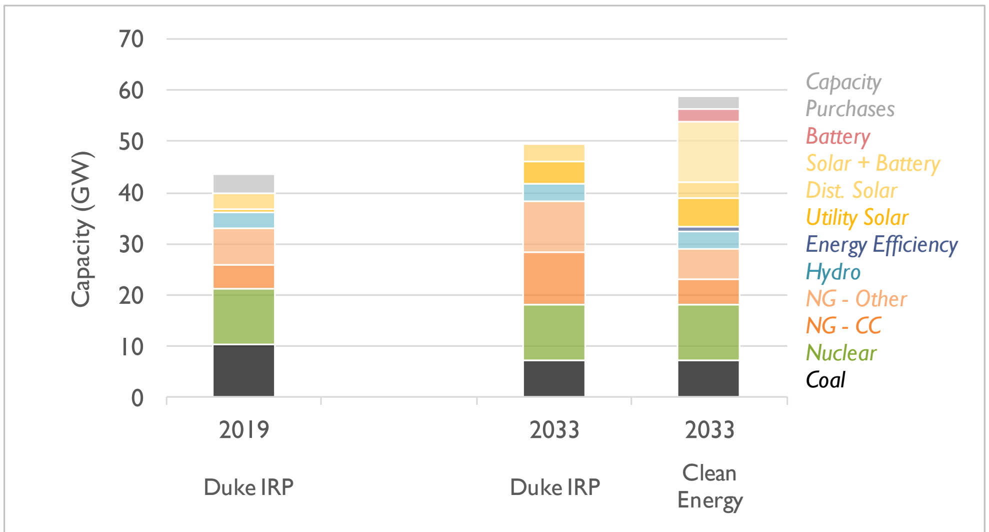
3. Results

3.1. Electric Sector Modeling

New generating capacity is constructed during the analysis period to meet the respective reserve margins in both the Duke IRP and Clean Energy scenarios; however, the type of capacity constructed differs between scenarios. The Duke IRP scenario relies heavily on generic natural gas-fired combined cycle and combustion turbine units, with renewable resources (solar PV and battery storage) added only in amounts sufficient for Duke Energy to comply with North Carolina House Bill 589. The Clean Energy scenario, on the other hand, relies on a slate of clean energy resources to meet its reserve margin requirement that includes energy efficiency, utility-scale storage and solar, and paired solar-plus-storage resources. EnCompass model results are presented here for the entirety of Duke Energy's service territory in both North and South Carolina.

Figure 1, below, shows the generating capacity in the Duke IRP and Clean Energy scenarios in 2033, as compared to Duke's actual capacity mix in 2019. As shown in Figure 1, approximately 55 percent (22 GW) of Duke's installed capacity in 2019 is fossil fuel-powered thermal (coal- or natural gas-fired), 27 percent (10.7 GW) of capacity is nuclear, and the remaining 18 percent (7 GW) comes from hydroelectric, renewable, and distributed energy resources. By 2033, the proportion of fossil-fired resources in the Duke IRP scenario is unchanged at 56 percent (27 GW), while clean energy resources have increased modestly to 23 percent (11 GW).

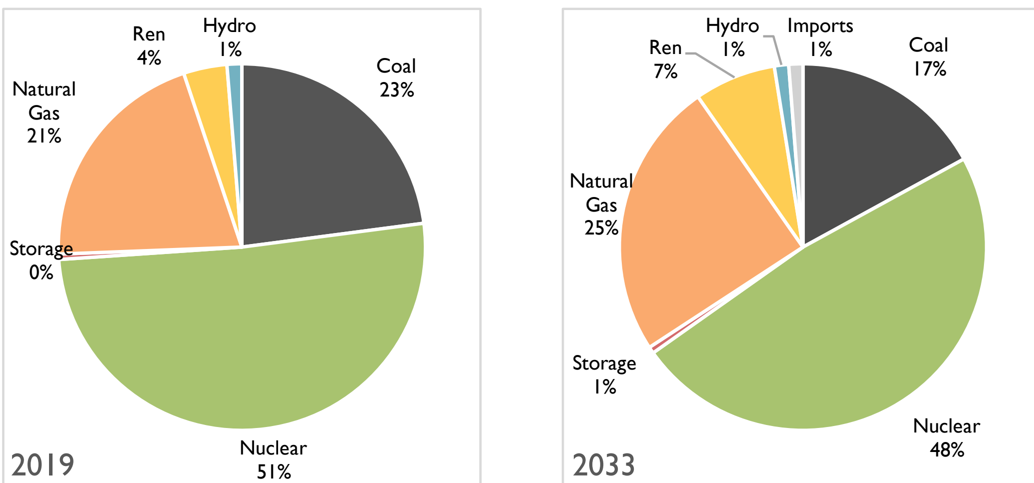
Figure 1. Duke Energy modeled nameplate capacity by scenario, 2019 and 2033



In contrast, gas and coal resources in the Clean Energy scenario drop to 32 percent (18 GW) of the capacity mix by 2033, and renewable energy resources comprise 49 percent (27 GW) of the utility mix. Nuclear capacity remains constant in both scenarios throughout the period. Notably, the EnCompass model makes the choice to retire the Allen coal plant at the end of 2019, accelerating the retirement from Duke Energy's anticipated dates of 2024 (for Units 1–3) and 2028 (for Units 4–5). While the coal capacity is the same at the end of the analysis period for both the Duke IRP and the Clean Energy scenarios, the latter retires a portion of this coal capacity earlier in the analysis period and thus has a lower volume of coal capacity during that time.

As shown in Figure 2 below, the fuel mix in Duke's service territory changes very little over time in the IRP scenario. Coal generation drops from 21 percent in 2019[3] to 17 percent in 2033, while natural gas generation increases over the study period from 19 percent to 25 percent. Renewable generation increases only slightly over the study period, from 4 percent in 2019 to 7 percent in 2033. Note that these percentages do not match those shown in Duke Energy's IRPs in Figure 12-F on pages 69 (Duke Energy Carolinas) and 71 (Duke Energy Progress). This is due to the different assumptions used by Duke Energy and Synapse around operational parameters of individual units and the regional market price of energy.

Figure 2. Modeled generation in the Duke IRP scenario, 2019 and 2033



In the Clean Energy Scenario, shown in Figure 3, renewable generation makes up 21 percent of the fuel mix in 2033 as compared to 7 percent in the Duke IRP scenario. Natural gas generation falls to 9 percent of total generation in 2033, as compared to 25 percent in the Duke IRP scenario in that same year. Imports make up a greater percentage of the generation in the Clean Energy scenario as the model takes advantage of lower out-of-system energy costs. Notably, coal generation is markedly lower in the Clean Energy scenario than in the Duke IRP scenario in 2019, and this immediate decrease can be attributed to the removal of the "must-run designations," which are present in the Duke IRP scenario and force units to run without consideration of their variable costs.[4] Duke's coal-fired power plants are some of the

[3] Note that approximately one-third of the coal generation shown in 2019 is exported to neighboring utility service territories rather than being used to meet Duke Energy's own load requirements.

[4] Must-run designations are set by Horizons Energy, the developers of the National Database used by the EnCompass model. They are based on Horizons' observations from EPA's Continuous Emissions Monitoring (CEMS) data as well as data from Energy Information Administration (EIA) Form 923. In setting the must-run designations, Horizons assumes that coal generators will retire a coal asset rather than running it under high stress (e.g. daily shut-down) situations for any period of time.

more expensive resources to operate in both scenarios. With the must-run designations applied, the Duke IRP scenario alternates between importing and exporting energy as it seeks to find a use for the costly must-run coal generation that has been forced into the electric grid. In contrast, coal generation falls at the beginning of the analysis period in the Clean Energy scenario when the must-run designations are removed.

Figure 3. Modeled generation in the Clean Energy scenario, 2019 and 2033

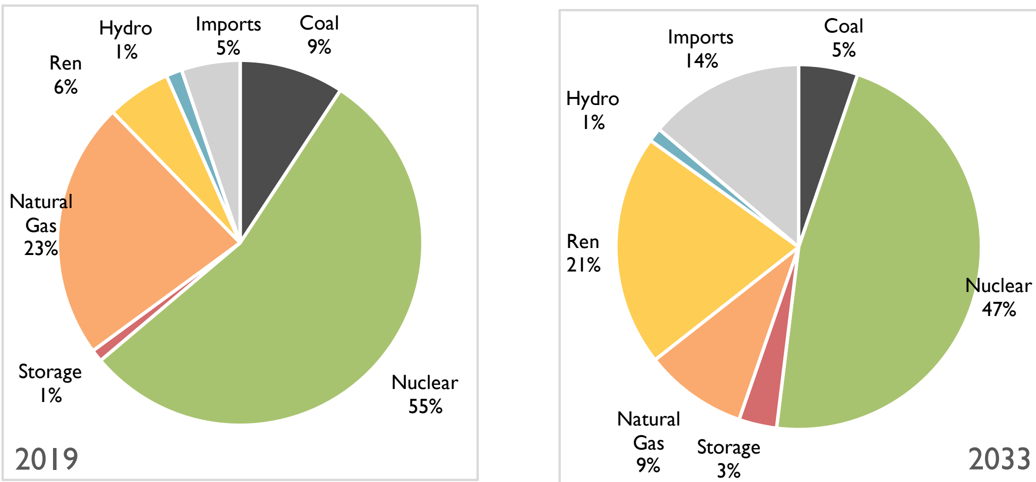
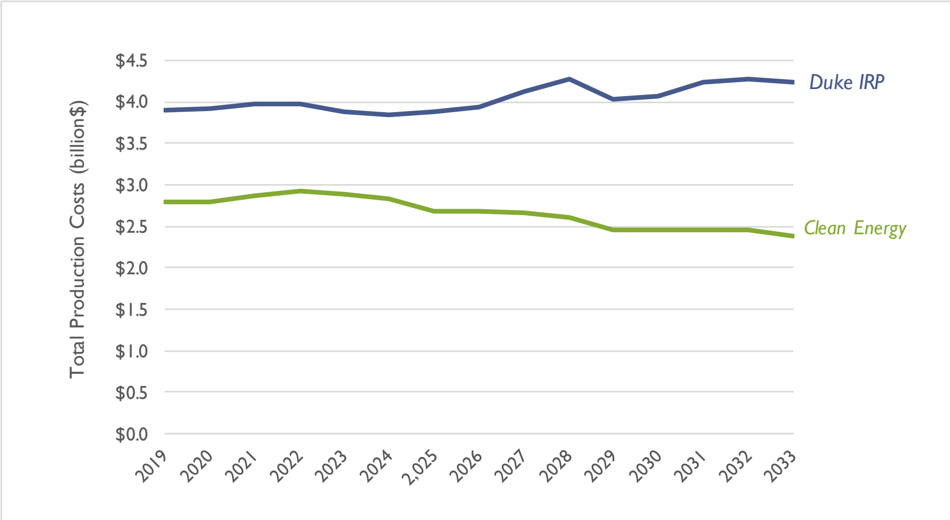


Figure 4 shows the total production cost associated with each scenario over the course of the analysis period. The Clean Energy scenario is considerably less expensive from an operational perspective than the Duke IRP scenario for two primary reasons. First, we note an immediate cost decline in the first year of the analysis period due to the removal of the must-run designations, as described above. Production costs immediately drop by 28 percent when uneconomic coal capacity is no longer forced to generate. In the absence of this coal-fired energy, EnCompass substitutes no- and low- variable cost energy from other sources.

Figure 4. Duke Energy total production cost by year by scenario



From a reliability perspective, Duke Energy meets its hourly demand requirements in all modeled days and hours during the analysis period. The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, even with the increased electric demand associated with the addition of new electric vehicles under Executive Order Number 80.

Figure 5 and Figure 6, below, show energy generation on January 3, 2028—a representative winter peak day—for the Duke IRP and Clean Energy scenarios. Both scenarios rely on nuclear generation and some level of energy imports to meet demand in peak hours and then export energy during the midday trough. The Duke Energy scenario dispatches must-run coal units throughout the day, and uses a mix of natural gas-fired, hydroelectric, and some solar generation to meet the hourly peaks. The modest amounts of battery storage capacity are charged in the early morning and midday hours. Conversely, the Clean Energy Scenario uses very little coal, less natural gas-fired generation, and relies on a greater mix of resources. Battery capacity is charged via solar generation during both an extended morning period and the midday trough, which allows batteries to discharge during evening hours to help meet the evening peak. Duke Energy's hourly load requirements are shown by the solid line. The area between the dashed line and the solid line in the two Figures represents the time in which battery resources are being charged, whether by solar resources within Duke's service territory or via imported energy. The area between the solid line and the dotted line represents energy exports.

Figure 5. Sample winter peak generation by fuel type, January 3, 2028, Duke IRP scenario

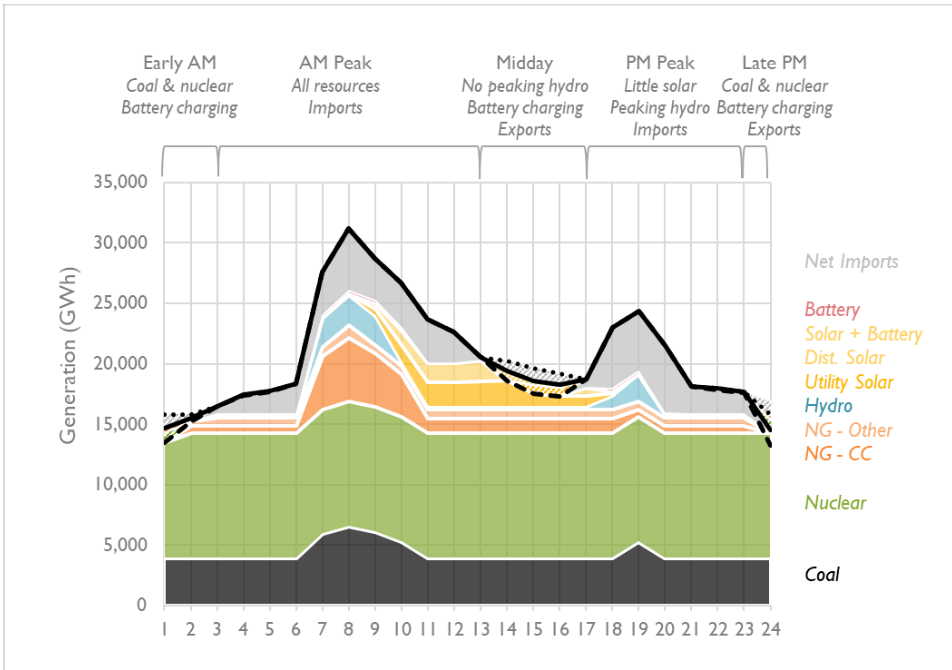
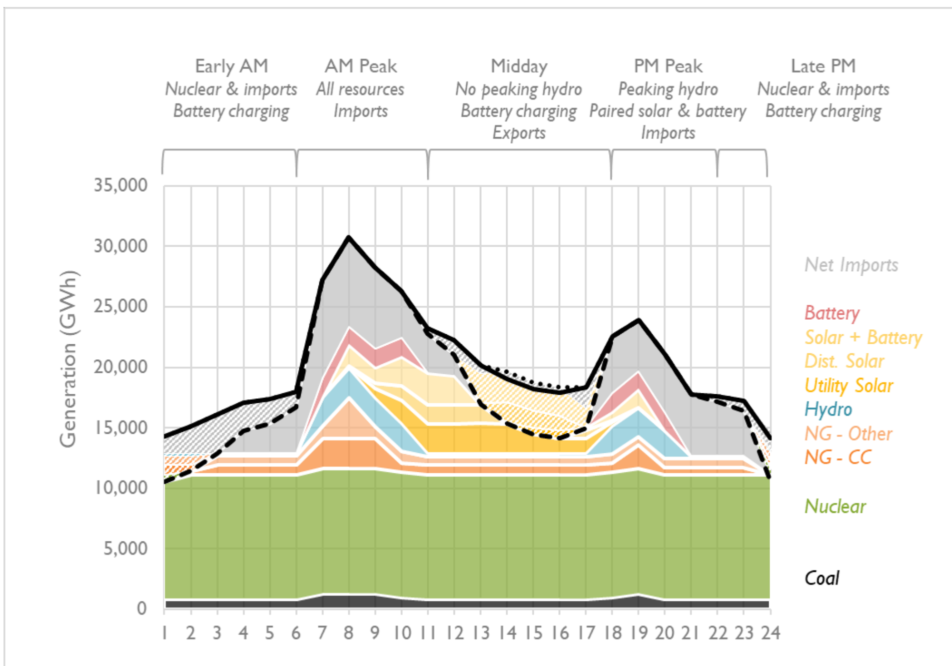
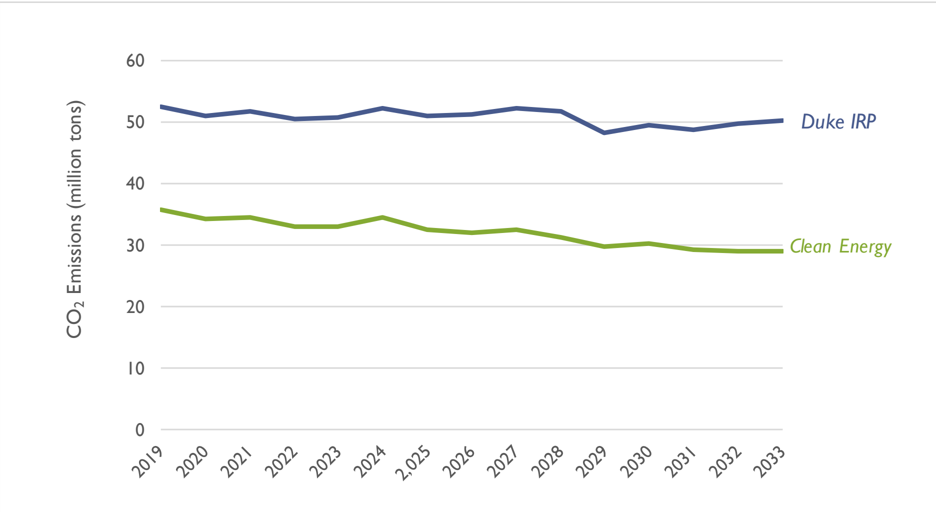


Figure 6. Sample winter peak generation by fuel type, January 3, 2028, Clean Energy scenario



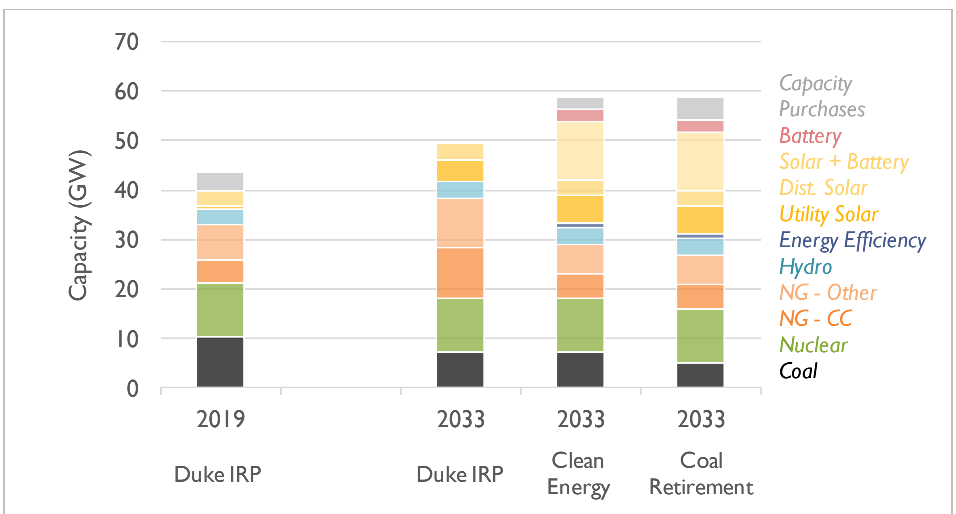
Finally, as expected based on the substantial difference in carbon-free capacity and generation between the two scenarios, the CO_2 emissions in the Clean Energy scenario are well below those in the Duke IRP scenario. The removal of the must-run coal designations immediately leads to a reduction in CO_2 emissions of almost 17 million tons in 2019. Though both scenarios see overall emissions decline, the gap between the two widens by the end of the period, when the Duke IRP scenario continues to emit almost 50 million tons of CO_2 while the Clean Energy scenario emits just under 30 million tons. Figure 7 depicts this widening gap, with both scenarios accounting for emissions associated with energy imports. Again, these volumes will differ from those reported by Duke Energy in Figure A-3 of each of its IRPs given the operational differences between generators that exist between the Company's modeled scenario and the Synapse Duke IRP scenario.

Figure 7. Duke Energy CO_2 emissions by year by scenario



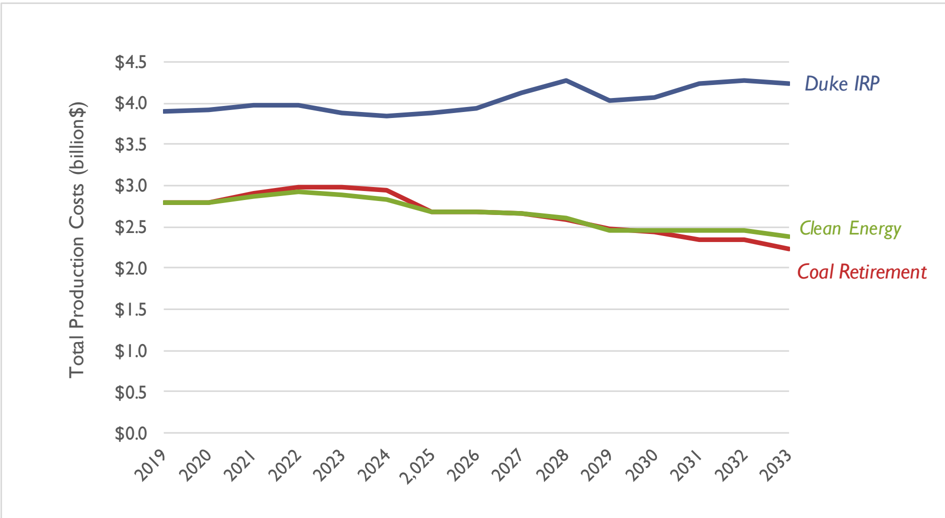
Synapse also examined an Accelerated Coal Retirement scenario in order to examine the ways in which advancing certain coal unit retirements changes system emissions and costs. This scenario accelerates Duke's retirement of the Roxboro Units 3 and 4 to December 2030 and the retirement of Marshall Units 1 and 2 to December 2032. As shown in Figure 8, the EnCompass model chooses to make up for the retired coal capacity through capacity purchases from surrounding states.

Figure 8. Duke Energy modeled nameplate capacity with Accelerated Coal Retirement, 2019 and 2033



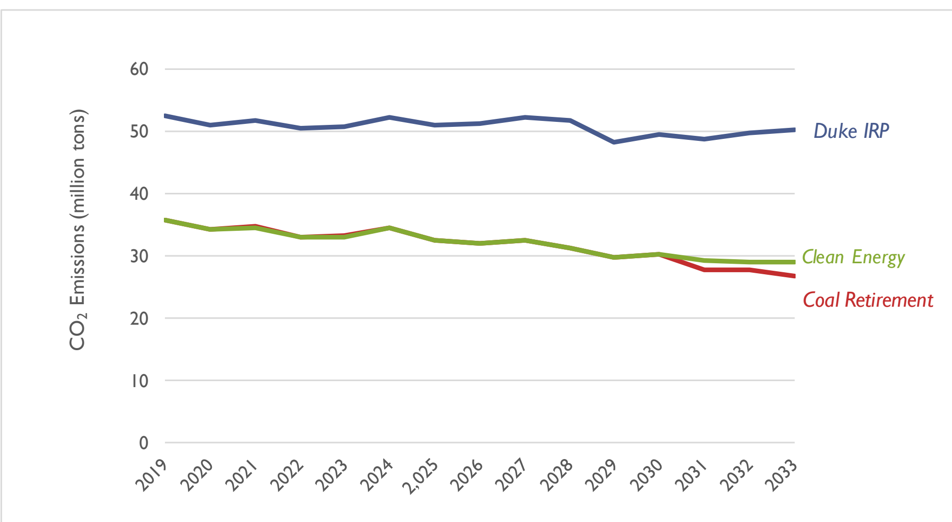
Production costs are extremely similar between the Clean Energy and Accelerated Coal Retirement scenarios, as shown in Figure 9. Costs drop slightly in the Accelerated Coal Retirement scenario in 2030 as the Roxboro 3 and 4 and Marshall 1 and 2 retirements move forward in time compared to the other scenarios. Energy imports increase slightly in the Accelerated Coal Retirement scenario as a replacement for the generation from these retiring units.

Figure 9. Duke Energy production cost by year by scenario



We see a comparable decrease in emissions after 2030 in the Accelerated Coal Retirement scenario, as shown in Figure 10.

Figure 10. Duke Energy CO_2 emissions by year by scenario



The following sections examine the impacts to human health, customer rates and bills, and state GDP and jobs of the Clean Energy scenario as compared to the Duke IRP scenario. Because the Clean Energy and Accelerated Coal Retirement scenarios were so similar, we limited our analysis to the differences between the Duke IRP and Clean Energy scenarios only.

3.2. Health Impacts

Synapse used the CO-Benefits Risk Assessment (COBRA) tool to assess the avoided health impacts in both North Carolina and South Carolina due solely to the change in emissions associated with our modeled Clean Energy scenario. Developed for the U.S. Environmental Protection Agency (EPA) State and Local Energy and Environment Program, COBRA utilizes a reduced form air quality model to measure the impacts of emission change on air quality and translates them into health and monetary effects. For this analysis, Synapse used modeled emissions (SO_2, NO_X, & $PM_{2.5}$) from the Duke IRP scenario as a baseline and compared them to modeled emissions from the Clean Energy scenario. The health and monetary benefits described below are those avoided by the Clean Energy scenario.

COBRA can estimate a number of detailed health impacts, including adult mortality, infant mortality, non-fatal heart attacks, respiratory hospital admissions, cardiovascular-related hospital admissions, acute bronchitis, upper respiratory symptoms, lower respiratory symptoms, asthma exacerbations, asthma emergency room visits, minor restricted activity days, and work loss days due to illness. A subset of those specific health impacts is shown in Table 1, with the numbers in the table representing the number of hospital visits and work loss days that could be avoided under the Clean Energy scenario.

Table 1. Avoided health impacts of the Clean Energy scenario

Year	Hospital Admits, Respiratory	Hospital Admits, Respiratory Direct	Hospital Admits, Asthma	Hospital Admits, Lung Disease	Hospital Admits, Cardio	Emergency Room Visits, Asthma	Work Loss Days
2020	6.0	4.3	0.5	1.2	7.1	10.8	2,398
2025	5.9	4.3	0.5	1.2	7.0	10.7	2,372
2030	4.9	3.5	0.4	1.0	5.8	8.9	1,966
2033	4.8	3.4	0.4	0.9	5.6	8.6	1,911

In 2020 the difference in Duke Energy's electric system dispatch in the Clean Energy scenario avoids approximately six respiratory-related hospital admits, seven cardiovascular-related hospital admits, and 11 asthma-related emergency room visits in North and South Carolina compared to the Duke IRP scenario. Notably, COBRA projects similar avoided health effects at the end of the modeling period (2033) compared to 2020. This is largely due to the removal of coal must-run designations in the Clean Energy scenario, which leads to an immediate decrease in emissions of air pollutants as coal generation drops. The Duke IRP scenario keeps uneconomic coal units online and, when not forced to generate, the Clean Energy scenario utilizes low-pollutant nuclear and renewable resources to generate in the place of coal. Thus, there is a sizeable difference in emissions between the two scenarios from the beginning of the period. The Duke IRP scenario slowly ramps down its reliance on coal-fired generation over the course of the analysis period, causing the gap in emissions avoided health impacts to narrow over time.

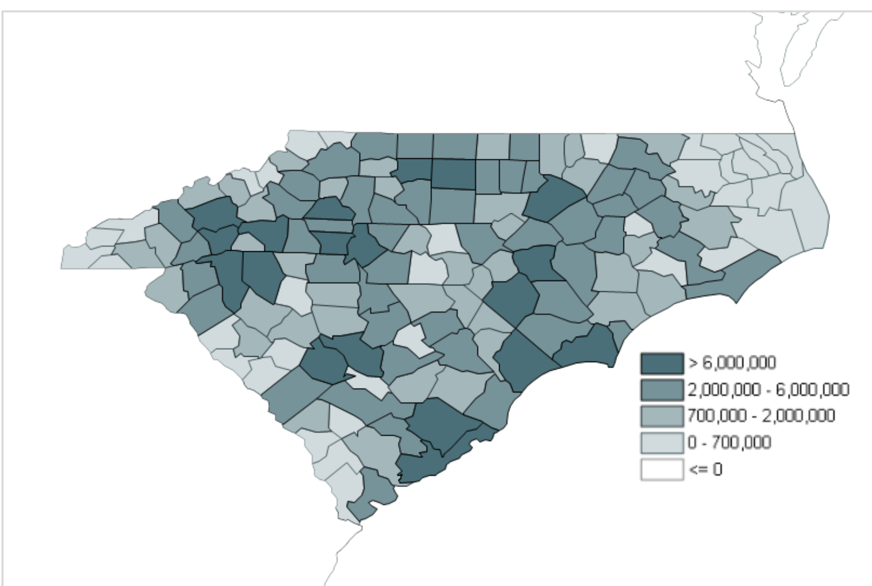
In addition to physical health effects and the costs of associated medical treatment, illnesses related to air pollution impose other costs on society, which include lost productivity and wages if a person misses work or school and restrictions on outdoor activity when air quality is poor. Table 2 shows low and high estimates of the monetized value of these total health benefits. These numbers place an economic value on all of the avoided health impacts modeled in COBRA, plus the value of minor restricted activity days and work loss days.

Table 2. Monetary benefits of all avoided health impacts under the Clean Energy scenario

Year	Total Health Benefits, Low	Total Health Benefits, High
2020	$196,778,415	$444,771,642
2025	$194,592,175	$439,830,666
2030	$161,291,821	$364,570,301
2033	$156,736,570	$354,274,856

The avoided health impacts and monetary benefits associated with the emissions reductions in the Clean Energy scenario vary by county, with the largest impacts seen in the most populous counties in North and South Carolina. Figure 11 shows the distribution of the monetized total health benefits across North and South Carolina in 2028. As one might intuit, greater benefits are realized in those counties with larger populations, where a larger number of people are affected by the local air quality.

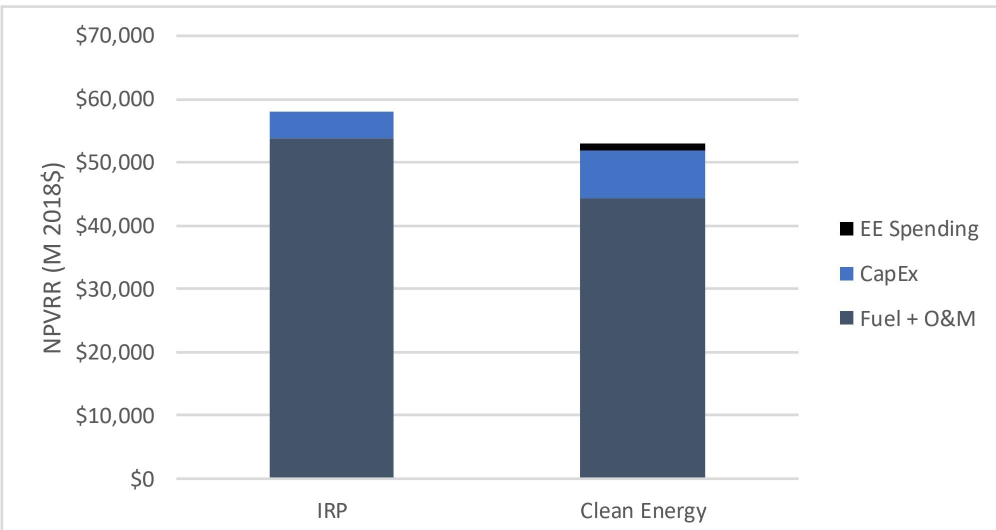
Figure 11. Total health-related monetary benefits ($ high estimate) of the Clean Energy scenario by county, 2028



3.3. Rate and Bill Impacts

Revenue requirements are lower under the Clean Energy scenario than in the IRP scenario, due primarily to the lower production cost associated with the operation of Duke's power plants. Capital expenditures in the IRP scenario are lower than in the Clean Energy scenario, as they represent only the cost of renewable procurement up to the levels specified by NC House Bill 589, along with North Carolina's portion of new, "optimized" combined-cycle and combustion turbine units added by Duke Energy post-2025. The Clean Energy scenario contains additional revenue requirements associated with capital spending on renewable resources over-and-above HB 589 levels and administration costs associated with incremental energy efficiency, but the fuel and operations and maintenance (O&M) savings from the operation of low- and no-variable cost resources lowers the total revenue requirement. These numbers do not include spending on transmission and distribution. Those revenue requirements are shown in Figure 12.

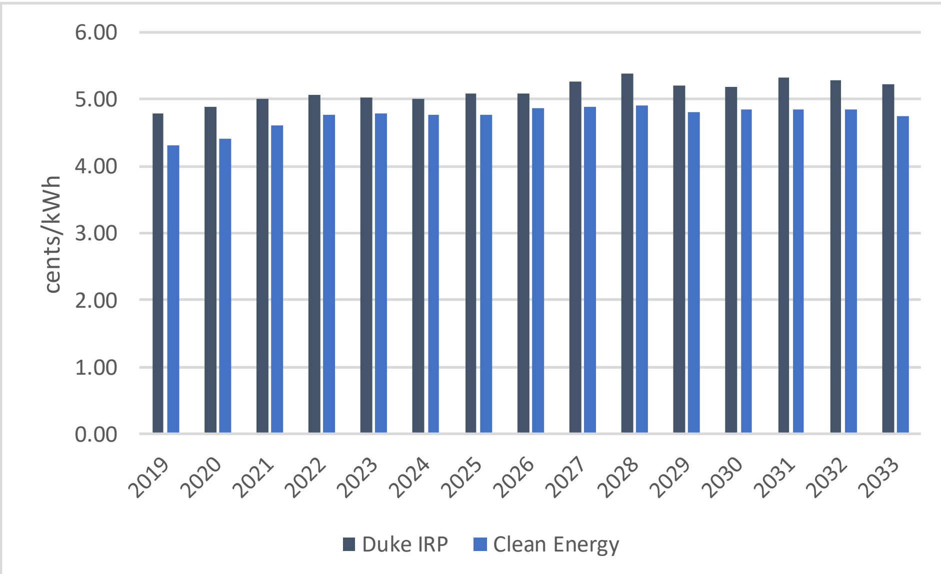
Figure 12. Revenue requirement of the Duke IRP and Clean Energy scenarios, North Carolina



Note that Duke Energy's capital cost assumptions were used for the resources in the IRP scenario. Synapse used capital costs for standalone solar and battery storage, wind, and paired solar and battery from NREL and Lazard. Duke's capital cost estimate for solar capacity from 2019 to 2033 is lower than the Synapse assumption, and the solar cost component of the capital spending revenue requirement is a conservative one.

Ratepayers in North Carolina save money under the Clean Energy scenario. Synapse calculated the estimated change in the rate components associated with capital spending and production costs. These values were taken from EnCompass and were allocated to North Carolina based on the percentage of Duke energy sales occurring in the state in 2017 according to EIA data. In the Clean Energy scenario, the increased spending on energy efficiency programs was added to this value. Total costs were then divided by Duke's energy sales to all customer classes to arrive at an average retail rate impact in each scenario that is associated with capital cost, production cost, and incremental energy efficiency spending.[5] We found that for any given year during the analysis period, ratepayers can expect to save anywhere from a minimum of .24 cents/kWh to a maximum of .48 cents/kWh, as shown in Figure 13, which translates to a savings of 4 to 9 percent over the study period.

Figure 13. Estimated average retail rate impact of the Duke IRP and Clean Energy scenarios



In order to estimate the total change in residential customers' electricity bills under the Clean Energy scenario, the average retail rate was multiplied by an assumed energy consumption by residential customers of 1,000 kWh per month, or 12,000 kWh per year. This was assumed to represent the component of residential rates associated with capital, fuel, variable O&M, and incremental energy efficiency spending (in the Clean Energy scenario). Costs associated with Transmission, Distribution, and Customer Charges were taken from slides 22 and 23 of the presentation entitled *North Carolina's Public Utility Infrastructure & Regulatory Climate* presented by the North Carolina Utilities Commission in October 2018.[6] A single weighted average of the sum of these costs for DEC and DEP was calculated based on the number of residential customers in each state, and was added to the capital/production cost component.

The lower production costs (fuel and variable O&M) in the Clean Energy scenario lead to immediate savings in customer electricity rates compared to the Duke IRP scenario. Under the Clean Energy scenario, North Carolina consumers also use less electricity under the Enhanced Energy Efficiency program. Lower electricity use,[7] coupled with the decrease in rates, causes residential consumers in the

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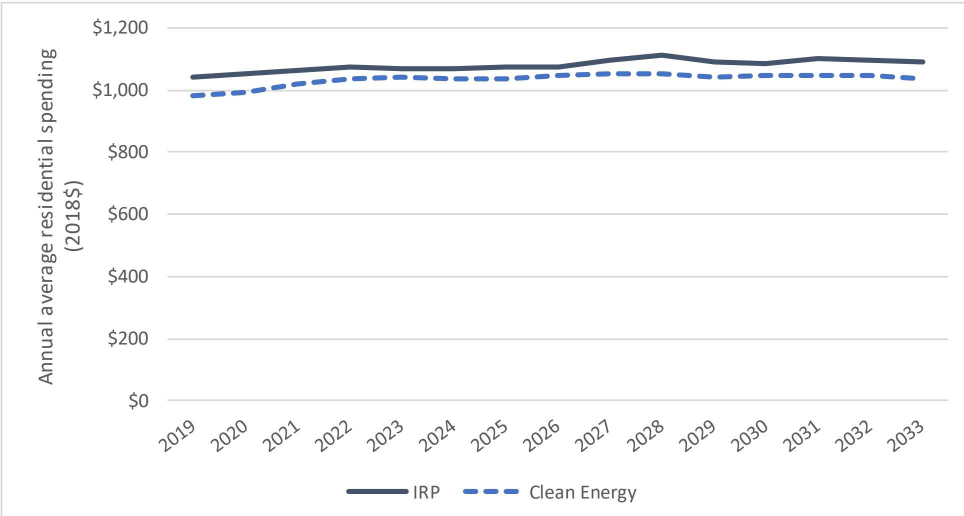
[5] For more information on the rate and bill impact calculation methodology, see Appendix A.

[6] This presentation is available at: https://www.ncuc.net/documents/overview.pdf

[7] Annual electricity use was calculated by dividing Duke Energy's forecasted energy sales by the forecasted customer count.

state see their average annual electricity costs decline by $27–$58 per year, or approximately 2.5 to 5.5 percent, depending on the year. This savings is shown in Figure 14.

Figure 14. Estimated residential bill impact of the Duke IRP and Clean Energy scenarios



3.4. Economic Impacts

Synapse used the IMPLAN model to evaluate the impacts of the Clean Energy scenario on employment, income, and Gross Domestic Product (GDP) in North Carolina. IMPLAN is an industry-standard model that can be used to evaluate the impacts of changes in direct spending patterns on a state's economy. For this analysis, North Carolina-specific spending impacts were determined by allocating Duke costs and spending based on North Carolina's proportion of system-wide energy sales. IMPLAN's framework enables us to assess not only impacts in directly affected industries, but also impacts on industries that serve as suppliers to directly impacted industries or that serve employees of directly and indirectly impacted industries. Synapse evaluated macroeconomic impacts resulting from changes in direct spending on the construction of each generation resource type, the operation of generation resources, and the installation of energy efficiency measures. We also assessed impacts associated with changes in disposable income among households and businesses facing lower (or higher) energy costs under the Clean Energy scenario.

Figure 15 displays the average annual North Carolina employment impacts of the Clean Energy scenario relative to the Duke IRP scenario in each of three five-year periods covering the IRP study timeframe. We find modest positive net positive employment impacts in each period, as positive impacts associated with re-spending of energy savings and increased spending on energy efficiency and renewable energy resources outweigh negative impacts associated with decreased spending on coal and natural gas power plants. Over the full IRP study period, our results indicate an average annual increase in North Carolina employment of approximately 3,000 full-time jobs.

Figure 15. Average annual employment impacts of Clean Energy scenario relative to Duke IRP scenario

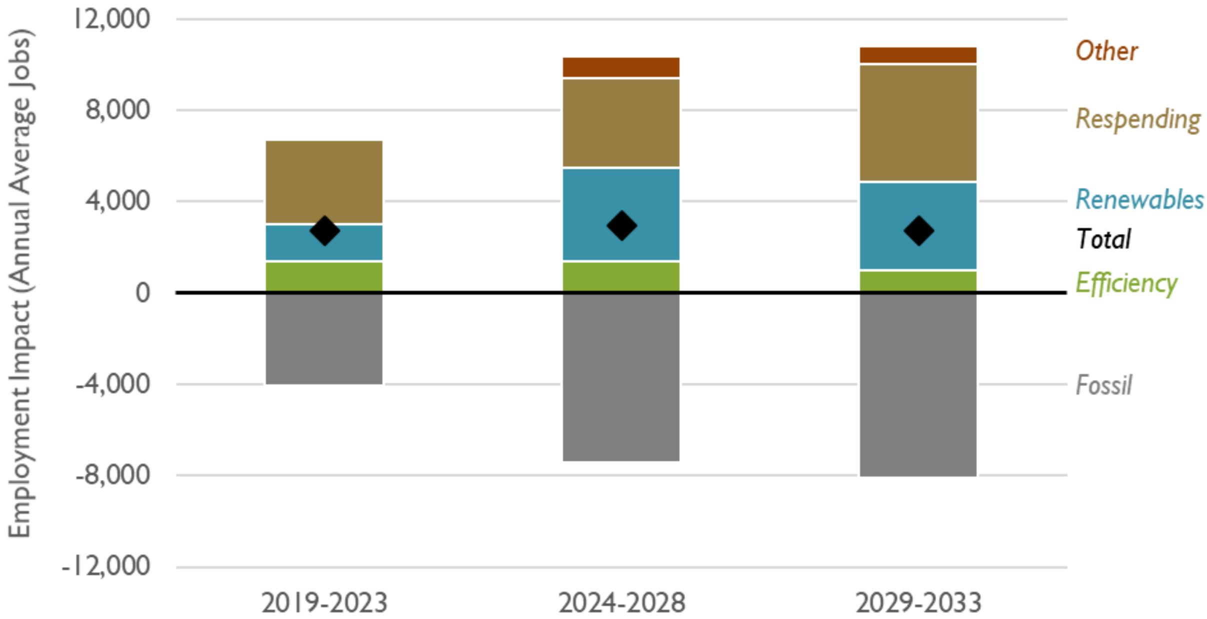


Figure 16 presents a similar picture regarding impacts on income of North Carolina residents. Our results indicate that the net increases in employment drive modest net increases in total income. Over the period from 2019 through 2023 we estimate net increases in average annual income of approximately $110 million.

Figure 16. Average annual income impacts of Clean Energy scenario relative to Duke IRP scenario

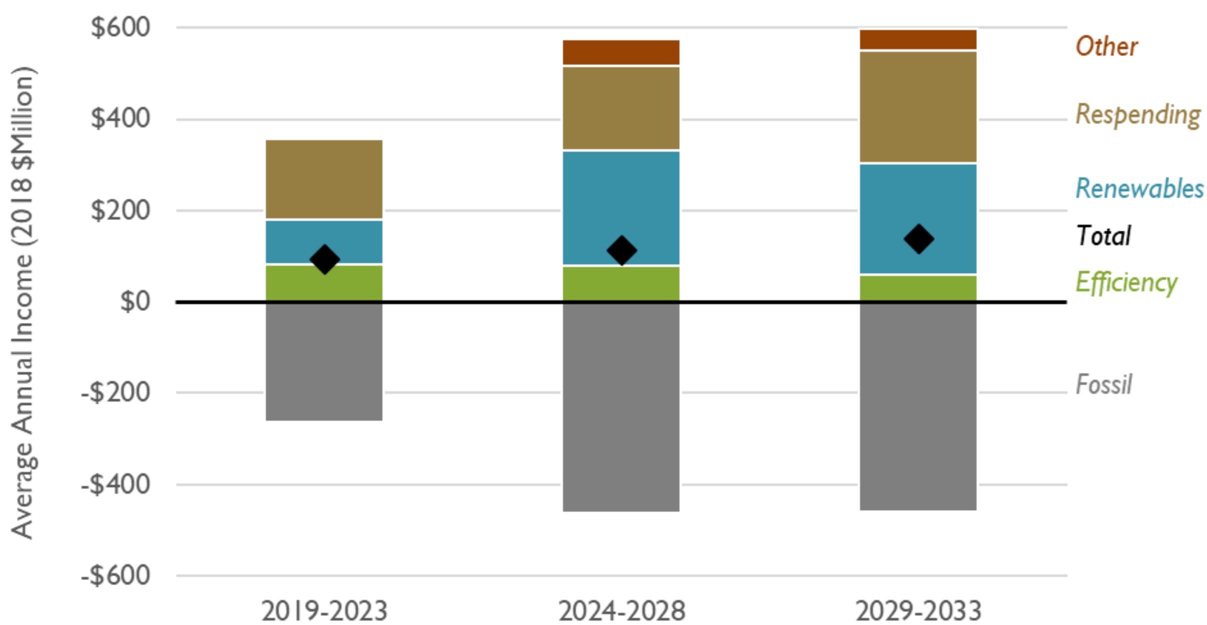
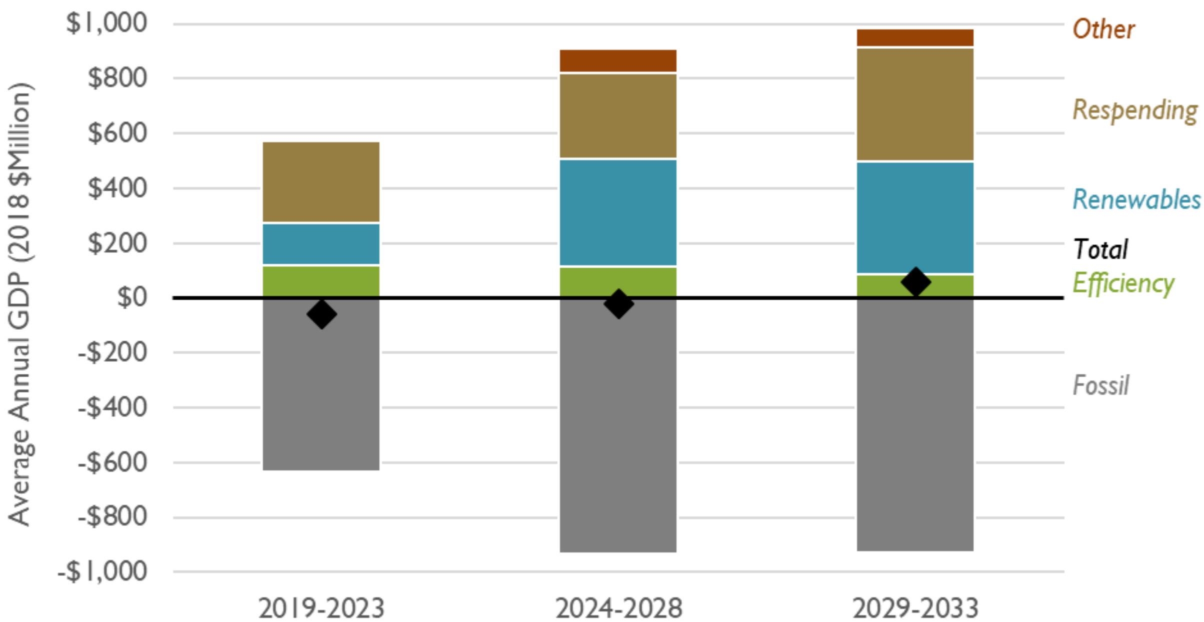


Figure 17 displays results for North Carolina state GDP. In this case, we find small net negative impacts, as GDP decreases associated with reduced spending on construction and operation of fossil fuel resources outweigh increases driven by greater spending on renewables, efficiency, and the wider economy. Over the period from 2019 through 2033 we find an average annual net GDP decrease of approximately $10 million. The discrepancy between this finding and our employment results reflects the fact that renewable resource and retail industries tend to be more labor-intensive than fossil fuel industries.

Figure 17. Average annual GDP impacts of Clean Energy scenario relative to Duke IRP



We note that all of these macroeconomic impacts are quite small in the context of North Carolina's economy. For example, our finding of an average annual employment increase of 3,000 amounts to less than 0.1 percent of the total number of jobs in North Carolina.[8] Similarly, an annual GDP impact of $10 million amounts to less than 0.01 percent of North Carolina's GDP.[9]

To summarize, Synapse performed a rigorous, scenario-based analysis to evaluate an alternative clean energy future compared to the more traditional portfolio of fossil-fueled resource additions included in Duke Energy's IRPs. In contrast to Duke's preferred resource portfolio, we found that the EnCompass model chooses to build out solar and storage resources to meet future capacity and energy needs with zero incremental natural gas-fired unit additions when allowed to select the most cost-effective future resource build. Coal generation declines between the Duke IRP and Clean Energy scenarios, lowering the

[8] Total employment in North Carolina is currently approximately 4.5 million. See https://www.bls.gov/news.release/laus.nr0.htm.

[9] 2017 North Carolina GDP was approximately $540 billion. See https://fred.stlouisfed.org/series/NCNGSP.

electric system production cost and reducing CO_2 emissions while maintaining system reliability. Our modeling shows that renewable resources are comparably cost-effective to new natural gas for North Carolina ratepayers and offer other benefits to consumers in the state, including a decrease in the number of hospital visits related to poor air quality, electricity rate and bill savings for consumers, and increased employment.

Appendix A. Technical Appendix

Synapse used EnCompass to model resource choice impacts in Duke's service territory in North and South Carolina. Developed by Anchor Power Solutions, EnCompass is a single, fully integrated power system platform that provides an enterprise solution for utility-scale generation planning and operations analysis. EnCompass is an optimization model that covers all facets of power system planning, including:

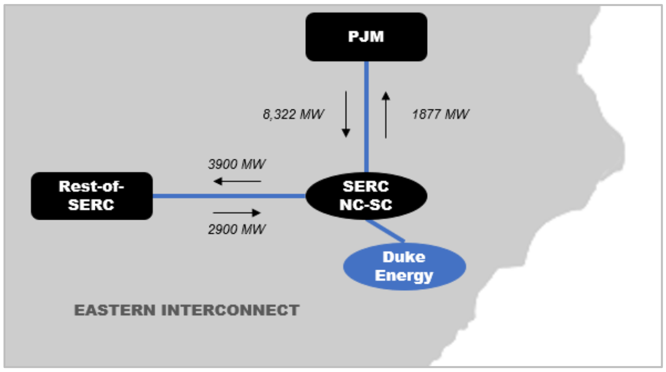
- Short-term scheduling, including detailed unit commitment and economic dispatch, with modeling of load shaping and shifting capabilities;
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis;
- Long-term integrated resource planning, including capital project optimization, economic generating unit retirements, and environmental compliance; and
- Market price forecasting for energy, ancillary services, capacity, and environmental programs.

Synapse used the EnCompass National Database created by Horizons Energy to model the Duke service territory. Horizons Energy has benchmarked dispatch and prices resulting from its comprehensive dataset to actual, historical data across all modeling zones. More information on EnCompass and the Horizons dataset is available at www.anchor-power.com.

Topology and Transmission

Synapse modeled two detailed areas with full unit-level operational granularity, the Duke Energy utility service territory, and the remaining SERC region comprised of North Carolina and South Carolina. Additionally, we modeled external contract regions representing the SERC and PJM balancing areas. We relied on transmission assumptions from the EnCompass National Database, displayed in Figure 18 below. Energy transfers between SERC NC-SC and the Rest-of-SERC and PJM regions are subject to a default 3.44 $/MWh tariff. Capacity transfers are unlimited within SERC regions. Energy from the PJM and Rest-of-SERC regions are priced at recent historical energy prices and escalated throughout the period.

Figure 18. Duke IRP modeling topology and energy transfer capabilities



Peak Load and Annual Energy

For the Duke Energy territory, Synapse relied on annual energy and peak load as defined in the 2018 Duke Energy Carolinas and Duke Energy Progress IRPs. Synapse used annual energy and peak projections from the NERC Long-term Reliability Assessment for the SERC-NC-SC region. We utilized hourly load shapes supplied by Horizons Energy in the EnCompass National Database for all modeled regions. Synapse also performed analysis in the proprietary Electric Vehicle Regional Emissions and Demand Impacts Tool (EV-REDI)[10] to model the load required to meet the electric vehicle (EV) target set in North Carolina Executive Order No. 80 (80,000 EVs by 2025, and an annual 5 percent increase through the end of the period). The additional EV load is included in the Clean Energy scenario.

Fuel Prices

For natural gas prices, Synapse relied on NYMEX futures for monthly Henry Hub gas prices through December 2019. For all years after 2019, Synapse used the annual average prices projected for Henry Hub in the AEO 2018 Reference case. We then applied trends in average monthly prices observed in the NYMEX futures to this longer-term natural gas price to develop long-term monthly trends. Delivery price adders for Zone 5 are sourced from the EnCompass National Database. Coal prices, from the Central Appalachia supply basin, and for the Carolinas delivery point are also sourced from the EnCompass National Database. Gas and coal price forecasts are shown in Figure 19 and Figure 20 below.

[10] More information on EV-REDI is available at: http://www.synapse-energy.com/tools/electric-vehicle-regional-emissions-and-demand-impacts-tool-ev-redi

Figure 19. Natural gas price forecast – Henry Hub and Zone 5 Delivery Point

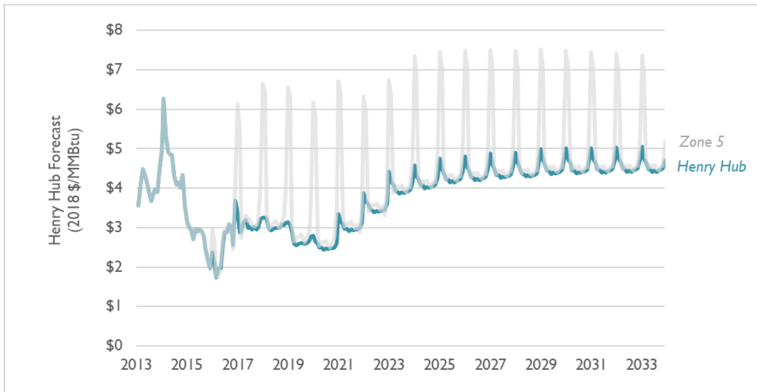
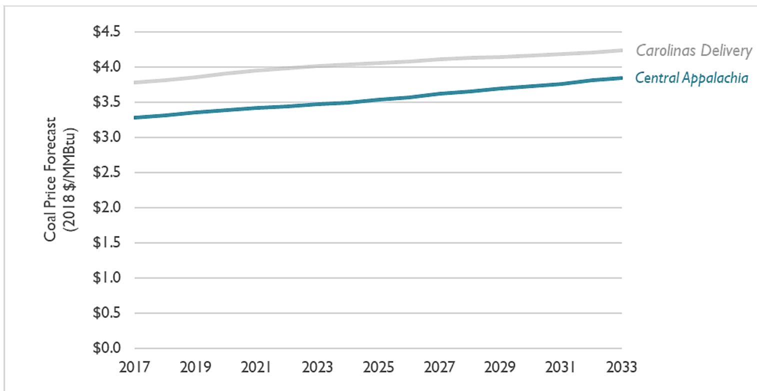


Figure 20. Coal price forecast – Central Appalachia Basin and Carolinas Delivery Point



Programs

Synapse modeled two major environmental programs: the North Carolina Renewable Energy & Energy Efficiency Portfolio Standard (REPS) and the carbon price forecast outlined in the 2018 Duke Energy IRPs. The REPS requires that 10 percent of electricity sales be met by renewable resources—stepping up to 12.5 percent in 2021—and up to 25 percent of the requirement can be met through energy efficiency technologies (40 percent after 2021). The carbon price outlined in the Duke IRPs begins at $5/ton (nominal) in 2025 and escalates at $3/ton annually.

Duke IRP Planned Resources

The Duke IRP scenario includes all planned additions, upgrades, and retirements described in the Duke IRPs, shown in Table 3 below, as well as generic combined cycle and combustion turbines added by the System Optimizer model in 2025 and beyond ("modeled additions").

Table 3. Duke IRP capacity (MW)

TYPE	PLANNED ADDITIONS	PLANNED RETIREMENTS	MODELED ADDITIONS
Coal		4,553	
CC	560	173	5,352
Hydro	260	1	
Nuclear	56		
CHP	81		
CT	402	843	3,220
Solar	673		
Storage	232		

Clean Energy Scenario Projects

For the Clean Energy scenario, Synapse allowed five generic project options in both North Carolina and South Carolina. They include onshore wind,[11] utility-scale battery, utility-scale solar, and a paired utility-scale battery and solar project. For these projects Synapse uses NREL's Advanced Technology Baseline projections and Lazard's Levelized Cost of Storage 2018 report to define cost and operational parameters.

Other Assumptions

Synapse made additional adjustments to our core modeling assumptions in consultation with the North Carolina Sustainable Energy Association. We list those assumptions below.

- In the Clean Energy scenario, the Duke territory has a required reserve margin of 15 percent, while the Duke IRP case uses the 17 percent reserve margin outlined in the Duke IRPs.
- Battery resources have a firm capacity credit of 75 percent throughout the analysis period, consistent with the recent study entitled *Energy Storage Options for North Carolina* and prepared by North Carolina State University.
- Coal must-run designations are applied in the Duke IRP scenario and are removed in the Clean Energy scenario.
- Energy efficiency is modeled as a supply-side resource in the Clean Energy scenario based on the Enhanced Energy Efficiency case described in the Duke IRPs. It is priced at the levels outlined in the *2016 Duke Energy North Carolina DSM Market Potential Study*.
- Carbon dioxide emissions associated with energy imports in each of the scenarios are calculated using a declining annual average emissions rate for generation in PJM. According to the region's emissions report *2013-2017 CO_2, SO_2 and NO_x Emissions*

[11] Offshore wind was not offered to the EnCompass model in Duke Energy's service territory. However, it was offered to the external NC-SC region and was not selected by the model.

Rates,[12] emissions of CO_2 have declined over the past five years. We applied this declining rate to the PJM System Average in 2017 to project future emissions rates. These rates were then multiplied by the volume of energy imports in each year, and calculated emissions were added to emissions from Duke's units to determine total annual CO_2 emissions from all sources.

COBRA Modeling Assumptions

The U.S. EPA's COBRA model contains baseline emissions estimates for the pollutants $PM_{2.5}$, SO_2, NO_x, NH_3, and VOCs for the year 2017. Users can adjust these estimates up or down, and the model utilizes a reduced form air quality model to estimate the effects of these emission changes on ambient particulate matter. It then calculates avoided health and monetary benefits associated with the emissions changes consistent with U.S. EPA practice. For more information visit https://www.epa.gov/statelocalenergy/co-benefits-risk-assessment-cobra-health-impacts-screening-and-mapping-tool.

To estimate the health and economic impacts of NO_X and SO_2, Synapse utilized annual emissions outputs from the EnCompass model scenarios for the Duke service territory in North and South Carolina. Emission rates were based on the following specific assumptions:

- EnCompass approximates NO_X and SO_2 emissions using unit-specific emission rates, as defined in the Horizons Energy National Database.
- For this project, Synapse incorporated an average $PM_{2.5}$ emissions rate for all coal fuels in EnCompass of 0.027 lb/mmBtu. This emissions rate is in line with emission rates compiled by Argonne National Laboratory for *GREET Model Emission Factors for Coal- and Biomass-fired Boilers* and by EPA for the Avoided Emissions and generation Tool (AVERT).

Synapse assumed a 7 percent discount rate for all COBRA analyses. Additionally, the COBRA analysis relies on historical county-level emissions allocations and assumes no county-level shifting.

Rate and Bill Impacts

Synapse used spreadsheet analysis to estimate the impact of the Clean Energy scenario on estimated electric rates and bills in North Carolina. Customer electric rates in a given year are made up of a number of components, including, but not limited to: utility capital expenditures inclusive of accumulated depreciation and an approved rate of return; the cost to a utility of generating the electricity necessary to meet customer demand; utility spending on any energy efficiency programs; and the volume of sales to customers.

[12] Available at: https://www.pjm.com/-/media/library/reports-notices/special-reports/20180315-2017-emissions-report.ashx?la=en

We determined utility capital expenditures for the Duke IRP scenario using Duke Energy's anticipated future resource portfolio and capital cost trajectories for the resource technologies added to its capacity mix. In their IRPs, DEC and DEP do not differentiate between new thermal capacity added in North Carolina versus South Carolina, and thus capital expenditures on new natural gas-fired resources were allocated to states based on the proportion of customer sales. Renewable additions were assumed to be necessary to comply with North Carolina HB 589 and capital expenditures were allocated to North Carolina ratepayers. In the Clean Energy scenario, the capital expenditures associated with the volume of renewable additions necessary for HB 589 was again allocated to North Carolina, with any capital expenditures from renewable additions above these volumes being allocated between North and South Carolina based on forecasted energy sales.

Production costs (fuel and fixed and variable O&M) in the two modeled scenarios were allocated between DEC and DEP based on forecasted energy sales. The volume of energy sales expected to occur in North Carolina versus South Carolina was calculated using the historical ratio of 2017 sales found in the most recent EIA 861 data. The historical percentage of sales occurring in North and South Carolina in DEC and DEP service territories was applied to the anticipated energy sales contained in the utilities' IRPs.

Program administration costs for energy efficiency are from the *2016 Duke Energy North Carolina DSM Market Potential Study* and the *2016 Duke Energy South Carolina DSM Market Potential Study*, both done by Nexant Consulting.

Estimated average retail rates were calculated by summing anticipated capital expenditures, production costs, and incremental utility energy efficiency costs, and dividing by total sales in North Carolina. Though actual rates differ between different customer classes, for the sake of this analysis we assumed one standard electricity rate across customer classes, referred to in the text as the "average retail rate."

In order to estimate the total change in residential customers' electricity bills under the Clean Energy scenario, the average retail rate was multiplied by an assumed energy consumption by residential customers of 1,000 kWh per month, or 12,000 kWh per year. This was assumed to represent the component of residential rates associated with capital, fuel, variable O&M, and incremental energy efficiency spending (in the Clean Energy scenario). Costs associated with Transmission, Distribution, and Customer Charges were taken from slides 22 and 23 of the presentation entitled *North Carolina's Public Utility Infrastructure & Regulatory Climate* presented by the North Carolina Utilities Commission in October 2018. A single weighted average of the sum of these costs for DEC and DEP was calculated based on the number of residential customers in each state, assumed to grow at real rate of 2 percent per year, and was added to the capital/production cost component.

Modeling Economic Impacts

The differences in capacity, generation, emissions, and system costs between the Clean Energy and Duke IRP scenarios drive differences in employment, income, and state Gross Domestic Product (GDP). Synapse used the IMPLAN model to evaluate the impact of the Clean Energy scenario on each of these macroeconomic indicators in North Carolina.[13] IMPLAN is an industry-standard input-output model that relies upon historical economic relationships to evaluate the effects of changes in direct spending patterns on employment, income, and GDP within a given study area. For this analysis, Synapse assessed impacts resulting from changes in spending on the following economic activities:

- Construction of generating resources
- Installation of energy efficiency measures
- Operation and maintenance of generation resources
- Consumer and business re-spending of energy savings

Our analysis accounts for three types of impacts: direct, indirect, and induced.

Direct impacts

Direct impacts consist of changes in employment, income, and GDP within energy resource sectors immediately impacted by the change in resource plan between the Duke IRP and Clean Energy scenarios. For example, direct employment impacts may consist of additional jobs for contractors, construction workers, and plant operators working on the building or operation of a power plant.

Indirect impacts

Indirect impacts are changes in employment, income, and GDP within sectors that serve as suppliers to directly affected industries. Examples of such sectors include turbine manufacturers and manufacturers of energy-efficient appliances. Note that our analysis only accounts for impacts among suppliers located within North Carolina.

Induced impacts

Induced impacts result from residents spending more or less money in the local economy. For energy resources, these impacts result from: (1) changes in disposable income among employees in directly and indirectly impacted industries and (2) changes in energy expenditures by North Carolina electricity customers.

Direct inputs to our economic impact modeling consist primarily of vectors of changes in spending by and on various industries. These inputs are generally direct outputs from our EnCompass modeling. They include changes in spending on the construction and operation of each type of electricity resource (e.g., natural gas power plants, solar power plants, battery storage facilities). For each industry, Synapse

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[13] IMPLAN is a commercial model developed by IMPLAN Group PLC. Information on IMPLAN is available at: http://implan.com/.

allocated the total change in spending across the available IMPLAN industry categories based on data from the National Renewable Energy Laboratory's JEDI model[14] and supplemental Synapse research.

[14] Available at: https://www.nrel.gov/analysis/jedi/

Appendix B. Qualifications and Experience

About Synapse

Synapse Energy Economics is a research and consulting firm specializing in energy, economic, and environmental topics. Since its inception in 1996, Synapse has grown to become a leader in providing rigorous analysis of the electric power sector for public interest and governmental clients.

Synapse's staff of 30 includes experts in energy and environmental economics, resource planning, electricity dispatch and economic modeling, energy efficiency, renewable energy, transmission and distribution, rate design and cost allocation, risk management, benefit-cost analysis, environmental compliance, climate science, and both regulated and competitive electricity and natural gas markets. Several of our senior-level staff members have more than 30 years of experience in the economics, regulation, and deregulation of the electricity and natural gas sectors. They have held positions as regulators, economists, and utility commission and ISO staff.

Services provided by Synapse include economic and technical analyses, regulatory support, research and report writing, policy analysis and development, representation in stakeholder committees, facilitation, trainings, development of analytical tools, and expert witness services. Synapse is committed to the idea that robust, transparent analyses can help to inform better policy and planning decisions. Many of our clients seek out our experience and expertise to help them participate effectively in planning, regulatory, and litigated cases, and other forums for public involvement and decision-making.

Synapse's clients include public utility commissions throughout the United States and Canada, offices of consumer advocates, attorneys general, environmental organizations, foundations, governmental associations, public interest groups, and federal clients such as the U.S. Environmental Protection Agency and the Department of Justice. Our work for international clients has included projects for the United Nations Framework Convention on Climate Change, the Global Environment Facility, and the International Joint Commission, among others.

Relevant Experience

Modeling Gas-Fired Plant Alternatives in New Mexico

Client: Sierra Club | Project ongoing

On behalf of the Sierra Club, Synapse is performing modeling of the electric system in New Mexico using the EnCompass model in both capacity expansion and production cost modes. Synapse is comprehensively modeling zero-emission alternatives to a new utility-proposed gas-fired generation option intended to replace the retiring San Juan Generating Station units in New Mexico in 2023. The modeling accounts for the interconnectedness of the electric power grid in the Desert Southwest region, including detailed representation of generation units in Arizona and New Mexico (and portions of Texas and California), and aggregated treatment for resources in the rest of the West. Synapse has found that a combination of utility-scale and small-scale solar PV, utility-scale battery storage, and incremental wind resource procurements would provide Public Service of New Mexico with a less-expensive, and lower-emitting alternative than its proposed gas-fired generation, while meeting all reliability requirements.

Nova Scotia Power Generation Utilization and Optimization Study

Client: Nova Scotia Utility and Review Board | Project completed August 2018

Synapse was asked to conduct an Integrated Resource Planning-type analysis on the overall utilization and optimization of Nova Scotia Power's coal and thermal generating fleet. Synapse used the PLEXOS electric sector simulation model for both capacity expansion and production cost purposes to estimate the costs associated with various unit retirement pathways and resource replacement options.

Value of Solar Implications of South Carolina Electric & Gas Fuel Costs Rider 2018

Client: Southern Environmental Law Center | Project completed May 2018

Synapse provided analysis and expert testimony on behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy for South Carolina Electric & Gas' (SCE&G) 2018 annual update of solar PV avoided costs under PURPA. Witness Devi Glick submitted testimony (Docket no. 2018-2-E) regarding the appropriate calculation of benefit categories associated with the value of solar calculation for PURPA QF rates and for Act 236 compliance.

Avoided Energy Supply Costs in New England

Client: AESC Study Group | Project completed March 2018

Synapse and a team of subcontractors used EnCompass and other tools to develop projections of electricity and natural gas costs that would be avoided due to reductions in electricity and natural gas use resulting from improvements in energy efficiency. The 2018 report provides projections of avoided costs of electricity and natural gas by year from 2018 through 2035 with extrapolated values for another 15 years. In addition to projecting the costs of energy and capacity avoided directly by program participants, the report provides estimates of the Demand Reduction Induced Price Effect (DRIPE) of efficiency programs on wholesale market prices for electric energy, electric capacity, and natural gas. The report also provides a projection of avoided costs of fuel oil and other fuels, non-embedded environmental costs associated with emissions of CO_2, avoided costs of transmission and distribution, and the value of reliability. The 2018 AESC study was sponsored by a group representing all of the major electric and gas utilities in New England as well as efficiency program administrators, energy offices, regulators, and advocates. Synapse conducted prior AESC studies in 2007, 2009, 2011, and 2013.

Clean Energy for Los Angeles

Client: Food & Water Watch | Project completed March 2018

The Los Angeles City Council has mandated that the Los Angeles Department of Water and Power (LADWP), the largest municipally run utility in the United States, analyze powering 100 percent of demand with renewable energy. To date, LADWP's efforts have been insufficient, as the utility has only published an analysis of a slight increase over current renewable energy targets and is not planning to finalize its 100 percent renewable study until 2020 at the earliest.

Food & Water Watch engaged Synapse to analyze a potential pathway to 100 percent clean energy in Los Angeles by 2030 using the EnCompass model. The modeled scenarios in the *Clean Energy for Los Angeles* report include a substantial amount of storage capacity. The two 100 percent renewable scenarios build between 2 and 3 gigawatts of storage capacity which is dispatched liberally in order to shift generation from solar resources to meet demand in the region. Our analysis included hourly modeling that demonstrated exactly how storage could be charged and dispatched over the course of the day to meet the utility's needs.

In our study, we found that it is possible for LADWP to exclusively use renewable resources to power its system in every hour of the year. What's more, we found that under one of the clean energy pathways analyzed, the transition to 100 percent renewable energy in every hour of the year can occur at no net cost to the system. The resulting report, *Clean Energy for Los Angeles*, provides a roadmap for how to achieve 100 percent renewables by integrating and harnessing renewable energy more efficiently and investing in additional efficiency, storage, and demand response.

Although the report only focuses on a single city, the results are important and applicable to many other parts of the country. Los Angeles's four million residents make the city larger than 22 entire states, while the annual energy served by LADWP is greater than sales in 13 individual states, indicating that if this transition is possible in Los Angeles, it is feasible in other parts of the country as well.

An Analysis of the Massachusetts RPS

Client: E4theFuture | Project completed August 2017

Synapse Energy Economics joined with Sustainable Energy Advantage (SEA), as well as members from NECEC, Mass Energy Consumers Alliance, E4theFuture, and other organizations to analyze the current state of regional renewable portfolio standards in light of many of new policy actions that have been put into place over the last several years. These policy actions include new legislation requiring long-term contracting for renewables and other resources in Massachusetts, Connecticut, and Rhode Island, revised incentives for distributed generation resources, changes to RPS polices in other states in New England, proposed Massachusetts-specific CO_2 caps, and newly-revised forecasts for electricity sales that take the full impact of new energy efficiency measures into account. The Synapse team used the EnCompass model for this analysis.

Clean Power Plan Reports and Outreach for National Association of State Utility Consumer Advocates

Client: National Association of State Utility Consumer Advocates | Project completed August 2015

Synapse supported the National Association of State Utility Consumer Advocates and its members in addressing the EPA's proposed Clean Power Plan in a manner that is cost-effective and efficient from an electricity consumer perspective. Prior to the release of the rule, Synapse presented to NASUCA members key issues regarding the details of the proposed rule and the primary compliance options that may be available to states. Following the rule's release, Synapse prepared a report focusing on the details of the rule as proposed. Recognizing that stakeholders have a wide range of reactions to the EPA's Plan, the intent of the report is to be a common resource to help all of NASUCA's members think through a broad range of potential implications of various compliance approaches to their respective consumers—whatever their individual state's positions. Synapse presented on the findings of *Implications of EPA's Proposed "Clean Power Plan"* at the 2014 NASUCA annual meeting in San Francisco, CA.

Synapse used its Clean Power Plan Planning Tool (CP3T) to perform multi-state analysis of the proposed rule to identify and explain a variety of challenges and opportunities related to multi-state compliance, including how states with dissimilar renewable technical potential, states with utilities that cross state boundaries, states with existing mechanisms for cooperation, etc., may approach regional compliance with the Clean Power Plan. Pat Knight, the lead developer of CP3T, provided a webinar for NASUCA members giving an overview of key issues surrounding the Clean Power Plan, as well as a walkthrough of CP3T's multi-state functionality. Synapse also prepared a report presenting the results of the analysis, presented at the NASUCA 2015 Mid-Year Meeting.

As a third element of Synapse's Clean Power Plan support to NASUCA members, Synapse prepared a report on best practices in planning for implementation of the Clean Power Plan. The report serves as a guide for consumer advocates to the logistics of developing a state implementation plan, with advice in areas such as stakeholder engagement, evaluating resource options, deciding on reasonable assumptions, identifying appropriate modeling tools, and selecting and implementing a plan.

Long-Term Procurement Plan Rulemaking

Client: California Office of Ratepayer Advocates | Project ongoing

Synapse is providing technical and expert witness services to the California Office of Ratepayer Advocates in connection with the Long-Term Procurement Plan proceeding affecting the three largest investor-owned utilities in California: Southern California Edison, Pacific Gas and Electric, and San Diego Gas and Electric. As part of this project, Synapse conducted modeling of the California ISO (CAISO) area using PLEXOS to assess loads and emissions throughout California based on various California Public Utilities Commission scenarios. Synapse analyzed model inputs, assumptions, forecast projections, and outputs, and examined alternatives including renewable energy integration and retirement scenarios. Synapse's modeling enabled determination of areas within California that would be capacity constrained.

Best Practices in Electric Utility Integrated Resource Planning

Client: Regulatory Assistance Project | Project completed June 2013

Synapse prepared a report for the Regulatory Assistance Project examining best practices in electric utility integrated resource planning. Synapse researched and discussed specific integrated resource plan (IRP) statutes, regulations, and processes in Arizona, Colorado, and Oregon; examined "model" utility IRPs from Arizona Public Service, Public Service Company of Colorado, and PacifiCorp; and developed recommendations for prudent integrated resource planning. Our report provided recommendations for both the IRP process and the elements that are analyzed and included in the resource plan itself. These elements include load forecast, reserves and reliability, demand-side management, supply options, fuel prices, existing resources, and environmental costs and constraints, among others.

Attachment 2

DUKE ENERGY CAROLINAS, LLC

Request:

Please describe how PPAs for energy and capacity between DEC and Qualifying Facilities (both compliance and non-compliance) that expire within the planning period are handled. Are these PPAs considered renewed after their initial terms?

Response:

In general, compliance and non-compliance qualifying facilities are expected to expire when the purchase power agreement terminates. For planning purposes, QF PPAs are expected to be either renewed or replaced in kind. Importantly, however, there is no explicit or implicit assumption in the IRP of contract renewals with any given existing QF facility owner.

DUKE ENERGY PROGRESS, LLC

Request:

Please describe how PPAs for energy and capacity between DEP and Qualifying Facilities (both compliance and non-compliance) that expire within the planning period are handled. Are these PPAs considered renewed after their initial terms?

Response:

In general, compliance and non-compliance qualifying facilities are expected to expire when the purchase power agreement terminates. For planning purposes, QF PPAs are expected to be either renewed or replaced in kind. Importantly, however, there is no explicit or implicit assumption in the IRP of contract renewals with any given existing QF facility owner.