BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan	)))))))	DOCKET NO. E-100, SUB 179

DIRECT TESTIMONY AND EXHIBITS OF

DR. UDAY VARADARAJAN

ON BEHALF OF

NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, AND THE SIERRA CLUB

September 2, 2022

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EXHIBITS

I. Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Uday Varadarajan. My business address is 1111 Broadway, Oakland, CA 94607. I lead the Utility Transition Finance Group at RMI.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I received an AB in Physics from Princeton University and an MA and PhD in Physics from the University of California, Berkeley. After graduation, I was a postdoctoral fellow in theoretical physics in the Weinberg Theory Group at the University of Texas at Austin. I subsequently became an AAAS Science and Technology Policy Fellow at the U.S. Department of Energy (DOE) and was on detail to the staff of the U.S. House of Representatives, Appropriations Committee. I then served as a program examiner in the U.S. White House Office of Management and Budget (OMB), where I oversaw the budget for DOE energy efficiency and renewable energy programs and the cost assessment and approval of the first $8 billion in DOE loans to automakers, including loans to Tesla and Nissan to build electric vehicles. My resume is attached to this testimony as Exhibit UV-1.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I am a Principal at RMI's Carbon-Free Electricity practice and a Precourt Energy Scholar at Stanford University's Sustainable Finance Initiative

(SFI), conducting financial, policy, and regulatory analysis to help drive a just transition to clean energy. Before joining RMI and Stanford, I was a Principal at Climate Policy Initiative Energy Finance (CPI-EF), where I managed CPI-EF’s San Francisco team. At CPI-EF, I led the development of financial, regulatory, and policy data analytics and tools to help consumers, utilities, and communities in states across the United States (including New York, Colorado, Missouri, Minnesota, and Utah) realize the benefits of a just and equitable transition from uneconomic dirty resources to clean energy—with a focus on the potential benefits of ratepayer-backed bond securitization.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. At RMI, I lead the Utility Transition Finance group, a team of approximately 15 staff that performs financial, policy, and regulatory analysis to help drive a just transition to clean energy.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. No, I have not previously testified before the North Carolina Utilities Commission (hereafter, the Commission). I have testified before the Iowa Utilities Board (Docket RPU-2019-0001), the South Carolina Public Service Commission (Docket 2017-207-E, 9-24-2018 & 10-29-2018), the Minnesota Public Utilities Commission (Docket E015/GR-16-664, 05-31-2017 & 06-29-2017), and the Colorado Public Utilities Commission (Docket 16A-0231E, 10-3-2016 & 10-25-2016).

II. Purpose

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present and explain results of an analysis of the ratepayer impacts of Duke Energy's ("Duke") proposed Carbon Plan and to compare those ratepayer impacts to those found in the alternative portfolios modeled by Synapse. This analysis was conducted using Optimus, RMI's utility financial modeling tool, and was performed under my supervision by RMI staff. I will also offer my opinion on the potential impact of the Inflation Reduction Act (IRA) on the economics of North Carolina's energy transition.

III. Summary

Q. PLEASE SUMMARIZE THE KEY TAKEAWAYS OF YOUR TESTIMONY FOR THE COMMISSION.

A. RMI's analysis indicates that Duke's proposed Carbon Plan does not represent the least-cost path to North Carolina's carbon emission reduction requirements under H951. An alternative portfolio that invests more aggressively in the near term in energy efficiency and zero-emitting resources—such as solar, wind, and battery storage—would be cheaper for ratepayers and better insulate ratepayers from the cost impacts of future fuel price spikes as well as unexpected increases in electricity demand and from certain implementation effects of the multi-year rate plan (MYRP) provisions of H951.

Using Optimus, a modeling tool developed by RMI and described more fully in the reports submitted in this docket,[1] RMI analyzed two alternatives to Duke's proposed Carbon Plan (as emulated by Synapse Energy Economics in its "Duke Resources" scenario):

1) an "Optimized" scenario that modifies the characteristics of the Duke Resources portfolio to include annual incremental utility energy efficiency savings of 1.5% of total retail electricity sales, shorter gas plant book lives, external estimates for nuclear and gas capital costs, and National Renewable Energy Lab projections for renewables and battery storage costs; and
2) a "Regional Resources" scenario that is the same as the Optimized scenario except that it also allows EnCompass to select Midwest wind resources procured via power purchase agreements through the PJM Interconnection (PJM).

The key insights of this analysis are presented below:

1) The Optimized and Regional Resources scenarios are both more cost-effective than the Duke Resources scenario, driven by savings from avoided gas and nuclear investments.
2) Both alternatives to the Duke Resources scenario yield lower aggregate bills, with the Regional Resources scenario resulting in the greater bill reduction, even when disaggregated between DEC and DEP (the "Companies").
3) The Duke Resources scenario would exacerbate rate disparity between DEC and DEP customers, whereas the Optimized and Regional Resources scenarios would mitigate the rate disparity between the Companies and better distribute the ratepayer cost across the region.

[1] See RMI, "Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal," report Prepared for North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club (July 15, 2022); and Uday Varadarajan, *et al.* "Supplemental Report: Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal and Synapse's Alternative Scenarios," report Prepared for North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club (September 2, 2022), Attached as Exhibit UV-2.

4) The Duke Resources scenario is more vulnerable to execution risks, such as fuel price shocks, than the Optimized and Regional Resources scenarios.

IV. Discussion

b. *<u>Sub-issues under topic "Coal unit retirement schedule; securitization"</u>*

Q. WHAT ARE THE KEY FINDINGS IN RMI'S ANALYSIS REGARDING DUKE'S PROPOSED COAL UNIT RETIREMENT SCHEDULE AND PLANS FOR SECURITIZATION?

A. The Duke Resources scenario underutilizes securitization as a source of ratepayer relief to mitigate rate spikes from early retirement of coal. Securitization is a low-cost refinancing mechanism that yields savings for ratepayers when applied to larger unrecovered balances. The later a coal retirement occurs (assuming no further investment in the unit), the smaller the potential savings that can be derived from securitization. RMI estimates that the Duke Resources scenario would result in approximately $14.1 million in savings from securitization for ratepayers as a net present value (NPV) in 2022 dollars. For information purposes, RMI also modeled the securitization of 50% of all unrecovered balances following a retirement of all subcritical Duke coal plants at the end of 2022 and estimated an additional $446 million in savings (NPV, 2022 dollars) for ratepayers. From this perspective, the Duke Resources scenario captures only 3% of the ratepayer savings available from securitization under H951. To illustrate the magnitude of the potential for savings available with securitization, RMI also modeled a securitization scenario outside the limits of H951. If all unrecovered balances from all Duke coal plants, including the supercritical Cliffside 6 and the recently retired G.G.

Allen units, were securitized at the end of 2022, ratepayer savings from such a refinancing could reach $1.26 billion (NPV, 2022 dollars).

Q. HOW MIGHT THE RECENTLY PASSED IRA AFFECT THE ABILITY OF NORTH CAROLINA'S RATEPAYERS TO BENEFIT FROM LOW-COST REFINANCING OF THE UNDEPRECIATED BALANCE OF UNECONOMIC COAL PLANTS?

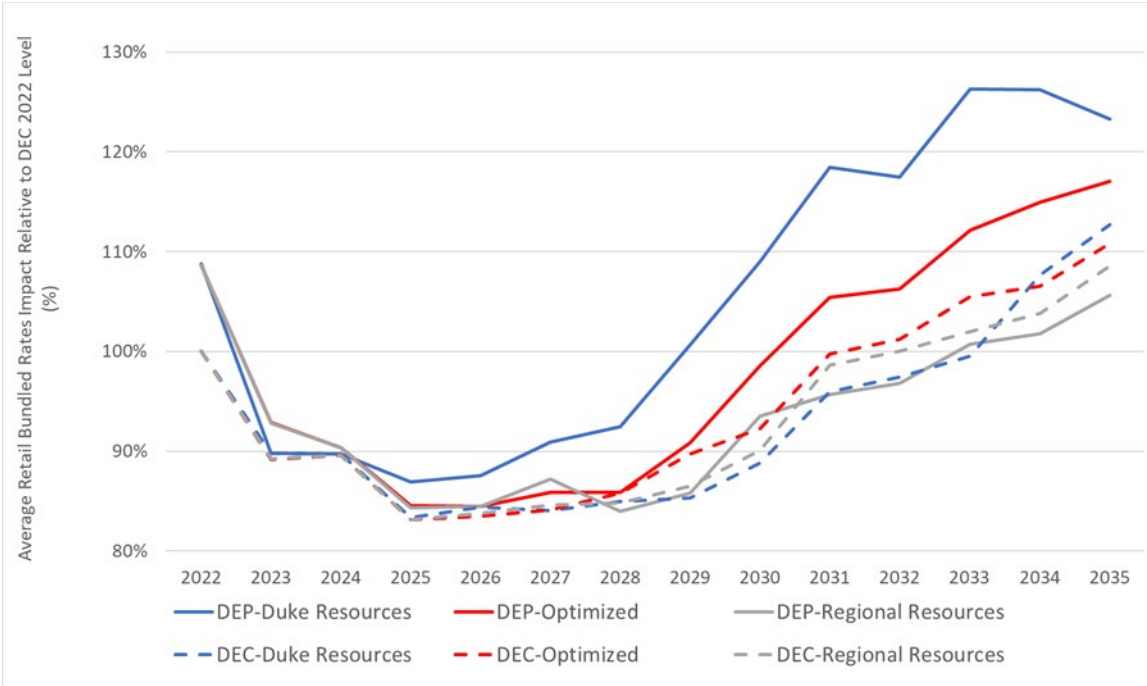
A. The IRA establishes a new Title 17 loan program at the U.S. Department of Energy known as Section 1706. The Section 1706 provision opens the way for low-cost financing for fossil asset transition without the restrictions on securitization in H951, in particular the 50% limit on retired plant balances eligible for securitization. With Section 1706, plant balances could be refinanced in full using debt backed by the guarantee of the federal government with interest rates similar to, and potentially lower than, those achievable with securitization, and over longer tenors (up to 30 years). As with securitization under H951, ratepayer savings under Section 1706 would tend to increase in line with the size of the plant balances refinanced and duration of the refinancing period, with earlier retirements yielding larger consumer benefits. Further, Section 1706 provides authority to extend the low-cost financing to environmental remediation, replacement with clean energy resources, and community reinvestment. This authority—which authorizes loan guarantees to support up to $250 billion in financing—could substantially reduce the cost of capital for more aggressive clean energy deployment scenarios, if utilized prior to its expiration toward the end of 2026.

g. *Sub-issues designated under the topic “Rate Disparity / Merger / State Alignment”*

Q. WHAT ARE THE KEY FINDINGS IN RMI’S ANALYSIS REGARDING DIFFERENT RATE IMPACTS FOR CUSTOMERS OF DEP AND DEC?

A. The overall rate impacts in 2030 relative to 2022 in the Duke Resources scenario show a similar level of disparity between DEC and DEP as that seen in Duke’s Carbon Plan analysis. DEP customers see a larger average rate impact in 2030 than DEC customers from the Duke Resources scenario across all customer classes. Duke’s proposed plan would thus significantly exacerbate rate disparity between DEC and DEP customers. In contrast, the Optimized and Regional Resources scenarios have lower rate and bill impacts across customer classes. Moreover, both scenarios significantly mitigate the rate disparity between DEC and DEP relative to the Duke Resources scenario. Therefore, the alternative scenarios help bridge the gap between the two utilities and better distribute the ratepayer cost across the region. Figure A below illustrates the rate disparity trends.

Figure A. Average Retail Bundled Rate Impact, DEP and DEP Respectively.



As explained more fully in the Supplemental Report,[2] the EnCompass modeling performed by Synapse of the Duke Resources, Optimized, and Regional Resources portfolios included the spike in natural gas prices that has occurred since the Russian invasion of Ukraine earlier this year. As a result, the Optimus model starts with higher retail bills across all scenarios (when compared to Duke's modeling[3]), which later drop as gas prices return to pre-invasion trends by 2025.

[2] Supplemental Report, p. 17; this explanation is consistent with results shown in RMI's first report. See Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal, p. 11.

[3] Duke, Carolinas Carbon Plan, Chapter 3 – Portfolios, Table 3-3: Summary of Portfolio Results, p. 20.

i. *<u>Sub-issues under the topic "Cost" and i(v) "Factual issues related to all-in total cost and rate impacts for customers"</u>*

Q. WHAT ARE THE KEY FINDINGS OF RMI'S ANALYSIS REGARDING "ALL-IN COST AND RATE IMPACTS FOR CUSTOMERS"?

A. Investments in new nuclear and gas units are the primary drivers of the total ratepayer cost increase in the Duke Resources scenario throughout the planning period. Near-term investment in gas capacity also exposes ratepayers to significant risk through investment in assets that will either need to be converted to hydrogen (at costs that are highly uncertain today as the technology has not yet been deployed at scale) or will be obsolete before they are fully depreciated.

The Optimized scenario yields lower aggregate bills for Duke's customers than the Duke Resources scenario. The savings are primarily driven by avoidance of new gas and nuclear buildout. Battery storage is the main driver of additional cost, but it is more than offset by the cost savings.

The Regional Resources scenario is even more cost-effective than the Optimized scenario relative to the Duke Resources scenario *in every single year*. Wind PPAs coupled with battery storage deployment are far more cost-effective than the fossil and nuclear investments made in the Duke Resources scenario.

k. *<u>Sub-issues under the topic "Execution Risks"</u>*

Q. CAN YOU ADDRESS THE LEVEL OF EXECUTION RISKS POSED BY THE VARIOUS SCENARIOS?

A. Compared with Optimized and Regional Resources scenarios, the Duke Resources scenario is more vulnerable to execution risks, including fuel price shocks, higher demand, and the implementation of H951's MYRP provisions.

Q. IN YOUR OPINION, WHAT IS THE MOST SIGNIFICANT EXECUTION RISK FOR THE CARBON PLAN?

A. Any resource scenario modeled under the policy framework that existed before the passage of the Inflation Reduction Act (IRA) on August 12, 2022, will not reflect the potential for enormous savings for North Carolina ratepayers from IRA policies. This is particularly true for portfolios that rely on new gas generation or keep coal plants running past their economically optimal retirement dates in place of non-carbon emitting resources such as solar, wind, and battery storage, which are all eligible for hundreds of billions of dollars in new and expanded federally funded incentives and key regulatory improvements (such as the provision for regulated utilities to opt-out of the requirement for tax normalization for ratemaking purposes of the Investment Tax Credit (ITC) for certain storage technologies, including battery storage). This new policy framework has the potential to radically alter the cost-effectiveness of clean resources, reduce the cost of retiring of fossil assets, and change incentives for ownership structures of clean resources.

Q. CAN YOU DESCRIBE IN MORE DETAIL THE MOST IMPORTANT PROVISIONS OF THE IRA DESIGNED TO INCENTIVIZE THE

DEPLOYMENT OF CLEAN ENERGY RESOURCES SUCH AS WIND, SOLAR AND BATTERY STORAGE?

A. Yes. The IRA includes approximately $370 billion in federal funding and tax benefits to advance climate and energy goals.[4] Foremost, the IRA provides a full decade (and, potentially, a longer period) of tax-credit certainty for solar, wind, and storage technologies. The existing 10-year Production Tax Credit (Section 45) is expanded to include solar as well as wind and extends credit eligibility at full value for projects deployed through the end of 2024. The existing Investment Tax Credit (Section 48) is continued at full value through the end of 2024 and now includes stand-alone energy storage projects. Notably, regulated public utilities may now opt-out of "tax normalization" of the ITC for ratemaking purposes, albeit for storage investments only, removing a federal legal barrier that has disadvantaged pricing (as flowed-through to customers) for utility-owned assets compared with technologically identical third-party-owned offerings. If newly implemented prevailing wage and apprenticeship "bonus" requirements are satisfied, the PTC for wind and solar is $26 per MWh (in 2022$), while the ITC is sized at 30% of project cost.

After 2022, an adder of 10% for the PTC and 10 percentage points for the ITC will apply if specific domestic materials requirements are met (phased in initially at 40%, though only 20% for offshore wind projects, and

[4] Committee for a Responsible Federal Budget, "What's In the Inflation Reduction Act?,"(12 August 2022), accessed on 17 August 2022 at https://www.crfb.org/blogs/whats-inflation-reduction-act.

rising to 55% for onshore projects beginning construction in 2027 or later and offshore projects beginning construction in 2028 or later). Relatedly, Section 50251(a) of the IRA authorizes the Secretary of the Interior to issue renewable energy leases, easements, and rights-of-way in areas of the outer continental shelf off the coast of North Carolina (and several other southeastern states) that were placed under a leasing moratorium by former President Trump for the period from July 1, 2022, through June 30, 2032.

The IRA also provides an ITC and PTC enhancement for projects placed in service within an "energy community" defined to include brownfield sites; a census tract or any adjacent census tract in which a coal mine has closed after 1999, or a coal-fired electric generating unit has been retired after 2009; and a metropolitan or nonmetropolitan statistical area that (1) at any time after 2009 has had at least 0.17% direct employment or 25% local tax revenues from the extraction, processing, transport, or storage of coal, oil, or natural gas and (2) had an unemployment rate at or above the national average for the previous year, in each case as determined by the Secretary. Assuming the prevailing wage and apprenticeship requirements are met, the amount of the base PTC is increased by 10% and the amount of any ITC is increased by 10 percentage points (or 2% and 2 percentage points, respectively, if the wage and apprenticeship requirements are not satisfied).

Since the bonuses and adders are stackable, a PTC project garnering them all would receive $31 per MWh (2022$) produced each year for ten years, while an ITC project would receive a 50% tax credit upon entering service.

Furthermore, the IRA addresses the issue of taxpayer "tax capacity" by allowing transferability, which will facilitate more cost-effective utilization of the expanded credits regime. Transferability—which allows taxpayers to sell their tax credits to an unrelated party—provides a more efficient way to monetize the present value of the tax credits. Prior to the enactment of the IRA, taxpayers without sufficient income-tax liability to self-monetize credits had to either (a) rely on expensive tax equity financing or (b) carry forward deferred tax assets on their own balance sheets with corresponding losses due to the time value of money. For tax exempt entities and Subtitle T electrical cooperatives, the IRA allows direct pay (cash refundability) of the credits.

For the period after 2024, the IRA creates a new technology-neutral 10-year clean energy PTC (Section 45Y) and maintains this credit in full for projects that begin construction by the later of either (a) 2032 or (b) the year that electric power sector emissions are equal to or less than 25% of 2022 electric power sector CO_2 emissions. A three-year phase-down of the credit level follows the relevant trigger year, with projects beginning construction in the first year of the phase-down period still eligible for 100% of the credit, which then reduces to 75% and 50% of full value over the next two years.

The bonus and adders are available as before. A new technology-neutral clean energy ITC (Section 48E) is also in the legislation with the same phase-down terms at the new PTC.

Combined with ITC eligibility for stand-alone energy storage projects and the normalization opt-out for ratemaking treatment of the storage ITC, these transferable credits will significantly reduce the costs of utility-supplied wind and solar energy, making these resources relatively more economic in the near and medium term. From 2025 onward, SMRs will also be eligible for the technology-neutral credits. But the future costs of mature technologies like wind and solar are reliably forecasted today, and credits will shift costs lower in predictable fashion. For still unseasoned technologies like SMRs, baseline asset costs and output levels for purposes of estimating the value of production credits are highly speculative.

Q: CAN YOU PROVIDE A TABLE SUMMARIZING TAX MEASURES UNDER THE IRA COMPARING THEM WITH THE POLICY LANDSCAPE BEFORE THE PASSAGE OF THIS IMPORTANT LEGISLATION?

A. Yes. The Table A below offers such a summary and comparison.

Table A. Comparison of Key Elements of Policy Environment before and after passage of the IRA

Policy	Pre-IRA	IRA
Production Tax Credit (PTC) for solar	Not available	Yes
Availability of PTC	Beginning of construction by end of 2021, with 4-year safe harbor for completion by end of 2025 (10-year safe harbor for offshore wind)	Beginning of construction in 2032 (or later if emissions reduction targets not achieved), followed by three-year phase-down of credit level
Duration of Investment Tax Credit (ITC)	For onshore wind: beginning of construction by end of 2021, with safe harbor for completion by end of 2025 For offshore wind: beginning of construction by end of 2025 For solar: placed in service by the end of 2025 to receive more than credit of 10% available without sunset	Beginning of construction in 2032 (or later if emissions reduction targets not achieved), followed by three-year phase-down of credit level
PTC level for wind and solar	For wind: phase-downs for projects begun after 2016, for instance 60% of full credit for projects begun in 2020 and 2021. For solar: not available	$26 per MWh (2022$) for ten years (inflation adjusted), if wage and apprenticeship requirements met
ITC level for wind and solar	For onshore wind: phase-downs for projects begun after 2016, for instance 60% of full credit for projects begun in 2020 and 2021 For offshore wind: 30% for projects that begin construction by the end of 2025 For solar: 26% for project that began construction in 2020, 2021 or 2022, and	30%, if wage and apprenticeship requirements met

	22% for projects starting construction in 2023. Projects must be placed in service by the end of 2025 to receive a credit higher than 10%	
ITC level for stand-alone storage	Not available	30%
Domestic content adders (may be stacked on top of PTC or ITC)	Not available	Up to 10% for PTC or 10 percentage points for ITC
"Energy Communities" adders (may be stacked on top of PTC or ITC)	Not available	Up to 10% for PTC or 10 percentage points for ITC
Low-income ITC adders for solar and wind (may be stacked on top of ITC)	Not available	Up to 20% for eligible installations of 5 MW in size or smaller, subject to annual nationwide 1.8 GW capacity cap
Direct pay of PTC and ITC for tax-exempt entities and all rural electricity co-ops and transferability of these credits for taxpayers	Not available	Yes
Normalization opt-out for storage ITC	Not available	Yes
Carbon capture and storage (45Q)	$50 per metric ton for sequestered CO_2, a level to be attained by 2026, available for 12 years, inflation adjusted. Projects must begin construction by end of 2025	$85 per metric ton for sequestered CO_2 if wage and apprenticeship requirements are met, a level to be attained by 2026, available for 12 years, inflation adjusted; projects must begin construction by end of 2032
Existing nuclear (45U)	Not available	With wage and apprenticeship requirements met, $15 per MWh, but is reduced when average annual price exceeds $25 per MWh; available through 2032

Clean hydrogen (45V)	Not available	Maximum $3 per kg (2022$), available for 10 years, inflation adjusted. May be combined with PTC for wind and solar and 45U for existing nuclear
Securitization and low-cost refinancing	NC H951 allows for securitization of 50% of retirement balances of subcritical coal plants	Federally backed refinancing for fossil assets (no balance limitation), replacement with clean resources, environmental remediation, and community reinvestment under Section 1706

Q: HOW MIGHT THE IRA IMPACT NORTH CAROLINA'S TRANSITION TO CLEAN ENERGY?

A: In my opinion, any future resource portfolio developed for North Carolina ratepayers using clean energy asset costs estimated without considering the IRA's provisions should be reevaluated to see if reliable transition pathways that are both cheaper and cleaner are feasible. I wish to emphasize that the IRA's provisions are designed to impact not only investment decisions later in this decade, but ones that are of pressing urgency today. Without considering the wide-ranging impacts of the IRA, the Commission risks selecting a near-term strategy for reaching the statutory carbon requirements that locks in extra costs for ratepayers and leaves savings opportunities untapped. As a result of the passage of the IRA, portfolios that rely in the short to medium term on new gas plants or on extending the operation of coal plants are going to be even more costly in comparison to portfolios that rely more heavily on efficiency, solar, battery storage, and wind.

Q. DID YOU IDENTIFY ANY HEIGHTENED EXECUTION RISKS ASSOCIATED WITH DUKE'S PROPOSED CARBON PLAN BEFORE THE IRA WAS PASSED AND WHICH ARE NOT DEPENDENT ON THAT LEGISLATION'S NEW AND EXPANDED INCENTIVES FOR CLEAN ENERGY TECHNOLOGIES?

A. Yes. Compared with the Duke Resources scenario, the Optimized and Regional Resources scenarios help to:

- insulate ratepayers from the risks of fuel price shocks.
- mitigate the cost risks to customers from inadequate system planning for the impacts of a rapidly electrifying economy.

Q. DO MYRPS AFFECT EXECUTION RISK?

A. The implementation of MYRPs and revenue decoupling for the residential class as specified by H951 would exacerbate the rate impact of higher-than-expected demand and fuel prices relative to a scenario without these mechanisms in place. In all scenarios, the MYRPs in N.C. Gen. Stat. § 62-133.16 result in higher average bills for ratepayers; however, the cleaner and lower-cost Optimized and Regional Resources scenarios better mitigate some of the bill increases.

Q. WHAT ARE RMI'S RECOMMENDATIONS FOR THE CURRENT CARBON PLAN PROCESS TO MITIGATE EXECUTION RISK ASSOCIATED WITH FUEL PRICE SHOCKS, HIGHER DEMAND, AND THE APPLICATION OF PERFORMANCE-BASED REGULATION?

A. RMI recommends that the Commission take under consideration before determining North Carolina's Carbon Plan:

1) the potential recurrence of destabilizing macro-economic and socio-political disruptions, such as those that the global economy has experienced in the last two years, and the downstream impacts these events may pose to ratepayers - collectively, and by class - under various Carbon Plan

proposals (e.g., the risks associated with increasing and potential volatile fuel costs, and uncertain fuel availability);

2) the potential impacts on the distribution of benefits and risks that are associated with forthcoming coming regulatory changes (e.g., PBR) in combination with each portfolio; and

3) the impact of a fully economic coal retirement schedule (such as a scenario that allows EnCompass to select the economic retirements without exogenous limitations) inclusive of and considering the associated benefits of securitization and other refinancing tools that are available under the IRA.

Q. WHAT ARE RMI'S RECOMMENDATIONS FOR THE CURRENT CARBON PLAN PROCESS TO MITIGATE EXECUTION RISK ASSOCIATED SPECIFICALLY WITH THE IRA?

A. To recapitulate, the passage of the IRA will significantly alter the cost of many clean energy technologies, making them far cheaper over the coming decade than was assumed in capacity expansion and production cost modeling conducted for the current Carbon Plan. For instance:

- the resource costs of solar, batteries, and wind will all be significantly lower with the extension and broadening of ITC and PTC;
- the availability of a solar PTC, which is not subject to tax normalization, and the normalization opt-out for the storage ITC, will increase the price competitiveness from a ratepayer perspective of utility-owned solar and storage assets relative to third-party owned assets;
- hydrogen production costs will be lower as a result of the Section 45V tax credits and, moreover, tax benefits will be greater for hydrogen that is produced with lower or zero lifecycle carbon emissions;
- EV costs and the costs of electrifying home space and water heating will be lower, which will impact load assumptions; and
- Section 1706 provides the potential for low-cost financing to reduce the rate impact of accelerated phase-out and replacement of fossil assets beyond the limitation of NC H951.

All of these changes impact the economics of resource selection, and consequently, the timing of CO2 reduction target feasibility. If production cost modeling were to be run today with the realities of the IRA reflected, scenarios with larger and more rapid deployment of mature clean energy resources than those currently before the Commission would likely be "least cost." The game-changing incentives of the IRA come into effect rapidly, and indeed, the critical changes for wind, solar, and battery are available today. Given this new policy reality, the IRA is of extreme relevance for near-term investment decisions and should be assessed accordingly for potential benefits that might accrue to North Carolina ratepayers and other stakeholders. The Commission should take whatever steps it can to ensure that Duke's near-term actions under the ultimate Carbon Plan reflect a no-regrets strategy from the perspective of the policies in the IRA.

Absent an effort to perform additional capacity expansion and production cost modeling in the near-term, any resource decisions, near-term execution plans, and relevant resource planning activity that occurs after the September 2022 Carbon Plan evidentiary hearing (including but not limited to the Commission's decision on the Carbon Plan and short-term execution plan, adjustments to the Carbon Plan, MYRP applications, and proceedings related to certification of public convenience and necessity) should include an analysis of the full scope of the IRA cost implications.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Dr. Uday Varadarajan on behalf of North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 2nd day of September, 2022.

s/ David L. Neal

David L. Neal

Dr. Uday Varadarajan, Ph.D.

Uday is a Principal in the Carbon-Free Electricity Practice at RMI and a Precourt Energy Scholar at the Sustainable Finance Initiative (SFI) at Stanford University, where he applies cutting edge data and analytics to develop new approaches to achieve an affordable and fair transition to zero-carbon energy system. His team's work pioneering the use of ratepayer-backed bond securitization to help make accelerated coal retirement more affordable and just has helped catalyze: $1.2 billion in four new coal transition transactions in the US, passage of enabling legislation in seven additional states, and the development of proposed national and international vehicles to scale the approach. Prior to moving to RMI and SFI, Uday was a Principal at Climate Policy Initiative (CPI) Energy Finance, managing their San Francisco team. At CPI, he led the development of innovative financial, regulatory, and policy data analytics and tools that are helping consumers, utilities, and communities in states across the US (including New York, Colorado, Missouri, Minnesota, Utah, and South Carolina) realize the benefits from a just and equitable transition from uneconomic dirty resources to clean energy. Prior to joining CPI, Uday was a program examiner in the U.S. White House Office of Management and Budget (OMB), where oversaw the $2 billion budget for U.S. Department of Energy (DOE) energy efficiency and renewable energy programs and the cost assessment and approval of the first $8 billion in DOE loans to automakers, including loans to Tesla and Nissan to build electric vehicles. Prior to joining OMB, Uday was a AAAS Science and Technology Policy Fellow, working first as an advisor on carbon sequestration programs and then on detail to the staff of the U.S. House of Representatives, Appropriations Committee. Prior to coming to Washington, Uday was a postdoctoral fellow in theoretical physics at the University of Texas at Austin. He received his Ph.D. in physics from the University of California at Berkeley, and his undergraduate degree in physics from Princeton University.

EXPERIENCE

Sustainable Finance Initiative at Stanford University — **July 2018 – Present**
Precourt Energy Scholar — *San Francisco*

Rocky Mountain Institute — **July 2018 – Present**
Principal — *San Francisco*

I lead the Utility Transition Financing team in the Carbon-Free Electricity Practice at RMI, and work with students, faculty, and staff at Stanford's Sustainable Finance Initiative on funding a just transition in the US through financial markets. The broad theme underlying all of my work is around how to use cutting edge data and financial, policy, and regulatory analysis to help drive an equitable and just transition to clean energy. This has included:

- Development of the Utility Transition Hub, a tool aimed at key utility stakeholders to help them chart a path to an equitable and affordable energy transition by surface and manage the less visible forces that drive future emissions outcomes in the electricity sector.
- Publication of *How to Retire Early* and *Financing the Coal Transition*, a plant-by-plant analysis of the global coal fleet that demonstrated that while in theory nearly 40% of coal generation could be economically phased out and replaced with clean energy with storage – and a detailed discussion of how financial tools such as securitization were necessary to avoid inequitable transition burdens on coal customers, workers, and communities for over 90% of that fleet.
- Development of a new approach to carbon pricing that uses carrots rather than sticks to align the incentives of carbon intensive industries, workers, and energy customers with rapid decarbonization as a key element of a sustainable recovery from the COVID crisis.

- Testimony and reports filed in Iowa, Minnesota, Colorado, and South Carolina describing how new utility financing and business models can align customer and utility investor interests with accelerated decarbonization.
- Providing analysis and thought leadership around the use of securitization to help finance a just transition from fossil generation to clean energy in regulated utilities across the US. This ongoing work has inspired the passage of securitization bills by legislatures in seven states (CO, NM, MT, KS, MO, IN, MN), the use of existing securitization bills to mitigate the rate impact of $1.5 billion of capital costs of retired coal assets in three states (WI, NM - including $40 million in just transition financing, MI), the introduction of securitization bills in two other states (SC, UT) and utility and stakeholder engagement towards action in several additional states (AZ, NC, FL, VA, KY, WV).

Climate Policy Initiative **2010 – July 2018**
Principal *San Francisco*

I led a team of five consultants and analysts based in San Francisco focused on developing innovative financial, policy, regulatory, and business structures to catalyse the efficient transition to clean energy resources.

- **Leading CPI Energy Finance's US Utility Capital Recycling program**, a $1.1 million effort in partnership with advocates and other stakeholders in four states, supported by nearly a dozen non-profit and governmental entities aimed at developing and deploying regulatory, financial, and policy tools (such as ratepayer-backed bond securitization) to recycle regulated utility capital locked up in expensive dirty plants into cheaper, cleaner generation. Regulatory and legislative action inspired in part by this work is underway in Colorado, Minnesota, Missouri, New Mexico, and Utah. The program has received support from TomKat Foundation ($150k), Heising Simons Foundation ($445k), Hewlett Foundation ($100k), Energy Foundation ($240k), McKnight Foundation ($48k), National Resources Defense Council ($64k), Minnesota Clean Energy Advocates ($20k), Western Resource Advocates ($20k), HEAL Utah and three Utah municipalities ($37k).
- **Leading an engagement with NYSERDA to efficiently transition to clean energy,** $200k in consulting to provide detailed financial and economic modeling to support the design of: mechanisms to procure over 700MW of oshore wind by 2022 and 2.4 GW of offshore wind by 2030, NY Green Bank loans to community PV projects, and development of a roadmap to deploy 1.5GW of storage by 2025.
- **Led the development of the Clean Energy Investment Trust (CEIT)**, a financial vehicle for renewable investment designed to address the shortcomings of the the YieldCo business model. This new, low-cost investment vehicle for long-term ownership of renewable assets was designed based on rigorous statistical analysis of historical risks and cash flows of modern North American wind farms to optimally address the barriers to institutional invesment in renewable energy.
- **Led a team to develop a vision for the transition to low-carbon electricity** under a $75k contract for Swedish Growth Analysis, resulting in a report discussing potential shifts in policies, market structures, and business models needed to cost-effectively drive a transition to a low-carbon electricity grid dominated by variable generation sources.
- **Developed key project and portfolio financial analysis tools** to assess the impact of new policy support structures, regulatory mechanisms, market structures, and business models (such as YieldCos and Master Limited Partnerships) on the cost of capital for renewable energy in the U.S. and E.U.
- **Developed a proposal to reform US tax credits** that would reduce their cost to government by 40% while providing the same level of benefit to wind developers and investors.

Executive Office of the President, Office of Management and Budget (OMB) **2008 – 2010**
Program Examiner in the Energy Branch *Washington, DC*

I was responsible for reviewing the Department of Energy's Office of Energy Efficiency and Renewable Energy's (EERE) budget submission to OMB and providing my recommendation to OMB's leadership regarding their funding for inclusion in the President's annual budget submission to Congress. I was also the examiner responsible for oversight of the Advanced Technology Vehicles Manufacturing Loan Program (ATVM).

- **Lead for OMB approval process for ATVM Loans to Nissan, Tesla, Ford, and Fisker –** As the first examiner for the ATVM program, I worked with DOE to develop and approve the credit subsidy model for the program, as required by the Federal Credit Reform Act. This model is being used to estimate the cost to the government of providing up to $25 billion in Federal direct loans to auto manufacturers. Worked with DOE to review and approve the subsidy cost for $8.4 billion in loans to Nissan, Tesla, Ford, and Fisker. Received an OMB division-level award for my work on this model and the program.
- **Supported OMB approval process for DOE Loan Guarantees –** Supported OMB review and assessment of cost to government of several loan guarantees made by the U.S. DOE Title XVII Loan Program, including loans to Solyndra, First Wind, Shepherd's Flat Wind, Abengoa's Solana CSP, and Ivanpah CSP.
- **Supported Obama transition team energy proposal development –** Worked with the Presidential Transition Team, providing analysis to inform their submissions to Congress regarding renewable energy and energy efficiency items for inclusion in the American Re-investment and Recovery Act
- **Oversaw OMB review of plans for $16.8 billion in Recovery Act EE and RE spending –** Subsequent to the passage of the Recovery Act, worked with EERE to review and approve their detailed project and program plans for nearly $16.8 billion in renewable energy and energy efficiency spending.
- **Developed energy tax incentive models to support budget development –** Worked with other examiners to use EIA data to model the impact of Federal tax incentives and loan programs on the cost of electricity from various sources to inform budget decision-making.
- **Worked with DOE to develop President's Budget for EE and RE for FY 2010 and 2011 –** Reviewed the FY 2010 and FY 2011 EERE budget submissions, and worked with DOE to review and approve their budget justifications to Congress. Continue to work with EERE to track program performance and execution in support of the Administration's energy policy objectives.

AAAS Science and Technology Policy Fellowship **2006-2008**
Fellow *Washington, DC*

2008: I was sent on detail from the Department of Energy (DOE) to the Majority Staff of the Committee on Appropriations, House of Representatives, Subcommittee on Energy and Water Development, where I supported development of the appropriations bill to fund the Department of Energy.

- I provided the Subcommittee with input, analysis, and advice in support of crafting the Committee's FY 2009 Energy and Water Appropriations bill and committee report, which fund the Department of Energy and other agencies. My primary responsibility was to address issues relevant to the DOE Office of Science, and serve as support on issues relevant to the DOE Fossil Energy, Energy Efficiency and Renewable Energy, and Energy Transmission and Distribution programs.
- Built an Access database, forms, and reports to allow quick & easy access to the Congressional requests made to the Subcommittee by the 435 members of the House of Representatives regarding the bill and used the database to analyze these requests and support decision-making.

2006-2008: I advised the Under Secretary on science issues relevant to the applied energy technology programs, particularly the fossil energy program and the scientific issues surrounding carbon dioxide capture and sequestration.

- **Lead for DOE basic and applied R&D coordination review –** Played a leading role in a review of the DOE R&D portfolio which resulted in the identification of six key opportunities for accelerating innovation through better coordination of R&D budgets in the basic and applied science and technology programs across the department. The President's FY 2009 budget funded requests across the department identified by our analysis as relevant to these six opportunities and presented integrated budgets for these areas for the first time.
- **Developed action plan for integrated basic and applied carbon storage R&D plan –** Led the creation of an action plan to implement an integrated basic and applied science program in support of the geological storage of carbon dioxide emissions from coal power plants. Worked with science and technology program staff to begin the implementation of this plan
- **Led development of a new DOE High Energy Physics website –** Leading the creation of a new web page for the Office of High Energy Physics at DOE, as well as a public outreach web portal for the field of high energy physics.
- **DOE lead staff for high energy density physics report –** Was the lead support staff in editing, producing, and rolling-out the Report of the Interagency Task Force on High Energy Density Physics, outlining a Federal strategy to support this emerging field of science with promising applications to fusion energy.

String Theory and Theoretical High Energy Physics **2001-2006**
Graduate Researcher and Post-Doctoral Fellow *Berkeley, CA and Austin, TX*

I was a postdoctoral fellow in the Weinberg Theory Group at UT Austin from 2003-2006, and before that, a graduate researcher in the Physics Division of Lawrence Berkeley Labs from 2001-2003. I worked on a range of topics within String Theory, a candidate "theory of everything". For instance, with Prof. Horava and collaborators, we suggested that a novel feature of string theory (holography) may exclude the possibility of time travel (for a popular account, see The New Scientist, Sep 20th, 2003, p.28).

Experimental Condensed Matter Physics - Carbon Nanotubes **1997-1999**
Graduate Researcher *Berkeley, CA*

I was a graduate researcher in the Material Science Division of LBNL, where I synthesized carbon nanotubes (long, thin tubes - just nanometers in diameter- each made up of a single, one atom thick layer of graphite). I also worked to characterize the materials at the National Center for Electron Microscopy and Berkeley Microlab using TEM, SEM, and AFM techniques. I further explored the electronic properties of tangles of tubes as well as individual tubes using nanodevices we fabricated using electron-beam lithography.

Other Physics Research (Princeton Undergraduate) **1993-1996**
Undergraduate Researcher *Princeton, NJ*

- **Biophysics:** Senior Thesis w/ C. Callan - a model for DNA stretching. (1995-1996)
- **High Energy Experiment:** Simulation of a HERA-B pretrigger. (Summer 1995)
- **Plasma Physics:** DOE Fellowship at PPPL - numerical Poisson Solver.(Summer 1994)
- **Nuclear Physics:** Simulation of the Borexino Neutrino Detector. (1993-1994)

EDUCATION

University of California at Berkeley **2003**
Ph.D., Physics *Berkeley, CA*

- Advisor: Bruno Zumino
- Dissertation: "Geometry, Topology and String Theory"

University of California at Berkeley **1998**
M.A., Physics *Berkeley, CA*

- Advisor: Alex Zettl
- Focus: Synthesis and Characterization of Carbon Nanotubes

Princeton University **1996**
A.B. (Magna Cum Laude), Physics *Berkeley, California*

- Certificates in Mathematical Physics and Engineering Physics (1996)
- Thesis Advisor: Curtis G. Callan
- Senior Thesis: "The Role of Solitons in the Overstretching of B-DNA"
- Allen G. Shenstone Prize in Physics, Princeton University (1996)
- Kusaka Memorial Prize in Physics, Princeton University (1995)

OTHER

Foreign Languages

Spanish (competent), Tamil (basic).

Computer Skills

Office Software: MS Office (Access, Excel, Word, Powerpoint), Google Docs, Sheets, and Forms.

Programming Languages: Python, Excel and Access VBA, SQL, Google Apps Script, Java, C, C++, Pascal, Fortran, HTML, SPARC Assembly.

Mathematical Packages: Numpy, Stata, R, Mathematica, Maple.

Docket No. E-100, Sub 179
Exhibit UV-2

Supplemental Report:

Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal and Synapse's Alternative Scenarios

Prepared for North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club

September 2, 2022

Authors: Uday Varadarajan, Diego Angel, Jacob Becker, Rachel Gold, Becky Li, David Posner, Jeffrey Sward, and Gennelle Wilson

RMI

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Executive Summary

In this report, RMI compares the ratepayer financial impacts of Duke Energy's proposed Carbon Plan with the scenarios modeled by Synapse Energy Economics (Synapse) in its report *Carbon-Free by 2050; Pathways to Achieving North Carolina's Power Sector Carbon Requirements At Least Cost to Ratepayers*. It will be critical for the North Carolina Utilities Commission to consider the ratepayer impacts of various carbon plan scenarios as it charts the least-cost path toward meeting or exceeding the statutory requirements of 70% carbon dioxide emission reduction from 2005 levels by 2030 and carbon neutrality by 2050.

RMI used its utility financial modeling software, Optimus, to analyze the ratepayer impacts of Duke Energy's "Portfolio 1 – Alternate" scenario, as modeled by Synapse ("Duke Resources"), both with and without RMI-designed fuel price and load sensitivities. RMI similarly analyzed the scenarios developed by Synapse—Optimized and Regional Resources—for comparison. The key insights of this analysis are presented below:

1. The Optimized and Regional Resources scenarios are both more cost-effective than the Duke Resources scenario, driven by savings from avoided gas and nuclear investments.
2. Both alternatives to the Duke Resources scenario yield lower aggregate bills, with the Regional Resources scenario resulting in the greater bill reduction, even when disaggregated between DEC and DEP (the "Companies").
3. The Duke Resources scenario would exacerbate rate disparity between DEC and DEP customers, whereas the Optimized and Regional Resources scenarios would mitigate the rate disparity between the Companies and better distribute the ratepayer cost across the region.
4. The Duke Resources scenario is more vulnerable to execution risks, such as fuel price shocks, than the Optimized and Regional Resources scenarios.

RMI's Optimus results indicate that:

- ◊ **Duke Energy's proposed Carbon Plan does not represent the least-cost path to North Carolina's emission reduction requirements.**
- ◊ **A portfolio that invests more aggressively in the near term in energy efficiency and zero-emitting resources—such as solar, wind, and battery storage—will better insulate ratepayers from the potential cost impacts of future fuel price spikes, performance-based regulation, and a future in which electricity demand is higher than anticipated.**

However, the recently passed Inflation Reduction Act (IRA) has immediate and far-reaching consequences for the least-cost path toward North Carolina's carbon reduction requirements. The magnitude of the IRA—$370 billion in federal funding designed to deliver unprecedented cost savings for ratepayers while offering large-scale transition assistance for fossil energy workers and communities—has major implications for the results of capacity expansion and production cost modeling carried out before the legislation's passage. The IRA's tax credits and other provisions for wind, solar, and storage will bring down the costs of these market-ready and already cost-competitive resources, further reducing the cost of modeled portfolios that rely on clean energy resources relative to portfolios that include new gas and keep coal plants running past their economically optimal retirement dates. **If the IRA is not accounted for, North Carolina is at risk of selecting a near-term strategy for reaching the statutory carbon requirements that locks in extra costs for ratepayers and leaves savings opportunities untapped.**

RMI recommends that any resource decisions, near-term execution plans, and relevant resource planning activity that occurs after the September 2022 Carbon Plan evidentiary hearing (including but not limited to adjustments to the Commission's decision on the Carbon Plan and short-term execution plan, adjustments to the Carbon Plan, MYRP applications, and proceedings related to certification of public convenience and necessity) should include an analysis of the full scope of the IRA's cost implications.

Introduction

On July 15, 2022, the North Carolina Sustainable Energy Association ("NCSEA"), Southern Alliance for Clean Energy ("SACE"), Sierra Club and the Natural Resources Defense Council ("NRDC") filed a report authored by RMI: ***Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal*** ("RMI's first report").[1] In that report, RMI presented the results of an analysis of the ratepayer impacts of Duke Energy's ("Duke") proposed Carbon Plan Portfolio 1-alternate ("P1-alt" or "Duke Resources" as modeled in EnCompass by Synapse) using RMI's utility financial modeling tool, Optimus.[2]

In this supplemental report, RMI presents the results of a similar analysis that uses the EnCompass modeling results presented in the Synapse Energy Economics ("Synapse") report ***Carbon Free by 2050: Pathways to Achieving North Carolina's Power Sector Carbon Requirements at least cost to Ratepayers*** as inputs to the Optimus model.[3]

As with the first report, the purpose of this supplemental report is to inform the efforts of the North Carolina Utilities Commission (NCUC) in fulfillment of H951 directives, specifically to "take all reasonable steps to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO2) emitted in the State from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030 and carbon neutrality by the year 2050."[4] Building on the insights in RMI's first report and Synapse's report, this supplement evaluates the distributional economic impacts of Synapse's Optimized and Regional Resources scenarios in comparison with the Duke Resources scenario, a representation of Duke's proposed P1-alt scenario as modeled in EnCompass by Synapse.[5]

Consistent with RMI's first report, RMI strives to consider and incorporate local, national, and global developments that may affect the cost of the decarbonization of North Carolina's power sector into this supplemental report. Since NC stakeholders submitted their proposed Carbon Plans this summer, new federal policy with far reaching and profound economic implications for the determination of a least-cost path to North Carolina's statutory emission reduction requirements has become law. Though there was insufficient time to calculate the impacts of the Inflation Reduction Act (IRA) for this report, RMI is convinced of the need to estimate and include the cost implications of this policy into near-term action plans and decisions, above all to avoid locking in unnecessary costs for ratepayers.

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[1] Docket E-100 Sub 179. Joint Comments of the NCSEA, SACE, Sierra Club and NRDC, Exhibit 1.

[2] *See* Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal, p. 1 for more information about Optimus.

[3] Docket E-100 Sub 179. Supplemental Joint Comments of NCSEA, SACE, Sierra Club and NRDC (July 20, 2022).

[4] North Carolina General Assembly, Session 2021, Session Law 2021-165, House Bill 951, p. 1.

[5] To ensure that this report is streamlined and focused primarily on analytical findings, RMI will reference sections and page numbers from its first report as much as possible where the narrative remains consistent with the supplemental report.

In light of the IRA's importance, RMI begins this report with a qualitative discussion of the legislation's potential implications for North Carolina's Carbon Plan and implementation efforts. The subsequent section briefly reiterates RMI's methodology and outlines the revised scope of this supplemental report. This is followed by a discussion of the findings of the Optimus analysis. The report concludes by addressing the implications of the findings and presenting RMI's recommendations to the Commission.

The Inflation Reduction Act—a "game changer" for North Carolina's economic and equitable transition to clean energy

The Inflation Reduction Act (IRA) enacted on August 12, 2022, includes approximately $370 billion in federal funding and tax benefits to advance climate and energy goals.[6] The legislation significantly expands federal tax credits for wind, solar, and battery storage in size, duration, and flexibility. Notably, the credits now include optional bonuses and adders that can be stacked to increase the total value of the federal incentive available when investments address the needs of workers (by satisfying prevailing wage and apprenticeship requirements), US businesses (by means of domestic content thresholds), and environmental justice (by locating in prescribed "energy communities"). For emerging technologies like hydrogen there are new tax credits designed to accelerate the timeline to achieving scale. The IRA also funds up to $250 billion in low-interest, federal financing to reduce the rate burden of fossil asset retirements, replacement clean resources, and environmental remediation, as well as support community reinvestment.

Given the IRA's immediate implications for the costs of the clean technologies that will shape the clean transition of North Carolina's power sector, it is a significant execution risk to rely solely on the results of capacity expansion and production cost modeling that do not capitalize on the legislation's effects on lowering costs for solar, wind, and storage, even with regard to short-term action plans. By the same token, the results of modeling that rely heavily on new gas resources or on extending the life of coal plants will need to be reconsidered in light of the IRA.

Table A. Comparison of Key Elements of Policy Environment before and after passage of the IRA

Policy	Pre-IRA	IRA
Production Tax Credit (PTC) for solar	Not available	Yes
Availability of PTC	Beginning of construction by end of 2021, with 4-year safe harbor for completion by end of 2025 (10-year safe harbor for offshore wind)	Beginning of construction in 2032 (or later if emissions reduction targets not achieved), followed by three-year phase-down of credit level
Availability of Investment Tax Credit (ITC)	<u>For onshore wind</u>: beginning of construction by end of 2021, with safe harbor for completion by end of 2025 <u>For offshore wind</u>: beginning of construction by end of 2025	Beginning of construction in 2032 (or later if emissions reduction targets not achieved), followed by three-year phase-down of credit level

[6] Committee for a Responsible Federal Budget, "What's In the Inflation Reduction Act?,"(12 August 2022), accessed on 17 August 2022 at https://www.crfb.org/blogs/whats-inflation-reduction-act.

Policy	Pre-IRA	IRA
	For solar: placed in service by the end of 2025 to receive more than credit of 10% available without sunset	
PTC level for wind and solar	For wind: phase-downs for projects begun after 2016, for instance 60% of full credit for projects begun in 2020 and 2021. For solar: not available	$26 per MWh (2022$) for ten years (inflation adjusted), if wage and apprenticeship requirements met
ITC level for wind and solar	For onshore wind: phase-downs for projects begun after 2016, for instance 60% of full credit for projects begun in 2020 and 2021 For offshore wind: 30% for projects that begin construction by the end of 2025 For solar: 26% for project that began construction in 2020, 2021 or 2022, and 22% for projects starting construction in 2023. Projects must be placed in service by the end of 2025 to receive a credit higher than 10%	30%, if wage and apprenticeship requirements met
ITC level for stand-alone storage	Not available	30%
Domestic content adders (may be stacked on top of PTC or ITC)	Not available	Up to 10% for PTC or 10 percentage points for ITC
"Energy Communities" adders (may be stacked on top of PTC or ITC)	Not available	Up to 10% for PTC or 10 percentage points for ITC
Low-income ITC adders for solar and wind (may be stacked on top of ITC)	Not available	Up to 20% for eligible installations of 5 MW in size or smaller, subject to annual

Policy	Pre-IRA	IRA
		nationwide 1.8 GW capacity cap
Direct pay of PTC and ITC for tax-exempt entities and all rural electricity co-ops and transferability of these credits for taxpayers	Not available	Yes
Normalization opt-out for storage ITC	Not available	Yes
Carbon capture and sequestration (45Q)	\$50 per metric ton for sequestered CO2, a level to be attained by 2026, available for 12 years, inflation adjusted. Projects must begin construction by end of 2025	\$85 per metric ton for sequestered CO2 if wage and apprenticeship requirements are met, a level to be attained by 2026, available for 12 years, inflation adjusted; projects must begin construction by end of 2032
Existing nuclear (45U)	Not available	With wage and apprenticeship requirements met, \$15 per MWh, but is reduced when average annual price exceeds \$25 per MWh; available through 2032
Clean hydrogen (45V)	Not available	Maximum \$3 per kg (2022\$), available for 10 years, inflation adjusted. May be combined with PTC for wind and solar and 45U for existing nuclear
Securitization and low-cost DOE refinancing	NC H951 allows for securitization of 50% of retirement balances of subcritical coal plants	Federally backed refinancing for fossil assets (no balance limitation), replacement with clean resources, environmental remediation, and community reinvestment under Section 1706

Wind, Solar, and Batteries

The IRA provides a full decade (and, potentially, a longer period) of tax credit certainty for solar, wind, and storage technologies. The existing 10-year Production Tax Credit previously available for wind (Section 45 of the Internal Revenue Code) is expanded to include solar and extends credit eligibility at full value for projects deployed through the end of 2024. The existing Investment Tax Credit (Section 48) is continued at full value through the end of 2024 and newly applies to stand-alone energy storage projects. Significantly, regulated public utilities may now opt-out of "tax normalization" of the ITC for ratemaking purposes, albeit for storage investments only, removing a federal legal barrier that has disadvantaged pricing (as flowed-through to customers) for utility-owned assets compared with technologically identical third-party-owned offerings.

If newly implemented prevailing wage and apprenticeship "bonus" requirements are satisfied, the PTC for wind and solar is $26 per MWh (in 2022$), while the ITC is sized at 30% of the project cost.

After 2022, an adder of 10% for the PTC and 10 percentage points for the ITC will apply if specific domestic materials requirements are met (phased in initially at 40%, though only 20% for offshore wind projects, and rising to 55% for onshore projects beginning construction in 2027 or later and offshore projects beginning construction in 2028 or later). Relatedly, Section 50251(a) of the IRA authorizes the Secretary of the Interior to issue renewable energy leases, easements, and rights-of-way in areas of the outer continental shelf off the coast of North Carolina (and several other southeastern states) that were placed under a leasing moratorium by former President Trump for the period from July 1, 2022, through June 30, 2032.

The IRA also provides an ITC and PTC enhancement for projects placed in service within an "energy community" defined to include brownfield sites; a census tract or any adjacent census tract in which a coal mine has closed after 1999, or a coal-fired electric generating unit has been retired after 2009; and a metropolitan or nonmetropolitan statistical area that (1) at any time after 2009 has had at least 0.17% direct employment or 25% local tax revenues from the extraction, processing, transport, or storage of coal, oil, or natural gas and (2) had an unemployment rate at or above the national average for the previous year, in each case as determined by the Secretary. Assuming the prevailing wage and apprenticeship requirements are met, the amount of the base PTC is increased by 10% and the amount of any ITC is increased by 10 percentage points (or 2% and 2 percentage points, respectively, if the wage and apprenticeship requirements are not satisfied).

Since the bonuses and adders are stackable, a PTC project garnering them all would receive $31 per MWh (2022$) produced each year for ten years, while a utility-scale ITC project would receive a 50% tax credit upon entering service.

Furthermore, the IRA addresses the issue of taxpayer "tax capacity" by allowing transferability, which will facilitate more cost-effective utilization of the expanded credits regime. Transferability—which allows taxpayers to sell their tax credits to an unrelated party—provides a more efficient way to monetize the present value of the tax credits.

Prior to the enactment of the IRA, taxpayers without sufficient income-tax liability to self-monetize credits had to either (a) rely on expensive tax equity financing or (b) carry forward deferred tax assets on their own balance sheets with corresponding losses due to the time value of money. For tax exempt entities and Subtitle T electrical cooperatives, the IRA allows direct pay (cash refundability) of the credits.

For the period after 2024, the IRA creates a new technology-neutral 10-year clean energy PTC (Section 45Y) and maintains this credit in full for projects that begin construction by the later of either 2032 or the year in electric power sector emissions are equal to or less than 25% of 2022 electric power sector CO2 emissions. A three-year phase-down of the credit level follows the relevant trigger year, with projects beginning construction in the first year of the phase-down period still eligible for 100% of the credit, which then reduces to 75% and 50% of full value over the next two years. The bonus and adders are available as before. A new technology-neutral clean energy ITC (Section 48E) is also in the legislation with the same phase-down terms at the new PTC.

Combined with ITC eligibility for stand-alone energy storage projects and the normalization opt-out for ratemaking treatment of the storage ITC, these transferable credits will significantly reduce the costs of utility-supplied wind and solar energy, making these resources relatively more economic in the near and medium term. From 2025 onward, SMRs will also be eligible for the technology-neutral credits. But the future costs of mature technologies like wind and solar are reliably forecasted today, and credits will shift costs lower in predictable fashion. For still unseasoned technologies like SMRs, baseline asset costs and output levels for purposes of estimating the value of production credits are highly speculative.

Predictably lower costs for mature clean resources could significantly impact the prudency of proposed short-term actions or investment decisions resulting from the Carbon Plan, forthcoming PBR applications, and proceedings related to certificates of public convenience and necessity.

Ultimately, the IRA will allow greater utilization of wind, solar, and battery storage resources while also lowering net ratepayer costs. RMI is actively working on Optimus modeling efforts to quantify the increased deployment potential and resultant economic benefits of these credits. RMI would welcome the opportunity to share the results of that modeling with the Commission as a supplement to this report.

Electrification

Though a full discussion of consumer tax credits is beyond the purview of this report, it should be noted that the IRA extends and expands tax credits for consumers that should contribute to increased electrical load, for instance through support for building electrification and the Clean Vehicle Tax Credit designed to incentivize the purchase of new and used electric vehicles.

Clean Hydrogen

The IRA created a clean hydrogen production tax credit (Section 45V) that is calculated according to an "applicable percentage" of the achieved credit rate—\$3.00 if wage and apprenticeship requirements are satisfied, and indexed to inflation from 2022 onward—multiplied by the kilograms of clean hydrogen produced by the taxpayer at a qualified facility during the taxable year. The "applicable percentage" is determined by the lifecycle greenhouse gas emission rate achieved in producing clean hydrogen. Thus, the lower the emissions associated with production of the hydrogen, the greater the tax credit. As a result, to the extent that the NCUC incorporates hydrogen as part of the Carbon Plan, greater near-term investment in clean resources that can produce lower- or zero-emission hydrogen in the future should reduce costs for ratepayers.

Table B. Clean Hydrogen Credit Applicable Percentages

Hydrogen Production Lifecycle GHG Emissions Rate (CO_{2e} per kg)	Applicable Percentage
2.5 ≥ x < 4 kg	20%
1.5 ≥ x < 2.5 kg	25%
0.45 ≥ x < 1.5 kg	33.4%
X < 0.45	100%

Significantly, the 45V credit is combinable with the production tax credits for wind, solar, and existing nuclear resources creating a rich incentive for "storing" clean generation as hydrogen. This credit is transferrable and also eligible for direct pay by tax exempt and non-exempt entities.

Carbon Capture and Sequestration (CCS)

The expanded credits for carbon capture and sequestration (Section 45Q) are as much as \$85 per metric ton for carbon dioxide from an electric power plant that is permanently sequestered, if prevailing wage and apprenticeship requirements are satisfied. The credits are available for 12 years, with inflation adjustments after 2026. Lesser credits are available for carbon dioxide that is used for enhanced oil recovery. The amount of carbon dioxide that must be captured at a qualifying facility has been significantly reduced relative to pre-IRA policy to only 18,750 metric tons annually, provided the facility captures not less than 75% of the baseline historical carbon emissions of the facility or 60% in the case of electricity generating facilities not yet or recently placed in service. Facilities must begin construction by the end of 2032. The lower capture requirement in terms of absolute metric tons could potentially allow CCS credits to be used cost-effectively with existing natural gas-fired plants. This credit is transferrable and also eligible for direct pay by tax exempt and non-exempt entities.

Existing Nuclear

Nuclear facilities in service at the time of the IRA's passage and which did not receive an advanced nuclear production tax credit allocation (Section 45J) are eligible for the newly created Zero-Emission Nuclear Power Production Credit (Section 45U). Provided prevailing wage and apprenticeship requirements are satisfied, the credit amount is $15 per MWh, subject to a formula that offsets the credit in linear fashion when average annual revenues exceed $25 per MWh and fully erases it when average revenues exceed approximately $44 per MWh. This credit is designed to benefit plants selling into organized markets and terminates at the end of 2032.

<u>DOE Loan Guarantees</u>

The IRA establishes transformative program within DOE to facilitate hundreds of billions of dollars in low-cost financing for fossil asset retirements and reinvestments in furtherance of the clean transition. Under Section 1706 of Title 17, plant balances are eligible for refinancing using debt backed by the guarantee of the federal government with interest rates similar to, and potentially lower than, those achievable with securitization.

In its first report, RMI a modeled a securitization scenario outside the limits of H951,[7] finding that if all unrecovered balances from all Duke coal plants, including the supercritical Cliffside 6 and the recently retired G.G. Allen units, were securitized at the end of 2022, ratepayer savings from such a refinancing could reach $1.26 billion (NPV, 2022$). Under Section 1706, such a comprehensive refinancing would be possible. Indeed, the savings could well be greater, as the legislation allows longer tenors (up to 30 years) than RMI assumed and potentially lower interest rates (as low as 37.5 basis points above the federal government's borrowing rate).

Moreover, Section 1706 extends low-cost financing beyond addressing unrecovered plant balances to include low-cost financing for environmental remediation, replacement with clean energy resources, and community reinvestments. These authorities—which enable up to $250 billion in such financing—could substantially reduce the weighted average cost of capital for more aggressive clean energy deployment scenarios, if the authorities are utilized prior to their expiration at the end of September 2026.

<u>Corporate Alternative Minimum Tax</u>

The IRA adds a 15% alternative minimum tax (CAMT) on corporate profits that would apply to corporations that have average annual adjusted financial statement income in excess of $1 billion over a three-year period. Of note, the corporate AMT may be offset by general business credits under Section 38, such as the ITC and PTC (up to 75% of the sum of a corporation's normal income tax). The IRA allows corporations to reduce adjusted financial statement income by including accelerated depreciation. Five-year MACRS accelerated depreciation is already available for solar and wind and, as a result of the IRA, will be available for storage from 2025 onward.

In conclusion, the cumulative and additive impact of new, expanded, and extended tax credits for clean resources and low-financing mechanisms have unequivocally, fundamentally, and immediately altered the economics of decarbonization in the U.S.

[7] H951 stipulates that a maximum of 50% of the remaining plant balances only for sub-critical units are eligible securitization.

These changes impact the economics of resource selection in North Carolina, and consequently, the feasibility of earlier, cost-effective achievement of CO_2 reduction targets.

Methodology & Scope

This section briefly presents the scenarios and sensitivities modeled in Optimus for the supplemental analysis.

Portfolio Scenarios Modeled

The EnCompass portfolio scenarios that RMI modeled in Optimus for this report are described in ***Table C***.

Table C. EnCompass Portfolio Scenarios Modeled in Optimus

Scenario	Description
Duke Resources	Using Duke's own EnCompass modeling database as a shared foundation, this scenario uses the revised model inputs detailed in Synapse's report[8] but maintains the resources that Duke Energy proposed in "Portfolio 1 – Alternate." This scenario serves as a basis for comparison with the other Synapse scenarios.
Optimized	This scenario reflects selection by EnCompass of the optimal scenario based on revised inputs, such as utility energy efficiency incremental annual savings of 1.5% of total retail sales, shorter gas plant book life, external estimates for nuclear and gas capital costs, and National Renewable Energy Lab projections for renewables and battery storage costs.
Regional Resources	Same as the Optimized scenario with the addition of allowing EnCompass to select Midwest wind resources procured via power purchase agreements through the PJM Interconnection (PJM).

Optimus Sensitivities

RMI's first report described the results from using Optimus to model the impacts of regulatory mechanisms from the NC H951 legislation, applying macroeconomic and federal policy sensitivities. For this supplemental report, macroeconomic sensitivities were applied to all three EnCompass portfolio scenarios described above,[9] but federal policy and securitization sensitivities were not modeled.

The August 12th passage of the Inflation Reduction Act of 2022 (IRA) did not allow sufficient time for RMI to make all make all the relevant policy changes to the Optimus model.[10] Moreover, these changes have profound implications on economic selection of

[8] *See* Supplemental Joint Comments of NCSEA, SACE, Sierra Club and NRDC; report from Synapse Energy Economics, Inc., *Carbon-Free by 2050: Pathways to Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers*, Table 3, pp. 10-11.

[9] *See* Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal, pp. 3-5.

[10] Public Law No: 117-169.

the resource portfolio that are better explored via capacity expansion and production cost models, such as EnCompass.

Similarly, RMI did not model a securitization sensitivity in the supplemental report primarily because the IRA substantively changes the refinancing landscape through the U.S. Department of Energy's Title 17 Loan Program.

Appendix A.1 provides further details and caveats regarding the sensitivities RMI modeled for the supplemental report.

Key Differences between the EnCompass and Optimus Methodologies

EnCompass and Optimus can produce similar metrics but are distinguished by their different approaches to calculating them. The differences explained in RMI's first report are still applicable in this supplemental report, as follows:[11]

- Optimus calculates *annual ratepayer costs* using the full revenue requirement as opposed to using only the forward-looking incremental costs;
- Optimus calculates *bill impacts* using a holistic perspective of the portfolio (existing assets + additions) and uses cost causation principles and the historical allocation across customer classes to estimate the differential impact amongst different ratepayer classes; in contrast, Duke used EnCompass to estimate bill impacts as an average of the incremental portfolio additions agnostic of allocation amongst classes;
- Optimus calculates the *net present value of portfolio costs and the utility revenue requirement* using
  - the full revenue requirement rather than just the incremental costs, and
  - a hybrid discount factor that incorporates the nature of capital markets rather than just using the utility' weighted average cost of capital (WACC).

Limitations of this Analysis

Unlike with RMI's first report, **the disclaimer regarding the EnCompass version 6.0.9 software error does not apply to the findings in this supplemental report**. This is because the findings described herein rely on Synapse's modeling of scenarios using EnCompass version 6.0.4.[12]

However, other limitations described in RMI's first report do still apply to the supplemental report.[13] For example, the supplemental report continues to analyze Synapse's "Duke Resources" scenario, which *replicates* Duke's P1-alternate buildout. This proxy was necessary because RMI was unable to validate and calibrate Duke's analysis using the data provided by Duke. Additionally, for projects constructed over multiple years, Optimus assumes that the total installed costs apply to the single year when construction is completed, as opposed to spreading those costs over the full construction

[11] *See* Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal, p. 6-7 and Appendix p. F-I.
[12] *Id*. at p. 8.
[13] *Id.* at p. 8.

period for rate base and tax treatments. This may mean that the net present value of revenue requirements is slightly underestimated. In our opinion, these simplifying assumptions have not materially impacted the findings in this supplemental report.

Findings

1. The Optimized and Regional Resources scenarios better mitigate and distribute ratepayer costs between utilities than the Duke Resources scenario.

RMI's analysis of the ratepayer impacts using Optimus is focused on the near and medium term (2022-2035). Because differences in resource mixes between scenarios have a significant impact on ratepayer costs, the resource mixes of all scenarios (derived from Synapse's EnCompass results) are shown in ***Figure 1*** below. Appendix A.2 includes additional details on the resource mixes and trends in the long term (2022-2050)**.**

In the Duke Resources scenario, 3.1 GWs of new combined cycle and combustion turbine gas, 14.6 GWs of solar, 3.6 GWs of standalone storage, 1.8 GWs of onshore wind, and 0.9 GWs of nuclear would be deployed between 2022-2035.[14] The capital deployment is unevenly split between DEC and DEP: the majority of new gas and onshore wind is added in DEP, the majority of solar is added in DEC, and substantial battery storage additions occur in both utilities. These factors drive a higher cost increase in DEP compared to DEC in the Duke Resources scenario, widening the cost disparity between the two utilities.

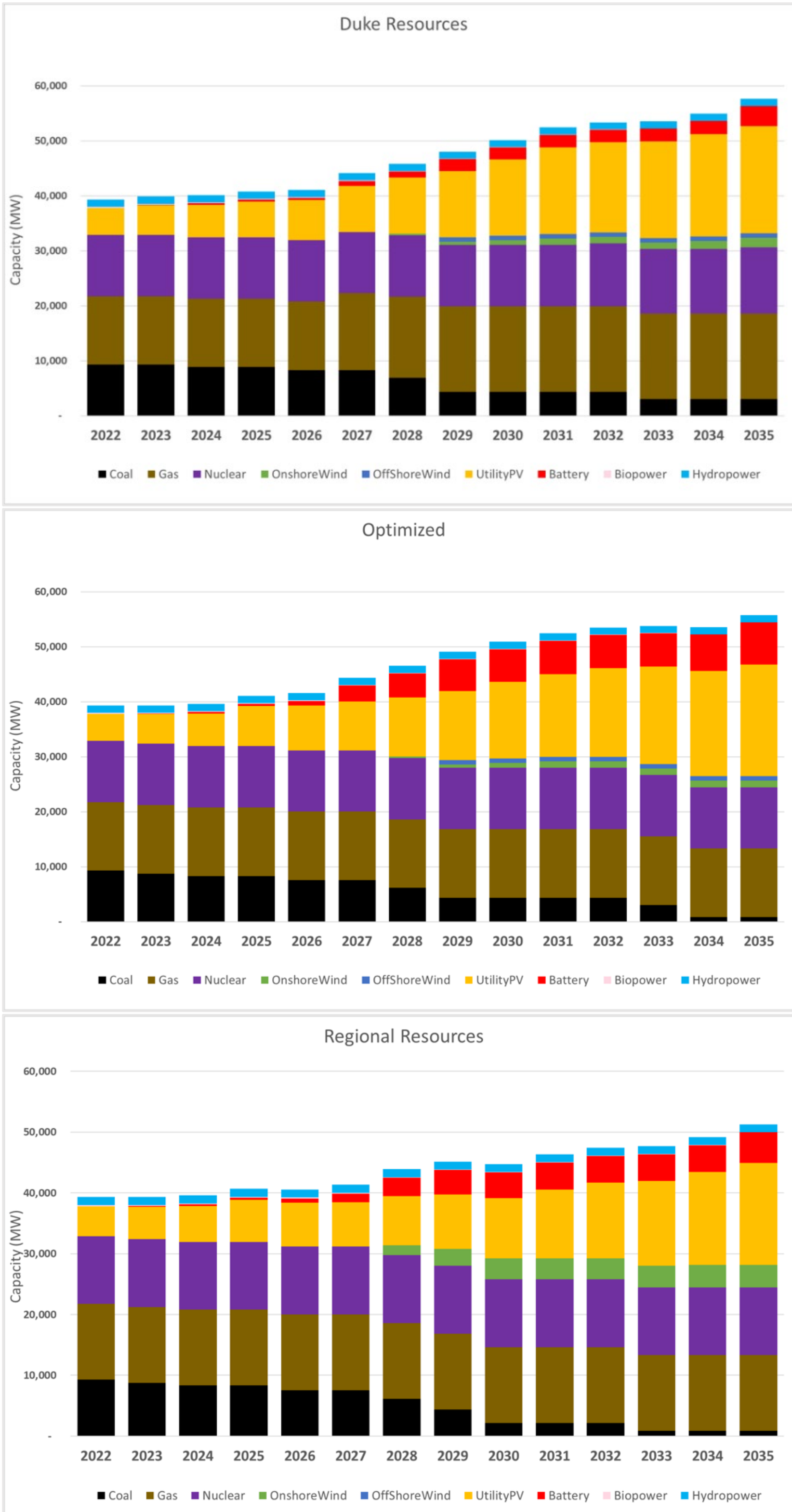
The Optimized scenario sees an accelerated deployment of solar compared with Duke Resources in 2025, slower growth relative to Duke Resources in 2027 and 2030-2031, and then higher solar deployment again starting in 2032. In the Optimized scenario, there is a significantly higher quantity of battery storage than in the Duke Resources scenario in 2026-2030 and 2034-2035. Solar plus battery storage resources in the Optimized scenario are substitutes for the new gas and nuclear capacity built out in the Duke Resources scenario. These dynamics in the Optimized scenario result in a less dramatic cost disparity between DEC and DEP compared with the Duke Resources scenario.

The Regional Resources scenario has significantly higher deployment of onshore wind between 2028-2030 than the Duke Resources scenario. Solar buildout is relatively smaller in the medium term compared with the Duke Resources scenario, as the cost-effective Midwest wind resources procured through PJM substitute for solar. As such, the Regional

[14] These capacity resource addition numbers are slightly different from what is included in Duke's Carbon Plan for this portfolio (Table E-82 in Appendix E). These apparent differences are because: (1) Synapse's solar number includes deployment related to pre-existing programs like HB589 and Green Source Advantage, which are excluded from Duke's number; (2) Synapse's numbers include projects added in December 2035, which account for the slight differences in gas, onshore wind, and nuclear; and (3) Synapse's number includes only standalone storage under "storage," whereas Duke's number under "Battery" includes battery capacity that is both standalone and paired with solar.

Resources scenario even further mitigates the cost disparity between DEC and DEP that is seen in the Duke Resources scenario and, to a lesser extent, in the Optimized scenario.

Figure 1. Resource Portfolio Capacity Buildout 2022-2035.



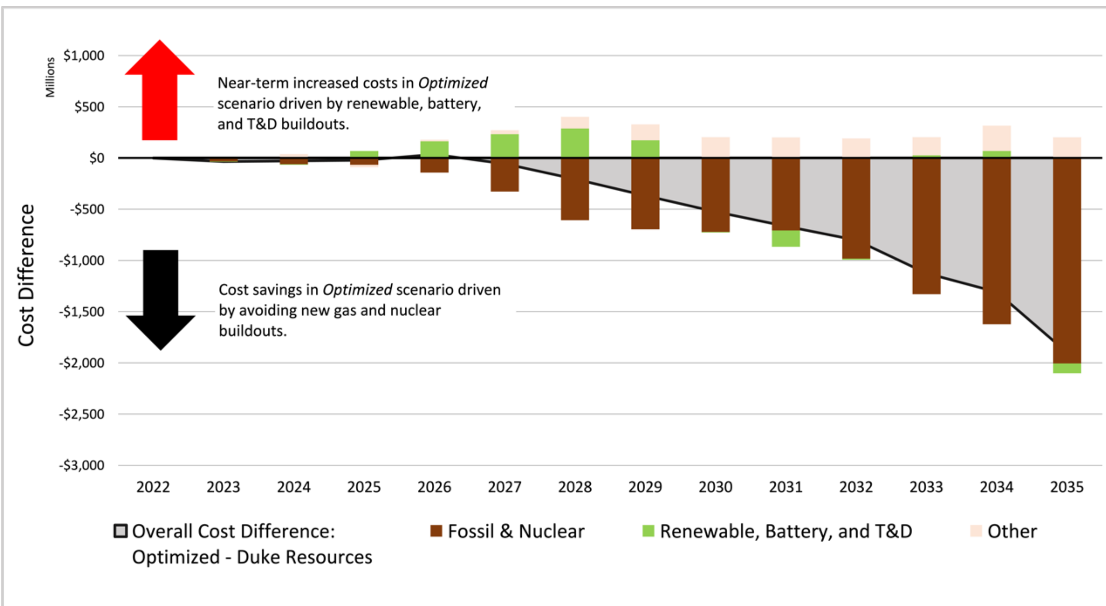
Although not shown in ***Figure 1***, the Optimized and Regional Resources scenarios deploy higher levels of energy efficiency (1.5% of total retail load) relative to the Duke Resources scenario (1% of eligible retail load), which reduces the overall load and contributes to cost savings in the near, medium and long term.

We explain below how these key differences between resource portfolios are linked to different rate impacts.

2. The Optimized and Regional Resources scenarios are more cost-effective than Duke Resources, driven by avoided gas and nuclear investment.

The Optimized scenario is less expensive than the Duke Resources scenario in most years ***(Figure 2).*** The savings in ratepayer costs are primarily driven by avoidance of new gas and nuclear buildout, which represents a decrease in gas Capex and nuclear costs relative to Duke Resources scenario. Battery storage is the main driver of additional cost, but it is more than offset by the cost savings.

Figure 2. Ratepayer Cost Comparison of Optimized – Duke Resources, DEC and DEP Combined. [15]

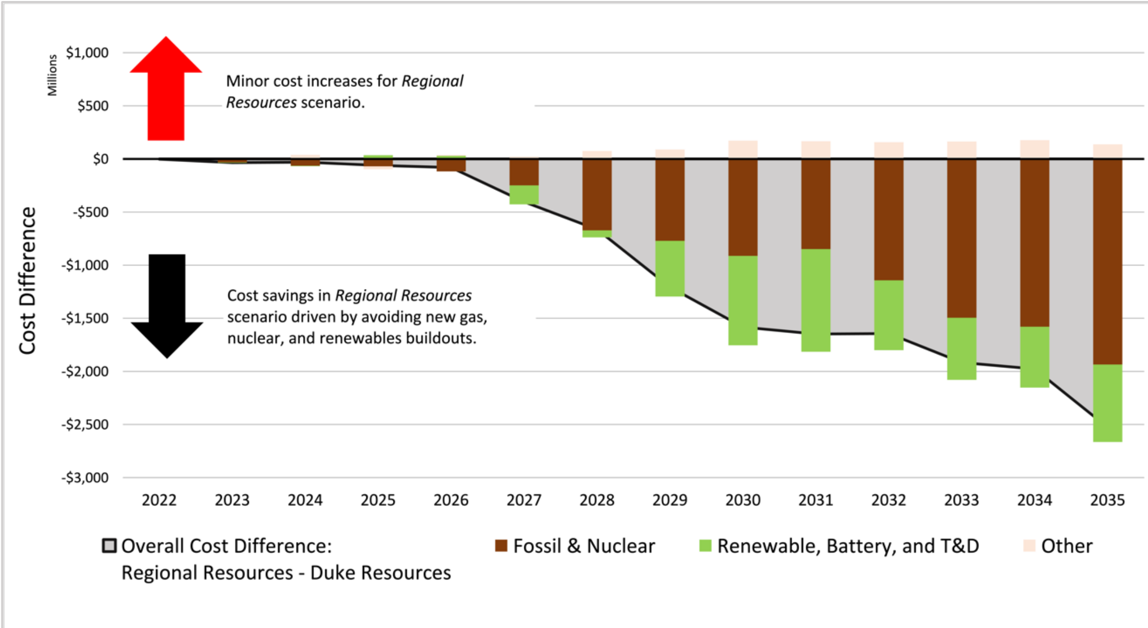


The Regional Resources scenario is even more cost-effective than the Optimized scenario, reducing costs relative to the Duke Resources scenario every year. Wind PPAs coupled with battery storage deployment in the Regional Resources scenario are significantly

[15] Costs labeled as "Other" in this chart and the following charts with technology breakdown includes the following components: 1) Cost from the EnCompass model outputs that are not technology-specific, including demand response, energy efficiency, purchases, sales, and any utility-level expenses that are not associated with individual generators (inter-utility transactions, taxes, program costs, and commitment costs); and 2) Cost projected based on utility-reported historical data that reflected non-production expenses, including Selling, General and Administrative (SG&A) expenses (which are the operating costs associated with utility operation), pension obligations, etc.

more cost-effective than the fossil and nuclear investments made in the Duke Resources scenario (***Figure 3***).

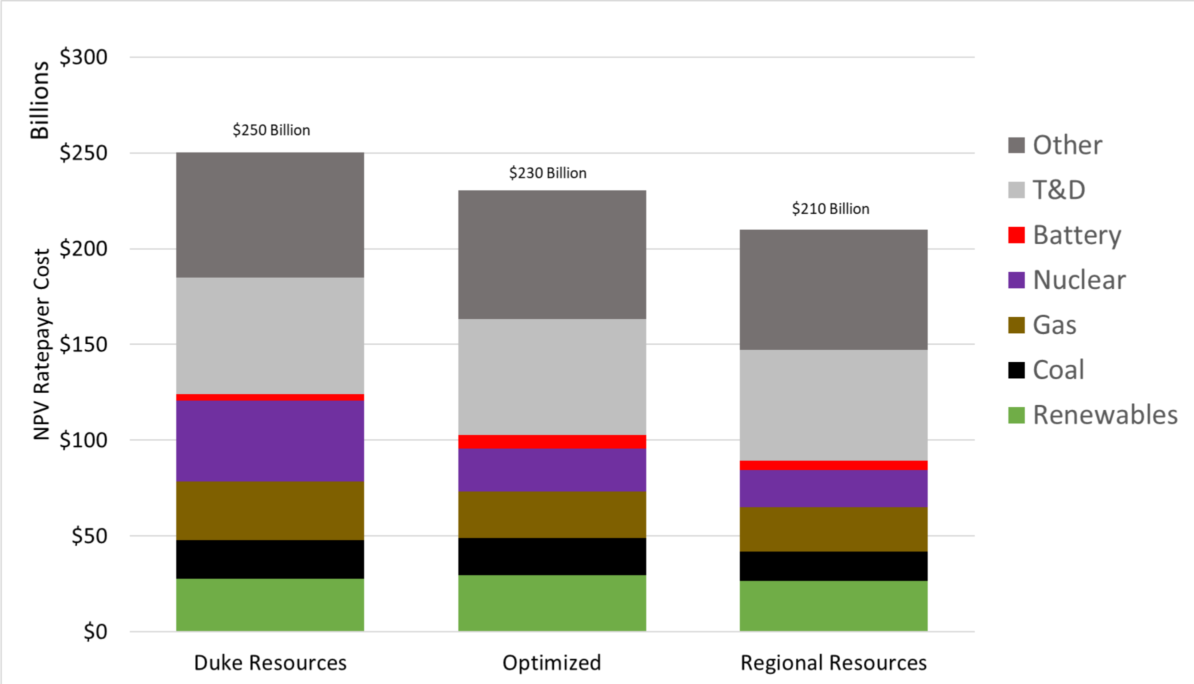
Figure 3. Ratepayer Cost Comparison of Regional Resources – Duke Resources, DEC and DEP Combined.



Although not shown in ***Figures 2 and 3*** the costs and benefits of shifting to a cleaner resource pathway are unevenly distributed between the Companies in all scenarios, driven by the different investments associated with each portfolio. Appendices A.3 and A.4 detail the breakdown of costs and benefits by operating utility and technology type.

In the long term, the Optimized scenario has slightly higher renewables and battery costs which are offset by much larger savings associated with avoided nuclear and gas buildout costs, resulting in more than $20 billion in NPV savings for ratepayers over 28 years (***Figure 4)***.

Figure 4. Ratepayer Cost Comparison 2022-2050, DEC and DEP Combined.[16]



3. The Optimized and the Regional Resources scenarios yield lower rates and aggregate bills than the Duke Resources scenario.

The Optimized and Duke Resources scenarios have very similar bill impacts through 2024 across all retail customer classes (residential, commercial, and industrial). However, beginning in 2025, all customer classes see bill savings in the Optimized scenario relative to the Duke Resources scenario, with the largest relative savings for residential customers. This is because the significant battery capacity deployment in the Optimized scenario is allocated mainly to demand charges, and residential customer bills are less influenced by demand-related costs compared to commercial and industrial (C&I) customers. The savings grow significantly in 2033 when the Optimized scenario begins considerable deployment of solar and storage.

The Optimus model indicates that each EnCompass scenario modeled by Synapse—including Duke Resources—would yield a decrease in residential bills through 2030 relative to 2022 bills.[17] However, Duke's own analysis of its proposed Carbon Plan portfolios show average monthly residential bill *increases* of $5-$8/month in DEC and $18-$35/month in DEP in 2030 relative to 2022.[18] Two factors drive this difference:[19]

[16] Energy Efficiency cost is included in "Other" and is roughly 1-2% of total cost for a given scenario.
[17] These savings are consistent with results shown in RMI's first report. See *Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal*, p. 11.
[18] Duke, *Carolinas Carbon Plan*, Chapter 3 – Portfolios, Table 3-3: Summary of Portfolio Results, p. 20.
[19] *See* Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal, p. 11.

1) Synapse's EnCompass modeling incorporates the more pronounced natural gas price shock seen this year resulting from the conflict in Ukraine, while Duke's modeling was completed before the extent of the shock became clear in market prices. This resulted in significantly higher baseline 2022 costs in Synapse's modeling for all scenarios followed by a drop to pre-war price trends in fuel costs by 2025.
2) Optimus considers cost allocations between retail customer classes, differentiating cost impacts to residential, commercial, and industrial classes. The only additions to rate base between 2022 and 2027 in the Duke Resources scenario are the maintenance Capex of existing transmission and distribution assets. As these are demand-related costs, they are borne more heavily by C&I customers and are likely to have relatively small impacts on residential rates in Optimus modeling. On the other hand, Duke's estimated bill impacts reflect averaged system-wide cost impacts across customer classes and would be comparable to the weighted average of bills across customer classes.

Residential customers see a 22% decrease in bills by 2030 compared with 2022 in the Optimized Scenario and a 25% decrease over this period in the Regional Resources scenario, compared with a 16% decrease in the Duke Resources scenario. The advantages are more pronounced in 2035, when, under the Duke Resources scenario, residential customers would be paying 2% *more* than they were in 2022, while they would be paying 10% *less* in the Optimized scenario and 15% *less* in the Regional Resources scenario.

On a disaggregated basis, there are noticeable differences in the rate and bill impacts across customer classes between DEC and DEP.

First, the overall rate impacts in 2030 relative to 2022 in the Duke Resources scenario show a similar level of disparity between DEC and DEP as seen in Duke's Carbon Plan analysis, even though the absolute impact is lower in Optimus modeling due to the two factors laid out above. DEP customers see a larger average rate impact in 2030 than DEC customers from the Duke Resources scenario across all customer classes (***Figure 5***). Optimus modeling confirms that Duke's proposed plan would significantly exacerbate the existing rate disparity between DEC and DEP customers.

In contrast, the Optimized and Regional Resources scenarios have lower rate and bill impacts across customer classes (***Figure 6*** and ***Figure 7***). Moreover, both scenarios significantly mitigate the rate disparity between DEC and DEP (Figure 5) relative to the Duke Resources scenario. Therefore, the alternative scenarios help bridge the gap between the two utilities and better distribute the ratepayer cost across the region.

Figure 5. Average Retail Bundled Rate Impact, DEP and DEP Respectively.

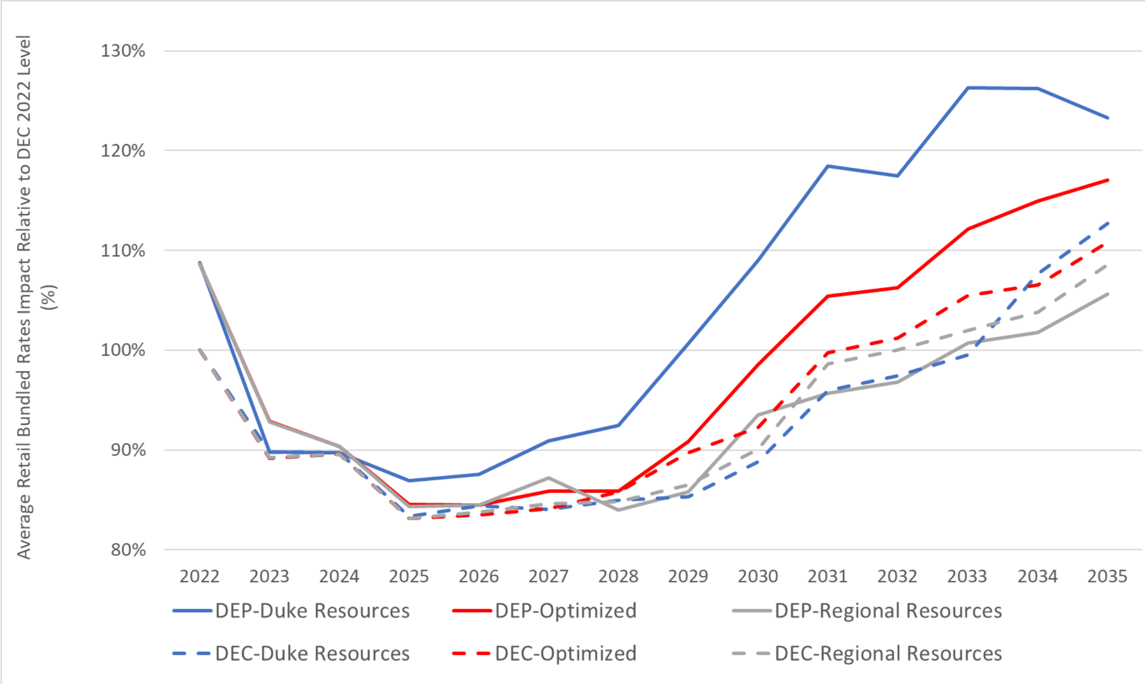


Figure 6. Average Monthly Bill Change – Duke Resource and Optimized, DEC and DEP Combined.

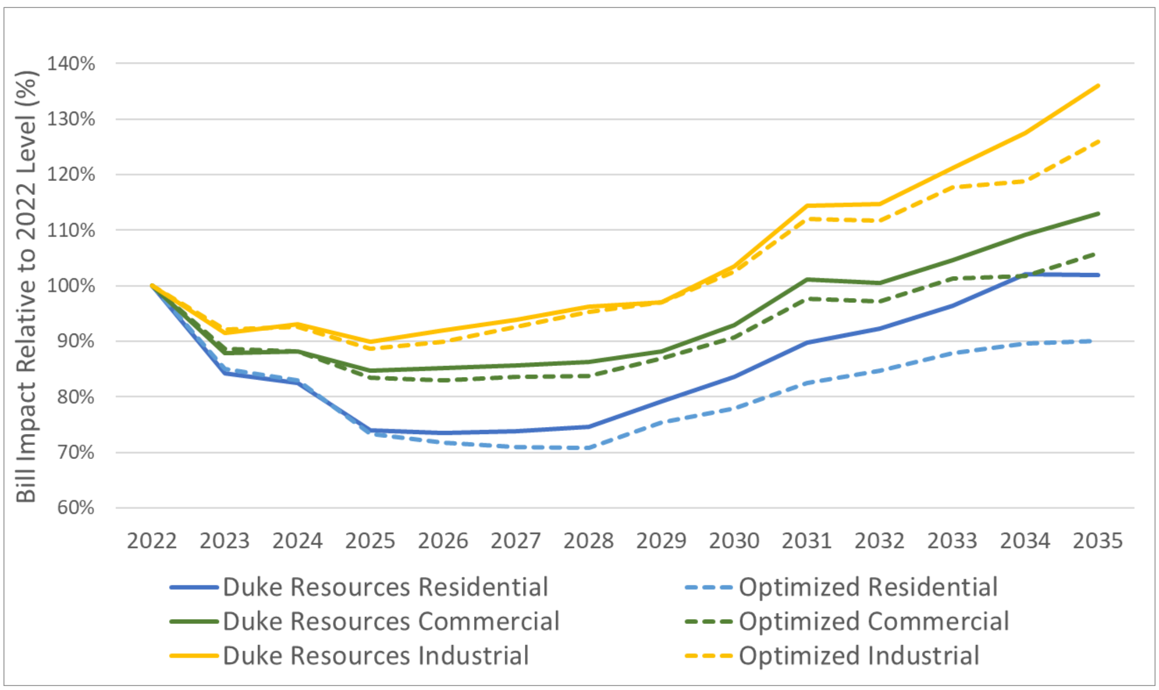
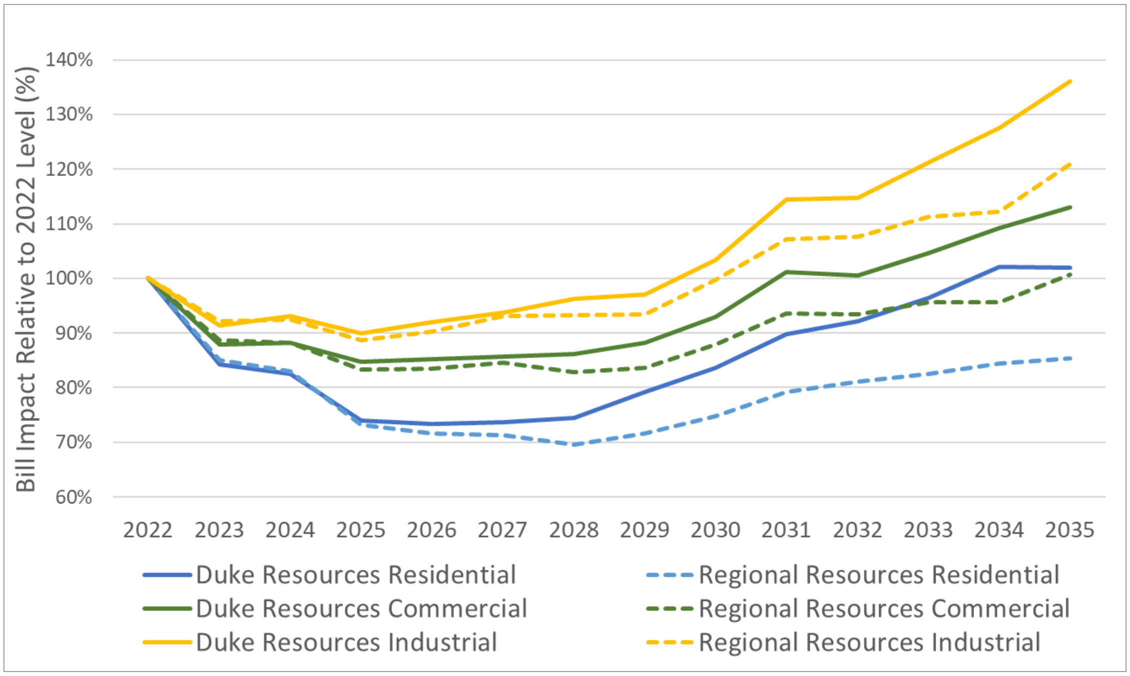


Figure 7. Average Monthly Bill Change – Duke Resources and Regional Resources, DEC and DEP Combined.



4. The Optimized and Regional Resources scenarios are more resilient than the Duke Resources scenario to execution risks.

The following subsections describe several findings from Optimus scenarios that modeled the execution risk associated with: (4a) fuel price shocks in years where all scenarios are most reliant upon fossil fuels; (4b) a load growth assumption that is higher than what Duke Energy modeled in its proposed Carbon Plan; and (4c) the application of a multi-year rate plan and revenue decoupling for residential customers.

4a. The Optimized and Regional Resources scenarios better insulate ratepayers from the risks of fuel price shocks.

The Optimized scenario provides the greatest protection to customers from an unanticipated fuel price shock (a doubling of fuel prices) during the period of highest reliance on fossil fuels for the combined DEC and DEP utilities.

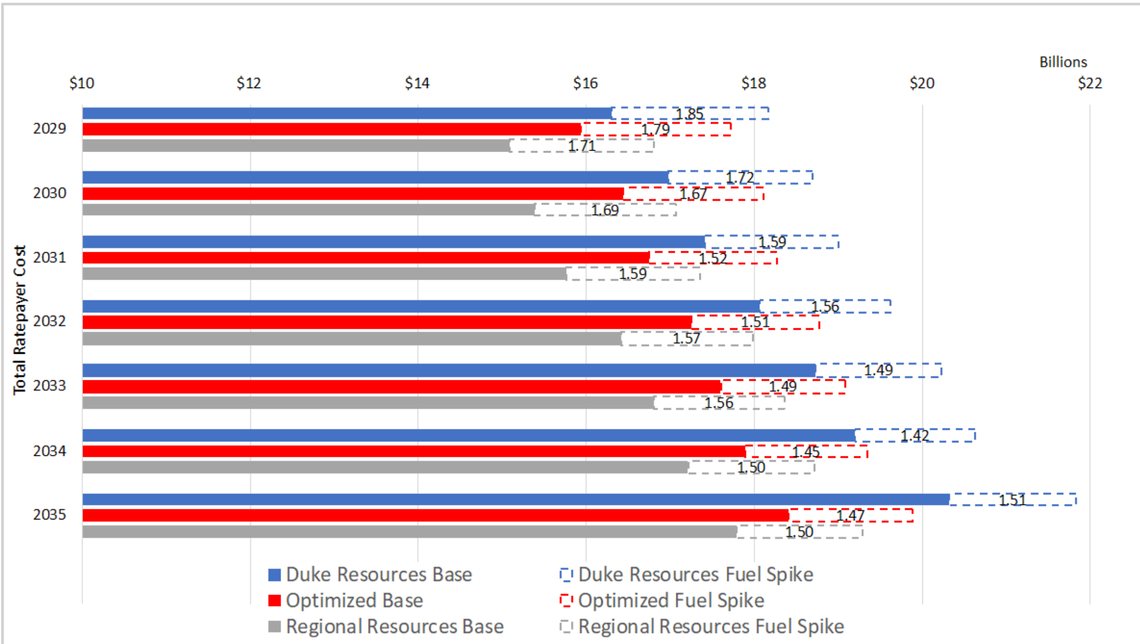
All three scenarios see peak utilization of fossil fuel generators between 2029-2035. In that period, the Optimized scenario is more resilient to fuel cost volatility than the Duke Resources scenario. On average, ratepayer costs in the Optimized scenario increase by 2% less than in the Duke Resources scenario in the event of a six-year fuel price shock, which equates to $243 million of cumulative reduction in the impact of the price shock during the six-year sensitivity period (***Figure 8***).

The Regional Resources scenario is equally as vulnerable to fuel cost volatility as the Duke Resources scenario during 2029-2035 even as the overall costs of the Regional Resources portfolio remain substantially less than the Duke Resources scenario. This is driven by the coal consumption in the DEC territory before 2030 and the higher reliance on gas in the

DEP territory post-2030 compared to the Optimized scenario, which in aggregate offsets the benefit from the increase in clean capacity.

The total ratepayer costs in both the Optimized and Regional Resources scenarios in all years of the fuel price shock sensitivity period (2029-2035) are lower than those in Duke Resources, indicating that customers would see overall savings from alternative scenarios even under significant fuel shocks, as shown in ***Figure 8***.

Figure 8. Fuel Price Spike Sensitivity Applied to Years Where Fossil Fuel Generation is Relied Upon Most, DEC and DEP Combined (note that the x-axis minimum is $10 Billion).



This analysis confirms that resource portfolios that rely more upon clean energy resources and feature higher levels of energy efficiency can cost-effectively reduce ratepayers' vulnerability to fuel price volatility.

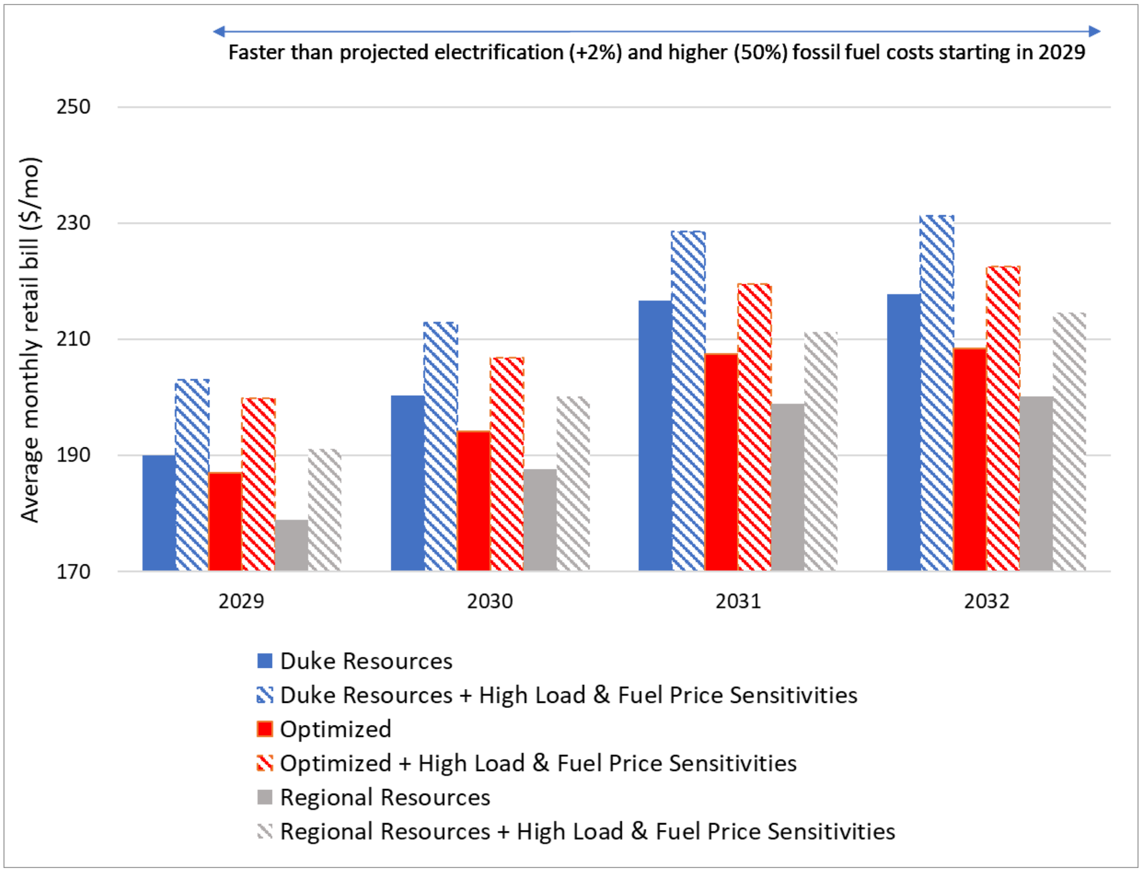
4b. The Optimized and Regional Resources scenarios can mitigate the cost risk to customers of inadequately planning for the impacts of a rapidly electrifying economy.

RMI modeled the risk of inadequately planning for rapid electrification via a sensitivity with a 50% fuel price shock coupled with a higher-than-expected load projection starting in 2029 and spanning two rate case periods (2029-2032). All three scenarios see an increase in average monthly bills under this sensitivity (***Figure 9***).

The relative bill increases associated with all three scenarios are roughly the same, but the Optimized and Regional Resources scenarios have lower baseline costs and thus remain cheaper than Duke Resources in each year. Indeed, customer bills in the Regional Resources scenario modeled with the sensitivity are still lower in most years than customer bills in the Duke Resources scenario without the sensitivity.

In sum, a pathway with higher reliance on energy efficiency and higher penetration of fossil-free resources can better prepare the utility to manage unanticipated increases in loads and fuel costs that may arise in a rapidly electrifying economy, as hypothesized in RMI's first report.[20]

Figure 9. Average Bill Impact Under Higher Electrification & Fuel Cost Assumptions – DEC and DEP Combined.



However, as noted in previous findings and detailed in Appendix A.4, differences in resource investments between DEC and DEP result in a more nuanced story at the individual operating utility level. While DEP customers do indeed see lower average bill impacts under a high load and price sensitivity in the Optimized scenario across customer classes, DEC customers see higher bills. This is driven by higher gas utilization by older coal and gas co-fired DEC assets in the Optimized scenario. This renders DEC customers in the Optimized scenario more vulnerable to fuel price volatility than in the Duke Resources scenario, and this vulnerability is exacerbated by a high load projection. As noted above, because rates for DEP's retail customers are currently higher than those for DEC's retail customers, the relatively higher bill impacts for DEC customers under this sensitivity would have the effect of shrinking that rate disparity. Appendix A.4 includes the bill impact charts that illustrate the detailed trends for DEC and DEP individually.

Ultimately, a combination of fossil-free resources as well as targeted demand-side resources can mitigate the impact of electrification and improve the resilience and cost-effectiveness of any resource portfolio.

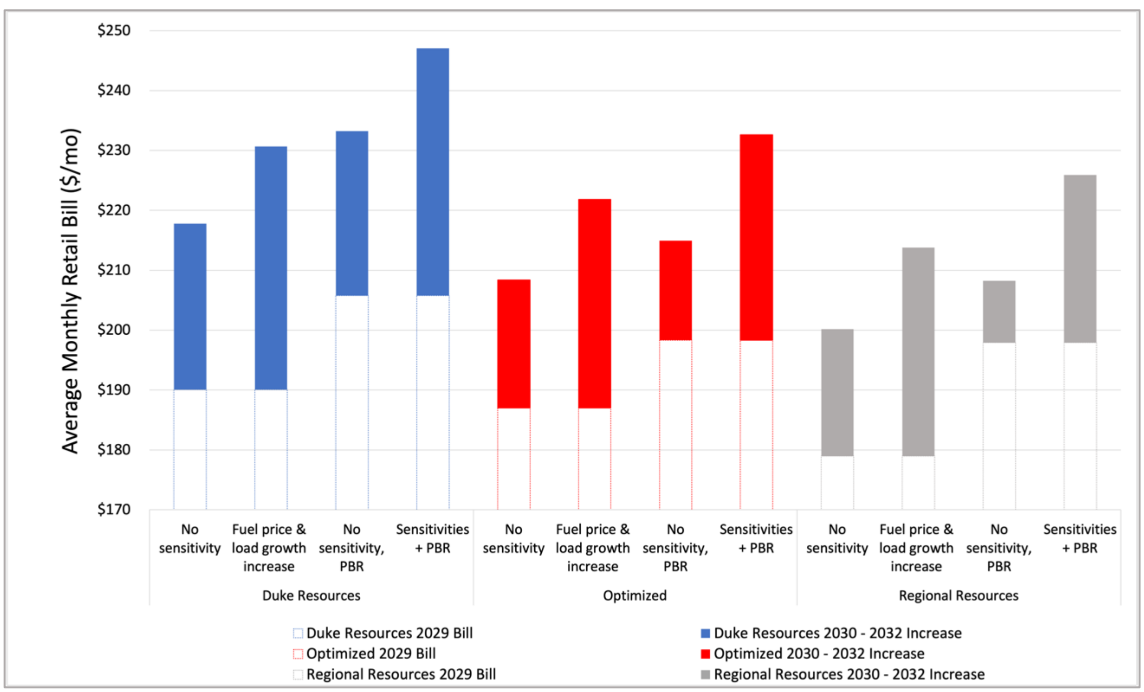
[20] *Id.* at p. 19-20.

4c. In all scenarios, the PBR mechanisms set forth in NC H951 could lead to higher average bills for ratepayers; however, the cleaner and lower-cost Optimized and Regional Resources scenarios can mitigate a portion of the potential bill increases.

RMI modeled the PBR mechanisms included in H951—which RMI assumes will include the maximum allowed 4% annual revenue adjustment in each multi-year rate plan (MYRP) period starting in 2023—in tandem with high load and fuel price shocks actually realized within one MYRP period (2030-2032). The model assumption that annual revenue adjustments are always maximal is intended to model a future in which the risk of load growth and fuel price hikes in every MYRP period is sufficiently high to justify a high annual adjustment. ***Figure 10*** compares the total average bill increases over the 2030-2032 MYRP in scenarios in which the fuel price and load shock is or is not realized and with and without PBR in place.

Optimus analysis suggests that the presence of the PBR mechanisms in H951, in conjunction with high load growth and fuel price spikes, will result in an increase in average baseline bills in 2029 (shown as the invisible bar at the bottom of each stacked bar) in all three portfolio scenarios. This is an expected direct consequence of the compounding impact of the annual maximal revenue adjustment, high load growth, and fuel price hikes. However, the Optimized and Regional Resources scenarios yield a lower overall increase in bills over the course of a 36-month MYRP period (bill increase shown as the solid bar at the top of each stacked bar) relative to the Duke Resources scenario regardless of whether the fuel and load shocks come to pass or PBR is in place.

Figure 10. Average Bill Effects of a 2030 – 2032 MYRP and Decoupling Under Higher Electrification and Fuel Cost Increases, DEC and DEP Combined.



The story diverges slightly at the individual operating utility level. Appendix A.4 includes the bill impact charts that illustrate the detailed trends for DEC and DEP individually.

As some specific design elements of PBR remain uncertain until a PBR application is approved in North Carolina, this sensitivity analysis is meant to provide an initial illustrative indication of the impact of certain PBR parameters (in this case the MYRP assumptions). This analysis shows that in North Carolina, MYRPs and revenue decoupling would result in lower average bill increases when applied to a portfolio comprising a higher proportion of clean resources with significantly diminished variable costs.

Implications and Recommendations for Current & Future Carbon Planning Effort

This updated analysis supports the conclusion that portfolios with higher reliance on energy efficiency and higher penetration of renewables can be less expensive than Duke's proposed Carbon Plan portfolio and still meet the requirement for a 70% emission reduction by 2030. The two alternative portfolio scenarios modeled by Synapse Energy Economics—Optimized and Regional Resources scenarios—both represent less risky paths for the NC Carbon Plan in terms of fuel cost, higher than anticipated load, and the introduction of PBR.

Even absent consideration of the aforementioned execution risks, the Optimized and Regional Resources scenarios in aggregate distribute the costs of the transition more equitably amongst ratepayer classes. Moreover, the Optimized and Regional Resources scenarios appear to meaningfully reduce the rate disparity gap between the DEC and DEP territories relative to the Duke Resources scenario, which exacerbates the disparity.

Though RMI did not have sufficient time to conduct modelling analysis on the implications of the IRA passage on proposed Carbon Plan scenarios, the cumulative and additive impact of new, expanded, and extended tax credits for clean resources and low-financing mechanisms have unequivocally, fundamentally, and immediately altered the economics of decarbonization in North Carolina. RMI expects that the IRA will make low-carbon technologies far cheaper over the coming decade than was assumed in capacity expansion and production cost modeling conducted for the current Carbon Plan. For instance:

- the resource costs of solar, batteries, and wind will all be significantly lower with the extension and broadening of ITC and PTC;
- the availability of a solar PTC, which is not subject to tax normalization, and the normalization opt-out for the storage ITC, will increase the price competitiveness from a ratepayer perspective of utility-owned solar and storage assets relative to third-party owned assets;
- hydrogen production costs will be lower as a result of the Section 45V tax credits and, moreover, tax benefits will be greater for hydrogen that is produced with lower-lifecycle or zero-carbon emissions;
- EV costs and the costs of electrifying home space and water heating will be lower, which will impact load assumptions; and
- Section 1706 provides the potential for low-cost financing to reduce the rate impact of accelerated phase-out and replacement of fossil assets beyond the limitation of NC H951.

All of these changes impact the economics of resource selection, and consequently, the timing of CO_2 reduction target feasibility. If capacity expansion and production cost modeling were run today with the realities of the IRA reflected, scenarios with accelerated deployment of mature clean energy resources such as wind, solar, and storage and lower utilization of fossil fuels would likely have even lower costs than the scenarios currently before the Commission.

As such, RMI offers the following recommendations for the Commission's consideration **for current & future Carbon Planning efforts:**

For the Current Carbon Plan:

Absent an effort to perform additional capacity expansion and production cost modeling in the near-term, any resource decisions, near-term execution plans, and relevant resource planning activity that occurs after the September 2022 Carbon Plan evidentiary hearing (including but not limited to the Commission's decision on the Carbon Plan and short-term execution plan, adjustments to the Carbon Plan, MYRP applications, and proceedings related to certification of public convenience and necessity) should include an analysis of the full scope of the IRA cost implications.

For future Carbon Plans:

RMI reiterates the same recommendations from its first report regarding the transparent provision of assumptions, inputs, outputs, and calculation methodologies related to the estimation of costs for resources and the allocation of those costs to ratepayer.[21]

[21] *Id.* at p. 35.

APPENDIX

A.1. Optimus Sensitivities Methodology and Caveats

The high-load and fuel-price sensitivities largely follow the same methodology described in RMI's first report. However, the years when they are assumed to occur have been modified to correspond with rate case and multi-year rate plan timelines in order to better represent a true shock rather than a change in long-term trends.

1. *High load projection*: as explained in RMI's first report, Optimus explores how each scenario would fare in the event of an unexpected growth in load driven by electrification. After establishing the level of load growth through the inputs, Optimus then applies the increase in load to the total marginal cost (fuel cost and non-fuel variable Opex) of the portfolio and adds this additional quantity to the original ratepayer cost. This methodology assumes that all dispatchable resources would increase output proportionally to the increase in load. It is a conservative assumption given that, under economic dispatch, it is likely that the more expensive marginal resources would need to, in aggregate, ramp up more than the dispatchable resources that run most of the time. For the supplemental report, the high load projection sensitivities are applied only within 1-2 rate cases or multi-year rate plan periods to reflect a shock rather than a shift in trends through 2050. Over that longer horizon, system planning could adjust for load growth that initially exceeded forecasted expectations.
2. *Fuel price sensitivities*: as explained in RMI's first report, RMI gauged how the planning scenarios would fare in the event of an unexpected, temporary fossil fuel price spike. Whether modeling single-year or multi-year price increases, Optimus applies the percent increase input equally to the per unit cost of all fossil fuels used in the production cost model. Then, using output of each unit, a new total annual fuel cost is calculated. The new total fuel cost is then reflected in the total ratepayer cost. Applying the same fuel cost increase to all fossil assets means that fossil-fueled asset dispatch would not likely be significantly impacted but ignores the possibility that cheaper variable cost resources like nuclear or hydro might be able to ramp up. For this supplemental report, the prolonged fuel price sensitivities are applied from 2030 through 2035 (two multi-year rate plan periods) to simulate temporary impact.
3. *PBR mechanisms:* This Optimus sensitivity scenario models the design elements of a MYRP described in NC statute (i.e., 36 months, 4% annual revenue adjustment, revenue requirement based on forecasted costs) and residential class revenue decoupling. The MYRP is assumed to begin in 2023.

Optimus is a post-processing tool that relies on extrinsically determined planning scenarios. The fuel cost and load growth sensitivities could reasonably be expected to affect regulatory proceedings, planning strategies and, eventually, resource procurements. The sensitivity results therefore are correct in magnitude and direction insofar as they reflect unexpected alternate futures applied consistently to resource portfolios that are not readjusted in reaction to the sensitivities (i.e., not remodeled in capacity expansion or production cost software). As such, the sensitivities can aid the Commission in evaluating how different resource portfolios are affected by potential real-world circumstances that were not initially analyzed in proposed Carbon Plans. The RMI analysis did not include any portfolio adjustments following its sensitivity analysis.

A.2. Capacity Trends by Technology and Scenario 2022-2050

Figure 11. Annual Capacity by Technology for Duke Resources Scenario, 2022-2050.

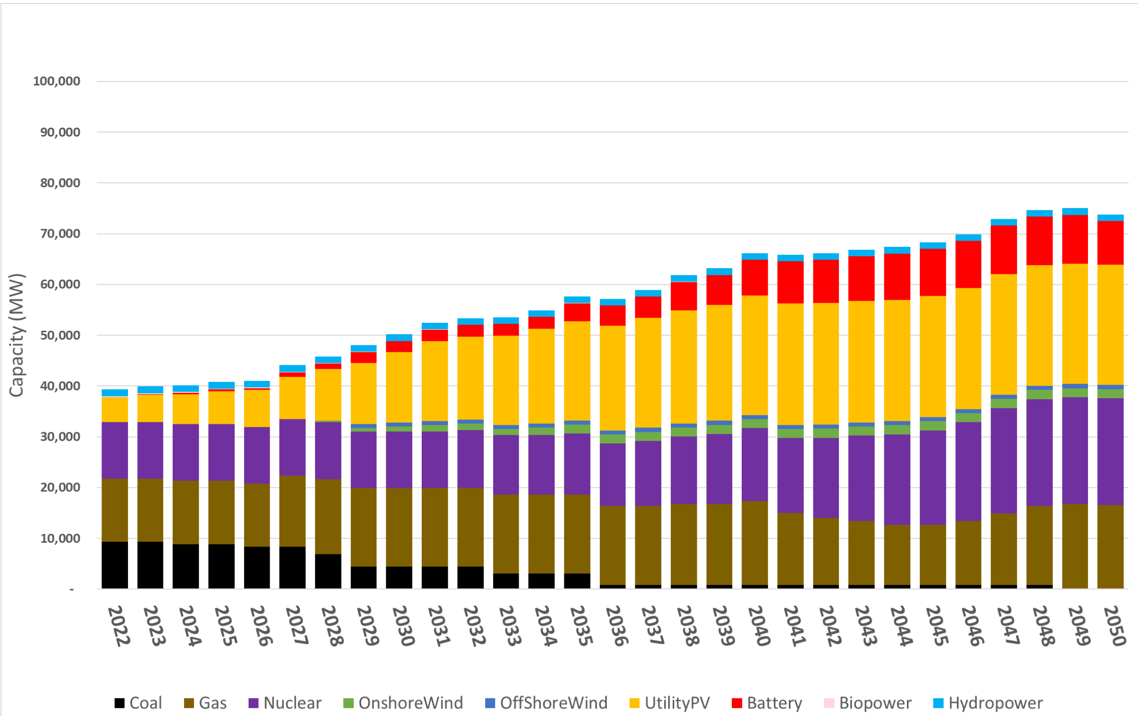


Figure 12. Annual Capacity by Technology for Optimized Scenario, 2022-2050.

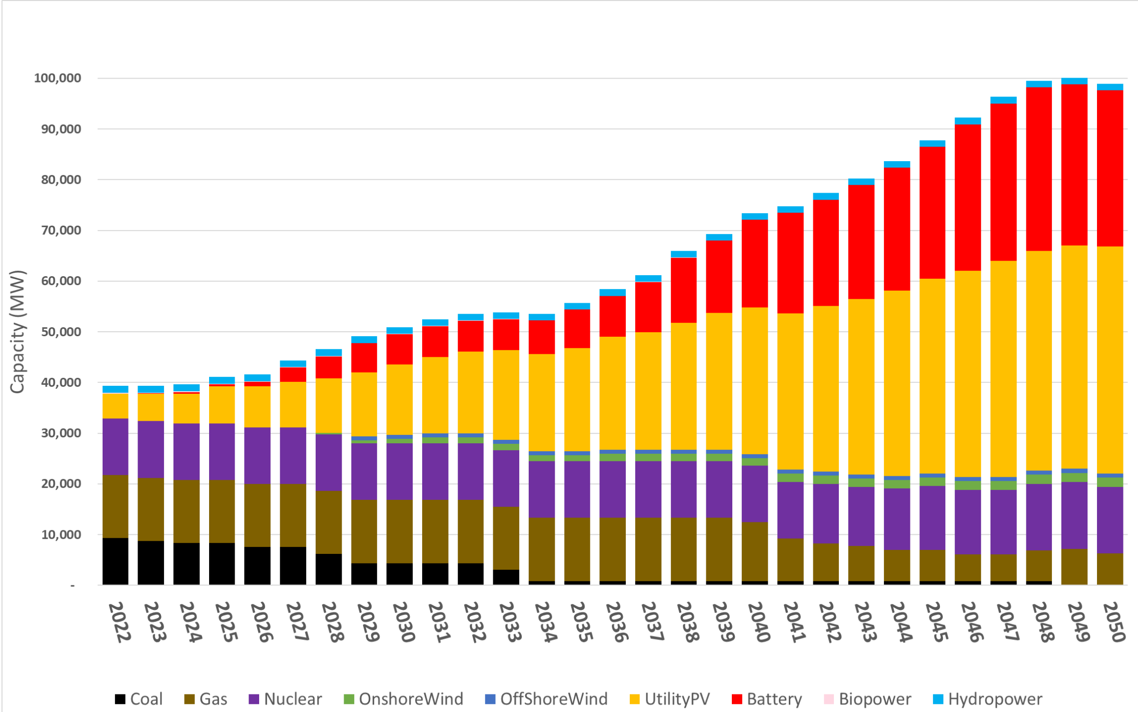
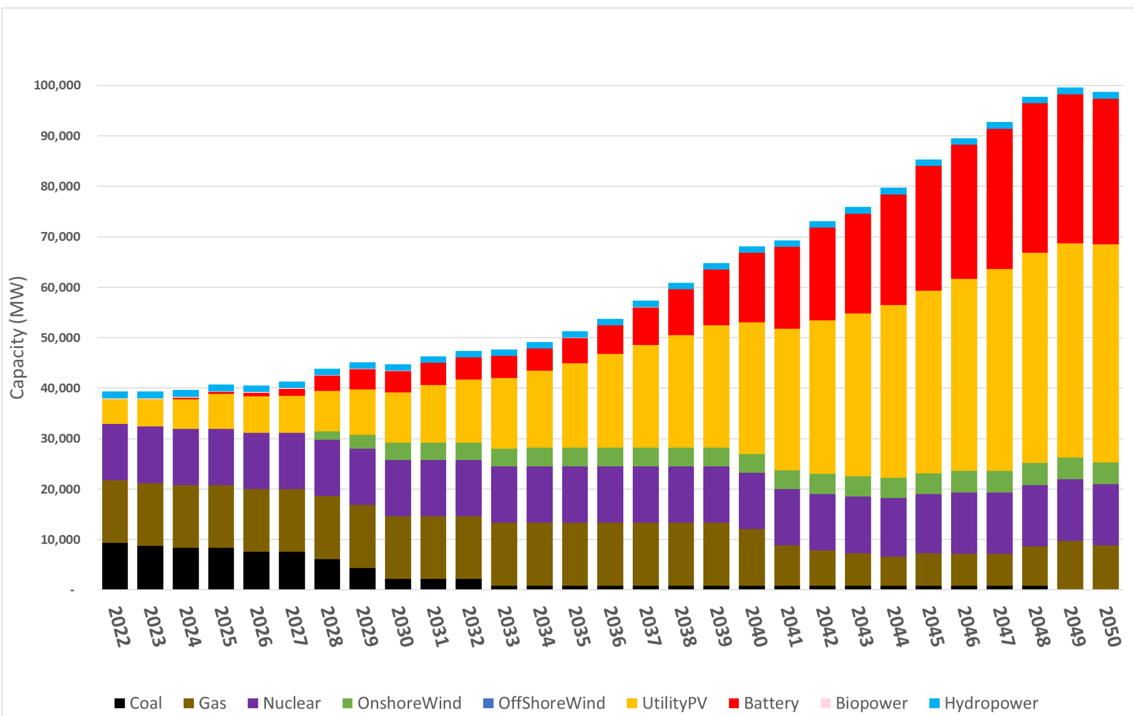


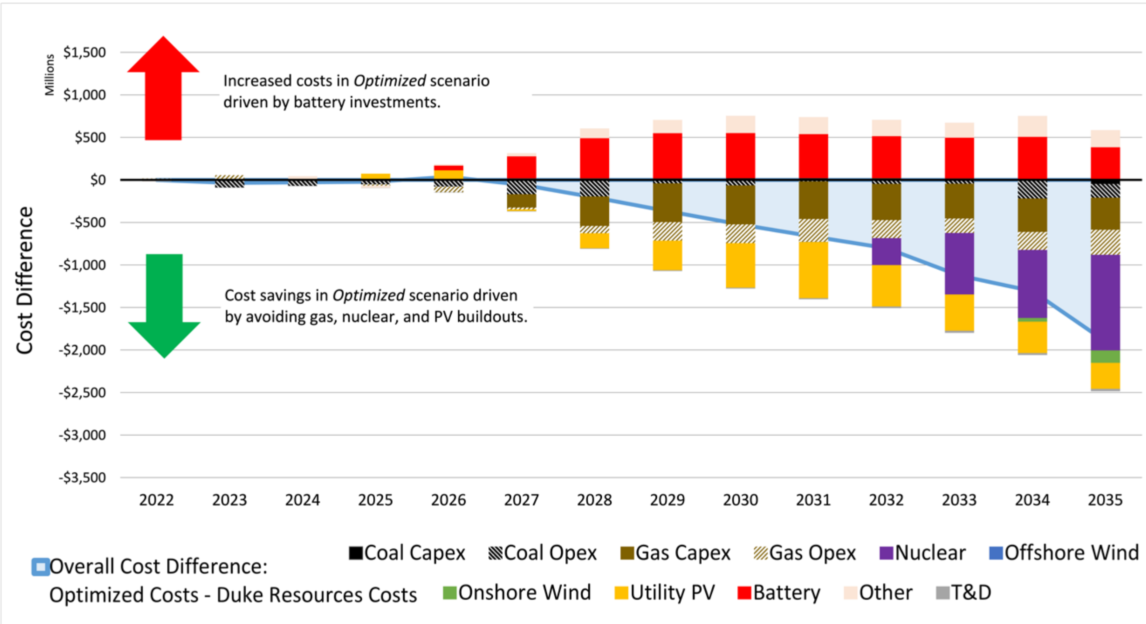
Figure 13. Annual Capacity by Technology for Regional Resources Scenario, 2022-2050.



A.3. Ratepayer Cost and Bill Impact by Technology Type

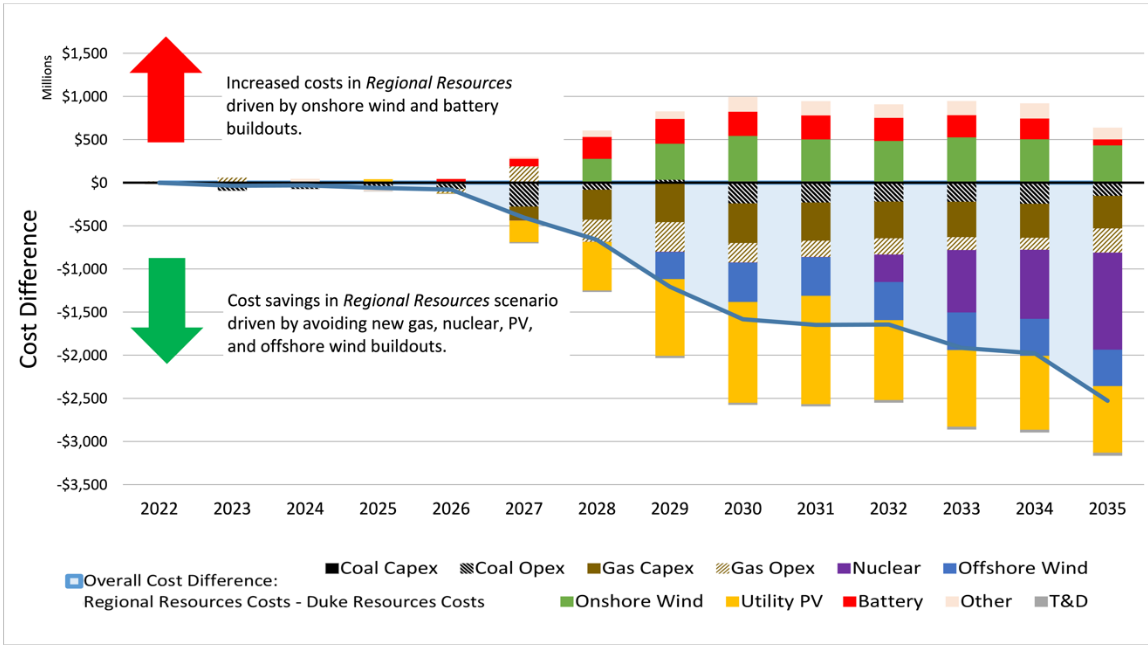
Both the Optimized scenario and the Regional Resources scenario save ratepayers money over the medium term when compared with the Duke Resources scenario when looking at the combined impact across DEC and DEP. In the Optimized Scenario, slight near-term cost increases are driven by faster deployment of utility PV and batteries, while cost savings over the medium term are driven by avoiding buildouts of new gas and nuclear infrastructure as well as utility PV (**Figure 14**).

Figure 14. Ratepayer Cost Comparison by Technology Type, Optimized – Duke Resources, DEC and DEP Combined.



The Regional Resources scenario sees no cost increases in the near term, and higher costs associated with building batteries and onshore wind are offset—with increasing savings over time—by avoiding additional buildout of gas, utility PV, nuclear, and offshore wind (**Figure 15**).

Figure 15. Ratepayer Cost Comparison by Technology Type, Regional Resources – Duke Resources, DEC and DEP Combined.



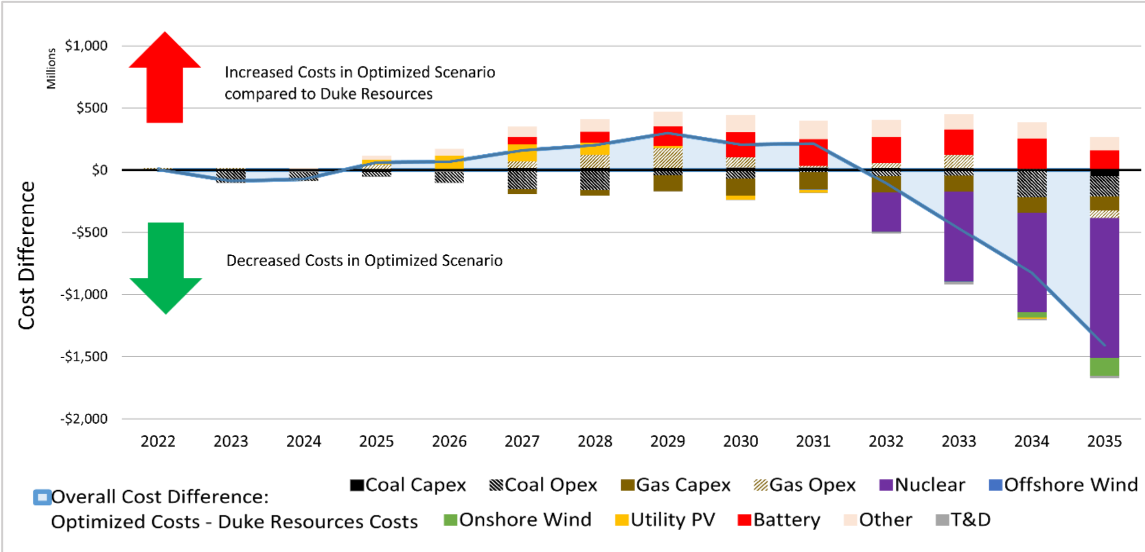
A.4. DEC vs. DEP Ratepayer Cost and Bill Impact

Whereas much of the findings included in the main body of the report reflect a combined DEC and DEP perspective, this appendix describes the differential impact of sensitivity scenarios applied to DEC and DEP as distinct entities.

A.4.1. Annual total ratepayer cost by utility

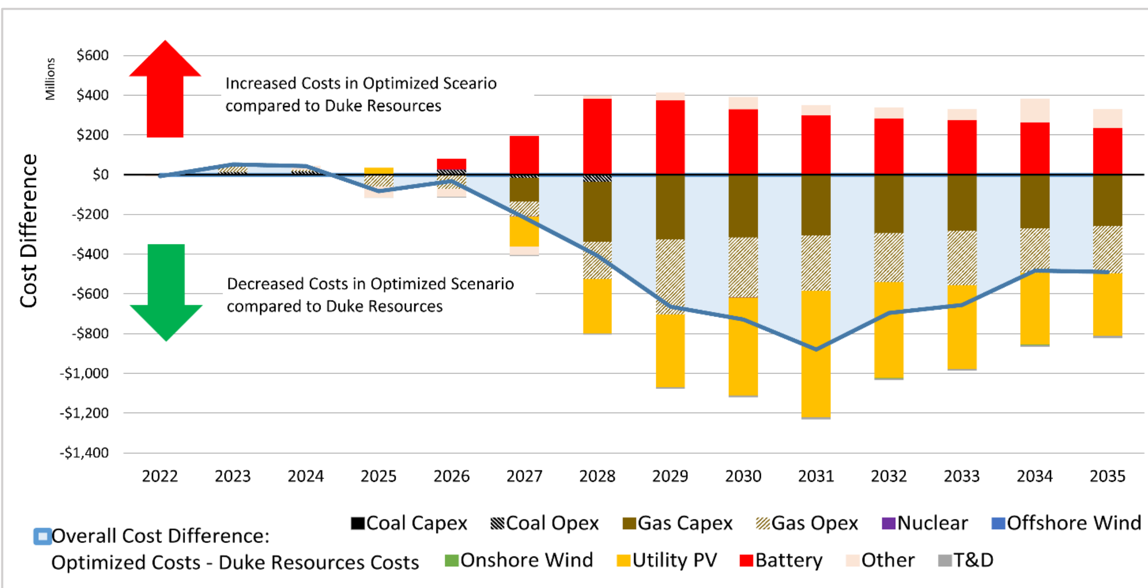
In DEC, the Optimized scenario saves ratepayer costs by avoiding new gas buildout (avoided gas Capex) relative to Duke Resources scenario. However, the ramping of co-fired unit operation (increase in gas operational expenditures, Opex) somewhat counters the avoided gas Capex savings. Additionally, the Optimized scenario also deploys more solar PV and battery in the early years in lieu of gas buildout. Though this is more costly in the near term, the costs associated with nuclear in the Duke Resources scenario in 2032 and beyond are significantly more expensive, driving significant relative savings in the Optimized scenario (***Figure 16***).

Figure 16. DEC Ratepayer Cost Comparison, Optimized – Duke Resources.



In DEP, the Optimized scenario is more cost effective as early as 2025, when investments in battery storage are more than outweighed by combined savings from avoided gas Capex, gas Opex, and utility PV investment costs associated relative to the Duke Resources scenario (***Figure 17***).

Figure 17. DEP Ratepayer Cost Comparison, Optimized – Duke Resources



The significant savings in DEP far exceed the higher near-term costs in DEC between 2027-2031, which is why the DEC-DEP combined chart demonstrates net savings for the Optimized portfolio.

A.4.2. Bill impact by utility and by customer classes

Figure 18 shows that in the Duke Resources scenario, total monthly bills for the average DEP retail customer are overall 10% higher than for the average DEC retail customer in 2030, whereas the DEP residential bills are 30% higher than for DEC residential customers in 2030. This is consistent with Duke's Carbon Plan results, which showed 29% higher residential bills for DEP than for DEC in 2030. The impacts for individual customer classes across time are, however, more nuanced.

In DEP, the Optimized scenario results in lower average monthly bills for residential, commercial, and industrial classes alike, when compared with the Duke Resources scenario (***Figure 18***). In DEC, the Optimized scenario results in similar bills for the residential class through 2030, after which residential bills are lower than the Duke Resources scenario (***Figure 19***). For C&I customers, the Optimized scenario results in higher average bills between 2029-2033, which is driven by the demand-related cost associated with battery deployment.

Figure 18. DEP Average Monthly Bill Change – Duke Resources and Optimized.

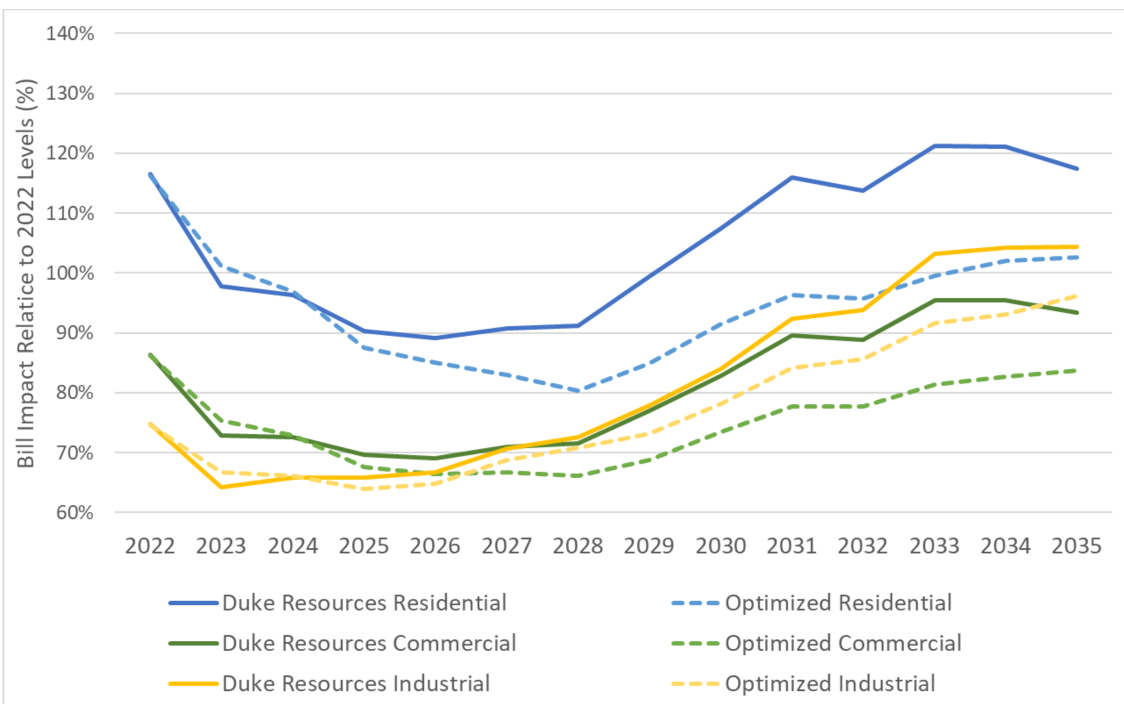
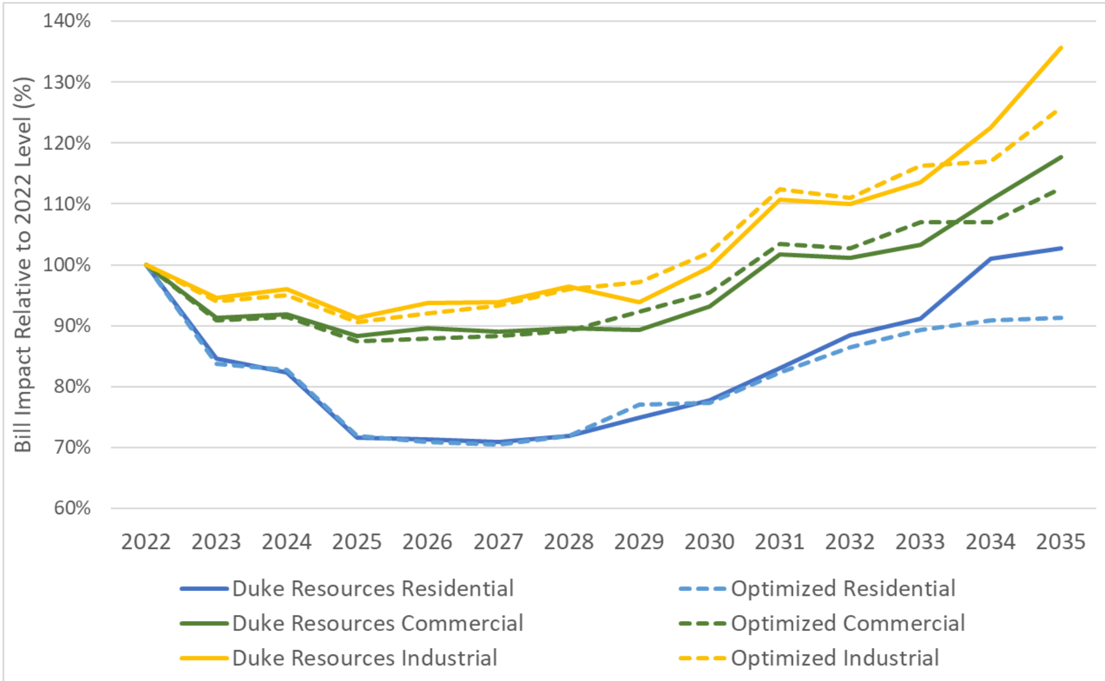


Figure 19. DEC Average Monthly Bill Change – Duke Resources and Optimized.



In contrast, the Regional Resources scenario results in average monthly bills that are lower than the Duke Resources scenario for both DEC and DEP across all customer classes in almost all years (***Figure 20 & 21***).

Figure 20. DEP Average Monthly Bills – Duke Resources and Regional Resources.

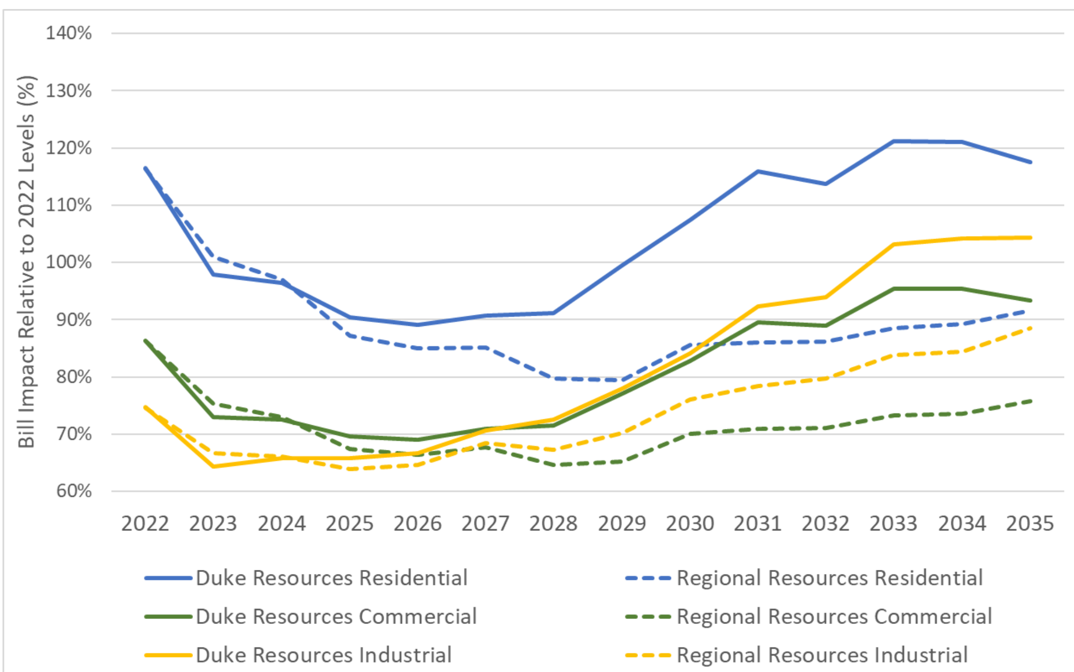
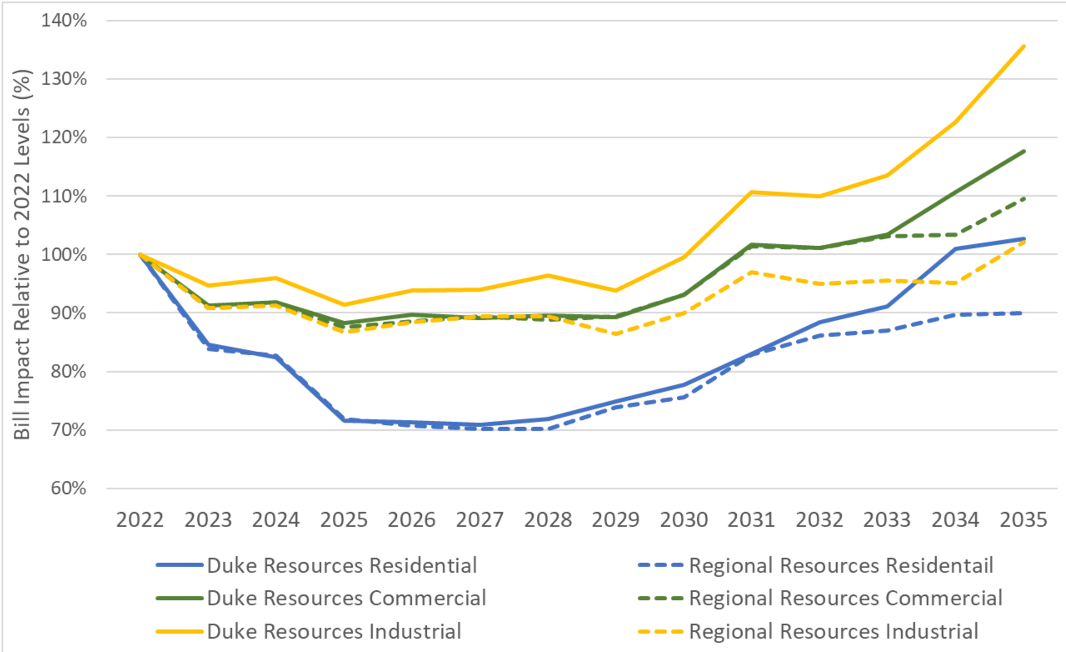


Figure 21. DEC Average Monthly Bills – Duke Resources and Regional Resources.



A.4.3. Bill impact by utility, with sensitivities

Optimus modeling results suggest that the impact of a fuel price spike in the Optimized scenario, while still lower than the Duke Resources scenario on a combined basis, is slightly higher for DEC customers than in the Duke Resources scenario. This is driven by the higher gas utilization in co-fired units in the Optimized scenario. The overall impact across both utilities is mitigated by the savings observed in DEP.

When fuel price and high load sensitivities are applied in tandem, DEC average bill impacts under the Optimized scenario are likewise slightly higher compared to the Duke Resources scenario (***Figure 23)***. The opposite is true for DEP. In contrast, the Regional Resources scenario is equivalent to Duke Resource in both DEC and DEP with high load and fuel price sensitivities (***Figures 22 & 23).***

Figure 22. Average DEP Bill Impact Under Higher Electrification & Fuel Cost Assumptions

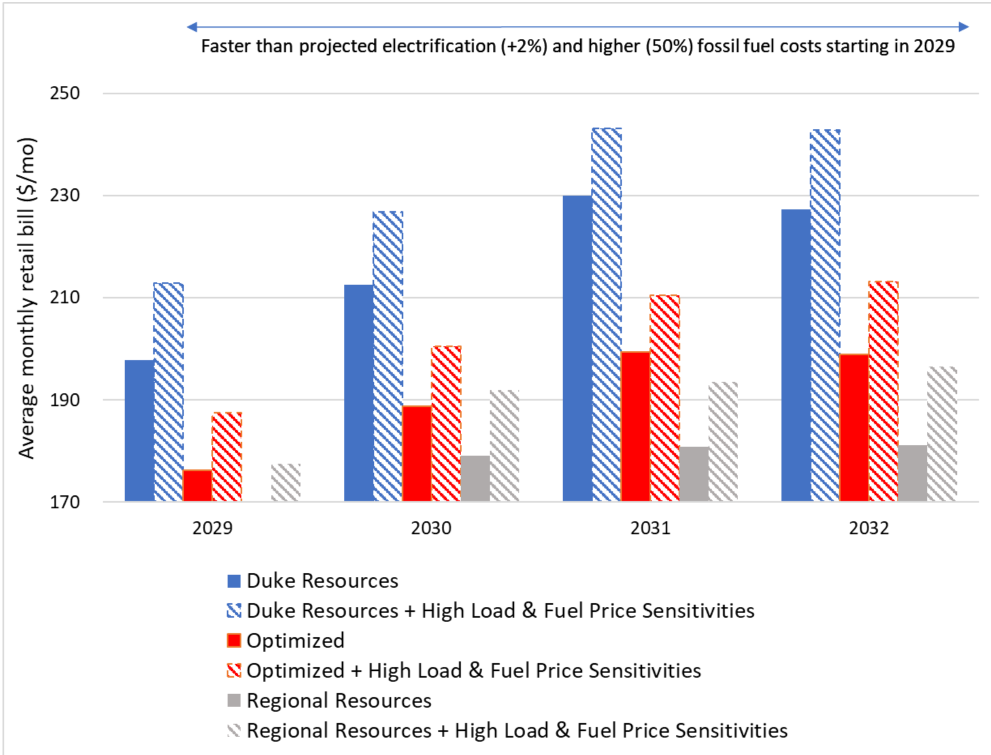
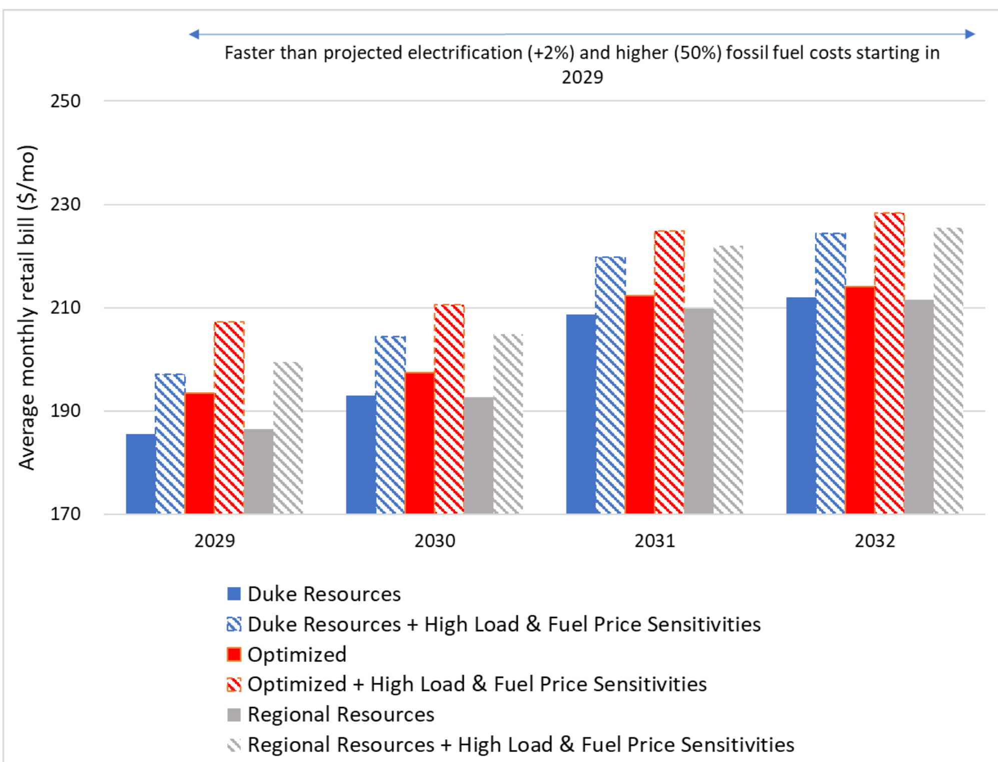


Figure 23. Average DEC Bill Impact Under Higher Electrification & Fuel Cost Assumptions



Figures 24 and 25 illustrate different trends in the impact of PBR between the two utilities. For DEP, both the Optimized scenario and Regional Resources scenario always result in more affordable bills for the average customers compared with the Duke Resources scenario. In contrast, in the absence of PBR, bills in 2032 under both the Optimized and Regional Resources scenarios in DEC are slightly higher than bills under the Duke Resources scenario. However, in the presence of PBR, DEC customer bills in both the Optimized and Regional Resources scenarios are lower than in the Duke Resources scenario at the end of the MYRP period.

Figure 24. Average DEP Bill Effects of a MYRP and Decoupling Under Higher Electrification and Fuel Cost Increases

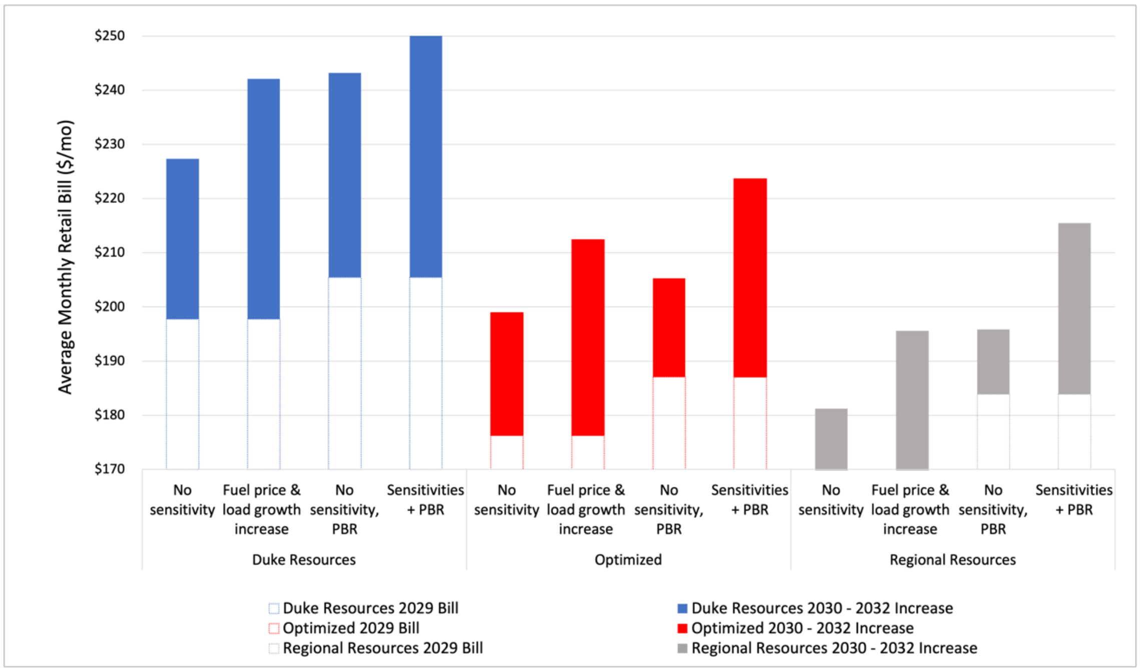


Figure 25. Average DEC Bill Effects of a MYRP and Decoupling Under Higher Electrification and Fuel Cost Increases