INFORMATION SHEET

PRESIDING: Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Duffley, Hughes, McKissick, and Kemerait
PLACE: Dobbs Building, Raleigh, NC
DATE: Friday, September 23, 2022
TIME: 1:15 p.m. – 4:56 p.m.
DOCKET NO(s): E-100, Sub 179
COMPANY: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC
DESCRIPTION: 2022 Biennial Integrated Resource Plans and Carbon Plan

VOLUME NUMBER: 23

APPEARANCES
See Attached

WITNESSES
See Attached

EXHIBITS
See Attached

CONFIDENTIAL COPIES OF TRANSCRIPTS AND EXHIBITS ORDERED BY:

REPORTED BY: Tonja Vines	TRANSCRIPT PAGES: 188
TRANSCRIBED BY: Tonja Vines	PREFILED PAGES: 128
DATE FILED: October 3, 2022	TOTAL PAGES: 316

PLACE: Dobbs Building, Raleigh, North Carolina
DATE: Friday, September 23, 2022
TIME: 1:15 p.m. - 4:56 p.m.
DOCKET NO. E-100, SUB 179
BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Kimberly W. Duffley
Commissioner Daniel. G. Clodfelter
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.
Commissioner Karen M. Kemerait

IN THE MATTER OF:
Duke Energy Progress, LLC, and
Duke Energy Carolinas, LLC,
2022 Biennial Integrated Resource Plans
and Carbon Plan

VOLUME 23

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Table 3: Summary of Carbon Abatement Costs Relative to P1

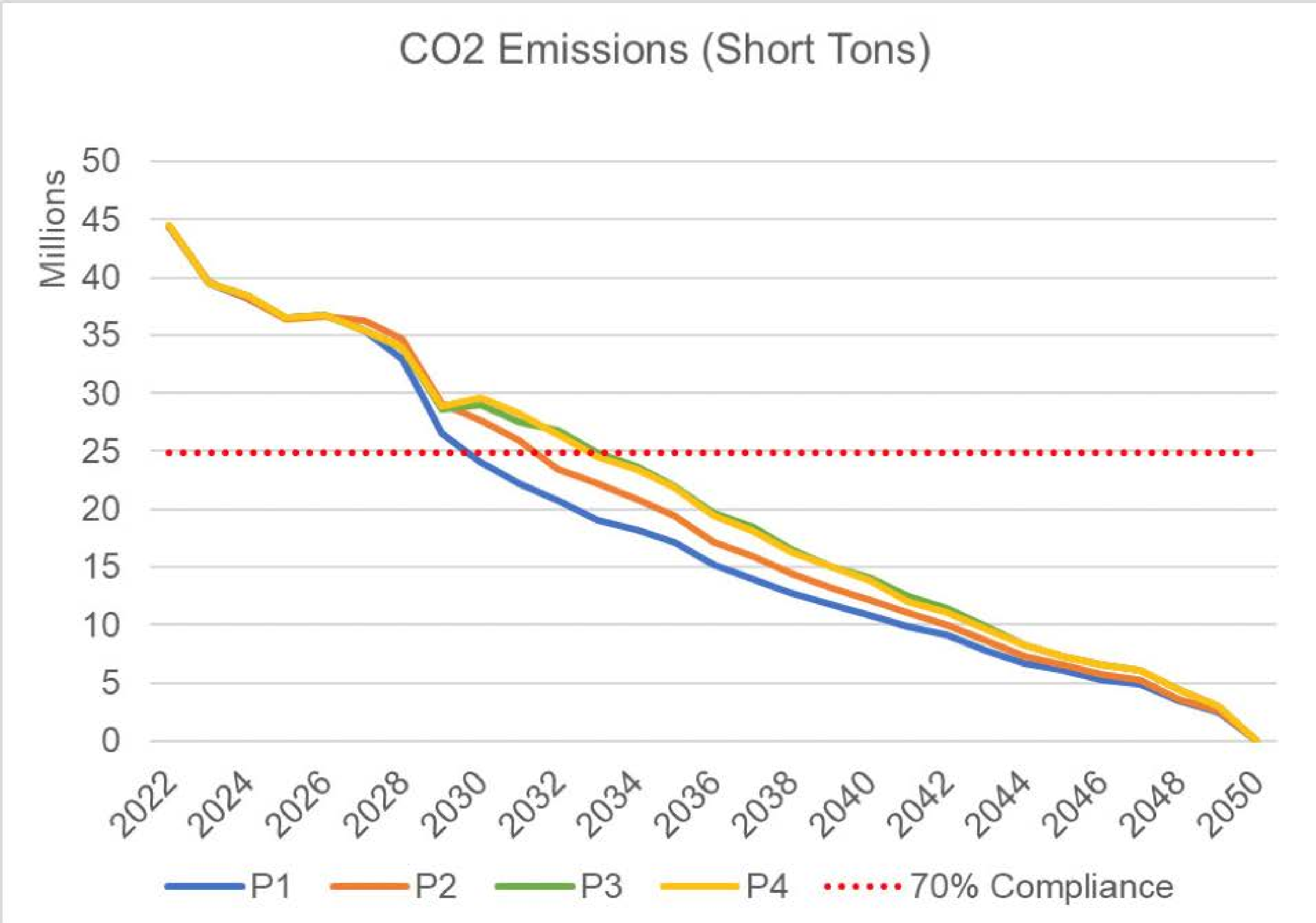
Portfolio	Cumulative CO_2 (M short tons)	Incremental CO_2, Relative to P1 (M short tons)	Total PVRR ($B)	PVRR Savings, Relative to P1 ($B)	Cost of Carbon Abatement ($/short ton)	US Gov SCC[13] ($/short ton)
Through 2035						
P1	412	-	$ 47.3	-	-	$ 61
P2	435	23	$ 45.5	$ (1.7)	$ 76	
P3	448	36	$ 43.9	$ (3.3)	$ 93	
P4	448	36	$ 44.1	$ (3.2)	$ 89	
Through 2050						
P1	532	-	$ 101.1	-	-	$ 61
P2	568	36	$ 98.8	$ (2.3)	$ 65	
P3	601	69	$ 95.2	$ (5.9)	$ 86	
P4	599	67	$ 95.5	$ (5.6)	$ 84	

CIGFUR II & III Public Staff Panel 1 Direct Cross Examination Exhibit 2

I/A

Figure 1 - NC Public Staff
Initial Comments
Docket No. E-100, Sub 179

Figure 1: Annual CO2 Emissions in Each Portfolio



DEC and DEP Combustion Turbine Sites

Utility	Site	# of Units	Notes
DEC	Lincoln CT	16	
DEC	Mill Creek	8	
DEC	Rockingham	5	
DEP	Richmond / Smith	5	Co-located with CC
DEP	Wayne	5	Located adjacent to HF Lee CC facility
DEP	Blewett	4	
DEP	Weatherspoon	4	Located at former coal site
DEP	Darlington	2	Built as multi-unit site, 11 units since retired
DEP	Asheville	2	Co-located with CC at former coal site
DEP	LV Sutton	2	Co-located with CC at former coal site
DEC	WS Lee	2	Co-located with CC at former coal site

Table D-2 from Carbon Plan Appendix D

Table D-2: Combustion Turbines – Existing Generating Units and Ratings

COMBUSTION TURBINES									
		UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	RELICENSING STATUS
DEC	Lee	7C	48	42	Pelzer, SC	Natural Gas/Oil	Peaking	15	N/A
DEC	Lee	8C	48	42	Pelzer, SC	Natural Gas/Oil	Peaking	15	N/A
DEC	Lincoln	1	94	73	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	2	96	74	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	3	95	73	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	4	94	73	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	5	93	72	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	6	93	72	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	7	95	72	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	8	94	72	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	9	94	71	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	10	96	73	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	11	95	73	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	12	94	73	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	13	93	72	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	14	94	72	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	15	94	73	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Lincoln	16	93	73	Stanley, NC	Natural Gas/Oil	Peaking	27	N/A
DEC	Mill Creek	1	94	71	Blacksburg, SC	Natural Gas/Oil	Peaking	19	N/A
DEC	Mill Creek	2	94	70	Blacksburg, SC	Natural Gas/Oil	Peaking	19	N/A
DEC	Mill Creek	3	95	71	Blacksburg, SC	Natural Gas/Oil	Peaking	19	N/A
DEC	Mill Creek	4	94	70	Blacksburg, SC	Natural Gas/Oil	Peaking	19	N/A
DEC	Mill Creek	5	94	69	Blacksburg, SC	Natural Gas/Oil	Peaking	19	N/A
DEC	Mill Creek	6	92	71	Blacksburg, SC	Natural Gas/Oil	Peaking	19	N/A
DEC	Mill Creek	7	95	70	Blacksburg, SC	Natural Gas/Oil	Peaking	19	N/A
DEC	Mill Creek	8	93	71	Blacksburg, SC	Natural Gas/Oil	Peaking	19	N/A
DEC	Rockingham	1	179	165	Reidsville, NC	Natural Gas/Oil	Peaking	21	N/A

COMBUSTION TURBINES

		UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	RELICENSING STATUS
DEC	Rockingham	2	179	165	Reidsville, NC	Natural Gas/Oil	Peaking	21	N/A
DEC	Rockingham	3	179	165	Reidsville, NC	Natural Gas/Oil	Peaking	21	N/A
DEC	Rockingham	4	179	165	Reidsville, NC	Natural Gas/Oil	Peaking	21	N/A
DEC	Rockingham	5	179	165	Reidsville, NC	Natural Gas/Oil	Peaking	21	N/A
DEP	Asheville	3	185	160	Arden, NC	Natural Gas/Oil	Peaking	23	N/A
DEP	Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking	23	N/A
DEP	Blewett	1	17	13	Lilesville, NC	Oil	Peaking	51	N/A
DEP	Blewett	2	17	13	Lilesville, NC	Oil	Peaking	51	N/A
DEP	Blewett	3	17	13	Lilesville, NC	Oil	Peaking	51	N/A
DEP	Blewett	4	17	13	Lilesville, NC	Oil	Peaking	51	N/A
DEP	Darlington	12	131	118	Hartsville, SC	Natural Gas/Oil	Peaking	48	N/A
DEP	Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking	48	N/A
DEP	Smith	1	192	157	Hamlet, NC	Natural Gas/Oil	Peaking	21	N/A
DEP	Smith	2	192	156	Hamlet, NC	Natural Gas/Oil	Peaking	21	N/A
DEP	Smith	3	192	155	Hamlet, NC	Natural Gas/Oil	Peaking	21	N/A
DEP	Smith	4	192	159	Hamlet, NC	Natural Gas/Oil	Peaking	21	N/A
DEP	Smith	6	192	145	Hamlet, NC	Natural Gas/Oil	Peaking	21	N/A
DEP	Sutton	4	49	42	Wilmington, NC	Natural Gas/Oil	Peaking	5	N/A
DEP	Sutton	5	48	42	Wilmington, NC	Natural Gas/Oil	Peaking	5	N/A
DEP	Wayne	1/10	195	169	Goldsboro, NC	Oil/Natural Gas	Peaking	22	N/A
DEP	Wayne	2/11	195	174	Goldsboro, NC	Oil/Natural Gas	Peaking	22	N/A
DEP	Wayne	3/12	195	164	Goldsboro, NC	Oil/Natural Gas	Peaking	22	N/A
DEP	Wayne	4/13	195	162	Goldsboro, NC	Oil/Natural Gas	Peaking	22	N/A
DEP	Wayne	5/14	195	153	Goldsboro, NC	Oil/Natural Gas	Peaking	22	N/A
DEP	Weatherspoon	1	41	31	Lumberton, NC	Natural Gas/Oil	Peaking	52	N/A
DEP	Weatherspoon	2	41	31	Lumberton, NC	Natural Gas/Oil	Peaking	52	N/A
DEP	Weatherspoon	3	41	32	Lumberton, NC	Natural Gas/Oil	Peaking	52	N/A
DEP	Weatherspoon	4	41	30	Lumberton, NC	Natural Gas/Oil	Peaking	52	N/A
Total DEC CT			3,249	2,633					
Total DEP CT			2,898	2,408					
Total NC CT			5,036	4,160					
Total SC CT			1,111	881					
Total DEC/DEP CT			6,147	5,041					

Note: Unit information is provided by state, but resources are dispatched on a system-wide basis.

Note: Resource type based on NERC capacity factor classifications which may vary over the forecast per viod.

Public Staff
Docket No. E-100, Sub 179
2022 Carbon Plan
Public Staff Data Request No. 13
Item No. 13-5

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Beginning on p. 19, the Companies present their plan for wind energy resources.

a. Do the Companies assume that any onshore or offshore wind must be utility-owned (either DEC or DEP – not a Duke affiliate) per HB 951, or are the Companies assuming that a PPA from a merchant generator would suffice?
   i. Please explain how the Companies modeled these wind energy costs and ownership in the Carbon Plan and explain if and how the model included wheeling costs.

RESPONSE:

The Companies are assuming that any onshore or offshore wind shall be utility-owned in accordance with HB951. The Company modeled these resource as utility-owned resources, and not as PPAs, in the Carbon Plan.

As discussed in Appendix J and shown in response to PSDR 5-14, wheeling costs were included for imported wind into DEC. For DEP, the Company assumed onshore wind could be developed within the DEP service territory.

Responder: Matt Kalemba, Director, DET Planning & Forecasting

Virginia Electric and Power Company's 2022 Update to the 2020 Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

Case No. PUR-2022-00147
Docket No. E-100, Sub 182

Filed: September 1, 2022

1.2.2 Small Modular Reactors

SMRs are a classification of nuclear reactors designed to produce up to 300 MW of electricity per reactor. Their modular nature allows for portions of the plant to be factory-fabricated and delivered to the site, improving construction quality and reducing construction timelines. Design improvements to SMRs have reduced the safety risks associated with traditional nuclear technology, and when coupled with their small size and modular construction process, make it possible to locate SMRs on a wide variety of sites, including brownfield sites (*e.g.*, retired fossil-fuel generation sites), existing nuclear power generation sites, other industrial areas, and areas closer to the electric demand.

Among the key benefits and improvements of SMRs over traditional nuclear technology is the increased use of passive safety systems. Passive safety systems rely on natural forces such as gravity, pressure differences, or natural heat convection to accomplish safety functions without the need for operator action or for a power source. This results in a power plant that is simpler, has less equipment, and does not require an emergency source of power. The fabrication of SMRs includes the repeat production of modular assemblies, incorporating a variety of components to a consistent design, reducing cost and time for production, and thus making the SMRs scalable.

Another key advantage of SMRs is their capability to produce electricity around the clock, providing reliability and stability to the electric grid. The SMR designs being developed in the market are also expected to be dispatchable, meaning that they will be able to ramp up and down to meet demand or complement our generation resources within timeframes comparable to natural gas-fired combined cycle facilities, thus providing another resource to ensure that the system remains reliable and resilient for the Company's customers into the future.

Although this technology has not yet been deployed at scale, SMR design activities and regulatory licensing are accelerating both domestically and abroad. The NRC has engaged in varying degrees of pre-application activities with several SMR reactor designers and license applicants. Earlier this year, the NRC issued a final rule certifying the first SMR design in the United States, with others expected to be approved over the next several years.

Based on the status of SMR development, the Company anticipates SMRs could be a feasible supply-side resource as soon as the early 2030s. The Company has thus included SMRs as a supply-side option starting in December 2032 in all Alternative Plans. Starting in 2034, the Company assumed that one 285 MW SMR could be built per year. For some light-water SMR designs that utilize current nuclear fuel technologies with an available supply chain, the commercial availability may be even sooner.

The Company plans to continue evaluating the feasibility, operating parameters, and costs of SMRs and will update modeling assumptions related to SMRs in future filings. Potential cost reductions relative to the assumptions reflected in the 2022 Update may be realized as the design of SMRs matures and as anticipated construction schedules are established. Based on updated capital, operating and maintenance costs, continued progress of licensing timelines, and new policy initiatives or legislative changes, it is conceivable that the deployment of SMRs could be further accelerated by the Company with the first SMR being placed in service within a decade.

Avangrid Renewables, LLC

REQUEST:

1) Please provide the estimated LCOE for an offshore wind project in the Kitty Hawk region, based on an 800 MW block and a 1,300 MW block.[1] Please provide supporting documents and explain major assumptions, such as (but not limited to) the use of HVDC or HVAC cables, transmission upgrades required, transmission landing point in the general vicinity of New Bern/Havelock area, etc.

    a) For each of these projects, please also provide the minimum Power Purchase Agreement (PPA) price that would meet Avangrid's internal rate of return target, assuming that current contingency estimates are sufficient to account for any project cost overruns or delays.

    b) If Avangrid were to sell its Kitty Hawk offshore wind facility to Duke Energy as part of the Carbon Plan, would this sale be based on a $/kW basis, or would other considerations be made?

        i) If such a sale were to be made, what would be the minimum $/kW price that would meet Avangrid's internal rate of return target, assuming that current contingency estimates are sufficient to account for any project cost overruns or delays?

RESPONSE:

LCOE

Objection. This Data Request seeks information that is confidential and proprietary commercial information.

Subject to said objection, and without waiving same, Avangrid Renewables, LLC (herein "Avangrid Renewables" or "Avangrid") wishes to be as open and forthcoming as possible in a discussion of offshore wind pricing. However, pricing is among Avangrid Renewables' most sensitive proprietary and commercial information. While Avangrid can share certain information with the Public Staff to help further its analysis of these issues, Avangrid is unable to share full LCOE or power purchase agreement (PPA) rates without a formal structure that clearly stipulates the requirements of the pricing, for example term, commercial operations date, delivery, credit, minimum/maximum project size, point of interconnection, economic development, port and workforce, and other requirements. Only with these variables controlled, in a format that ensures bidder confidentiality, will an apples-to-apples comparison be possible. A true comparison holds all potential developers accountable to honor their proposals – whether for LCOE, PPA, or raw

[1] This amount is based on Avangrid's comments on page 11 of its Initial Comments, in which Avangrid stated that, "[c]urrently, HVDC technology can transmit approximately 1,320 MW per 320 kV circuit." If Avangrid anticipates that a different size block may better represent the offshore wind capacity available to Duke Energy through a PPA, please modify this number and provide an explanation for the capacity used.

inputs - and provides appropriate protections for confidentiality. If the Commission were to design and implement such a process – for example, through a third-party study of owner-provided inputs, as recommended in Avangrid Renewables' Limited Comments, or an RFP – Avangrid Renewables would look forward to sharing any and all input information requested with the Commission and the Public Staff.

Notwithstanding the foregoing reservations, Avangrid Renewables is prepared to share the relative difference in LCOEs between an 800MW and 1,300MW project, assuming both use high voltage, direct current ("HVDC") technology. Avangrid Renewables believes HVDC technology to be a necessity for any project developed out of the Kitty Hawk Wind lease area or either of the Carolina Long Bay (CLB) lease areas, given the technical limits of HVAC technology and the export cable lengths required to reach the most likely POI options: New Bern, Greenville, and Havelock. Importantly, HVDC transmission is a fixed cost while most other costs in OSW development, construction, and operation scale with size. As such, Avangrid Renewables believes the difference in LCOE between an 800 MW and 1,300 MW project developed in any of the three lease areas offshore of the Carolinas is a savings of approximately $10/MWh to the LCOE, which reflects the benefit of spreading an $700M+ total HVDC investment over 500 more MW.

Several of the core inputs to the Kitty Hawk (and potential CLB projects') LCOE(s) are available in Avangrid Renewables' Limited Comments, as reflected in the table below (the tables in Appendix I include additional critical factors):

	OCS-A 0508 "Kitty Hawk" Avangrid Renewables	OCS-A 0545 "CLB West" TotalEnergies Renewables USA	OCS-A 0546 "CLB East" Duke Energy Renewables Wind
Acres	122,405	54,937	55,154
Lease Price (2022$)	$11 million	$160 million	$155 million
Est. NCF[A]	43%	36%	36%
Est. Capacity[B]	~2.5 GW	0.6 – 1.3 GW [C]	0.7 – 1.3 GW [C]
Earliest COD	2029	2032	2032

Note A: NCF: Net Capacity Factor
Note B: Assuming 15-MW wind turbine generator power rating[27], ~0.75x1.25 spacing.
Note C: Range due to potential 24-nautical mile viewshed buffer, requested by North Carolina Delegation.[28]

The NCF, earliest COD, and lease cost are the biggest differentiating factors between Kitty Hawk and CLB lease areas, as other terms (including project size – as every lease area has the potential to support a 1.3 GW project – and project life/contract terms, CapEx – except lease price, OpEx, etc.) could be similar between projects.

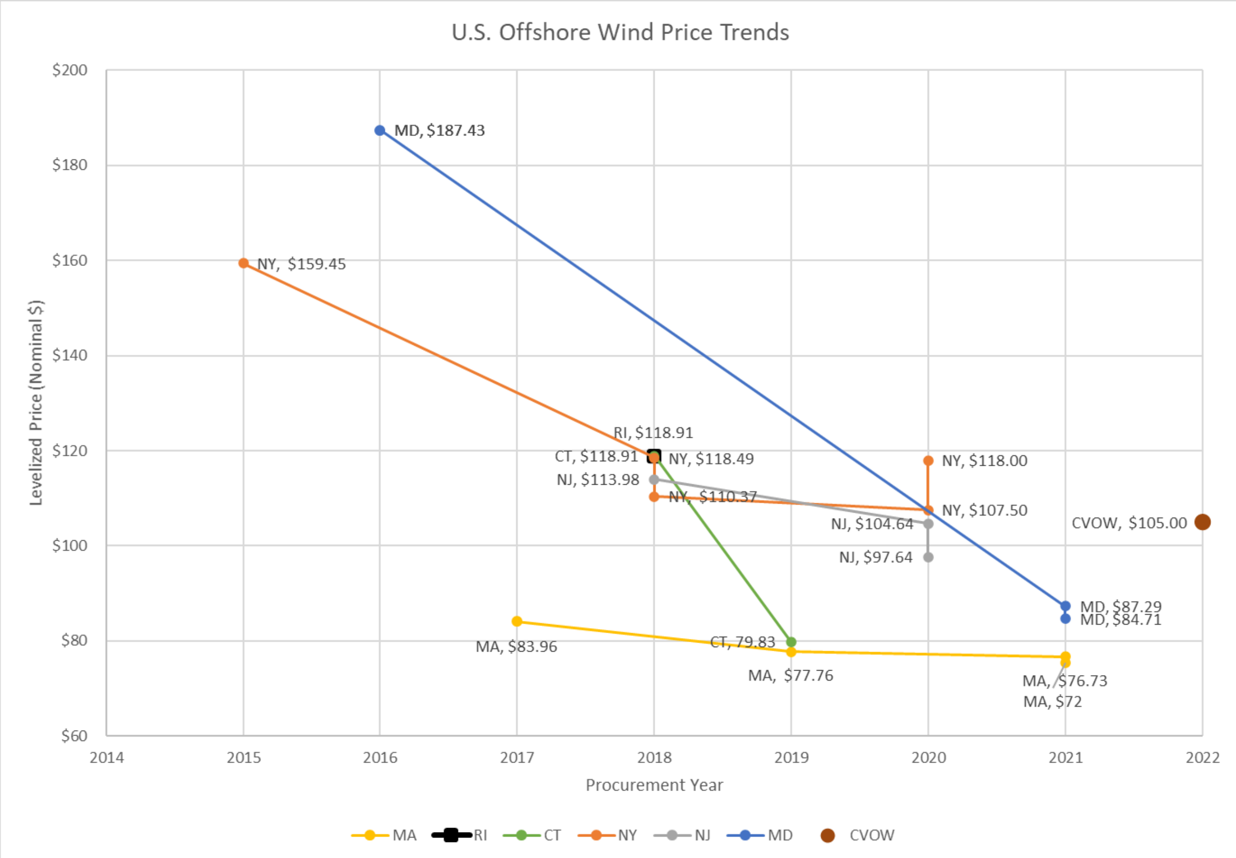
PPA Price

Developing a PPA price is a major and time-intensive commitment that is undertaken through a formal or negotiated process resulting from detailed analysis and an understanding of the project requirements. North Carolina does not currently have a marketplace structure that enables transparent PPA pricing in the way it does for utility scale solar. As a result, while the company appreciates the purpose of the Staff's question to improve price discovery for offshore wind, Avangrid Renewable cannot reasonably provide a PPA price at this time.

Competitive price discovery in other state jurisdictions pursuing offshore wind power contracts has been critical to relieving electricity consumers of development risk and incentivizing lowest cost LCOE. To achieve relative price discovery in this proceeding, Avangrid Renewables has recommended a third-party study (or another formal process to ensure accountability, apples-to-apples comparisons, and confidentiality) to develop the LCOEs of each lease area available to serve load for Duke's North Carolina utilities by collecting and verifying key project inputs from owners. The results of this study would differentiate project characteristics and costs and could be used to identify a "bid stack" that would prioritize the lowest cost LCOE projects and bring them online first.

Avangrid Renewables, as part of the Vineyard Wind joint venture, has responded to six competitive requests for proposals for offshore wind utility PPAs or offshore renewable energy credits ("ORECs"). Responses were submitted to Massachusetts, Connecticut, and New York. The joint venture was successful in three competitive solicitations – twice in Massachusetts and once in Connecticut. The resulting total contract awards were approximately 2,800 MW.

Experience in these competitive requests for proposals has shown that utility and state evaluators typically award contracts to offshore wind developers based on a combination of price, economic benefits, and viability, generally with a heavy weighting towards price. This auction dynamic requires offshore wind developers to maximize benefits for electricity consumers by strenuously pursuing lowest costs, maximizing economic development, and developing the most viable solutions. The latter is particularly critical for developers, which only recover initial lease acquisition and development cost if projects achieve commercial operation and deliver energy, environmental attributes, and other revenue streams (e.g. capacity, ancillary services as eligible) through the terms of a PPA or OREC contract.



Project developers normally provide PPA or OREC proposals as part of a formal process with the expectation that prices are actionable, and that the developer will need to stand behind those prices through agreed-to contract commitments. The development of PPA or OREC prices result from a four- to six-month process of constant refinement of key cost variables, including, among other things: project net capacity factor ; project delivery timeline; development costs; quotes from suppliers for major offshore wind components (wind turbine generators, monopiles foundations, offshore export cables, electric service platforms, and array cables); transmission upgrade costs; vessel, construction, and installation costs; required or proposed economic and ports investments; and contingency. Proposals also include financial considerations such as the cost of capital and incentives, such as the Investment Tax Credit achievable at the time of expected project delivery. Pricing is directly informed by the formal terms offered by the PPA or OREC solicitation. Such terms include length of contract, offtake to be purchased (e.g. energy, RECs, other environmental attributes, capacity, and ancillary services), and project commitments (e.g. local siting, economic development, ports, workforce, and other commitments).

As Avangrid Renewables proposed in its comments, a third-party study is one way Public Staff, other intervenors, and the Commission can identify relative project/lease areas' LCOEs. The

Commission could also invite a formal process by which relative project lease area LCOEs could be discovered. The process would be less complex and formal than proposing a PPA price, which is developed with the expectation of meeting a transaction commitment but could provide key information for decision-makers. Such a request would ask lease holders to provide best available information on key variables of difference between the lease areas, including NCF and lease area costs. This information could be used in the EnCompass model to inform the relative LCOE of the project areas and determine a preferred "bid stack" for offshore wind's participation in the carbon plan. Developers could provide a response to such a request with a reasonably short time period – depending on the detail required, between two and eight weeks.

Terms of Potential Sale

In the case of a sale of the Kitty Hawk lease area, the pricing structure would be based on a number of considerations. Avangrid does not have an innate preference for a particular basis of payment. Different ownership and project delivery structures may require different payment styles – for example a scenario in which Duke purchases the entire asset at once, may be best accomplished through a one-time payment based on expected capacity ($/kW) or similar metric. Another case, in which Duke purchases some amount of the lease and retains Avangrid for services may be better served through some combination of fixed payments and variable payments.

Any future bilateral transaction would result from detailed negotiations that aim to satisfy the mutual interests of the parties. In addition to the factors described in the response to the previous question, the answer would greatly depend on the size of the lease area sold, which assets in addition to the lease are included in the sale, the stage of development at which the sale occurs, and the contractual terms of the sale.

Response Provided by: Becky Gallagher and Eric Thumma, Avangrid Renewables, LLC.

Kitty Hawk North Wind Project

PERMITTING DASHBOARD PROJECT POSTING DATE: FEBRUARY 12, 2021

All dates below are specific to the schedule of the Environmental Review and Permitting processes for this project.

ENVIRONMENTAL REVIEW AND PERMITTING STATUS
IN PROGRESS

ESTIMATED COMPLETION DATE OF ENVIRONMENTAL REVIEW AND PERMITTING
SUBJECT TO CHANGE

0 out of 11
ENVIRONMENTAL REVIEW AND PERMITTING PROCESSES COMPLETED

SECTOR
Renewable Energy Production

CATEGORY
Project Category FAST-41 Covered Projects

LEAD AGENCY
Department of the Interior, Bureau of Ocean Energy Management

Other Agencies with Actions or Authorizations:

Department of the Army, US Army Corps of Engineers - Regulatory

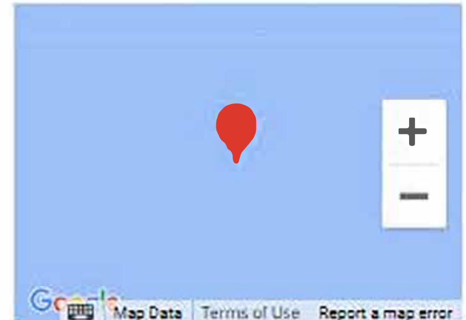
Department of the Army, US Army Corps of Engineers - Civil Works

Department of Commerce, National Oceanic and Atmospheric Administration

Department of the Interior, Fish and Wildlife Service

View more...

Coordinates



Primary Location

Coordinates
36.228221, -75.435297

Lead Agency Information:

POC Name: Ian Slayton
POC Title: NEPA Coordinator
POC Email: ian.slayton@boem.gov
Agency/Department: Bureau of Ocean Energy Management

Sponsor Contact Information:

Project Sponsor:
Kitty Hawk Wind LLC
POC Name: Marcus Cross
POC Title: Project Director
POC Email:
marcus.cross@avangrid.com

Description:

Update: In June 2022, the project name changed from Kitty Hawk Wind Project to Kitty Hawk North Wind Project to reflect the segmenting of the project.

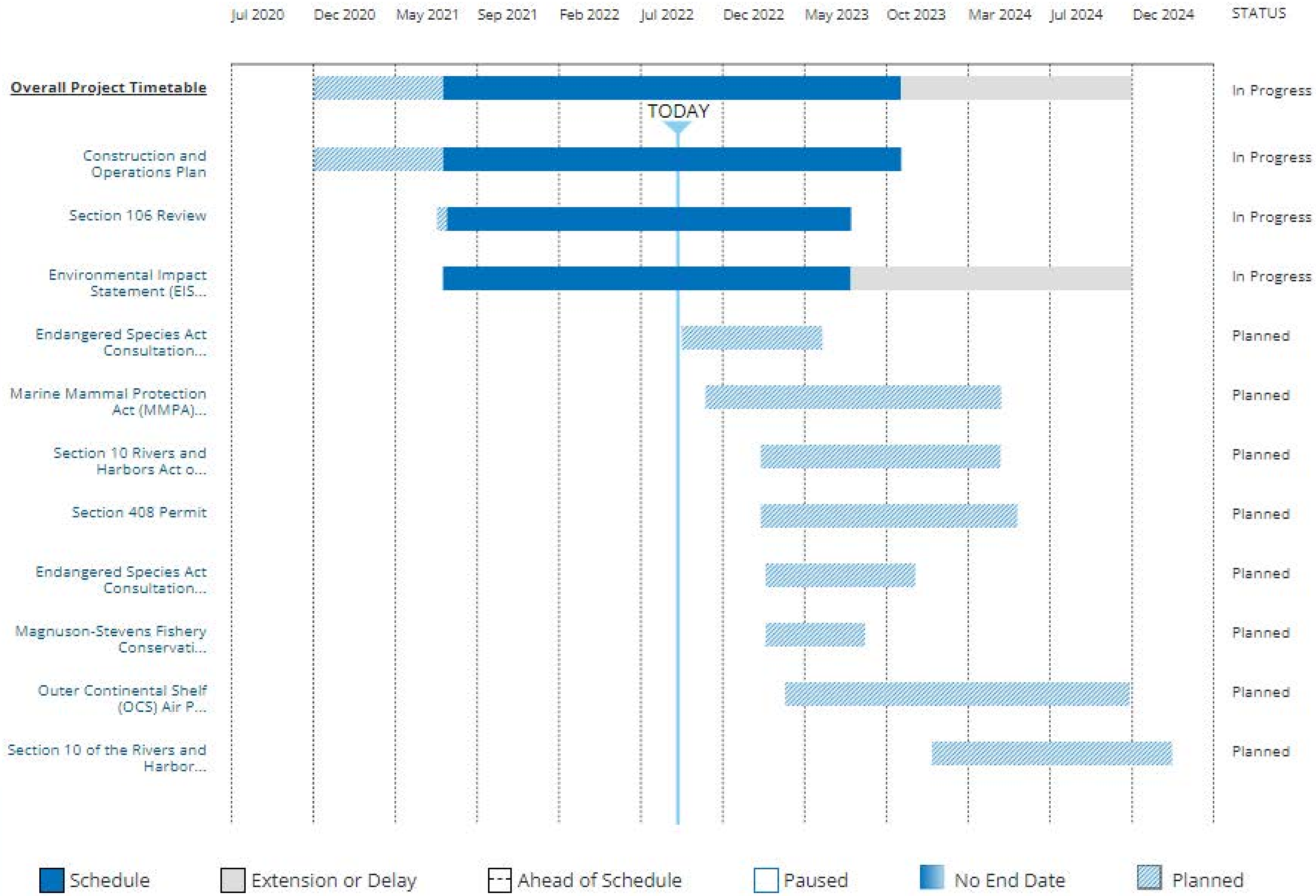
The purpose of the Kitty Hawk North Wind Project is to develop a commercial-scale, offshore wind energy facility in Commercial Lease OCS-A 0508 offshore North Carolina, with up to 69 total wind turbine generators, 1 offshore substation (also called "electrical service platform"), inter-array cables, 1 onshore substation, and up to 2 transmission cables making landfall in Virginia Beach, Virginia, and connecting to the Pennsylvania-New Jersey-Maryland (PJM) Interconnection energy grid. Kitty Hawk is actively seeking one or more power purchase agreement awards for this project. The project is intended to substantially contribute to the region's electrical reliability and help Virginia achieve its renewable energy goals as stated in the Virginia Clean Economy Act.

FAST-41 provides increased transparency and predictability by requiring Federal agencies to publish comprehensive permitting timetables for all "covered" projects, and provides clear procedures for modifying permitting timetables to address the unpredictability inherent in the environmental review and permitting process for significant infrastructure projects. For more information, see "The FAST-41 Process" at https://www.permits.performance.gov/fpisc-content/fast-41-process.

Permitting Timetable

The permitting timetable below displays data as reported by agencies. Dates for Environmental Review and Permitting processes (Actions) that are in 'Paused' or 'Planned' status are subject to change and are not indicative of a project's final schedule.

- For information about extensions, select an Action from the timetable below and select 'View Action Details' at the bottom of the page.



Action Information

For additional information, please select an Action from the Permitting Timetable above.

I/A

Duke Energy Avangrid Direct
Cross-Examination Exhibit 2
Page 1 of 3

PERMITTING DASHBOARD
FEDERAL INFRASTRUCTURE PROJECTS

ABOUT PROJECTS RESOURCES & TOOLS FAST-41 DATA PORTAL

Home

Kitty Hawk South Offshore Wind Project

PERMITTING DASHBOARD PROJECT POSTING DATE: MAY 12, 2022

PROJECT WEBSITE: http://www.KittyHawkOffshore.com

All dates below are specific to the schedule of the Environmental Review and Permitting processes for this project.

ENVIRONMENTAL REVIEW AND PERMITTING STATUS
IN PROGRESS

ESTIMATED COMPLETION DATE OF ENVIRONMENTAL REVIEW AND PERMITTING
SUBJECT TO CHANGE

0 out of 10

ENVIRONMENTAL REVIEW AND PERMITTING PROCESSES COMPLETED

SECTOR
Renewable Energy Production

CATEGORY
Project Category FAST-41 Covered Projects

LEAD AGENCY
Department of the Interior, Bureau of Ocean Energy Management

Other Agencies with Actions or Authorizations:

Department of Commerce, National Oceanic and Atmospheric Administration

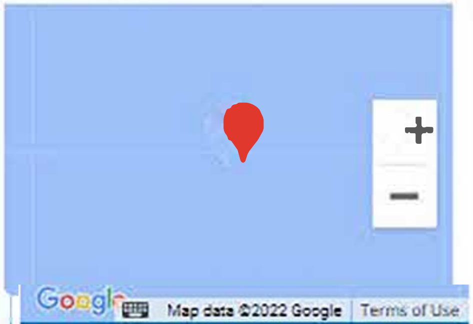
Department of the Army, US Army Corps of Engineers - Regulatory

Department of the Army, US Army Corps of Engineers - Civil Works

Department of the Interior, Fish and Wildlife Service

View more...

Coordinates



Primary Location

Coordinates
36.3071193, -75.066826

Lead Agency Information:

POC Name: Ian Slayton
POC Title: NEPA Coordinator
POC Email: ian.slayton@boem.gov
Agency/Department: Bureau of Ocean Energy Management

Sponsor Contact Information:

Project Sponsor:
Kitty Hawk Wind LLC
POC Name: Marcus Cross
POC Title:
Director - Business Development, Avangrid Renewables, LLC
POC Email:
marcus.cross@avangrid.com

Description:

Update: In June 2022, the project name changed from Kitty Hawk Wind Project to Kitty Hawk South Wind Project to reflect the segmenting of the project.

Kitty Hawk Wind, LLC proposes to construct, own, and operate the Kitty Hawk South Offshore Wind Project. The Project will be located in the designated Renewable Energy Lease Area OCS-A 0508 (Lease Area). The Commercial Lease of Submerged Lands for Renewable Energy Development on the Outer Continental Shelf of Lease Area OCS-A 0508 was awarded through the BOEM competitive renewable energy lease auction of the Wind Energy Area offshore of North Carolina. The Lease Area covers 49,536 hectares (ha) and is located 44 kilometers (km) offshore of Corolla, North Carolina.

At this time, the Company is proposing to develop the Kitty Hawk South Offshore Wind Project in the eastern portion of the Lease Area (33,768 ha; referred to as the Wind Development Area), located approximately 61 km east of Corolla, North Carolina and approximately 54 km northeast of Kill Devil Hills, North Carolina. The offshore components of the Project, including the WTGs, offshore substations, and inter-array cables, will be located in federal waters within the Lease Area. The offshore export cable corridor will traverse both federal waters and state territorial waters of Virginia and/or North Carolina. Onshore Project components, including the export cable landfall location(s), onshore export and interconnection cables, and onshore electrical facilities, will be located in one or more of the following:

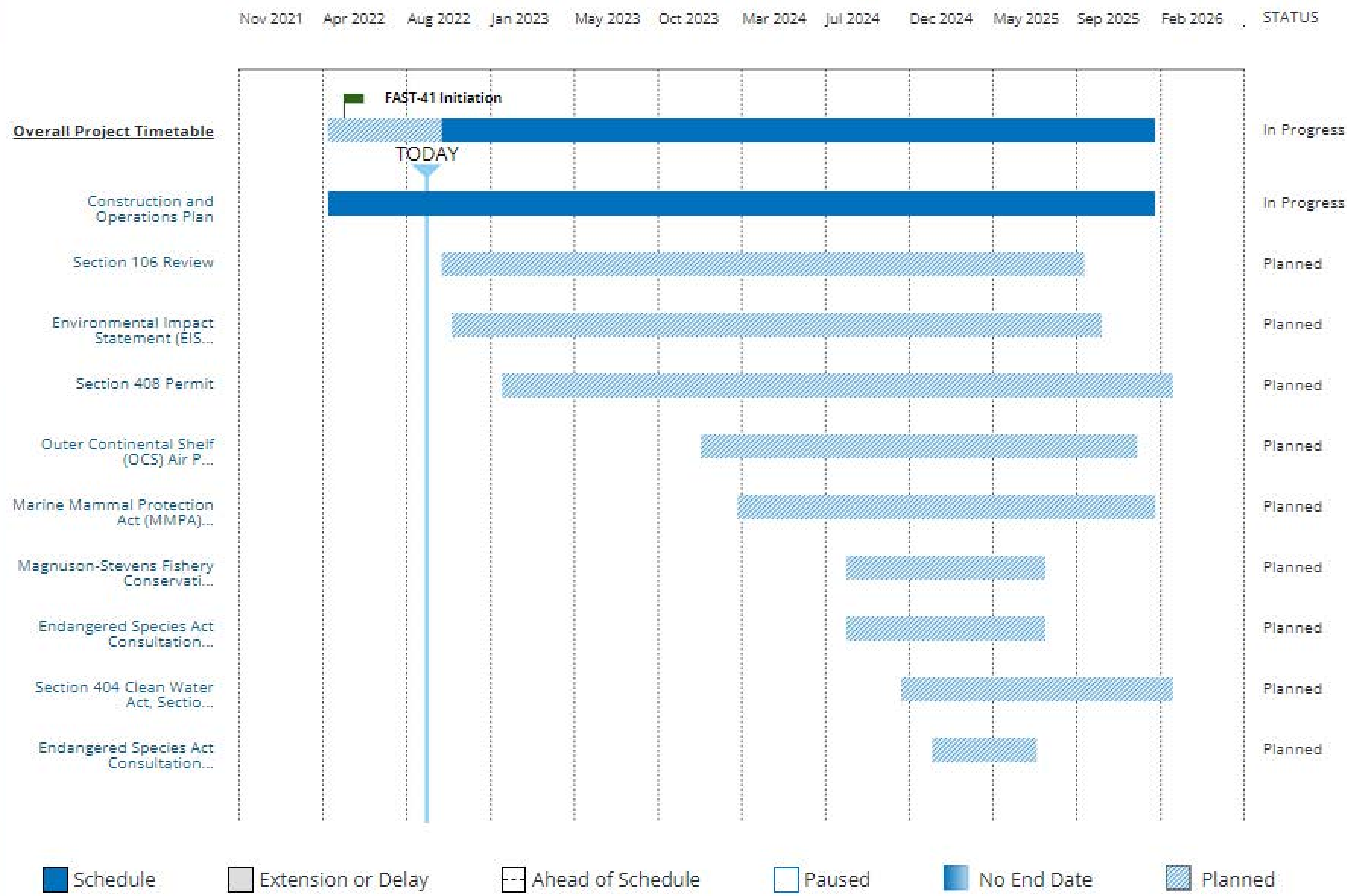
- City of Virginia Beach, Virginia;
- Dare County, North Carolina;
- Carteret County, North Carolina; and
- Craven County, North Carolina.

A COP for the Project, which includes detailed assessments of environmental, cultural, and historic resources, was submitted to BOEM on April 14, 2022.
Additional Project information is located at www.KittyHawkOffshore.com.

Permitting Timetable

The permitting timetable below displays data as reported by agencies. Dates for Environmental Review and Permitting processes (Actions) that are in 'Paused' or 'Planned' status are subject to change and are not indicative of a project's final schedule.

- For information about extensions, select an Action from the timetable below and select 'View Action Details' at the bottom of the page.



Action Information

For additional information, please select an Action from the Permitting Timetable above.

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Regarding the first sentence of the last paragraph on p. 24 that presents the Companies' planned "substantial development work on three longer lead time resources":

a. Please describe why the Companies believe that the Commission must approve the development plans specified by Duke at this point in time.
   i. Do the Companies believe that they cannot consider and evaluate these longer lead time resources absent NCUC approval of a development plan? If so, please explain why.
b. Do the Companies intend to pursue approval of a development plan for these longer lead time resources from the PSCSC? If so, when? If not, why not?
c. Please provide previous examples of Duke's requests for development plan approval for new generation assets from the NCUC. Please explain if the NCUC approved these requests and where the development was described in Duke's Integrated Resource Plans.
d. During the planning phase of the currently operational Bad Creek Hydro facility, did the Company request a development plan approval from the NCUC or PSCSC? If so, please provide docket numbers for the Company's request and Commission ruling of said request.
e. Reference Figure 6 in Duke's Carbon Plan, SMR (New Nuclear) is listed as a resource in Portfolios 3 and 4, but no new nuclear is selected in P1 and P2 prior to 2034. Please describe why a development plan for SMRs must be approved by the NCUC in the 2022 Carbon Plan if Portfolio 1 or 2 is selected.
f. The Companies have requested approval of development activities for multiple technologies in this filing. Please provide a summary of: (1) all expected development activities (listing deliverables and scope), (2) estimated annual costs and total costs, (3) labor requirements (hours and additional employees), (4) timeline of the development activities (listing key milestones), (5) expected cost accuracy, (6) how the costs of the development activities are expected to be recovered (R&D, CWIP, plant held for future use, etc.), and (7) how these expected development activities are factored into the PVRR analysis.
g. Are the Companies proposing a maximum cap or annual cap on how much they spend on development activities? Discuss why or why not.
h. Please list all reporting requirements or conditions that the Companies believe should be part of an approved development plan.

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DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

RESPONSE:

a. The development activities reflected in the Carbon Plan are necessary to ensure a diversity of resources and technologies are available as options to meet the CO2 reductions targets and future resource needs. It is appropriate for the Commission to approve the proposed development activities in light of the Commission's responsibility to both develop a Carbon Plan and select the new generation resources and other resources to be utilized to achieve HB 951 CO2 reduction targets. This request is also consistent with the intent and purposes of G.S. 62-110.7.

b. The Companies have not made a determination at this time regarding future requests to the PSCSC in this respect.

c. The Companies object to this request as it calls for legal analysis, research, and conclusions and furthermore, seeks information regarding Commission precedent that is publicly available.

d. The Companies object to this request as it calls for legal analysis, research, and conclusions and, furthermore, seeks information regarding NCUC and PSCSC precedent that is publicly available. Notwithstanding such objection, the Companies are not aware at this time of a request for development plan approval for the currently operational Bad Creek Hydro facility from the NCUC or PSCSC.

e. As an initial matter, the Companies do not believe it is necessary at this time for the Commission to select among the four portfolios. However, SMRs are needed under all portfolios by 2033 at the latest (end of 2032 for P1, P3 and P4 and end of 2033 for P2). Importantly, the exact window of need could evolve over time under all portfolios, in part due to any future potential execution challenges arising with respect to other resources. Finally, commencing work on an Early Sight Permit (ESP) is reasonable because an ESP can be approved for up to 20 years and can be renewed for up to 20 additional years.

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The following is the responsive information, broken out by technology type for the three long-lead time resources. In general, the generic costs assumed in the modeling and the PVRR analysis include all costs necessary to construct such resources, including the development costs. The Companies expect that the development costs will be recovered through base rates. The

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Companies are currently considering whether CWIP cost recovery will be necessary in certain cases.

In the case of supply-side resources with longer lead times and greater external dependencies – offshore wind, SMRs, and pumped storage hydro – substantial development work will be needed in the near-term to maintain optionality and the in-service dates contemplated in the Plan. Initial development work is needed both to gather information to provide a more refined cost estimate to the Commission, as well as to be positioned to implement such resources on a timeline consistent with the portfolios. Stated simply, if the Companies do not undertake development activities in the near-term for these long-lead-time resources, these new resources will not be available on the timelines contemplated by the portfolios. But it is also important to note that all three resources are likely to be needed to achieve carbon neutrality by 2050, and therefore, the development work performed in the near term is likely to be needed as the Companies progress the energy transition towards carbon neutrality.

The nature and scope of the development activities needed in the near term with respect to each of these three longer-lead time resources varies and is described in greater detail below, in the Execution Plan, as well as the respective technology appendices. While the assumed timelines for all the longer-lead time items are aggressive, the timelines for offshore wind assumed in the Plan, informed by stakeholder input, are extremely aggressive, particularly under P1. Achievement of such timelines will require the immediate commencement of more substantial development activities in the near term. Substantial development work is needed both for the offshore wind site and for the associated onshore transmission and interconnection facilities. Furthermore, due to the limited number of potential wind energy areas ("WEA") available, it will be necessary for the Companies to secure a WEA lease in the near term (assuming consistency with the estimated costs in the Carbon Plan modeling). Without securing a WEA lease in the near-term and initiating key project development activities, it will be impossible to even have the potential to achieve the offshore wind timelines assumed in the modeling under any of the portfolios.

This forward-looking approval of development activity is necessary and appropriate in this unique context where substantial development activities are needed in advance of final selection by the Commission in order to ensure that such resources can achieve commercial operation on a timeline consistent with the Companies' proposed portfolios and HB 951's targeted timelines.

SMR

As referenced in the last paragraph on p. 24 of the Executive Summary, the following near-term development activities are described in Chapter 4 (Execution Plan). Table 4-1, of the Execution Plan provides the near-term development activities for New Nuclear.

- Begin new nuclear ESP for one site, and begin development activities for the first of two SMR units.
- ESP development activities, including deliverables and scope, are provided in the U.S. Nuclear Regulatory Commission (NRC) Regulations Title 10 of the Code of Federal Regulations, Part 52 (10 CFR 52), Subpart A. Contents of an ESP application may include, but is not limited to, the following:
    - A Site Safety Evaluation, scope in part,
        - Plant Parameter Envelope
            - Geography and Demography
            - Nearby Industrial, Transportation, and Military Facilities
            - Meteorology
            - Hydrologic Engineering
            - Geology, Seismology, and Geotechnical Engineering
        - Design of Structures, Systems, Components, and Equipment
        - Radioactive Waste Management
        - Conduct of Operations
            - Emergency Preparedness
            - Physical Security
        - Accident Analysis
        - Quality Assurance
    - A complete Environmental Report as required by 10 CFR 51.50(b)
        - NUREG-1555 Environmental Standard Review Plan, scope in part,
            - Environmental Impacts of Construction
            - Environmental Impacts of Station Operation
            - Environmental Measurements and Monitoring Programs
            - Environmental Impacts of Postulated Accidents Involving Radioactive Materials
            - Need for Power
            - Alternatives to the proposed Action
            - Environmental Consequences of the Proposed Action
    - Emergency Plans (EPs)
        - Major Features
        - Complete and Integrated EPs

Other initial development activities include the following:

- Develop a siting study to support site selection for an ESP
- Perform technology selection
- Industry engagement
- Vendor engagement

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- Initial work on a plant licensing

Further deliverables and scope will be determined when the projects are authorized.

The estimated total cost for obtaining the ESP is provided in Appendix L (Nuclear) of the Carbon Plan on p. 14, and is estimated to cost $50-75 million. It is expected that the ESP will take a total of four years to develop and be approved by the NRC. Total costs for the first two years (i.e., 2023-2024) are estimated to be $35 million.
It is estimated that the total costs of the other development activities will be approximately $2 million, and can assumed to be spread equally over two years (i.e., 2023-2024).

The estimated annual costs of Year 1 and 2 for the above are:

[$35M + $2M] / 2 = $18.5 million

A new advanced nuclear organization will be created, that will initially consist of approximately 5-15 employees, with the make-up of the group being split between in-house personnel and new supplemental workers. In addition, multiple vendor contracts will be required for key expertise to support development of the ESP application.

For the other development activities, we do not anticipate any additional employees in the advanced nuclear organization from those noted above. Some contract support services will be needed though for key expertise to accomplish some of these functions.

The timeline for the ESP is provided in Appendix L (Nuclear) of the Carbon Plan, Figure L-3, on p.12.

No detailed timeline has been developed for the additional development activities. These activities must start as soon as possible to meet a mid-2032 date for the first online new nuclear unit. Detailed timelines will be developed once the projects are authorized.

The cost estimate for the ESP was developed by benchmarking the utility that has the only approved ESP for an advanced nuclear site. The estimate is expected to be within the range provided in Appendix L (Nuclear) of the Carbon Plan on p. 14, plus/minus 10%.

The estimated total cost of the additional $2 million for the other development activities, provided in response 6.f.(2) above, is an approximation and will not be known until the projects are authorized (e.g., vendor is selected and contract awarded to develop a siting study, perform a technology selection, and a new advanced nuclear organization is created).

Offshore Wind

Offshore wind is uniquely situated in that two interrelated threshold determinations are needed in connection with the development of offshore wind: (1) whether the Commission agrees that development activities should be pursued and (2) for which WEA can/should development activities be pursued. Further, as noted in Appendix J, "achieving the January 1, 2030, in-service date would require partnering on an offshore project that has already advanced beyond the leasing stage."

Putting aside such threshold determinations, the following provides a general overview of the development activities need to facilitate offshore wind. The primary development activities include:

- Develop Site Assessment Plan (SAP) (6-12 months) – Develop and submit the SAP for approval by the Bureau of Ocean Energy Management (BOEM) within 12 months of acquiring lease (June 2023). The SAP provides a description of the activities associated with installation of meteorological and oceanographic measurement equipment that will be deployed to inform the engineering and development of the lease area. Importantly, the development of the SAP will enable the team to better understand the needed site assessment activities and the cost of conducting the site assessment activities noted below in the Survey Plan. Activities proposed in the SAP, typically, includes the installation of meteorological and oceanographic measurement equipment—meteorological buoy(s)—to collect wave, wind, current and other data that will help inform the design of foundations, towers, and wind turbine components. BOEM must approve the SAP before meteorological buoys for data collection can be deployed.
- Develop the Survey Plan to support site assessment activities (3-6 months) (2022) – The SAP Survey Plan will support the SAP and will characterize areas potentially impacted by installation of the meteorological and oceanographic measurement equipment. The Survey Plan provides a general description of the environmental and physical condition of the lease area and the timeline of the surveys to be completed during the site assessment phase. The survey plan is used to support the submission of the SAP and includes results of desktop studies on existing offshore activities, potential hazards, and environmental conditions. The desktop studies typically include Anthropogenic Conditions and Hazards (undersea cables, shipwrecks, etc.), Biological Conditions (fisheries, marine sanctuaries, protected species, etc.) and Environmental Conditions and Hazards (bathymetry, geology, seafloor conditions etc.). The Survey Plan must be submitted for review by BOEM before any survey activities can be conducted.

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- Conduct Site Assessment Activities (2023-25): Site assessment activities are conducted to support the development of the Construction and Operations Plan (COP) and to establish a baseline for the analysis of the environmental effects from development, operation and decommissioning activities. Site assessment activities include, but are not limited, to the following:
    - Geophysical surveys
    - Geotechnical investigations
    - Archaeological resources surveys
    - Baseline biological surveys
    - Meteorological and oceanographic data collection (deploy floating Light Detection and Ranging [LiDaR] and metocean buoys)

The specific costs of the site assessment activities, including the Survey Plan, will be refined as the SAP is developed in 2022.

- Develop the Construction and Operation Plan (COP) (2023-26) –The COP must include a description of all planned facilities, including onshore and support facilities, as well as anticipated project easement needs for the offshore wind development project. It must also describe the activities related to the project including construction, commercial operations, maintenance, decommissioning, and site clearance procedures. The COP includes the results of the baseline survey activities, and engineering, design and fabrication reports for the proposed offshore wind project and serves as the basis for the analysis of the environmental and socioeconomic effects of the proposed construction, operation, and decommissioning activities. The COP is required to be approved by BOEM – subject to the National Environmental Policy Act (NEPA) – before any construction activities can be performed. All other federal, state and local approvals are pursued in parallel with BOEM's review of the COP. Development of the COP can take as few as 3 years and the lease allows no more than 5 years once the SAP is approved by BOEM. BOEM's review of the COP and other federal, state and local approvals can take approximately 2-3 years. Target date for COP submission: 2026.

- Additionally, work will have to be done on the transmission planning with optionality for how many MW of offshore wind (depending on the portfolio that is selected by the commission) gets injected into the system.

- For the radial transmission (part of interconnection facilities) from the landing of the submerged cables to the New Bern Point of Interconnection, the following activities need to occur over the near term to meet a 2030 OSW in-service date.
  - Stakeholder/Public Engagement for routing, siting, and acquisition of new right-of-way.
  - The radial interconnection transmission facilities include an approximately 40 mile long high-voltage DC transmission radial line from the beach landing to the existing New Bern 230 kV Substation. Complete scoping and engineering for 500 kV DC line from beach landing to New Bern 230 kV Substation.
  - It is likely that DC/AC conversion equipment will be located at the New Bern substation. Complete scoping and engineering for expansion to New Bern 230 kV Substation. Placement of two new 500/230 kV transformers, new 500 kV lines, DC/AC conversion equipment and general layout of new 500 kV switchyard will need to be designed.
- For the network transmission from the New Bern Point of Interconnection into the DEP transmission system, the following activities need to occur over the near term to meet a 2030 in-service date.

- Submit Generator Interconnection Request(s) into the 2023 annual DISIS Cluster Study to determine required network upgrades and interconnection facilities needed to enable injecting of offshore wind energy and capacity into the New Bern substation.
  - To achieve 800 MW of wind generation injection at New Bern by 2030, the plan would be to upgrade the five 230 kV lines, two 230/115 kV transformers, and two 115 kV lines at New Bern to accommodate the new generation. The details of the upgrades will need to come from the official generation interconnection studies that would be performed in late 2023 if the wind generation is entered into the generation interconnection queue by mid-2023. The study work will extend into 2024 and that will leave limited time to complete the required upgrades by 2029.
    - Consider early start of engineering for 230 kV and 115 kV line upgrades.
  - To achieve 1600 MW of wind injection by 2032, then the following items should be considered:
    - Wommack 230 kV Substation: Placement of two new 500/230 kV transformers and layout of 500 kV switchyard will need to be designed

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- Verify that the 500 kV ROW is secured and commence design of approximately 100 miles of line
- Remove 230 kV Craven Co Wood Energy (CCWE) 1.3 mile tap line from 500 kV ROW and reconnect CCWE to New Bern-Wommack 230 kV South line
- Acquire 70 foot expansion to New Bern-Wommack 500 kV line ROW

In order to position any potential project for in-service date of 2030 or 2032, engineering will have to commence as early as possible. Therefore, engineering work has been estimated and presented in the costs under the heading of "Development Expenses," which include other non-engineering activities. The costs associated with the work described above through 2024 are provided in attachment "PSDR 7-6 (f) Offshore Wind Costs.xlsx". Total costs is $208M, which does not include the cost of obtaining a lease.

PSDR%207-6%20(f)
%20Offshore%20Wi

Regarding estimated labor requirements, the Companies currently expect that a mix of internal project development and external consultants will be utilized, including project management, engineering, environmental, stakeholder engagement and community outreach resources. No new Duke Energy staff will be added at this time.

The following provides a timeline of the development activities (listing key milestones)

- Draft Survey Plan developed and submitted for review by BOEM in Fall 2022
- Site Assessment Plan drafted and submitted as early as 12/31/2022 and no later than 06/01/2023.
- BOEM approval of SAP (Q1, 2023)
- Conduct initial Site Assessment Activities for Meteorological Buoy and Floating LiDAR deployment (Q2, 2023)
- Deploy Meteorological Buoy and Floating LiDAR (Q2, 2023)
- Initiate Survey Plan work to support site assessment activities for development of the Construction and Operation Plan (Q2-Q3, 2023)
    - Meteorological Data Collection Campaign
    - Geophysical surveys
    - Geotechnical investigations

  - Archaeological resources surveys
  - Biological surveys
- Construction Operations Plan submitted to BOEM (2026)
- BOEM initiates Federal environmental (NEPA) review as part of COP (2026). All other federal, state and local approvals are pursued in parallel with BOEM's review of the COP.
- COP approval (Q1-Q2, 2028)
- Facility Design Report and Fabrication and Installation Report due to BOEM (Q2, 2028)
- Expected start of construction (Q3, 2028)
- Transmission-specific milestones as describes in the previous sections.

Since detailed development and planning work has not occurred, the estimate provided is high level class 5 estimate, with a -50% to +100% level of accuracy.

Bad Creek II

Bad Creek II is in the early development stages. Not all development activities and costs have been determined at this time. Below is a summary of the activities/costs completed to date and development activities/costs expected through the end of 2024. This development work will allow Bad Creek II to remain a viable resource option with a 2033 in-service date.

The Company engaged HDR, a third-party engineering firm, to complete a Pre-Feasibility Study for Bad Creek II. This Pre-Feasibility Study was completed in January 2020 and included:

- Topographic Studies of the Bad Creek II site
- Geotechnical Studies of the Bad Creek II site
- Upper & Lower Reservoir Operational Impact Studies
- High Level Environmental Assessment
- Project Layout & Configuration Development
- Construction Cost Estimates & Schedules

The Company has further engaged HDR to perform a Feasibility Study. The objectives of the Feasibility Study are to build on the work completed in the Pre-Feasibility study and to provide more accurate technical, performance, and cost evaluations for developing the Bad Creek II Geotechnical/Geological Studies. This Feasibility Study is expected to be completed in Q3 2022 and will include:

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- Power Complex Refinement & Layout Studies
- Reservoir and Structures Refinement and Layout Studies
- Site Studies
- Construction Cost Estimates & Schedules
- Options for Variable vs. Single Speed Technology
- Environmental Studies

On February 22, 2022, the Company filed at the Federal Energy Regulatory Commission ("FERC") the Pre-Application Document ("PAD") for the relicensing of the Bad Creek facility. The PAD included the option for construction of Bad Creek II. The Company plans to continue supporting inclusion of Bad Creek II as a resource option through the final FERC application process, which will be filed in mid-2025.

The Company also intends to enter Bad Creek II in the 2022 DISIS Cluster Study, which closes at the end of June 2022.

Additionally in 2022, the Company will conduct Phase II of Geotechnical Studies, which are expected to be completed at the end of 2022. Optimization, which is the hydraulic analysis for the pump turbine centerline equipment, and the tender design, which is the development of the modeling for the pump turbine/generator, will also commence in 2022. The Company expects to issue a Request for Proposals ("RFP") in 2023 to select a vendor to design, test and analyze the model pump turbine/generator. That analysis is expected to be completed by the end of 2024.

Also in late 2022, the Company plans to begin preparations for the Engineering Procurement and Construction ("EPC") solicitation. A third-party engineering firm will be engaged to perform an independent EPC review of the construction estimate that will be included in the Feasibility Study. The Company expects this independent EPC review to be completed in 2023. The next step will be for the Company to develop its EPC contracting strategy, which will lead to an EPC Solicitation in early 2025.

Please see attachment "PSDR 7-6(f) Bad Creek II.xlsx" for development cost information through 2024.

PSDR%207-6%20(f)
%20%20Bad%20Cree

The Company has not yet determined whether hiring additional employees will be necessary, but it will continue to assess as the project develops further.

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This projected timeline below of the development milestones determined thus far is subject to change:

- Pre-Feasibility Study completed January 2022
- FERC license application process commenced February 2022 to continue through 2025.
- DISIS Cluster Study June 2022
- Feasibility Study expected completion Q3 2022
- Geotechnical Studies conclusion of 2022
- Support optimization & tender design completed in 2022/2023
- Issue RFP for model design and testing completed in 2023
- Model design and testing analysis completed in 2024
- Third party engineering firm review of construction estimate from Feasibility Study 2022-2023
- Development of EPC Strategy 2024
- Issue RFP for EPC 2025

The Companies believe that the Feasibility Study and DISIS Cluster deposit cost estimates are accurate. Other costs are best estimates based on information reviewed in the pre-feasibility study. The pre-feasibility study, however, was preliminary and did not include development costs such as the FERC licensing process. Therefore, the Companies believe that the development cost estimates included in this response are reasonably accurate but are subject to change due to unforeseen circumstances or as the project evolves.

g. No, the Companies' Carbon Plan did not include a proposed maximum or annual cap on development activities. The Companies will be required to demonstrate that all costs incurred are reasonable and prudent.

h. The Companies believe that some amount of reporting requirements would be reasonable in connection with any development activity approved by the Commission. While the Companies have not yet developed any such proposed reporting requirements, the Companies would be willing to consider any reporting requirements proposed by the Public Staff (or any intervenors).

Responder: Clift Pompee, Managing Director, Generation Technology; Ben Smith, Generation & Regulatory Strategy Director; Chris Nolan, Vice President, Nuclear Regulatory Affairs, Policy & Emergency Preparedness

I/A

Tech Customers – Public Staff Panel 1 – Cross Exam. Ex. 1

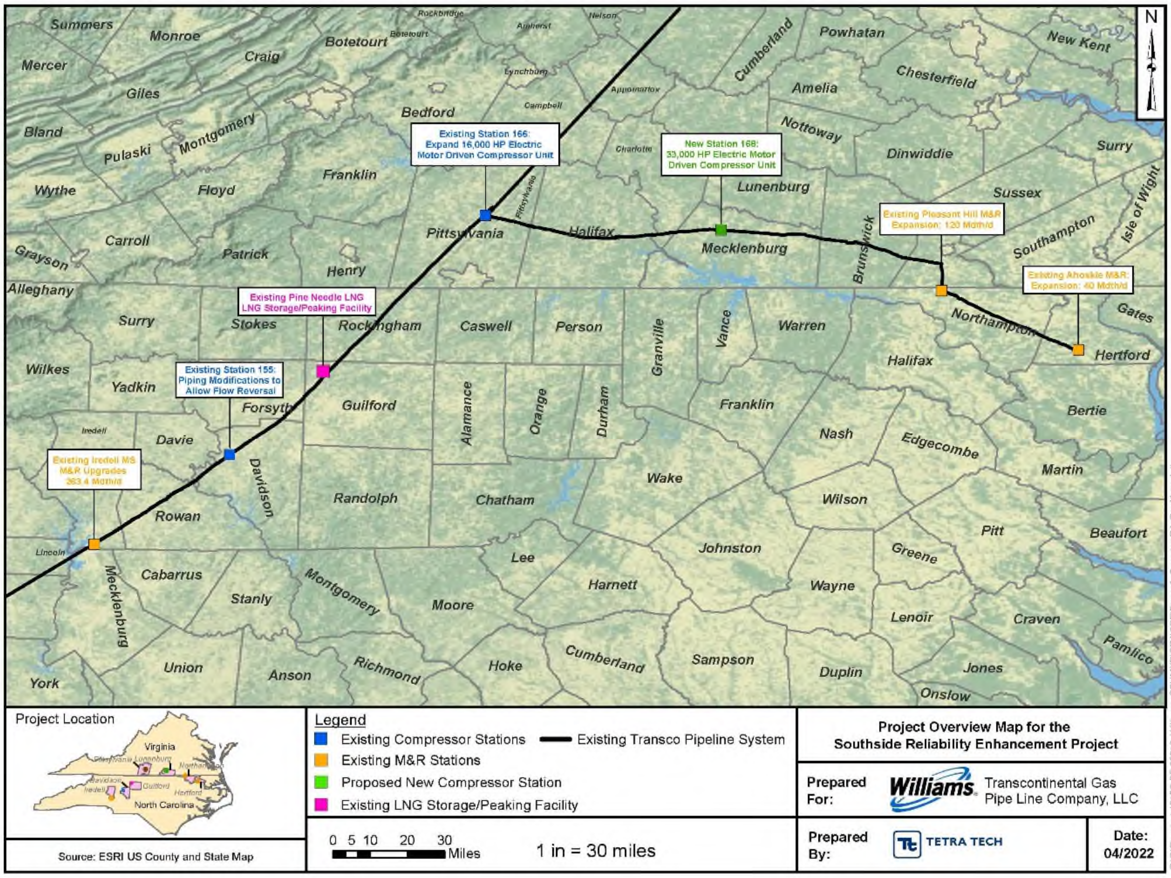
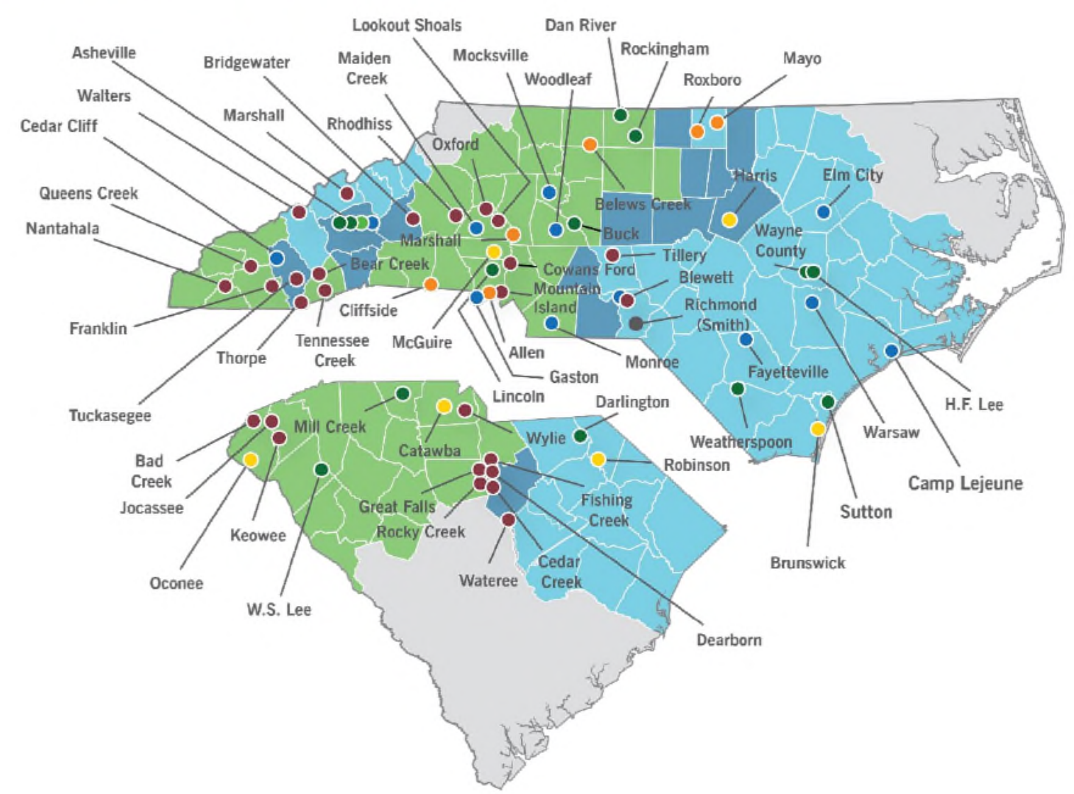


Figure C-2: DEC and DEP Service Areas



Independent Statistics & Analysis
U.S. Energy Information Administration

March 2022

Levelized Costs of New Generation Resources in the *Annual Energy Outlook 2022*

Every year, the U.S. Energy Information Administration (EIA) publishes updates to its *Annual Energy Outlook* (AEO), which provides long-term projections of energy production and consumption in the United States using EIA's National Energy Modeling System (NEMS). The AEO update for 2022 (AEO2022) includes projections through 2050 given certain specified assumptions and methodologies.

Investment in the expansion of electric generation capacity requires an assessment of the competitive value of generation technologies in the future that is determined as part of a complex set of modeling systems. To better understand investment decisions in NEMS, we use specialized measures that simplify those modeled decisions. Levelized cost of electricity (LCOE) refers to the estimated revenue required to build and operate a generator over a specified cost recovery period. Levelized avoided cost of electricity (LACE) is the revenue available to that generator during the same period. Beginning with AEO2021, we include estimates for the levelized cost of storage (LCOS). Although LCOE, LCOS, and LACE do not fully capture all the factors considered in NEMS, when used together as a value-cost ratio (the ratio of LACE-to-LCOE or LACE-to-LCOS), they provide a reasonable comparison of first-order economic competitiveness among a wider variety of technologies than is possible using LCOE, LCOS, or LACE individually.

In this paper, we present average values of LCOE, LCOS, and LACE for electric generating technologies entering service in 2024, 2027,[1] and 2040 as represented in NEMS for the AEO2022 Reference case. We present the costs for electric generating facilities entering service in 2027 in the body of this report, and we include the costs for 2024[2] and 2040 in Appendixes A and B, respectively. We provide both a capacity-weighted average based on projected capacity additions and a simple average (unweighted) of the regional values across the 25 U.S. supply regions of the NEMS Electricity Market Module (EMM), together with the range of regional values.

Levelized cost of electricity and levelized cost of storage

Levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) represent the average revenue per unit of electricity generated or discharged that would be required to recover the costs of building and operating a generating plant and a battery storage facility, respectively, during an assumed financial life and duty cycle.[3] LCOE is often cited as a convenient summary measure of the overall competiveness of different generating technologies. Although the concept is similar to LCOE, LCOS is different in that it represents an energy storage technology that contributes to electricity generation when discharging and

[1] Given the long lead time and licensing requirements for some technologies, the first feasible year that all technologies are available is 2027.
[2] Appendix A shows LCOE, LCOS, and LACE for the subset of technologies available to be built in 2024.
[3] *Duty cycle* refers to the typical utilization or dispatch of a plant to serve base, intermediate, or peak load. Wind, solar, or other intermittently available resources are not dispatched and do not necessarily follow a duty cycle based on load conditions.

consumes electricity from the grid when charging. Furthermore, LCOS is calculated differently depending on whether it is supplying electricity generation to the grid or providing generation capacity reliability.

In NEMS, we model battery storage in energy arbitrage applications where the storage technology provides energy to the grid during periods of high-cost generation and recharges during periods of lower cost generation, not as providing generation capacity reliability.

AEO2022 representation of tax incentives for renewable generation

Federal tax credits for certain renewable generation facilities can substantially reduce the realized cost of these facilities. Cost estimates in this report are for generators owned by the electric power sector, which are generally eligible for federal tax credits. These estimates are not for systems owned by the residential or commercial sectors. Where applicable, we show LCOE both with and without tax credits that we assume, based on the following representation, that they would be available in the year in which the plant enters service.

Production Tax Credit (PTC): As of 2021, new electric power sector wind, geothermal, and closed-loop biomass plants receive a tax credit of $25 per megawatthour (MWh) of generation; other PTC-eligible technologies receive $13/MWh. We adjust PTC values for inflation and apply them during the plant's first 10 years of service. Plants that were under construction before the end of 2016 received the full PTC. After 2016, wind continues to be eligible for the PTC but at a declining dollars-per-megawatthour rate. We assume that wind plants have five years after beginning construction to come online and claim the PTC.[4] As a result, we assume that wind plants entering service before January 1, 2026 will receive 60% of the full PTC value (inflation adjusted), and no PTC for any projects placed in service in 2026 and beyond.

Investment Tax Credit (ITC): We assume all electric power sector solar projects coming online before January 1, 2024 will receive the full 30% ITC.[4] The available ITC is then phased down to 26% for solar projects entering commercial service in 2024 and 2025 and 10% for those placed in service after December 31, 2025. Because we assume that battery storage is a standalone, grid-connected system, it is not eligible for the ITC. However, we assume that battery storage in the solar photovolataic (PV) hybrid system recharges exclusively from the co-located solar facility, and so it is eligible for the ITC with the same phaseout schedule as for standalone solar PV systems.

Both onshore and offshore wind projects are eligible to claim the ITC instead of the PTC. Although we expect that onshore wind projects will choose the PTC, we assume offshore wind projects will claim the ITC because of the relatively higher capital costs for those projects. We assume offshore wind projects are eligible for a 30% ITC if placed in service by December 31, 2035.[5]

[4] Based on Division EE (Taxpayer Certainty and Disaster Tax Relief Act of 2020) of the Consolidated Appropriations Act of 2021, signed into law in December 2020, and Notice 2021-41 released by the Internal Revenue Service (IRS) in June 2021.
[5] Based on Division EE of the Consolidated Appropriations Act of 2021 and IRS Notice 2021-05 released in December 2020.

Key inputs to calculating LCOE and LCOS include capital costs, fixed operations and maintenance (O&M) costs, variable costs that include O&M and fuel costs, financing costs, and an assumed utilization rate for each plant type.[6] For LCOS, in lieu of fuel cost, the levelized variable cost includes the cost of purchasing electricity from the electric power grid for charging. The importance of each of these factors varies across technologies. For technologies with no fuel costs and relatively small variable costs, such as solar and wind electric-generating technologies, LCOE changes nearly in proportion to the estimated capital cost of the technology. For technologies with significant fuel cost, both fuel cost and capital cost estimates significantly affect LCOE. Incentives, including state or federal tax credits (see text box *AEO2022 representation of tax incentives for renewable generation*), also affect the calculation of LCOE. As with any projection, these factors are uncertain because their values can vary regionally and temporally as technologies evolve and as fuel prices change. Solar photovoltaic (PV) hybrid technology is represented by LCOE and not LCOS because we assume it operates as an integrated unit supplying electricity to the grid.

Actual plant investment decisions consider the specific technological and regional characteristics of a project, which involve many other factors not reflected in LCOE (or LCOS) values. One factor is the projected utilization rate, which depends on the varying amount of electricity required over time and the existing resource mix in an area where additional capacity is needed. A related factor is the capacity value, which depends on both the existing capacity mix and load characteristics in a region. Because load must be continuously balanced, generating units with the capability to vary output to follow demand (dispatchable technologies) generally have more value to a system than less flexible units that use intermittent resources to operate (resource-constrained technologies). We list the LCOE values for dispatchable and resource-constrained technologies separately because they require a careful comparison. We include the solar PV hybrid LCOE under resource-constrained technologies because, much like hydroelectric generators, solar PV hybrid generators are energy-constrained and so are more limited in dispatch capability than generators with essentially continuous fuel supply. For combustion turbine and battery storage technologies, capacity might be added in regions with higher renewables penetration, particularly solar, to meet regional capacity reserve requirements for when intermittent resources are not available for generation during evening peak demand, and we show them as capacity resource technologies.

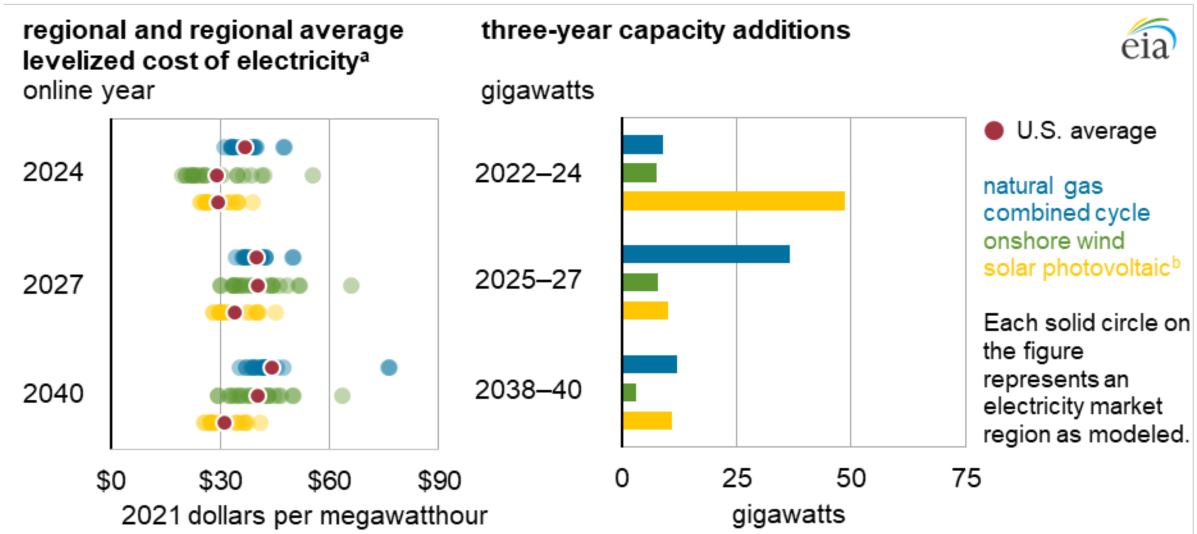
Levelized avoided cost of electricity

LCOE and LCOS by themselves do not capture all of the factors that contribute to actual investment decisions, making direct comparisons of LCOE and LCOS across technologies problematic and misleading as a method to assess the economic competitiveness of various generation alternatives. Figure 1 illustrates the limitations of using LCOE alone. In AEO2022, solar LCOE, on average, is lower than natural gas-fired combined-cycle (CC) LCOE in 2027. However, more CC generating capacity is installed than solar PV between 2025 and 2027. We project more CC capacity to be installed than solar PV capacity because the relative value of adding CC to the system is greater than for solar PV, which LCOE does not capture.

[6] The specific assumptions for each of these factors are provided in the *Assumptions to the Annual Energy Outlook*.

Along with LCOE and LCOS, we compare economic competitiveness between generation technologies by considering the value of the plant in serving the electric grid. This value provides a proxy measure for potential revenues from the sale of electricity generated from a candidate project displacing (or the cost of avoiding) another marginal asset. We sum this value over a project's financial life and convert that sum into an annualized value (that is, divided by the average annual output of the project) to develop the levelized avoided cost of electricity (LACE).[7] Using LACE along with LCOE and LCOS provides a more intuitive indication of economic competitiveness for each technology than either metric separately when several technologies are available to meet load. We calculate LACE-to-LCOE and LACE-to-LCOS ratios (or value-cost ratios) for each technology to determine which project provides the most value relative to its cost. Projects with a value-cost ratio greater than one (that is, LACE is greater than LCOE or LCOS) are more economically attractive as new builds than those with a value-cost ratio less than one (that is, LACE is less than LCOE or LCOS).

Figure 1. Levelized cost of electricity (with applicable tax subsidies) by region and total incremental capacity additions for selected generating technologies entering into service in 2024, 2027, and 2040



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] Levelized cost includes tax credits available for plants entering service during the projection period.
[b] Technology is assumed to be photovoltaic with single-axis tracking. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

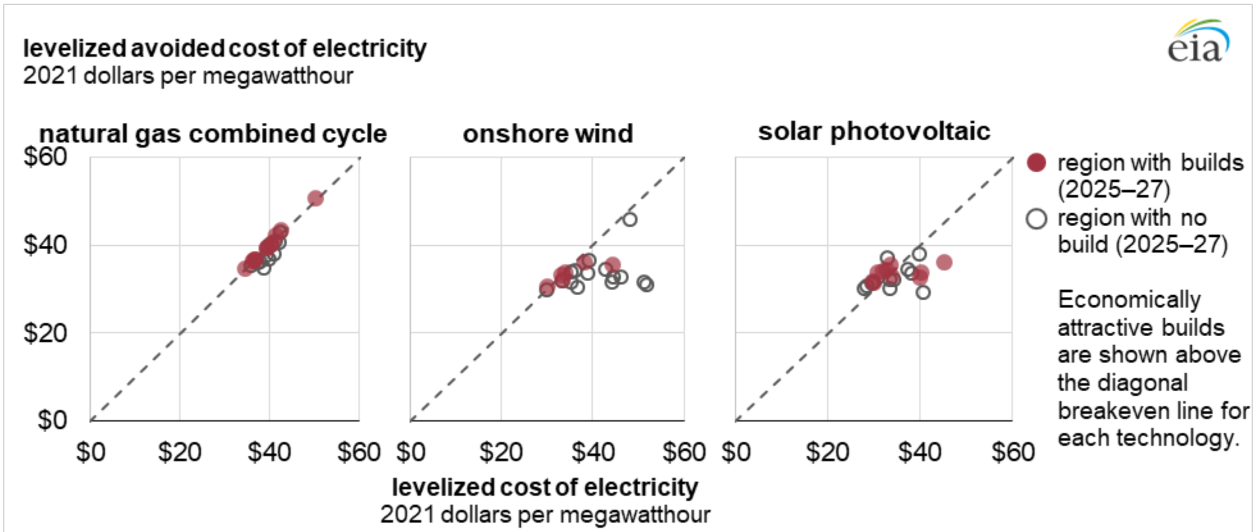
Estimating LACE is more complex than estimating LCOE or LCOS because it requires information about how the grid would operate without the new power plant or storage facility entering service. We calculate LACE based on the marginal value of energy and capacity that would result from adding a unit of a given technology to the grid as it exists or as we project it to exist at a specific future date. LACE accounts for both the variation in daily and seasonal electricity demand and the characteristics of the existing generation fleet to which new capacity will be added. Therefore, LACE compares the prospective new generation resource against the mix of new and existing generation and capacity that it would displace. For example, a wind resource that would primarily displace generation from a relatively

[7] Our website provides further discussion of the levelized avoided cost concept and its use in assessing economic competitiveness.

expensive natural gas-fired peaking unit will usually have a different value than one that would displace generation from a more efficient natural gas-fired combined-cycle unit or coal-fired unit with low fuel costs.

Although the modeled economic decisions for capacity additions in our long-term projections do not use the LACE, LCOE, or LCOS concepts, the LACE and value-cost ratio presented in this report is generally more representative of the factors contributing to the build decisions in our long-term projections than looking at LCOE or LCOS alone. Figure 2 shows selected generating technologies that could come online in 2027. CC and PV are the most economically attractive technologies to build because the value (or LACE) is greater than the cost (or LCOE). Onshore wind and PV add capacity in some less economically attractive regions. This outcome is partly because capacity additions are from the preceding three years, which reflect the years where onshore wind was subject to greater tax incentives than in 2027 alone. In addition, some regions are adding uneconomical capacity builds to fulfill state-level renewable portfolio standards (RPS) that require that a certain percentage of generation come from renewables. Even so, looking at both LCOE and LACE together (Figure 2) indicates more of the full analysis from the AEO2022 model than LCOE alone (Figure 1).

Figure 2. Levelized cost of electricity and levelized avoided cost of electricity by region for selected generation technologies, 2027 online year



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

Note: Each solid circle on the figure represents an electricity market region as modeled. Projects tend to be built in regions where revenue (levelized avoided cost of electricity, or LACE) exceeds costs (levelized cost of electricity, or LCOE).

Nonetheless, the LACE, LCOE, and LCOS estimates simplify modeled decisions, and these estimates may not fully capture all of the factors considered in NEMS or match modeled results. We calculate levelized costs using an assumed set of capital and operating costs, but investment decisions may be affected by factors other than the project's value relative to its costs. For example, the inherent uncertainty about future fuel prices, future policies, or local considerations for system reliability may lead plant owners or investors who finance plants to place a value on portfolio diversification or other risk-related concerns. We consider many of these factors in our analysis of technology choice in the electricity sector in NEMS, but not all of these concepts are included in LCOE, LCOS, or LACE calculations. Future policy-related factors, such as new environmental regulations or tax credits for specific generation sources, can also affect investment decisions. We derive the LCOE, LCOS, and LACE values presented here from the AEO2022 Reference case, which includes state-level renewable electricity requirements as of November 2021 and a phaseout of federal tax credits for renewable generation.

LCOE, LCOS, and LACE calculations

We calculate all levelized costs and values based on a 30-year cost recovery period, using a nominal after-tax weighted average cost of capital (WACC) of 6.2%.[8] In reality, a plant's cost recovery period and cost of capital can vary by technology and project type. The represented technologies are selected from available electric power sector technologies modeled in NEMS's Electricity Market Module (EMM) and not from distributed residential and commercial applications.[9] Starting in AEO2020, we model an ultra-supercritical[10] (USC) coal generation technology without carbon capture and sequestration (CCS), and we continue to model USC with 30% and 90% CCS. In December 2018, the U.S. Environmental Protection Agency (EPA) amended earlier 2015 findings that partial CCS was the *best system of emissions reductions* (BSER) for greenhouse gas reductions and proposed to replace it with the most efficient demonstrated steam cycle, which we assume is represented by USC technology.

The levelized capital component reflects costs calculated using tax depreciation schedules consistent with tax laws without an end date, which vary by technology. For AEO2022, we assume a corporate tax rate of 21%, as specified in the Tax Cuts and Jobs Act of 2017. For technologies eligible for the Investment Tax Credit (ITC) or Production Tax Credit (PTC), we report LCOE both with and without tax credits, which phase out and expire based on current laws and regulations in AEO2022 cases. Costs are expressed in terms of net alternating current (AC) power available to the grid for the installed capacity.

We evaluate LCOE, LCOS, and LACE for each technology based on assumed capacity factors, which generally correspond to the high end of their likely utilization range. This convention is consistent with using LCOE and LCOS to evaluate competing technologies in baseload operation such as coal and nuclear plants. Although sometimes used in baseload operation, some technologies, such as CC plants, are also built to serve load-following or other intermediate dispatch duty cycles. We evaluate combustion turbines that are typically used for peak-load duty cycles at a 10% capacity factor, which reflects the historical average utilization rate. We also evaluate battery storage at a 10% capacity factor, reflecting an expected use for energy arbitrage, especially in conjunction with intermittent renewable generation such as solar generation. The duty cycle for intermittent resources is not operator controlled, but rather, it depends on the weather, which does not necessarily correspond to operator-dispatched duty cycles. As a result, LCOE values for wind and solar technologies are not directly comparable with the LCOE values for other technologies that may have a similar average annual capacity factor, and we show them

[8] We use this WACC for plants entering service in 2027. The nominal WACCs used to calculate LCOE for plants entering service in 2024 and 2040 are 5.6% and 6.5%, respectively. An overview of the WACC assumptions and methodology is available in the *Electricity Market Module of the National Energy Modeling System: Model Documentation 2020*.

[9] The list of all technologies modeled in EMM is available in the *Electricity Market Module of the National Energy Modeling System: Model Documentation 2020*.

[10] USC coal plants are compatible with CCS technologies because they use boilers that heat coal to higher temperatures, which increases the pressure of steam to improve efficiency and results in less coal use and fewer carbon emissions than other boiler technologies.

separately as resource-constrained technologies. Hydroelectric resources, including facilities where storage reservoirs allow for more flexible day-to-day operation, and hybrid solar PV generally have signifcant seasonal and daily variation, respectively, in availability. We label them as resource-constrained to discourage comparison with technologies that have more consistent seasonal and diurnal availability. The capacity factors for solar, wind, and hydroelectric resources are the average of the capacity factors (weighted or unweighted) for the marginal site in each region, which can vary significantly by region, and will not necessarily correspond to the cumulative projected capacity factors for both new and existing units for resources in AEO2022 or our other analyses.

The LCOE and LCOS values we show in Tables 1a and 1b are averages of region-specific values weighted by the projected regional capacity builds in AEO2022 (Table 1a) and unweighted averages (simple average, Table 1b) for new plants coming online in 2027. We develop the weights based on the cumulative capacity additions during three years, reflecting the two years preceding the online year and the online year (for example, the capacity weight for a 2027 online year represents the cumulative capacity additions from 2025 through 2027).

Table 1a. Estimated capacity-weighted[a] levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) for new resources entering service in 2027 (2021 dollars per megawatthour)

Plant type	Capacity factor (percent)	Levelized capital cost	Levelized fixed O&M[b]	Levelized variable cost	Levelized transmis-sion cost	Total system LCOE or LCOS	Levelized tax credit[c]	Total LCOE or LCOS including tax credit
Dispatchable technologies								
Ultra-supercritical coal	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Combined cycle	87%	$8.56	$1.68	$25.80	$1.01	$37.05	*NA*	$37.05
Advanced nuclear	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Geothermal	90%	$21.80	$15.20	$1.21	$1.40	$39.61	-$2.18	$37.43
Biomass	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Resource-constrained technologies								
Wind, onshore	43%	$27.45	$7.44	$0.00	$2.91	$37.80	*NA*	$37.80
Wind, offshore	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Solar, standalone[d]	29%	$26.35	$6.34	$0.00	$3.41	$36.09	-$2.64	$33.46
Solar, hybrid[d,e]	26%	$39.12	$15.00	$0.00	$4.51	$58.62	-$3.91	$54.71
Hydroelectric[e]	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Capacity resource technologies								
Combustion turbine	10%	$55.55	$8.37	$49.93	$10.00	$123.84	*NA*	$123.84
Battery storage	10%	$64.74	$29.64	$18.92	$11.54	$124.84	$0.00	$124.84

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. We base the capacity additions for each region on additions from 2025 to 2027. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB*, or *not built*.

[b] O&M = operations and maintenance

[c] The tax credit component is based on targeted federal tax credits such as the Production Tax Credit (PTC) or Investment Tax Credit (ITC) available for some technologies. It reflects tax credits available only for plants entering service in 2027 and the substantial phaseout of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA,* or *not available*. The results are based on a regional model, and state or local incentives are not included in LCOE and LCOS calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[d] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[e] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

Table 1b. Estimated unweighted levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) for new resources entering service in 2027 (2021 dollars per megawatthour)

Plant type	Capacity factor (percent)	Levelized capital cost	Levelized fixed O&M[a]	Levelized variable cost	Levelized transmis-sion cost	Total system LCOE or LCOS	Levelized tax credit[b]	Total LCOE or LCOS including tax credit
Dispatchable technologies								
Ultra-supercritical coal	85%	$52.11	$5.71	$23.67	$1.12	$82.61	*NA*	$82.61
Combined cycle	87%	$9.36	$1.68	$27.77	$1.14	$39.94	*NA*	$39.94
Advanced nuclear	90%	$60.71	$16.15	$10.30	$1.08	$88.24	-$6.52	$81.71
Geothermal	90%	$22.04	$15.18	$1.21	$1.40	$39.82	-$2.20	$37.62
Biomass	83%	$40.80	$18.10	$30.07	$1.19	$90.17	*NA*	$90.17
Resource-constrained technologies								
Wind, onshore	41%	$29.90	$7.70	$0.00	$2.63	$40.23	*NA*	$40.23
Wind, offshore	44%	$103.77	$30.17	$0.00	$2.57	$136.51	-$31.13	$105.38
Solar, standalone[c]	29%	$26.60	$6.38	$0.00	$3.52	$36.49	-$2.66	$33.83
Solar, hybrid[c,d]	28%	$34.98	$13.92	$0.00	$3.63	$52.53	-$3.50	$49.03
Hydroelectric[d]	54%	$46.58	$11.48	$4.13	$2.08	$64.27	*NA*	$64.27
Capacity resource technologies								
Combustion turbine	10%	$53.78	$8.37	$45.83	$9.89	$117.86	*NA*	$117.86
Battery storage	10%	$64.03	$29.64	$24.83	$10.05	$128.55	*NA*	$128.55

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] O&M = operations and maintenance

[b] The tax credit component is based on targeted federal tax credits such as the Production Tax Credit (PTC) or Investment Tax Credit (ITC) available for some technologies. It reflects tax credits available only for plants entering service in 2027 and the substantial phaseout of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA,* or *not available*. The results are based on a regional model, and state or local incentives are not included in LCOE and LCOS calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[c] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[d] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

Table 2 shows a range of LCOE and LCOS values, which represent the significant regional variation attributed to local labor markets and the cost and availability of fuel or energy resources (such as windy sites). For example, the LCOE for incremental onshore wind capacity ranges from $30.01 per megawatthour (MWh) in the region with the highest-quality wind resources to $65.65/MWh in the region with the lowest-quality wind resources and/or higher capital costs for the best sites. Because onshore wind plants will most likely be built in regions that offer low cost and high value, the weighted average cost across regions is closer to the low end of the range at $37.80/MWh. Costs for wind generators may include additional expenses associated with transmission upgrades needed to access remote resources, as well as other factors that markets may not internalize into the market price for wind power.

Table 2. Regional variation in levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) for new resources entering service in 2027 (2021 dollars per megawatthour)

	Without tax credits				With tax credits[a]			
Plant type	**Minimum**	**Simple average**	**Capacity-weighted average[b]**	**Maximum**	**Minimum**	**Simple average**	**Capacity-weighted average[b]**	**Maximum**
Dispatchable technologies								
Ultra-supercritical coal	$73.86	$82.61	*NB*	$101.25	$73.86	$82.61	*NB*	$101.25
Combined cycle	$34.30	$39.94	$37.05	$50.09	$34.30	$39.94	$37.05	$50.09
Advanced nuclear	$82.76	$88.24	*NB*	$98.78	$76.23	$81.71	*NB*	$92.25
Geothermal	$36.86	$39.82	$39.61	$41.57	$34.98	$37.62	$37.43	$39.25
Biomass	$79.87	$90.17	*NB*	$141.03	$79.87	$90.17	*NB*	$141.03
Resource-constrained technologies								
Wind, onshore	$30.01	$40.23	$37.80	$65.65	$30.01	$40.23	$37.80	$65.65
Wind, offshore	$109.88	$136.51	*NB*	$170.31	$86.34	$105.38	*NB*	$128.93
Solar, standalone[c]	$30.13	$36.49	$36.09	$48.58	$27.93	$33.83	$33.46	$44.95
Solar, hybrid[c,d]	$43.15	$52.53	$58.62	$67.97	$40.30	$49.03	$54.71	$63.30
Hydroelectric[e]	$48.96	$64.27	*NB*	$82.65	$48.96	$64.27	*NB*	$82.65
Capacity resource technologies								
Combustion turbine	$106.02	$117.86	$123.84	$145.46	$106.02	$117.86	$123.84	$145.46
Battery storage	$114.70	$128.55	$124.84	$141.06	$114.70	$128.55	$124.84	$141.06

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

Note: We calculate the levelized costs for non-dispatchable technologies based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are 38%–47% for onshore wind, 41%–50% for offshore wind, 25%–33% for standalone solar PV, 24%–32% for hybrid solar PV, and 25%–80% for hydroelectric. Regional variations in construction labor rates and capital costs as well as resource availability also affect levelized costs.

[a] Levelized cost with tax credits reflects targeted federal tax credits such as the Production Tax Credit (PTC) or Investment Tax Credit (ITC) available for plants entering service in 2027 and the substantial phaseout of both the PTC and ITC as scheduled under current law.

[b] The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2025 to 2027. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB,* or *not built*.

[c] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[d] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

LACE accounts for the differences in the grid services that each technology provides, and it recognizes that intermittent resources, such as wind or solar, have substantially different duty cycles than the baseload, intermediate, and peaking duty cycles of conventional generators. Table 3 provides the range of LACE estimates for different capacity types. We calculate the LACE in this table by assuming the same maximum capacity factor that we used for the LCOE and LCOS calculations.

Table 3. Regional variation in levelized avoided cost of electricity (LACE) for new resources entering service in 2027 (2021 dollars per megawatthour)

Plant type	Minimum	Simple average	Capacity-weighted average[a]	Maximum
Dispatchable technologies				
Ultra-supercritical coal	$34.87	$38.69	*NB*	$43.82
Combined cycle	$34.71	$39.54	$37.45	$50.77
Advanced nuclear	$34.63	$38.42	*NB*	$43.44
Geothermal	$40.38	$45.11	$46.52	$50.40
Biomass	$34.97	$39.84	*NB*	$51.25
Resource-constrained technologies				
Wind, onshore	$29.84	$34.54	$34.37	$53.53
Wind, offshore	$30.90	$36.00	*NB*	$47.64
Solar, standalone[b]	$29.21	$32.85	$33.82	$38.02
Solar, hybrid[b,c]	$30.48	$45.53	$50.82	$57.14
Hydroelectric[c]	$31.48	$37.87	*NB*	$48.71
Capacity resource technologies				
Combustion turbine	$68.35	$101.74	$107.82	$132.10
Battery storage	$68.35	$101.01	$106.08	$126.39

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2025 to 2027. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB*, or *not built*.

[b] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[c] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

When the LACE of a particular technology exceeds its LCOE or LCOS, that technology would generally be economically attractive to build. The build decisions in actuality (and as we model in AEO2022), however, are more complex than a simple LACE-to-LCOE or LACE-to-LCOS comparison because they include factors such as policy and non-economic drivers. Nevertheless, the value-cost ratio (the ratio of LACE-to-LCOE or LACE-to-LCOS) provides a reasonable point of comparison of first-order economic competitiveness among a wider variety of technologies than is possible using LCOE, LCOS, or LACE tables individually. In Tables 4a and 4b, a value index of less than one indicates that the cost of the marginal new unit of capacity exceeds its value to the system, and a value-cost ratio greater than one indicates that the marginal new unit brings in value higher than its cost by displacing more expensive generation and capacity options. The *average value-cost ratio* is an average of 25 regional LACE-to-LCOE or LACE-to-LCOS ratios. The range of the LACE-to-LCOE or LACE-to-LCOS ratios represents the lower and upper bounds of the regional LACE-to-LCOE and LACE-to-LCOS ratios, and it is not based on the ratio between the minimum and maximum values shown in Tables 2 and 3.

As shown in Table 4a, the capacity-weighted average value-cost ratio is greater than one for standalone solar PV and geothermal in 2027, suggesting that these technologies will be built in regions where they are economically viable. Furthermore, the capacity-weighted average value-cost ratio for CC is above one, suggesting that the technology is an attractive marginal capacity addition and that the market has developed the technology to an equilibrium point where the net economic value is close to breakeven after having met load growth or displaced higher cost generation.[11]

Table 4a. Value-cost ratio (capacity-weighted) for new resources entering service in 2027

Plant type	Average capacity-weighted[a] LCOE[b] or LCOS[b] with tax credits (2021 dollars per megawatthour)	Average capacity-weighted[a] LACE[b] (2021 dollars per megawatthour)	Average value-cost ratio[c]
Dispatchable technologies			
Ultra-supercritical coal	*NB*	*NB*	*NB*
Combined cycle	$37.05	$37.45	1.01
Advanced nuclear	*NB*	*NB*	*NB*
Geothermal	$37.43	$46.52	1.25
Biomass	*NB*	*NB*	*NB*
Resource-constrained technologies			
Wind, onshore	$37.80	$34.37	0.92
Wind, offshore	*NB*	*NB*	*NB*
Solar, standalone[d]	$33.46	$33.82	1.02
Solar, hybrid[d,e]	$54.71	$50.82	0.94
Hydroelectric[e]	*NB*	*NB*	*NB*
Capacity resource technologies			
Combustion turbine	$123.84	$107.82	0.87
Battery storage	$124.84	$106.08	0.85

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*
[a] The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2025 to 2027. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB*, or *not built*.
[b] LCOE = levelized cost of electricity, LCOS = levelized cost of storage, and LACE = levelized avoided cost of electricity.
[c] The *average value-cost ratio* is an average of 25 regional value-cost ratios based on the cost with tax credits for each technology, as available.
[d] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.
[e] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

[11] For a more detailed discussion of the LACE versus LCOE measures, see [Assessing the Economic Value of New Utility-Scale Electricity Generation Projects].

Table 4b. Value-cost ratio (unweighted) for new resources entering service in 2027

Plant type	Average unweighted LCOE[a] or LCOS[a] with tax credits (2021 dollars per megawatthour)	Average unweighted LACE[a] (2021 dollars per megawatthour)	Average value-cost ratio[b]	Minimum[c]	Maximum[c]
Dispatchable technologies					
Ultra-supercritical coal	$82.61	$38.69	0.47	0.40	0.52
Combined cycle	$39.94	$39.54	0.99	0.91	1.03
Advanced nuclear	$81.71	$38.42	0.47	0.41	0.55
Geothermal	$37.62	$45.11	1.20	1.08	1.41
Biomass	$90.17	$39.84	0.45	0.28	0.52
Resource-constrained technologies					
Wind, onshore	$40.23	$34.54	0.88	0.60	1.03
Wind, offshore	$105.38	$36.00	0.34	0.27	0.43
Solar, standalone[d]	$33.83	$32.85	0.98	0.72	1.14
Solar, hybrid[d,e]	$49.03	$45.53	0.93	0.64	1.07
Hydroelectric[e]	$64.27	$37.87	0.60	0.45	0.80
Capacity resource technologies					
Combustion turbine	$117.86	$101.74	0.86	0.61	1.00
Battery storage	$128.55	$101.01	0.79	0.52	0.97

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] LCOE = levelized cost of electricity, LCOS = levelized cost of storage, and LACE = levelized avoided cost of electricity

[b] The *average value-cost ratio* is an average of 25 regional value-cost ratios based on the cost with tax credits for each technology, as available.

[c] The range of unweighted value-cost ratio represents the lower and upper bounds resulting from the ratio of LACE-to-LCOE or LACE-to-LCOS calculations for each of the 25 regions.

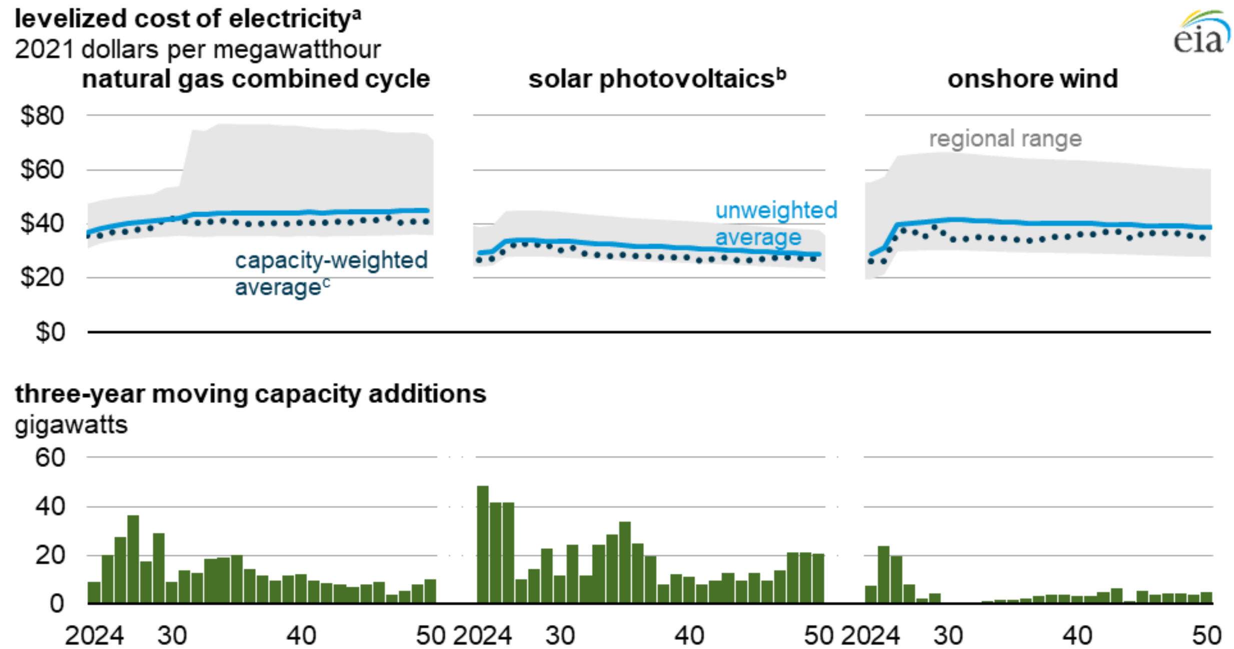
[d] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[e] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

LCOE and LACE projections

In Figure 3, we show capacity-weighted and unweighted LCOE for CC, solar PV (standalone), and onshore wind plants entering service from 2024 to 2050 in the AEO2022 Reference case. Changes in costs over time reflect a number of different model factors, sometimes working in different directions. For both solar PV and onshore wind, LCOE increases in the near term with the phasedown and expiration of the ITC and PTC, respectively. However, LCOE eventually declines over time because of technology improvement that tends to reduce LCOE through lower capital costs or improved performance (as measured by capacity factor for onshore wind or solar PV plants), offsetting some or all of the loss of the tax credits. The availability of high-quality resources may also be a factor. As the best, least-cost resources are used first, future development will occur in less favorable areas, potentially resulting in lower-performing resources, higher project development costs, and higher costs to access transmission lines. For CC, changing fuel prices also factors into the change in LCOE, as well as any environmental regulations that affect capital or operating costs.

Figure 3. Capacity-weighted and unweighted levelized cost of electricity (LCOE) projections and three-year moving capacity additions for selected generating technologies, 2024–50

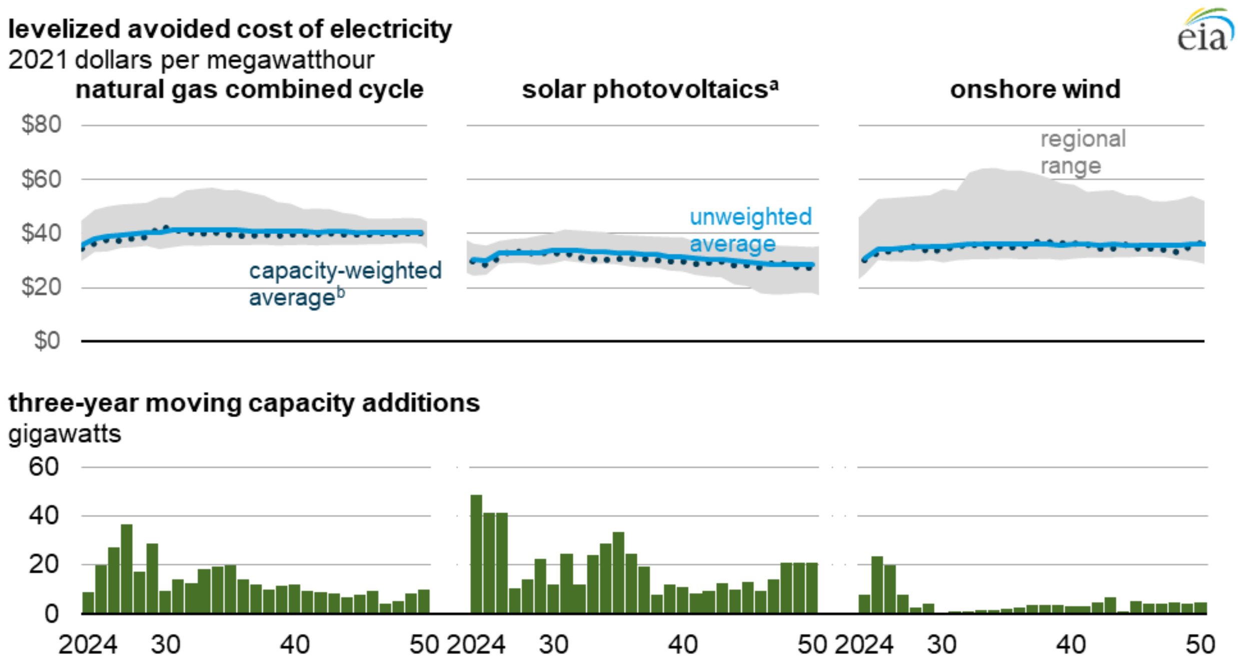


Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*
[a] Levelized cost includes tax credits available for plants entering service during the projection period.
[b] Technology is assumed to be photovoltaic with single-axis tracking. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.
[c] Capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in the previous three years in each region. For example, plants coming online in 2027 are based on additions from 2025 to 2027.

For all three technologies, the capacity-weighted average LCOE and unweighted average LCOE are not far apart from each other. In addition, all three technologies continue to be installed throughout the projection period so the capacity-weighted average LCOE stays lower than the unweighted LCOE, reflecting the build-out in low-cost regions. The capacity-weighted average LCOE and unweighted average LCOE for solar PV are closer to each other because we expect new builds across many regions throughout the projection period. The projected regional range for CC is generally narrow in the early years, but this range widens in later years because of the increase in variable costs for plants in California as a result of California's phaseout of fossil fuel-fired generation starting in 2030.

In Figure 4 we show capacity-weighted and unweighted average LACE over time. Changes in the value of generation, represented by LACE, are primarily a function of load growth. The LACE for onshore wind increases throughout the projection period as load increases. On the other hand, the LACE value for solar significantly decreases as generation from solar resources become more saturated with similar hourly operation patterns from strong daily or seasonal generation patterns within any given region. As this saturation occurs, generation from new facilities must compete with lower-cost options in the dispatch merit order. However, lower marginal electricity prices during daylight hours leads to declining LCOS for battery storage over the projection period, as it can take advantage of charging during the periods of lower electricity prices and discharges during evening peak-demand periods with higher electricity prices.

Figure 4. Capacity-weighted[1] and unweighted levelized avoided cost of electricity (LACE) projections and three-year moving capacity additions for selected generating technologies, 2024–50

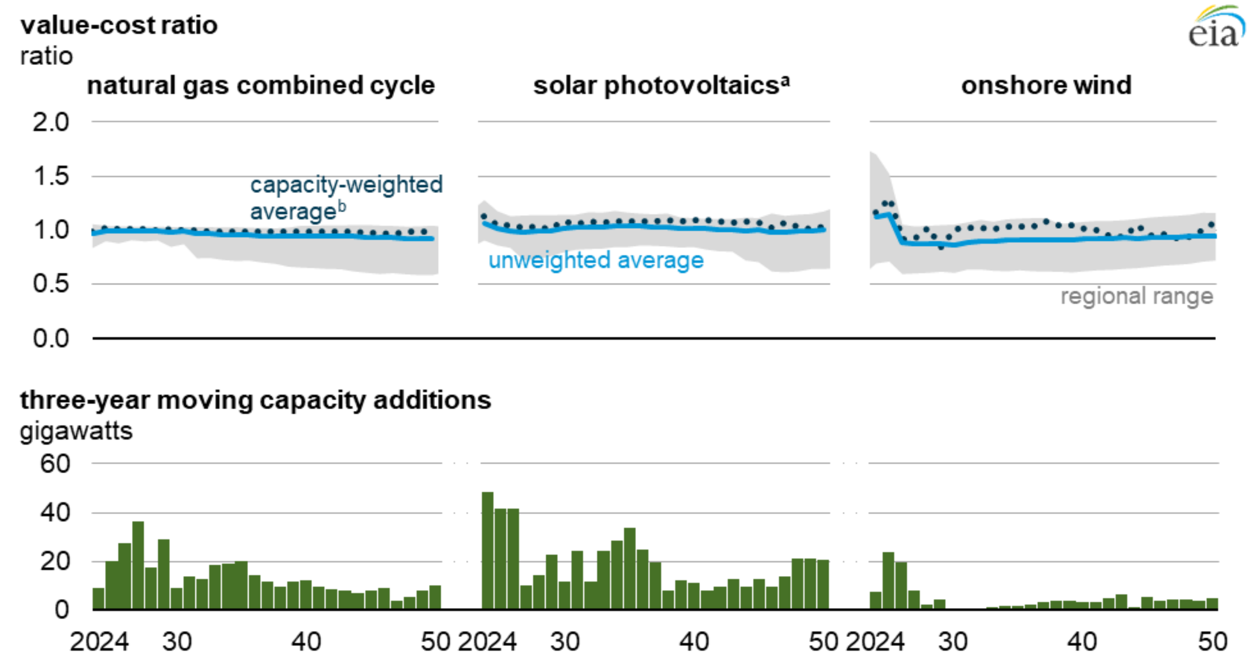


Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*
[a] Technology is assumed to be photovoltaic with single-axis tracking. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.
[b] Capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in the previous three years in each region. For example, plants coming online in 2027 are based on additions from 2025 to 2027.

Similar behaviors and patterns emerge with LACE as with LCOE; the capacity-weighted and the unweighted LACE stay close to each other throughout the projection period while the capacity-weighted LACE generally remains lower than the unweighted LACE.

When considering both the value and cost of building and operating a power plant, CC, solar PV, and onshore wind all reach market equilibrium or a break-even point (Figure 5). The break-even point represents a stable solution point where LACE equals LCOE. Once a technology achieves a value-cost ratio greater than one, its value-cost ratio tends to remain close to one, as seen with CC and solar PV. If the value-cost ratio is less than one, as seen with onshore wind in the near to mid-term, continued load growth, technology cost declines, or perhaps escalation in the fuel cost of a competing resource will tend to reduce the technology costs or increase the technology value to the grid over time. Similarly, if the value-cost ratio becomes significantly greater than one, the market will quickly build-out the technology until it meets the demand growth or displaces the higher cost incumbent generation. In all technologies, the capacity-weighted value-cost ratio stays mostly above the unweighted value-cost ratio, indicating that the capacity is being added in regions where it is most economical.

Figure 5. Value-cost ratio and three-year moving capacity additions for selected generating technologies, 2024–50



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*
[a] Technology is assumed to be photovoltaic with single-axis tracking. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.
[b] Capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in the previous three years in each region. For example, plants coming online in 2027 are based on additions from 2025 to 2027.

Market shocks may cause a divergence between LACE and LCOE and, therefore, disturb the market equilibrium. These market shocks include technology change, policy developments, or fuel price volatility that can increase or decrease the value-cost ratio of any given technology. However, we expect the market to reverse the divergence by either building the high-value resource (if the value-cost ratio increased) or waiting for slow-acting factors such as load growth to increase the value (if the value-cost ratio decreased) as seen for the capacity-weighted average value-cost ratios of both wind and solar PV.

Appendix A: LCOE tables for new generation resources entering service in 2024

Table A1a. Estimated capacity-weighted[a] levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) for new resources entering service in 2024 (2021 dollars per megawatthour)

Plant type	Capacity factor (percent)	Levelized capital cost	Levelized fixed O&M[b]	Levelized variable cost	Levelized transmis-sion cost	Total system LCOE or LCOS	Levelized tax credit[c]	Total LCOE or LCOS including tax credit
Dispatchable technologies								
Combined cycle	87%	$7.72	$1.68	$25.10	$1.03	$35.53	*NA*	$35.53
Resource-constrained technologies								
Wind, onshore	41%	$24.71	$7.65	$0.00	$2.56	$34.92	-$8.77	$26.15
Solar, standalone[d]	30%	$24.53	$6.03	$0.00	$2.51	$33.07	-$6.38	$26.69
Solar, hybrid[d,e]	30%	$32.35	$12.94	$0.00	$3.08	$48.37	-$8.41	$39.96
Capacity resource technologies								
Combustion turbine	10%	$46.75	$8.37	$40.64	$8.32	$104.07	*NA*	$104.07
Battery storage	10%	$64.08	$29.64	$36.25	$10.15	$140.11	*NA*	$140.11

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. We base the capacity additions for each region on additions from 2022 to 2024.

[b] O&M = operations and maintenance

[c] The tax credit component is based on targeted federal tax credits such as the Production Tax Credit (PTC) or Investment Tax Credit (ITC) available for some technologies. It reflects tax credits available only for plants entering service in 2024 and the substantial phaseout of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA,* or *not available*. The results are based on a regional model, and state or local incentives are not included in LCOE and LCOS calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[d] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[e] As modeled, we assume that hybrid solar PV generating assets have diurnal storage so that they can be dispatched within a day, but overall operation is limited by resource availablility during daytime.

Table A1b. Estimated unweighted levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) for new resources entering service in 2024 (2021 dollars per megawatthour)

Plant type	Capacity factor (percent)	Levelized capital cost	Levelized fixed O&M[a]	Levelized variable cost	Levelized transmis-sion cost	Total system LCOE or LCOS	Levelized tax credit[b]	Total LCOE or LCOS including tax credit
Dispatchable technologies								
Combined cycle	87%	$8.03	$1.68	$26.07	$1.03	$36.81	*NA*	$36.81
Resource-constrained technologies								
Wind, onshore	41%	$27.79	$7.65	$0.00	$2.36	$37.80	-$8.77	$29.03
Solar, standalone[c]	29%	$26.56	$6.34	$0.00	$3.16	$36.07	-$6.91	$29.16
Solar, hybrid[c,d]	28%	$35.57	$13.85	$0.00	$3.26	$52.68	-$9.25	$43.43
Capacity resource technologies								
Combustion turbine	10%	$47.70	$8.37	$42.41	$8.94	$107.42	*NA*	$107.42
Battery storage	10%	$63.85	$29.64	$29.39	$9.09	$131.98	*NA*	$131.98

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] O&M = operations and maintenance

[b] The tax credit component is based on targeted federal tax credits such as the Production Tax Credit (PTC) or Investment Tax Credit (ITC) available for some technologies. It reflects tax credits available only for plants entering service in 2024 and the substantial phaseout of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA*, or *not available*. The results are based on a regional model, and state or local incentives are not included in LCOE and LCOS calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[c] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[d] As modeled, we assume that hybrid solar PV generating assets have diurnal storage so that they can be dispatched within a day, but overall operation is limited by resource availablility during daytime.

Table A2. Regional variation in levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) for new resources entering service in 2024 (2021 dollars per megawatthour)

	Without tax credits				With tax credits[a]			
Plant type	Minimum	Simple average	Capacity-weighted average[b]	Maximum	Minimum	Simple average	Capacity-weighted average[b]	Maximum
Dispatchable technologies								
Combined cycle	$30.99	$36.81	$35.53	$47.40	$30.99	$36.81	$35.53	$47.40
Resource-constrained technologies								
Wind, onshore	$28.36	$37.80	$34.92	$64.14	$19.59	$29.03	$26.15	$55.37
Solar, standalone[c]	$29.96	$36.07	$33.07	$48.23	$24.22	$29.16	$26.69	$38.77
Solar, hybrid[c,d]	$43.54	$52.68	$48.37	$68.51	$35.96	$43.43	$39.96	$56.09
Capacity resource technologies								
Combustion turbine	$95.83	$107.42	$104.07	$132.85	$95.83	$107.42	$104.07	$132.85
Battery storage	$105.50	$131.98	$140.11	$148.49	$105.50	$131.98	$140.11	$148.49

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

Note: We calculate the levelized costs for non-dispatchable technologies based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are 37%–51% for onshore wind, 25%–33% for standalone solar PV, and 24%–32% for hybrid solar PV. Regional variations in construction labor rates and capital costs as well as resource availability also affect levelized costs.

[a] Levelized cost with tax credits reflects targeted federal tax credits such as the Production Tax Credit (PTC) or Investment Tax Credit (ITC) available for plants entering service in 2024 and the substantial phaseout of both the PTC and ITC as scheduled under current law.

[b] The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2022 to 2024.

[c] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[d] As modeled, we assume that hybrid solar PV generating assets have diurnal storage so that they can be dispatched within a day, but overall operation is limited by resource availablility during daytime.

Table A3. Regional variation in levelized avoided cost of electricity (LACE) for new resources entering service in 2024 (2021 dollars per megawatthour)

Plant type	Minimum	Simple average	Capacity-weighted average[a]	Maximum
Dispatchable technologies				
Combined cycle	$29.92	$35.48	$34.73	$44.82
Resource-constrained technologies				
Wind, onshore	$25.07	$30.95	$30.30	$48.24
Solar, standalone[b]	$24.45	$30.65	$29.96	$36.36
Solar, hybrid[b,c]	$28.02	$41.28	$40.93	$53.73
Capacity resource technologies				
Combustion turbine	$58.44	$90.11	$92.19	$120.32
Battery storage	$58.44	$89.82	$102.69	$119.52

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[1]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2022 to 2024.

[b] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[c] As modeled, we assume that hybrid solar PV generating assets have diurnal storage so that they can be dispatched within a day, but overall operation is limited by resource availablility during daytime.

Table A4a. Value-cost ratio (capacity-weighted) for new resources entering service in 2024

Plant type	Average capacity-weighted[a] LCOE[b] or LCOS[b] with tax credits (2021 dollars per megawatthour)	Average capacity-weighted[a] LACE[b] (2021 dollars per megawatthour)	Average value-cost ratio[c]
Dispatchable technologies			
Combined cycle	$35.53	$34.73	0.98
Resource-constrained technologies			
Wind, onshore	$26.15	$30.30	1.17
Solar, standalone[d]	$26.69	$29.96	1.12
Solar, hybrid[d,e]	$39.96	$40.93	1.03
Capacity resource technologies			
Combustion turbine	$104.07	$92.19	0.89
Battery storage	$140.11	$102.69	0.73

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2022 to 2024.

[b] LCOE = levelized cost of electricity, LCOS = levelized cost of storage, and LACE = levelized avoided cost of electricity.

[c] The *average value-cost ratio* is an average of 25 regional value-cost ratios based on the cost with tax credits for each technology, as available.

[d] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[e] As modeled, we assume that hybrid solar PV generating assets have diurnal storage so that they can be dispatched within a day, but overall operation is limited by resource availablility during daytime.

Table A4b. Value-cost ratio (unweighted) for new resources entering service in 2024

Plant type	Average unweighted LCOE[a] or LCOS[a] with tax credits (2021 dollars per megawatthour)	Average unweighted LACE[a] (2021 dollars per megawatthour)	Average value-cost ratio[b]	Minimum[c]	Maximum[c]
Dispatchable technologies					
Combined cycle	$36.81	$35.48	0.97	0.84	1.06
Resource-constrained technologies					
Wind, onshore	$29.03	$30.95	1.12	0.69	1.70
Solar, standalone[d]	$29.16	$30.65	1.06	0.91	1.28
Solar, hybrid[d,e]	$43.43	$41.28	0.95	0.66	1.06
Capacity resource technologies					
Combustion turbine	$107.42	$90.11	0.84	0.57	1.04
Battery storage	$131.98	$89.82	0.68	0.43	0.95

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] LCOE = levelized cost of electricity, LCOS = levelized cost of storage, and LACE = levelized avoided cost of electricity.

[b] The *average value-cost ratio* is an average of 25 regional value-cost ratios based on the cost with tax credits for each technology, as available.

[c] The range of unweighted value-cost ratio represents the lower and upper bounds resulting from the ratio of LACE-to-LCOE or LACE-to-LCOS calculations for each of the 25 regions.

[d] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[e] As modeled, we assume that hybrid solar PV generating assets have diurnal storage so that they can be dispatched within a day, but overall operation is limited by resource availablility during daytime.

Appendix B: LCOE and LACE tables for new resources entering service in 2040

Table B1a. Estimated capacity-weighted[a] levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) for new resources entering service in 2040 (2021 dollars per megawatthour)

Plant type	Capacity factor (percent)	Levelized capital cost	Levelized fixed O&M[b]	Levelized variable cost	Levelized transmis-sion cost	Total system LCOE or LCOS	Levelized tax credit[c]	Total LCOE or LCOS including tax credit
Dispatchable technologies								
Ultra-supercritical coal	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Combined cycle	87%	$8.07	$1.68	$29.43	$1.12	$40.29	*NA*	$40.29
Advanced nuclear	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Geothermal	90%	$23.09	$15.92	$1.21	$1.42	$41.64	-$2.31	$39.34
Biomass	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Resource-constrained technologies								
Wind, onshore	41%	$25.24	$7.78	$0.00	$3.06	$36.08	*NA*	$36.08
Wind, offshore	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Solar, standalone[d]	31%	$20.80	$5.86	$0.00	$2.82	$29.48	-$2.08	$27.40
Solar, hybrid[d,e]	30%	$27.95	$13.07	$0.00	$3.19	$44.21	-$2.80	$41.41
Hydroelectric[e]	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Capacity resource technologies								
Combustion turbine	10%	$50.53	$8.37	$48.19	$9.66	$116.75	*NA*	$116.75
Battery storage	10%	$57.84	$29.64	$8.31	$8.53	$104.33	*NA*	$104.33

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. We base the capacity additions for each region on additions from 2038 to 2040. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB*, or *not built*.

[b] O&M = operations and maintenance

[c] The tax credit component is based on targeted federal tax credits such as the Production Tax Credit (PTC) or Investment Tax Credit (ITC) available for some technologies. It reflects tax credits available only for plants entering service in 2040 and the substantial phaseout of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA*, or *not available*. The results are based on a regional model, and state or local incentives are not included in LCOE and LCOS calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[d] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[e] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

Table B1b. Estimated unweighted levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) for new resources entering service in 2040 (2021 dollars per megawatthour)

Plant type	Capacity factor (percent)	Levelized capital cost	Levelized fixed O&M[a]	Levelized variable cost	Levelized transmis-sion cost	Total system LCOE or LCOS	Levelized tax credit[b]	Total LCOE or LCOS including tax credit
Dispatchable technologies								
Ultra-supercritical coal	85%	$48.97	$5.71	$23.64	$1.14	$79.46	*NA*	$79.46
Combined cycle	87%	$9.10	$1.68	$32.11	$1.16	$44.05	*NA*	$44.05
Advanced nuclear	90%	$57.31	$16.15	$10.71	$1.10	$85.28	-$5.07	$80.20
Geothermal	90%	$22.84	$16.44	$1.21	$1.42	$41.91	-$2.28	$39.63
Biomass	83%	$37.86	$18.10	$29.36	$1.21	$86.53	*NA*	$86.53
Resource-constrained technologies								
Wind, onshore	40%	$29.45	$7.89	$0.00	$2.74	$40.08	*NA*	$40.08
Wind, offshore	43%	$64.77	$30.58	$0.00	$2.66	$98.01	*NA*	$98.01
Solar, standalone[c]	29%	$23.42	$6.41	$0.00	$3.59	$33.42	-$2.34	$31.07
Solar, hybrid[c,d]	28%	$30.93	$13.99	$0.00	$3.71	$48.63	-$3.09	$45.54
Hydroelectric[d]	56%	$46.11	$11.85	$3.86	$2.02	$63.83	*NA*	$63.83
Capacity resource technologies								
Combustion turbine	10%	$50.84	$8.37	$52.59	$10.07	$121.87	*NA*	$121.87
Battery storage	10%	$58.93	$29.64	$21.66	$10.24	$120.47	*NA*	$120.47

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] O&M = operations and maintenance

[b] The tax credit component is based on targeted federal tax credits such as the Production Tax Credit (PTC) or Investment Tax Credit (ITC) available for some technologies. It reflects tax credits available only for plants entering service in 2040 and the substantial phaseout of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA*, or *not available*. The results are based on a regional model, and state or local incentives are not included in LCOE and LCOS calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[c] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[d] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

Table B2. Regional variation in levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) for new resources entering service in 2040 (2021 dollars per megawatthour)

	Without tax credits				With tax credits[a]			
Plant type	Minimum	Simple average	Capacity-weighted average[b]	Maximum	Minimum	Simple average	Capacity-weighted average[b]	Maximum
Dispatchable technologies								
Ultra-supercritical coal	$70.43	$79.46	*NB*	$97.93	$70.43	$79.46	*NB*	$97.93
Combined cycle	$35.35	$44.05	$40.29	$76.22	$35.35	$44.05	$40.29	$76.22
Advanced nuclear	$80.09	$85.28	*NB*	$95.22	$75.02	$80.20	*NB*	$90.14
Geothermal	$33.74	$41.91	$41.64	$48.18	$32.15	$39.63	$39.34	$45.41
Biomass	$77.25	$86.53	*NB*	$138.23	$77.25	$86.53	*NB*	$138.23
Resource-constrained technologies								
Wind, onshore	$29.13	$40.08	$36.08	$63.46	$29.13	$40.08	$36.08	$63.46
Wind, offshore	$79.79	$98.01	*NB*	$117.39	$79.79	$98.01	*NB*	$117.39
Solar, standalone[c]	$27.45	$33.42	$29.48	$44.18	$25.52	$31.07	$27.40	$41.00
Solar, hybrid[c,d]	$39.77	$48.63	$44.21	$62.45	$37.26	$45.54	$41.41	$58.34
Hydroelectric[d]	$48.66	$63.83	*NB*	$82.08	$48.66	$63.83	*NB*	$82.08
Capacity resource technologies								
Combustion turbine	$105.50	$121.87	$116.75	$174.35	$105.50	$121.87	$116.75	$174.35
Battery storage	$104.33	$120.47	$104.33	$144.04	$104.33	$120.47	$104.33	$144.04

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

Note: We calculate the levelized costs for non-dispatchable technologies based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are 38%–47% for onshore wind, 41%–50% for offshore wind, 25%–33% for standalone solar PV, 24%–32% for hybrid solar PV, and 25%–80% for hydroelectric. Regional variations in construction labor rates and capital costs as well as resource availability also affect levelized costs.

[a] Levelized cost with tax credits reflects targeted federal tax credits such as the Production Tax Credit (PTC) or Investment Tax Credit (ITC) available for plants entering service in 2040 and the substantial phaseout of both the PTC and ITC as scheduled under current law.

[b] The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2038 to 2040. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB*, or *not built*.

[c] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[d] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

Table B3. Regional variation in levelized avoided cost of electricity (LACE) for new resources entering service in 2040 (2021 dollars per megawatthour)

Plant type	Minimum	Simple average	Capacity-weighted average[a]	Maximum
Dispatchable technologies				
Ultra-supercritical coal	$35.92	$40.21	*NB*	$44.63
Combined cycle	$35.75	$40.86	$39.52	$51.13
Advanced nuclear	$35.68	$39.99	*NB*	$44.43
Geothermal	$43.09	$46.14	$46.36	$50.71
Biomass	$36.04	$41.17	*NB*	$51.45
Resource-constrained technologies				
Wind, onshore	$30.77	$36.06	$36.41	$58.14
Wind, offshore	$30.88	$36.13	*NB*	$47.53
Solar, standalone[b]	$26.09	$31.42	$29.82	$38.71
Solar, hybrid[b,c]	$36.33	$45.50	$43.18	$57.68
Hydroelectric[c]	$32.16	$39.19	*NB*	$49.40
Capacity resource technologies				
Combustion turbine	$88.27	$101.73	$102.54	$130.18
Battery storage	$87.00	$100.64	$89.21	$129.98

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2038 to 2040. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB*, or *not built*.

[b] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[c] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

Table B4a. Value-cost ratio (capacity-weighted) for new resources entering service in 2040

Plant type	Average capacity-weighted[a] LCOE[b] or LCOS[b] with tax credits (2021 dollars per megawatthour)	Average capacity-weighted[a] LACE[b] (2021 dollars per megawatthour)	Average value-cost ratio[c]
Dispatchable technologies			
Ultra-supercritical coal	*NB*	*NB*	*NB*
Combined cycle	$40.29	$39.52	0.98
Advanced nuclear	*NB*	*NB*	*NB*
Geothermal	$39.34	$46.36	1.20
Biomass	*NB*	*NB*	*NB*
Resource-constrained technologies			
Wind, onshore	$36.08	$36.41	1.01
Wind, offshore	*NB*	*NB*	*NB*
Solar, standalone[d]	$27.40	$29.82	1.09
Solar, hybrid[d,e]	$41.41	$43.18	1.04
Hydroelectric[e]	*NB*	*NB*	*NB*
Capacity resource technologies			
Combustion turbine	$116.75	$102.54	0.88
Battery storage	$104.33	$89.21	0.86

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2038 to 2040. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB*, or *not built*.

[b] LCOE = levelized cost of electricity, LCOS = levelized cost of storage, and LACE = levelized avoided cost of electricity.

[c] The *average value-cost ratio* is an average of 25 regional value-cost ratios based on the cost with tax credits for each technology, as available.

[d] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[e] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

Table B4b. Value-cost ratio (unweighted) for new resources entering service in 2040

Plant type	Average unweighted LCOE[a] or LCOS[a] with tax credits (2021 dollars per megawatthour)	Average unweighted LACE[a] (2021 dollars per megawatthour)	Average value-cost ratio[b]	Minimum[c]	Maximum[c]
Dispatchable technologies					
Ultra-supercritical coal	$79.46	$40.21	0.51	0.42	0.57
Combined cycle	$44.05	$40.86	0.95	0.65	1.04
Advanced nuclear	$80.20	$39.99	0.50	0.44	0.58
Geothermal	$39.63	$46.14	1.19	0.99	1.53
Biomass	$86.53	$41.17	0.48	0.31	0.56
Resource-constrained technologies					
Wind, onshore	$40.08	$36.06	0.92	0.62	1.08
Wind, offshore	$98.01	$36.13	0.37	0.29	0.48
Solar, standalone[d]	$31.07	$31.42	1.02	0.84	1.11
Solar, hybrid[d,e]	$45.54	$45.50	1.00	0.87	1.09
Hydroelectric[e]	$63.83	$39.19	0.63	0.47	0.82
Capacity resource technologies					
Combustion turbine	$121.87	$101.73	0.84	0.60	1.05
Battery storage	$120.47	$100.64	0.84	0.71	1.04

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2022*

[a] LCOE = levelized cost of electricity, LCOS = levelized cost of storage, and LACE = levelized avoided cost of electricity

[b] The *average value-cost ratio* is an average of 25 regional value-cost ratios based on the cost with tax credits for each technology, as available.

[c] The range of unweighted value-cost ratio represents the lower and upper bounds resulting from the ratio of LACE-to-LCOE or LACE-to-LCOS calculations for each of the 25 regions.

[d] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[e] As modeled, we assume that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availablility by site and season for hydroelectric and by daytime for hybrid solar PV.

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.

I/A

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.

I/A

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

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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)	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	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.

<u>Electrification</u>

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.

DOE Loan Guarantees

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.

Corporate Alternative Minimum Tax

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.

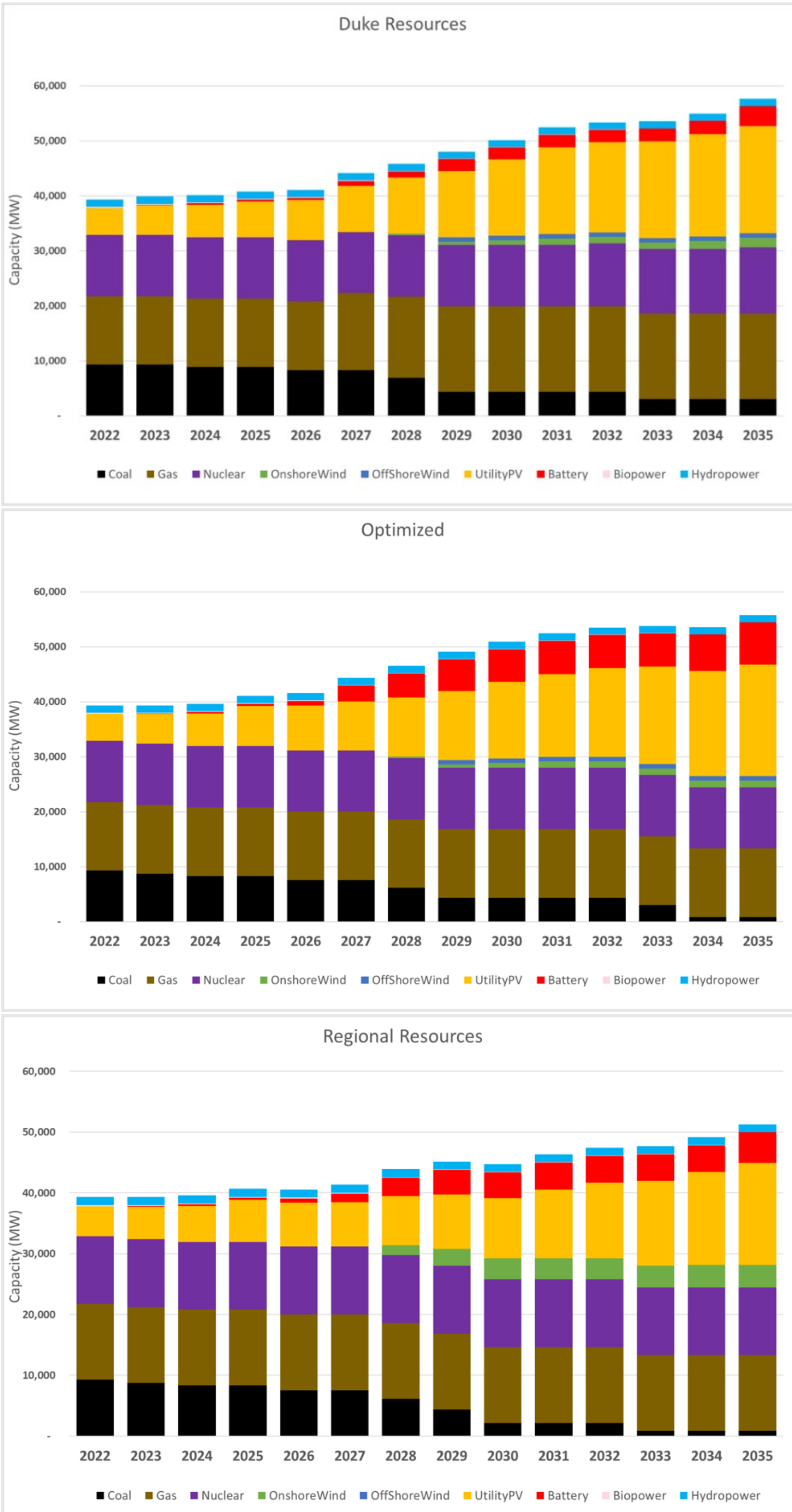
The Optimized scenario sees an accelerated deployment of solar compared with Duke Resources in 2025, slower growth relative to Duke Resources in 2027 and 2030-2031, and then higher solar deployment again starting in 2032. In the Optimized scenario, there is a significantly higher quantity of battery 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.



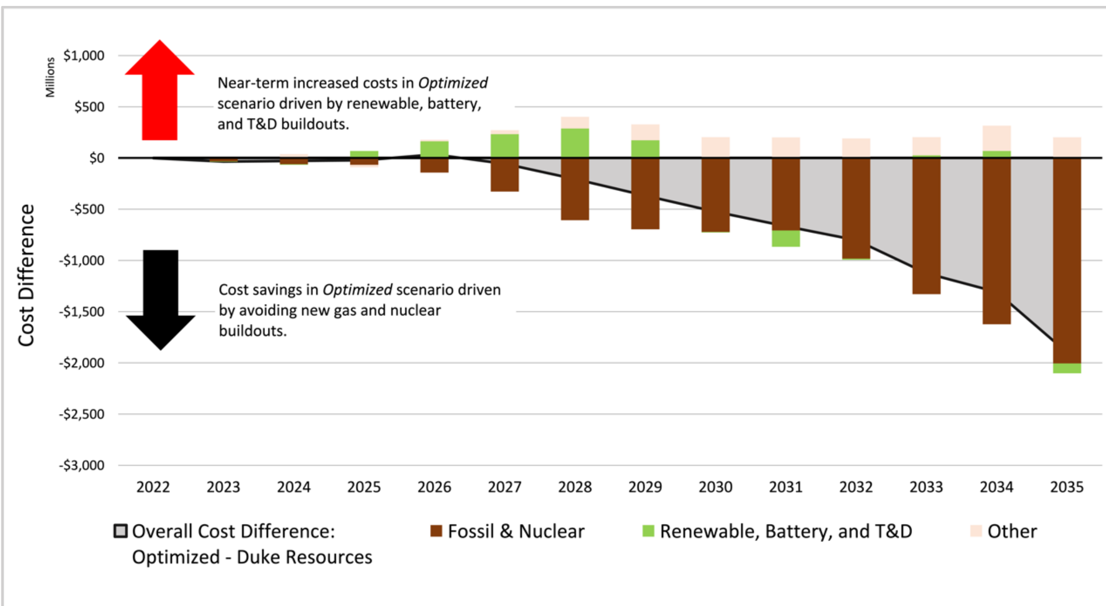
Although not shown in ***Figure 1***, the Optimized and Regional Resources scenarios deploy higher levels of energy efficiency (1.5% of total retail load) relative to the Duke Resources scenario (1% of eligible retail load), which reduces the overall load and contributes to cost savings in the near,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

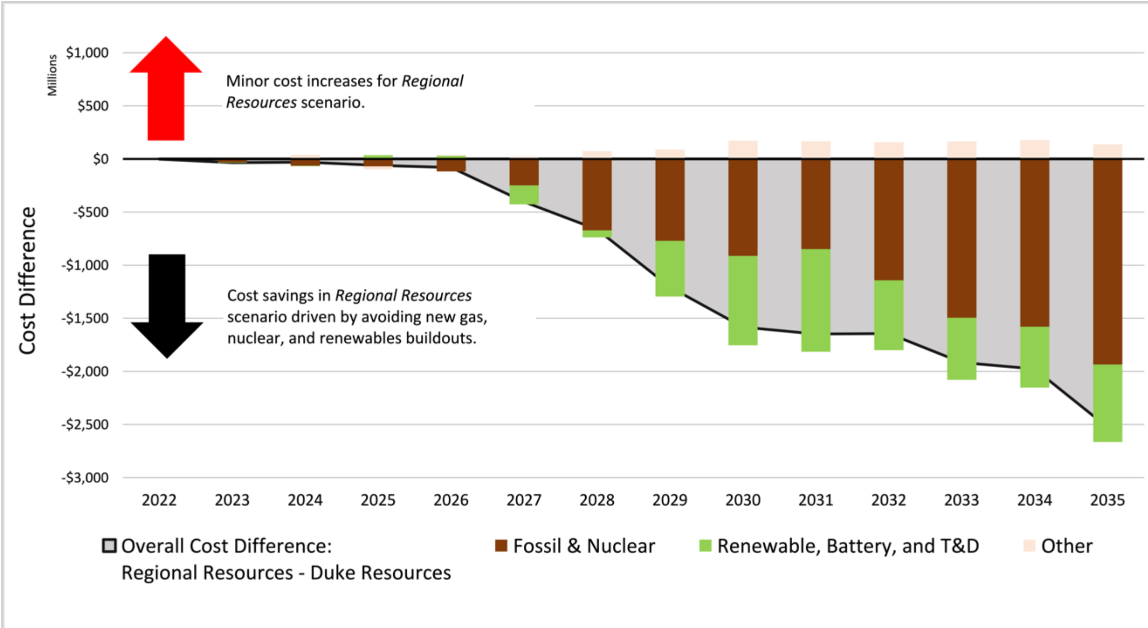


The Regional Resources scenario is even more cost-effective than the Optimized scenario, reducing costs relative to the Duke Resources scenario every year. Wind PPAs coupled with battery storage deployment in the Regional Resources scenario are significantly

[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***).

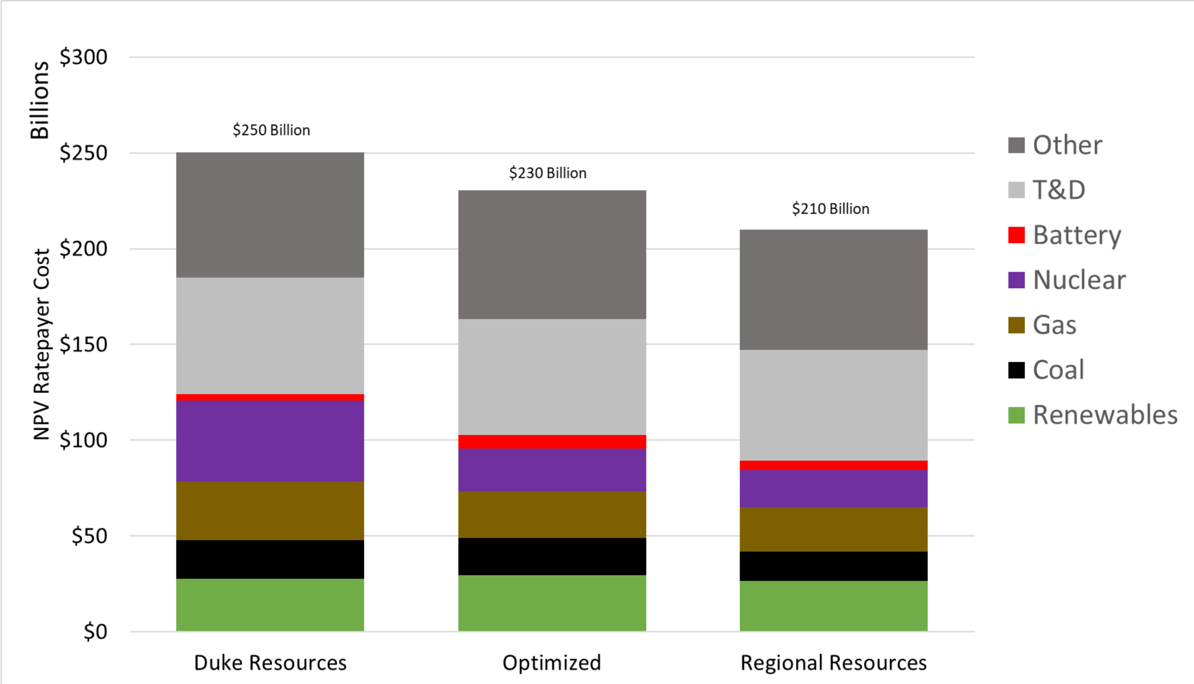
Figure 3. Ratepayer Cost Comparison of Regional Resources – Duke Resources, DEC and DEP Combined.



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]

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[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.

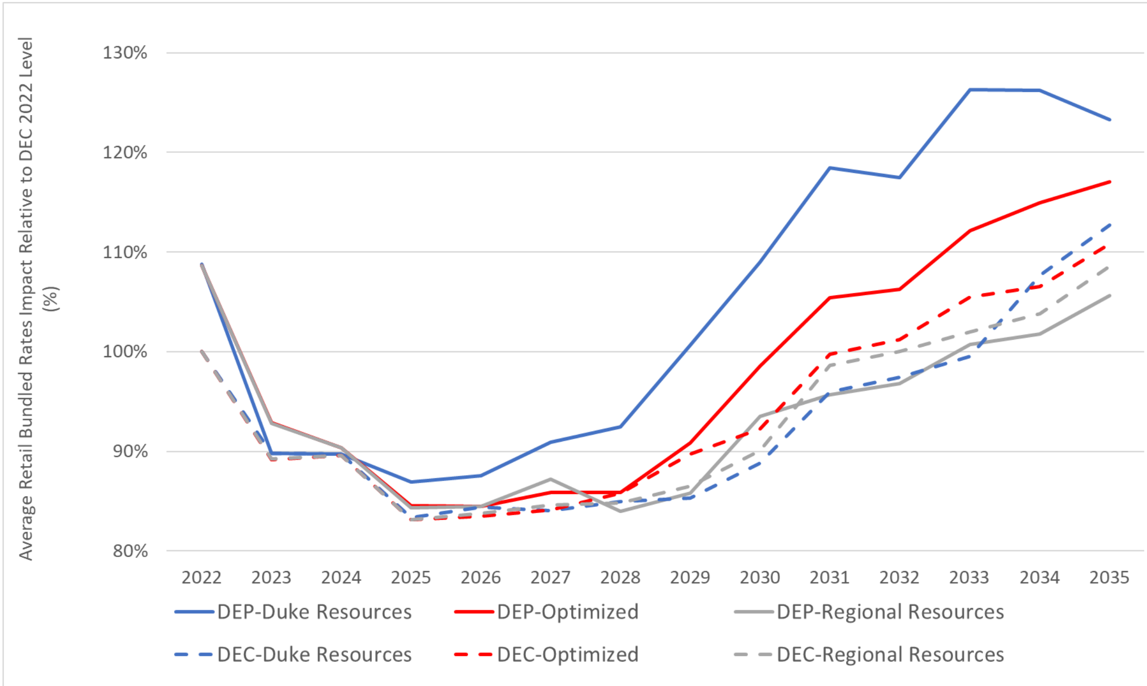


Figure 6. Average Monthly Bill Change – Duke Resource and Optimized, DEC and DEP Combined.

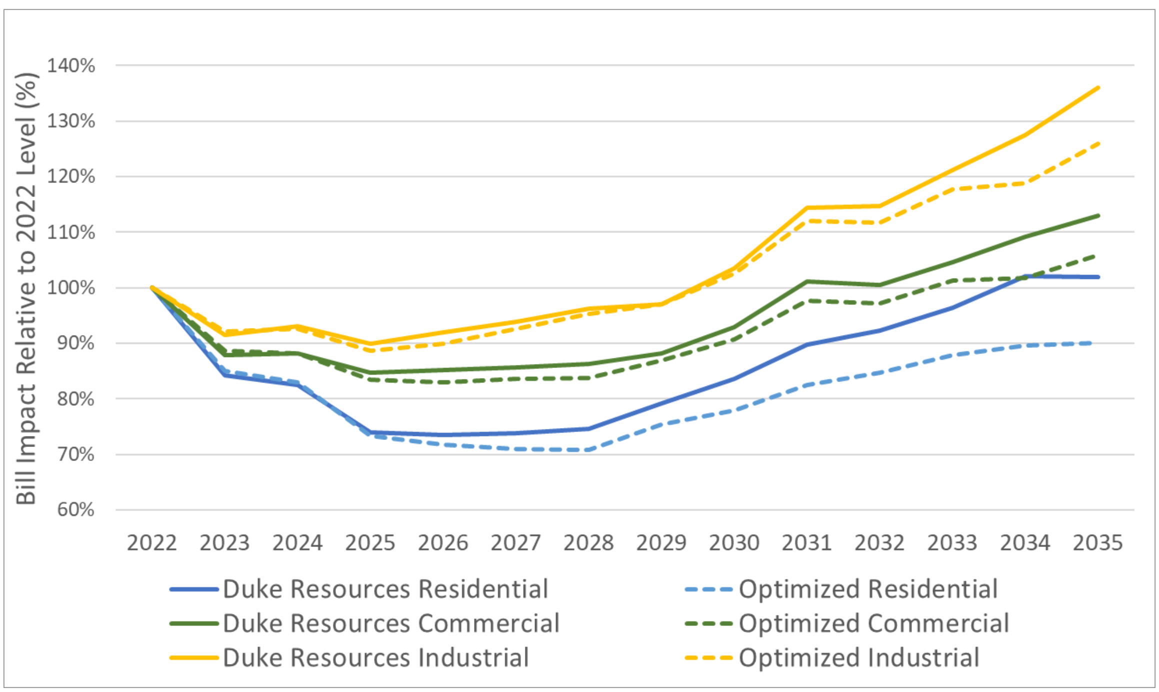
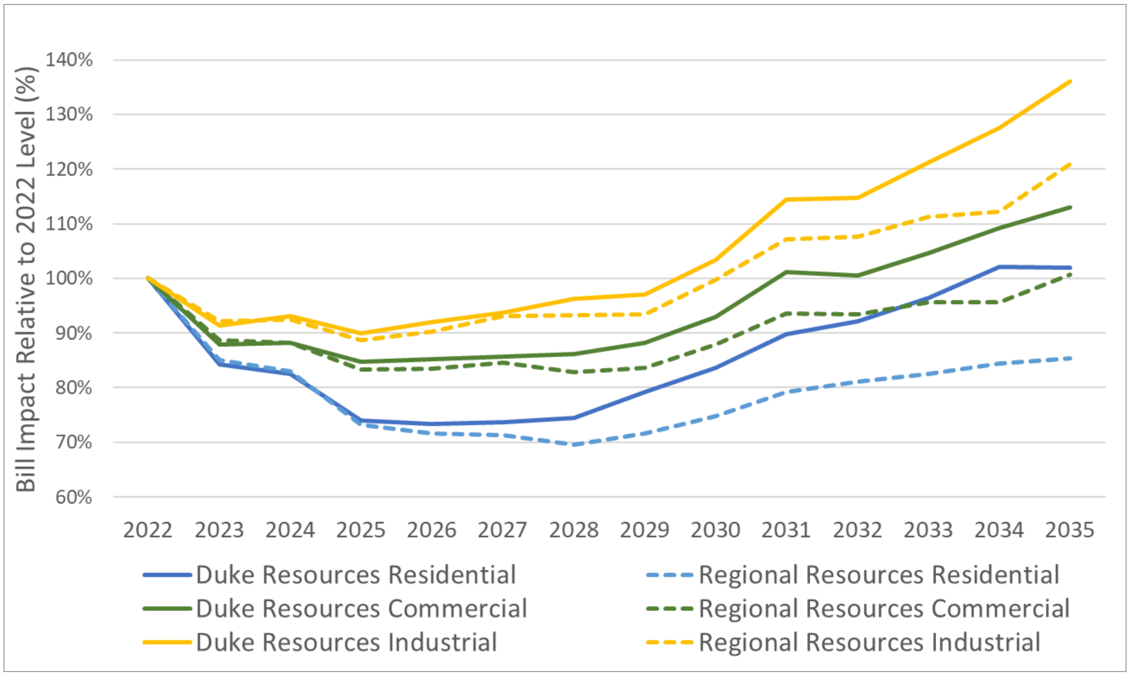


Figure 7. Average Monthly Bill Change – Duke Resources and Regional Resources, DEC and DEP Combined.



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.

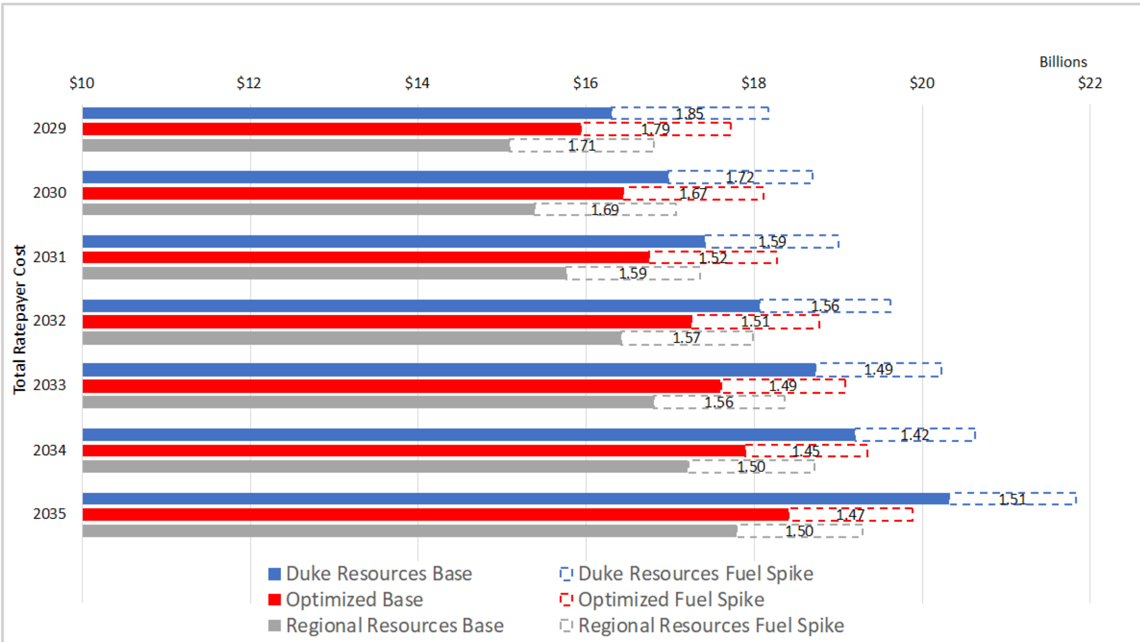
All three scenarios see peak utilization of fossil fuel generators between 2029-2035. In that period, the Optimized scenario is more resilient to fuel cost volatility than the Duke Resources scenario. On average, ratepayer costs in the Optimized scenario increase by 2% less than in the Duke Resources 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.

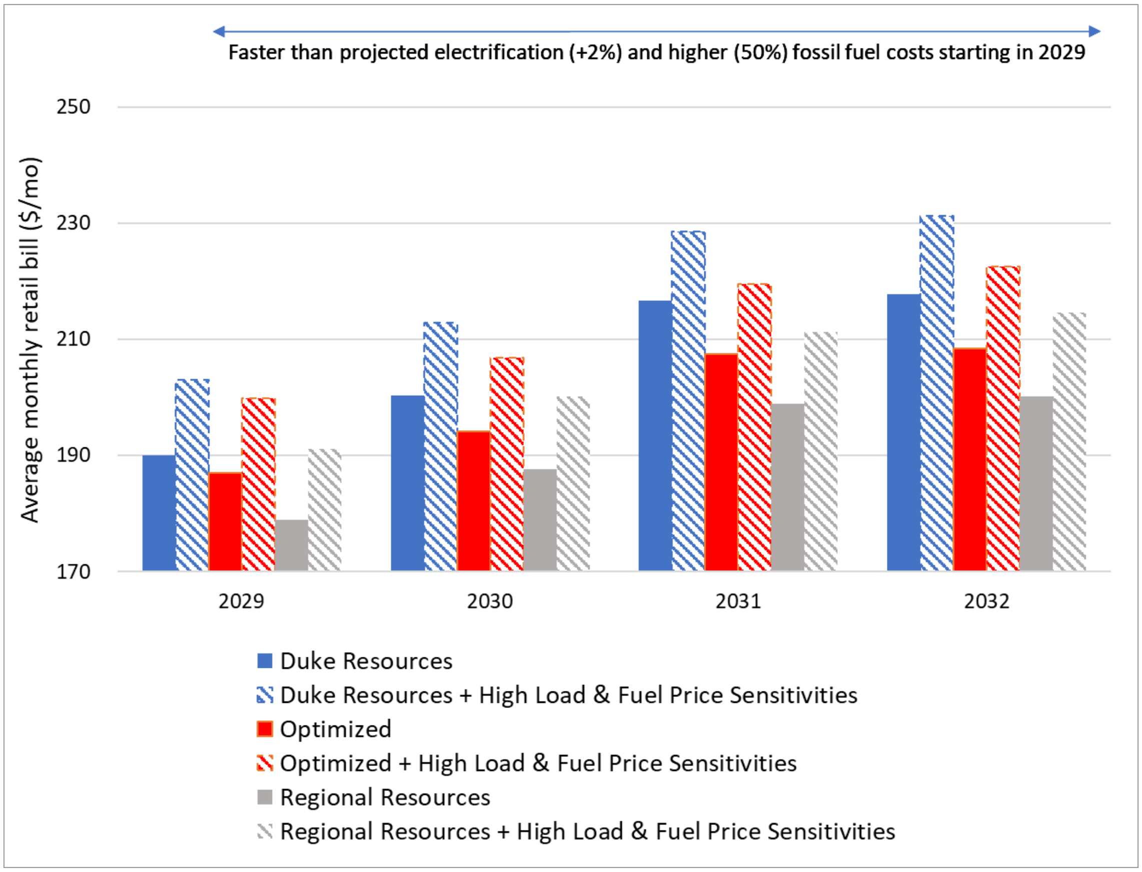
4b. The Optimized and Regional Resources scenarios can mitigate the cost risk to customers of inadequately planning for the impacts of a rapidly electrifying economy.

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.

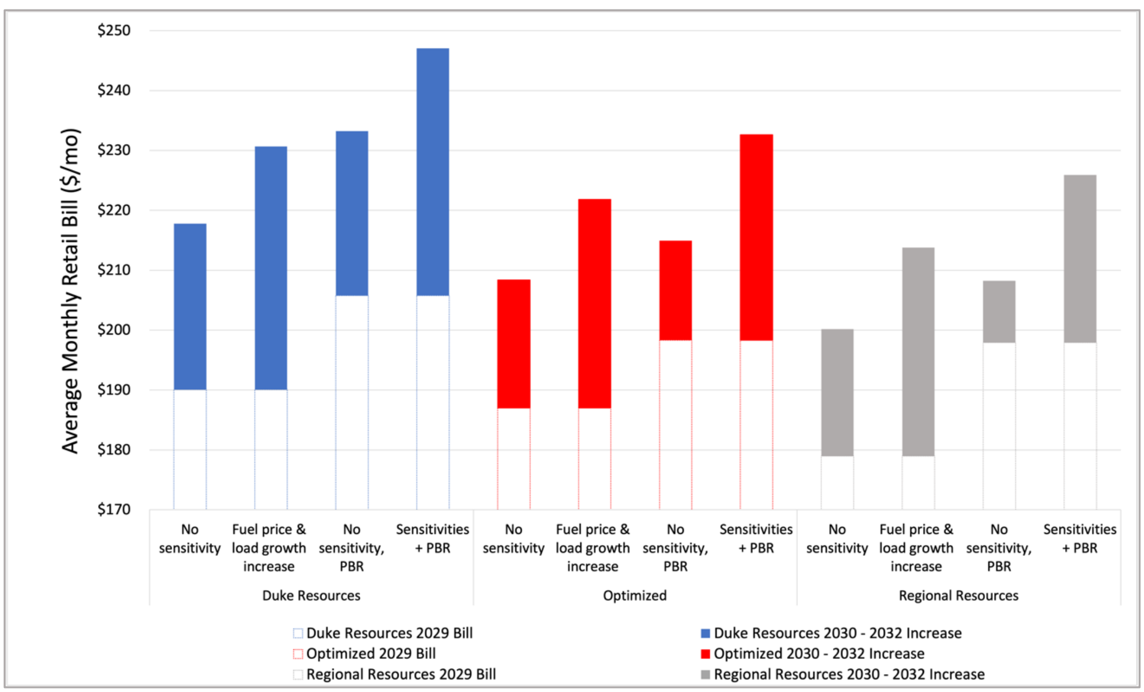
[20] *Id.* at p. 19-20.

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.

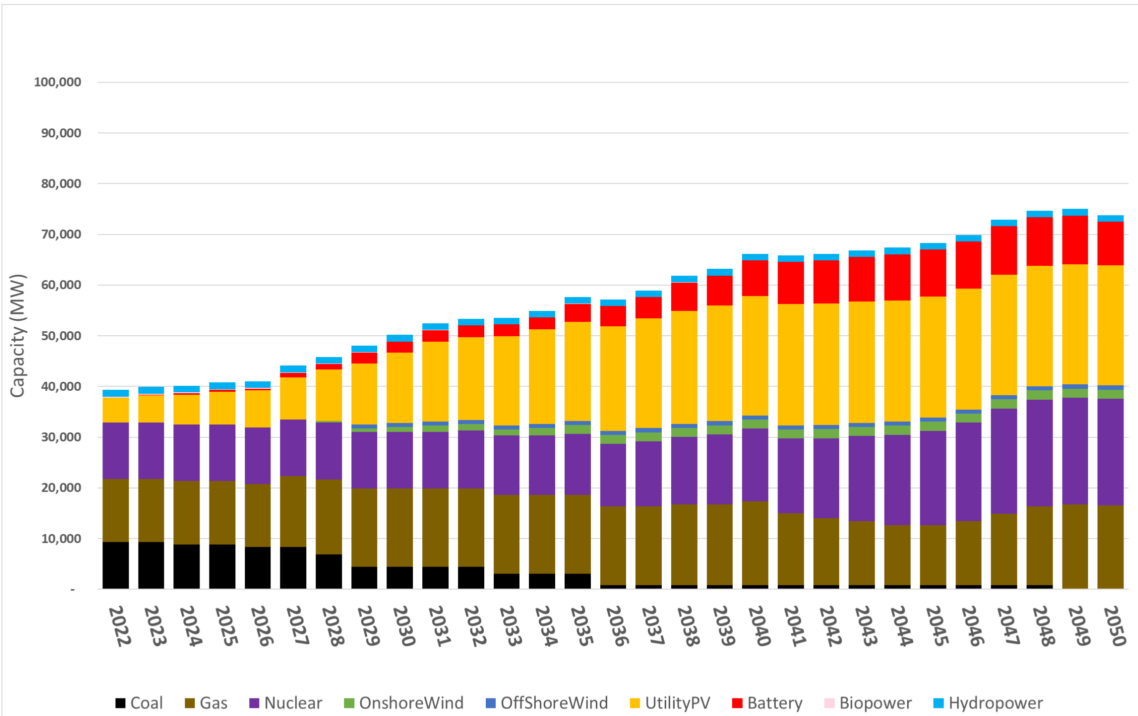


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Figure 12. Annual Capacity by Technology for Optimized Scenario, 2022-2050.

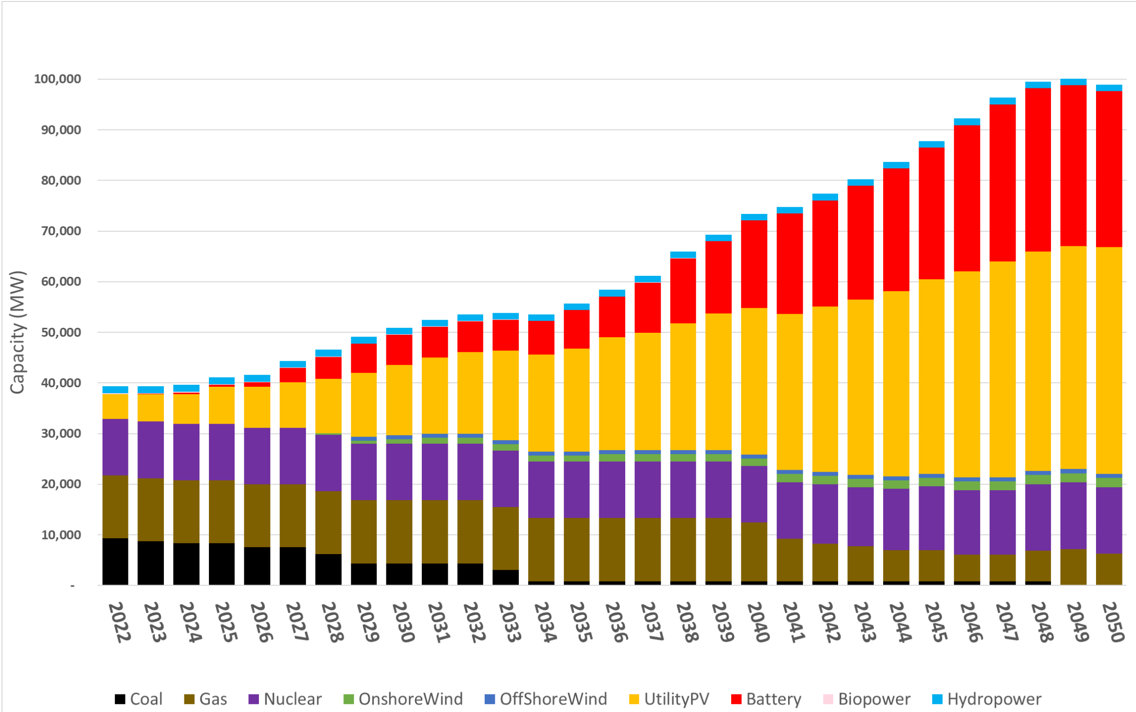
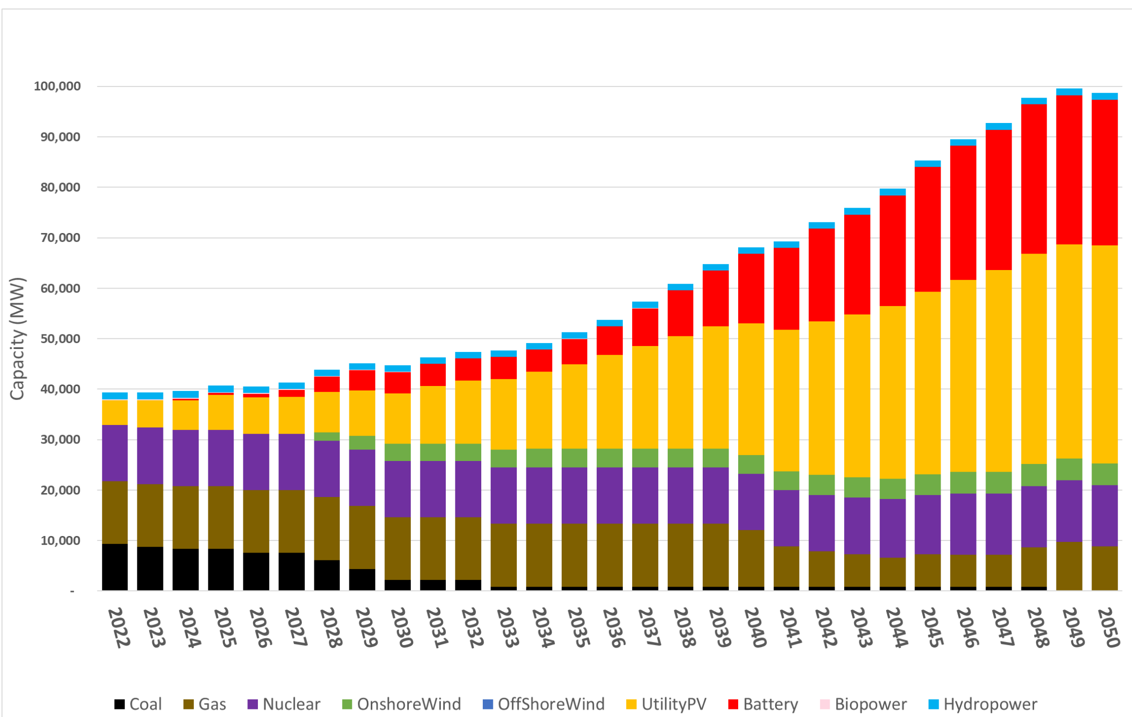


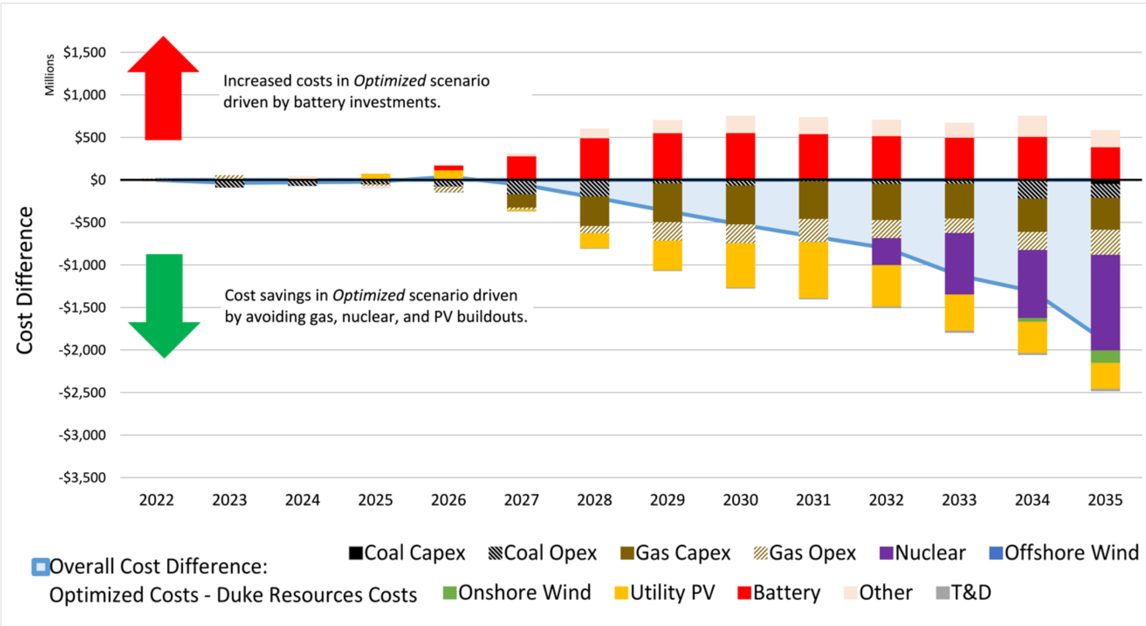
Figure 13. Annual Capacity by Technology for Regional Resources Scenario, 2022-2050.



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

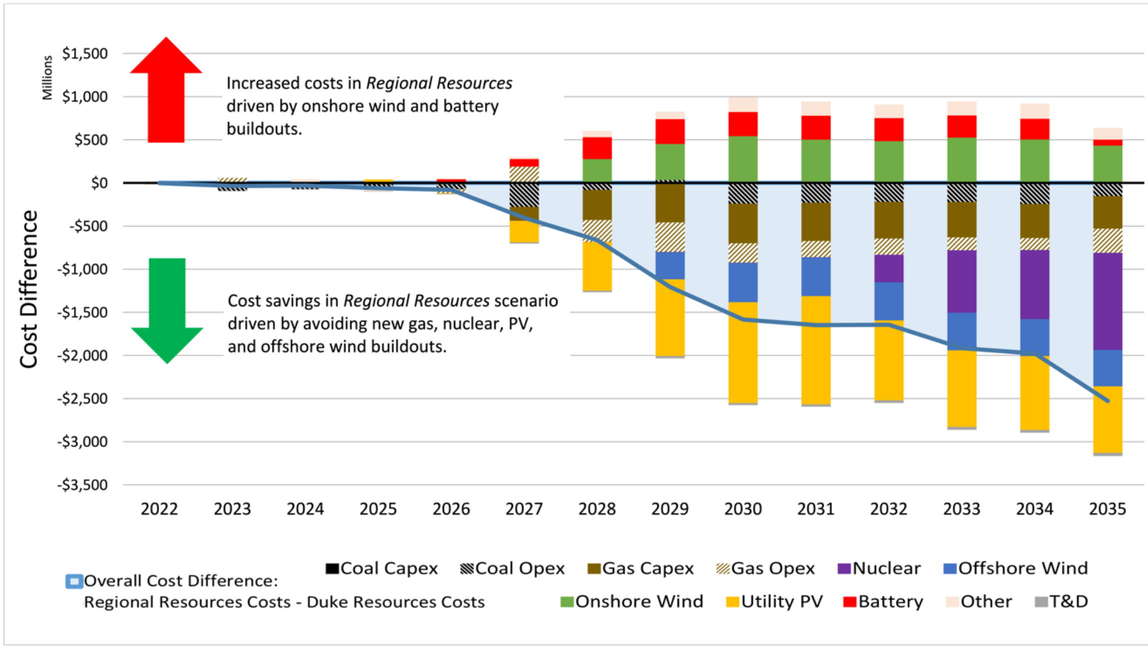
Both the Optimized scenario and the Regional Resources scenario save ratepayers money over the medium term when compared with the Duke Resources scenario when looking at the combined impact across DEC and DEP. In the Optimized Scenario, slight near-term cost increases are driven by faster deployment 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.



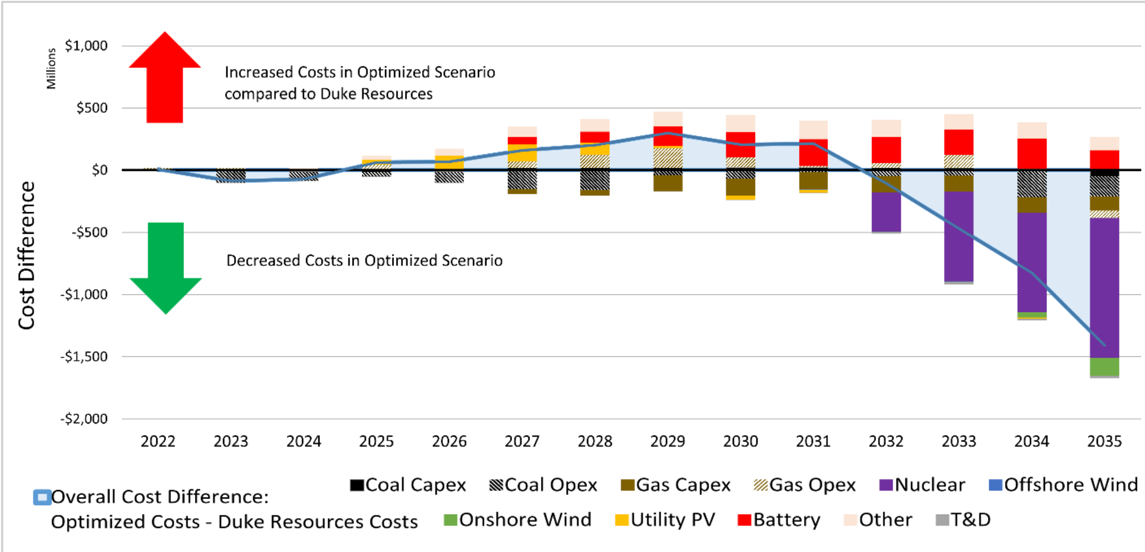
A.4. DEC vs. DEP Ratepayer Cost and Bill Impact

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

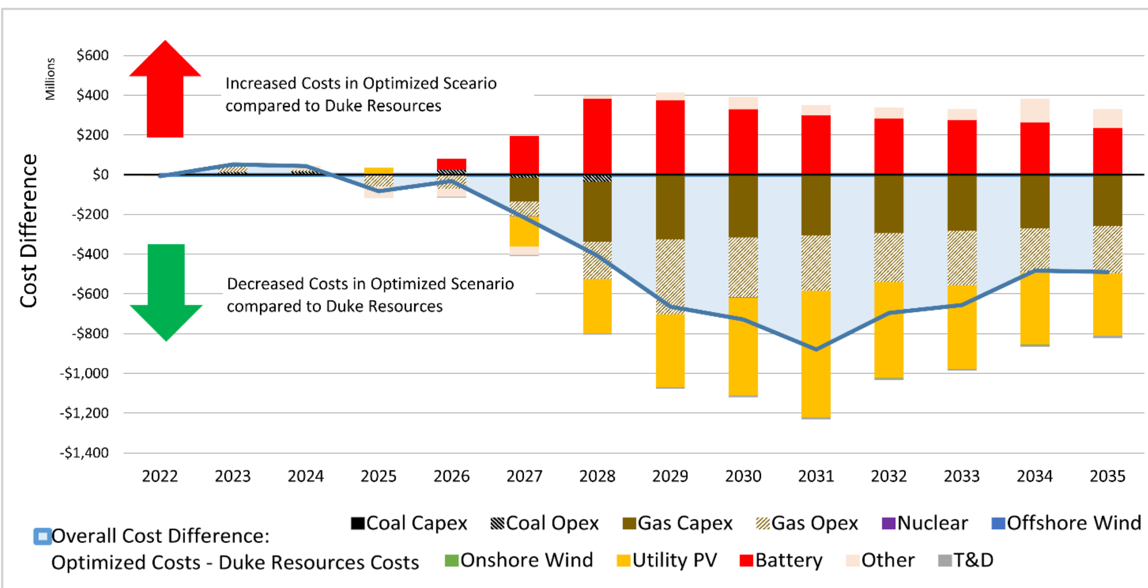
In DEC, the Optimized scenario saves ratepayer costs by avoiding new gas buildout (avoided gas Capex) relative to Duke Resources scenario. However, the ramping of co-fired unit operation (increase in gas operational expenditures, Opex) somewhat counters the avoided gas Capex savings. Additionally, the 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.

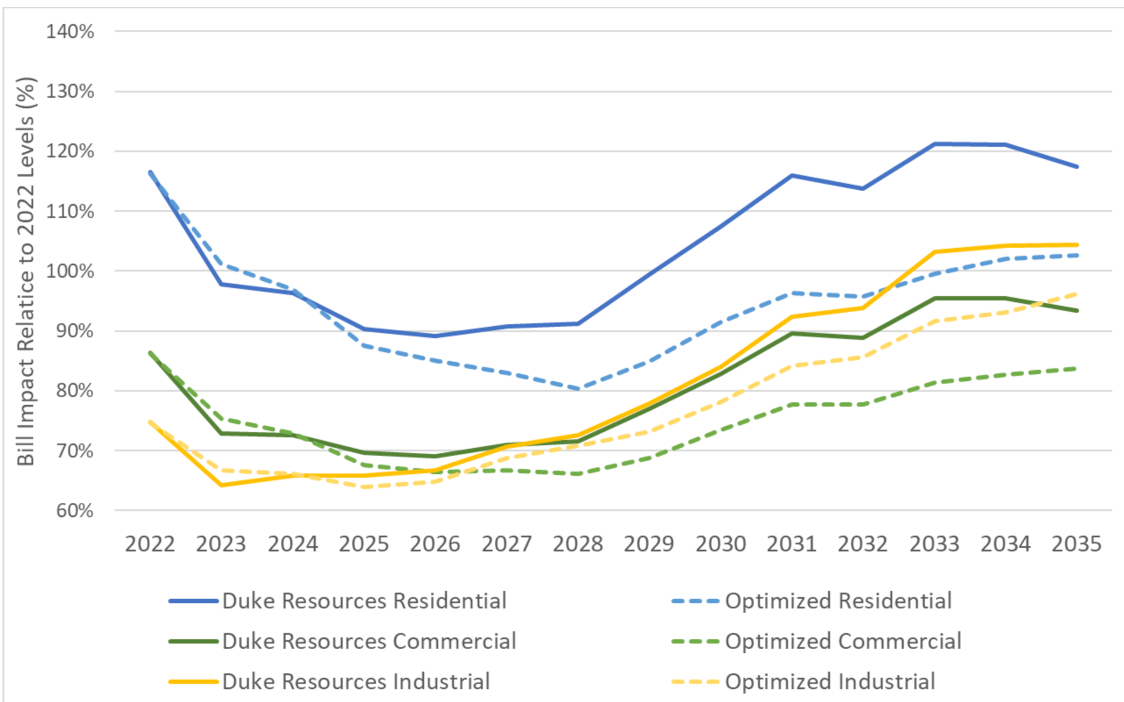
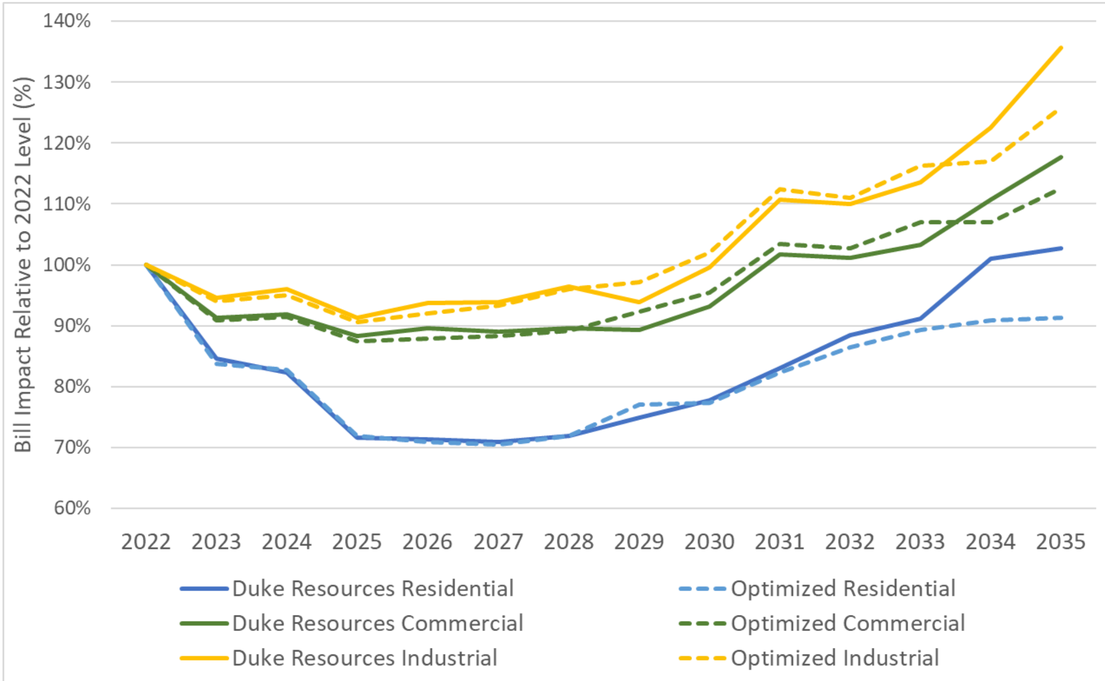


Figure 19. DEC Average Monthly Bill Change – Duke Resources and Optimized.



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.

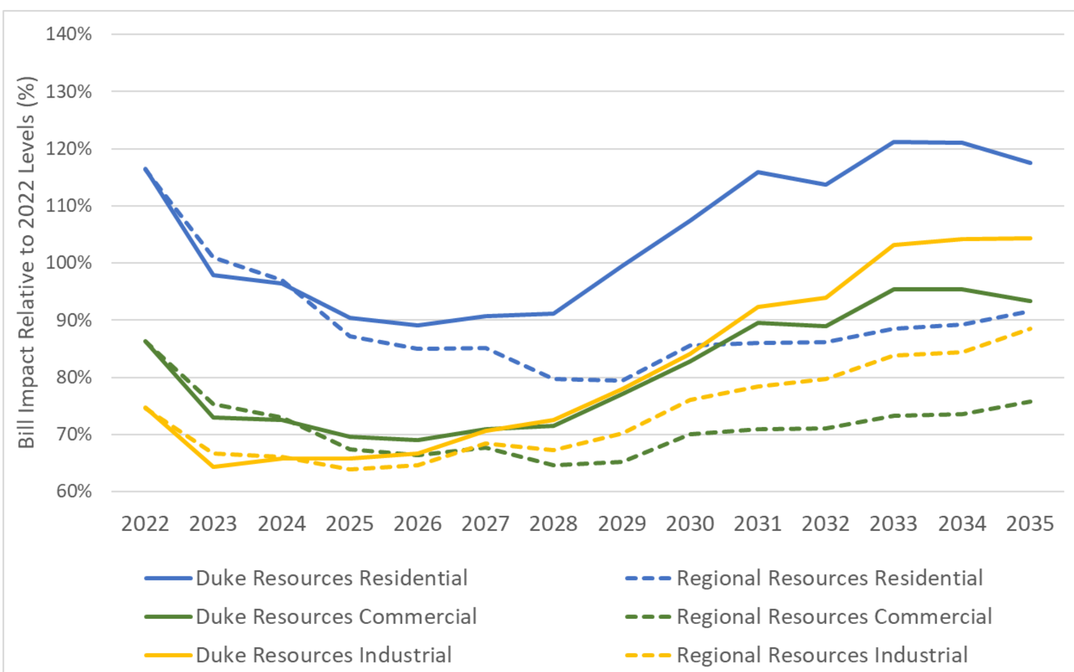
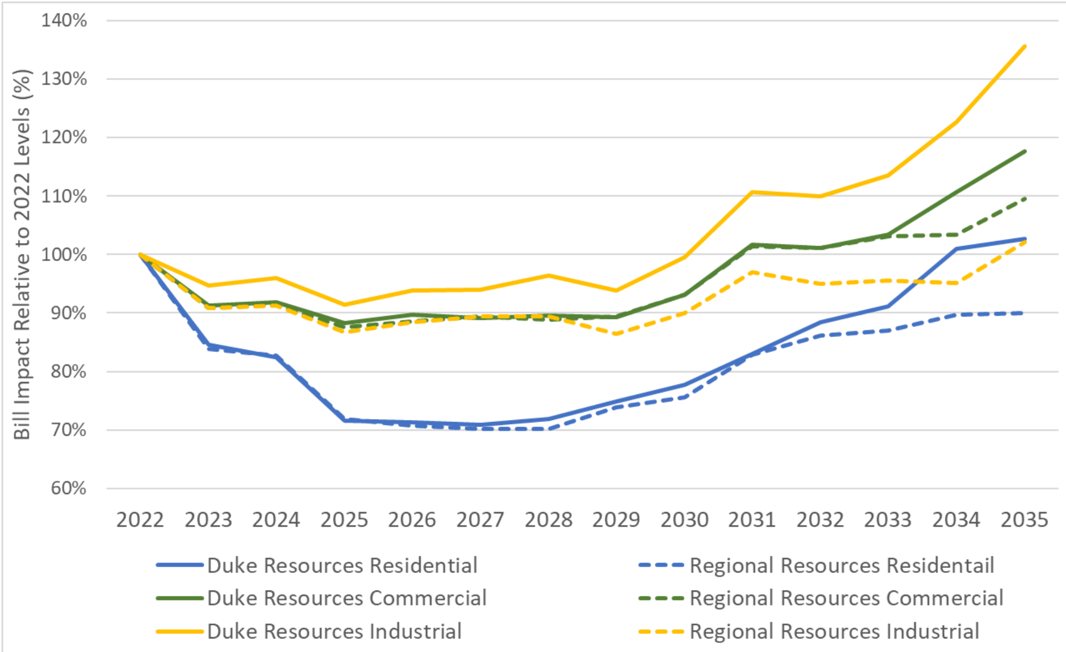


Figure 21. DEC Average Monthly Bills – Duke Resources and Regional Resources.



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

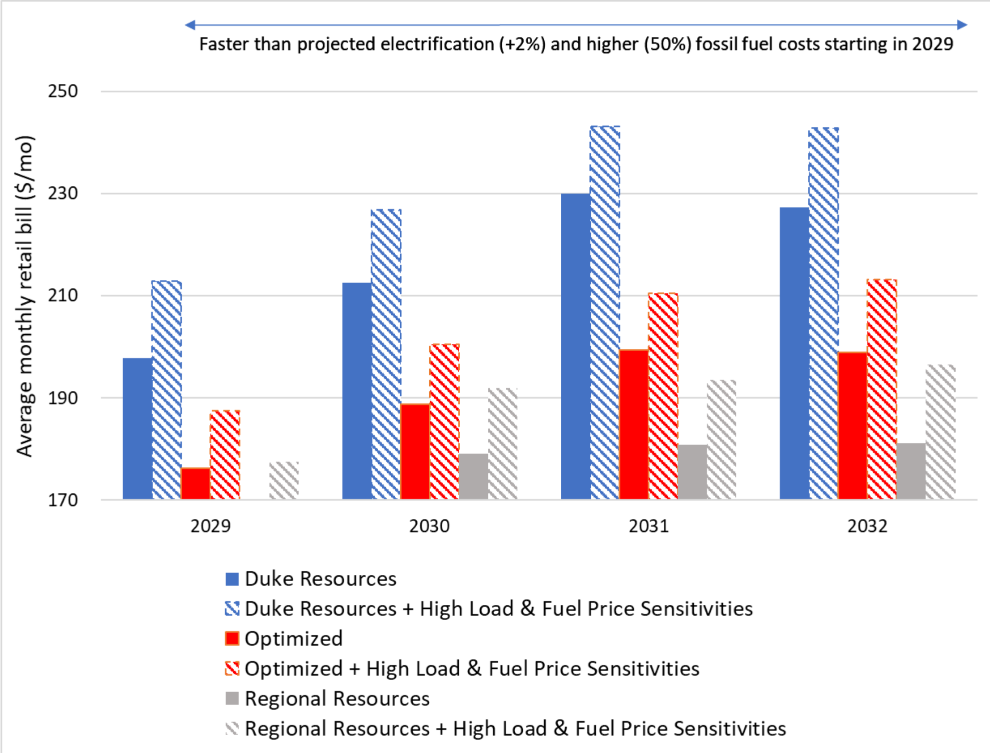
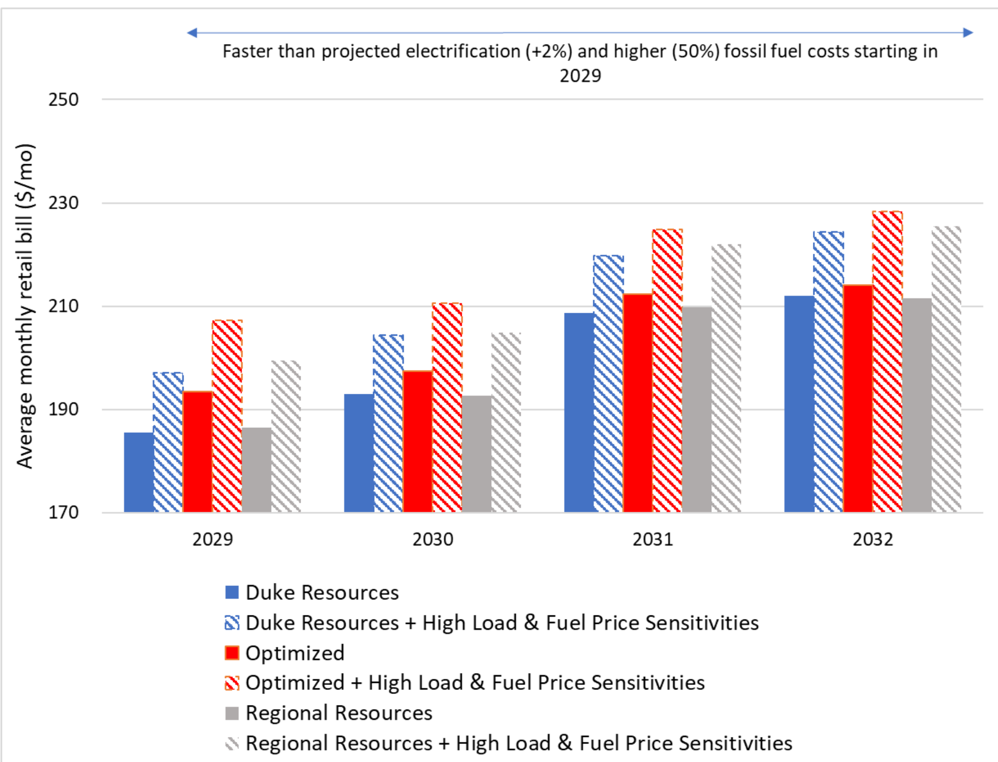


Figure 23. Average DEC Bill Impact Under Higher Electrification & Fuel Cost Assumptions



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

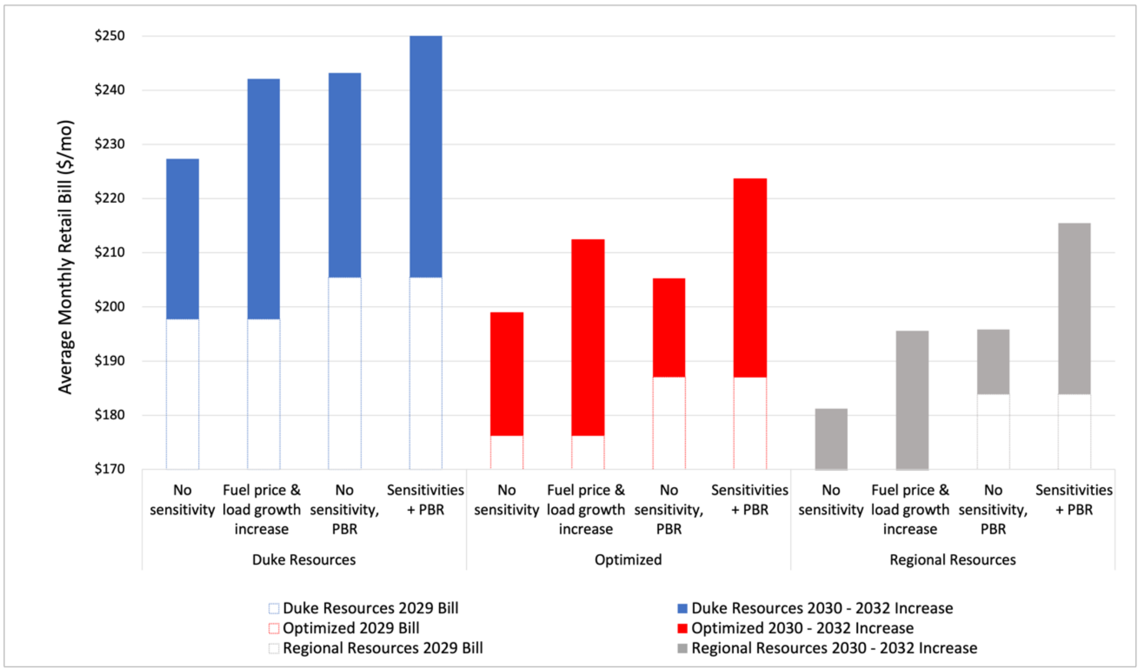
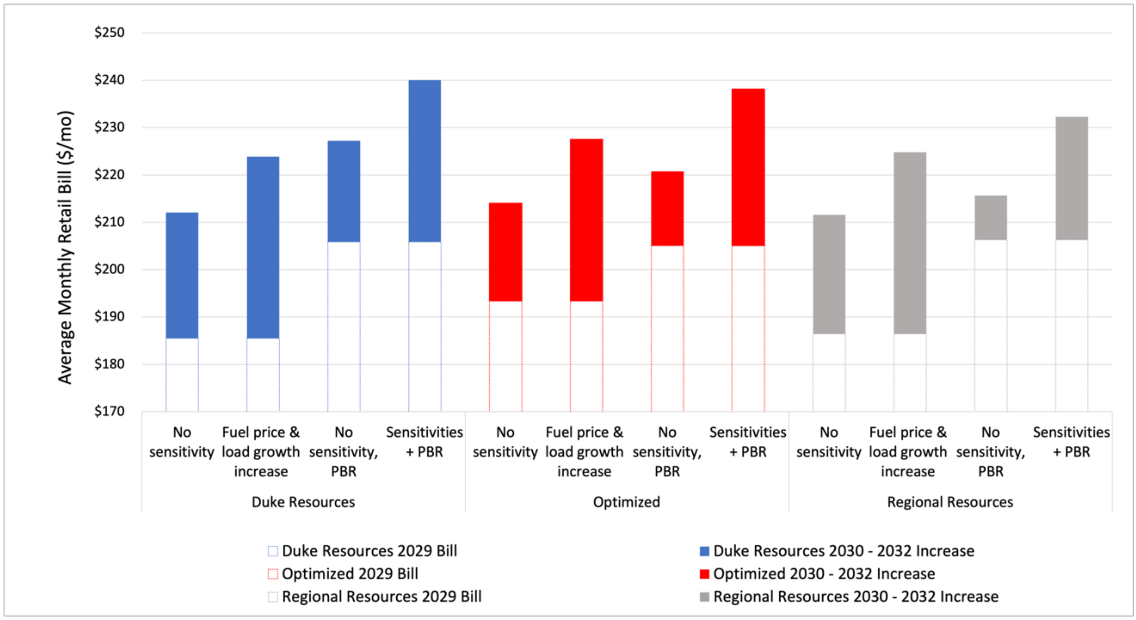


Figure 25. Average DEC Bill Effects of a MYRP and Decoupling Under Higher Electrification and Fuel Cost Increases



I/A

EXHIBIT 1
TO DIRECT TESTIMONY
OF RYAN WATTS
NCUC E-100, SUB 179

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Referring to Appendix E, Table E-31 and E-32. Please provide the underlying calculations and justification for the annual selection constraints applied to solar in both the base and high case.

Response:

The Companies do not have specific underlying calculations for the annual selection constraints. These constraints are based on engineering judgement and transmission planning experience. The transmission expansion needs and the time to construct new transmission infrastructure to accommodate increasing levels of renewables and other resources as described in Appendix P are critical factors influencing the annual solar interconnection constraints in the model. Additional factors, as described in response to CPSA DR1-8, include:

- Increasingly complex interconnections as solar facilities are located farther from existing infrastructure and load centers
- Unknown future solar project size and impacts on interconnections. Generally larger projects should enable more aggregate MWs to be connected on an annual basis, but it is unclear what the size of projects will be in the future and whether larger projects will lead to additional transmission expansion projects beyond those contemplated in Appendix P.
- Finite interconnection resources allocated to non-solar resources. Details of potential other non-solar resources can be found throughout the Carbon Plan including Chapter 3 and Appendix E.
- Historic annual interconnection data shows the average annual new solar capacity added to the grid is approximately 520 MW/year since 2015. While not the primary determining factor in developing the solar interconnection capability in the Carbon Plan, it is important to note that Carbon Plan allows for over 3x this annual amount in Portfolio A1 and over 2.5 X this annual amount in all other portfolios.

- Land availability and community acceptance. While not described in great detail in the Carbon Plan, 1,350 MW/year of solar will require approximately 10,800 acres/year of land to be developed, and 1,800 MW/year will require approximately 14,400 acres/year. Community acceptance of this level of development is an unknown factor that may impact the amount of solar that can be added annually.
- Energy storage development will be important to ensure energy supply meets demand and delays in storage development can limit the effectiveness of solar deployments needed to meet the goals of the Carbon Plan.

Additional SME: Sammy Roberts; GM Transmission Planning and Operations Strategy

Responder: Matthew Kalemba, Director DET Planning & Forecasting

I/A

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

Please reference page 156, lines 15 of the Modeling Panel testimony. Please describe with specificity what is meant by the phrase "increasingly complex interconnections."

RESPONSE:

"Increasingly complex interconnections" means that coordinating solar interconnections is becoming more challenging due to a variety of factors. For instance, constructing transmission-connected solar requires a transmission outage, and each identified transmission network upgrade could require an outage and potentially several outages across multiple outage seasons. While there are benefits to the shift to larger transmission tied resources, all of these transmission outages have to be coordinated to maintain system reliability, and some outages cannot occur at the same time. Furthermore, these outages may need to occur over multiple spring and fall outage seasons. Similarly, interconnections are becoming more complex due to the fact that many of the locations with simple and less costly interconnections have already been developed, which means that future interconnections are likely to be more complex and costly.

Responder: Matthew Kalemba, Director, DET Planning & Forecasting

Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal

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

July 15, 2022

Prepared by RMI[1]

[1] Authors and contributors to this report include Diego Angel, Jacob Becker, Rachel Gold, Becky Li, David Posner, Jeffrey Sward, Gennelle Wilson, and Uday Varadarajan

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Executive Summary

This report presents the results of RMI's analysis of the ratepayer and financial effects of Duke Energy's Carbon Plan proposal. RMI appreciates the opportunity to conduct this analysis and summarize its findings in support of the North Carolina Utilities Commission's effort to develop the least cost path toward the statutory requirements of 70% carbon dioxide emission reduction from 2005 levels by 2030 and carbon neutrality by 2050.

This analysis was conducted using Optimus, an open-source utility financial model developed by RMI. Optimus uses the results from capacity expansion modeling to estimate the ratepayer, utility earnings, and shareholder impacts of a given resource portfolio under a variety of sensitivity scenarios.

Due to a significant software error discovered by Synapse in EnCompass model version 6.0.9, RMI did not have access to an alternative scenario from Synapse to analyze in time for the July 15th filing deadline.[2] RMI's analysis of Duke Energy's Carbon Plan proposal is based on Synapse EnCompass version 6.0.9 modeling of a scenario that was designed to replicate Duke's Portfolio 1 with no new Appalachian gas transmission. This scenario is referred to as "Duke Resources." Should the Commission allow, RMI can conduct an Optimus analysis of any alternative scenarios developed using EnCompass by Synapse or any party to this proceeding as a supplement to this report.

Key Insights

RMI's analysis of the Duke Resources portfolio finds that:

1. ***Expensive nuclear and gas units drive up the total ratepayer costs for the Duke Resources scenario throughout the planning period.*** In particular, near-term investment in gas capacity introduces significant risks to ratepayers by locking in significant capital costs for assets that will either be converted to hydrogen (at uncertain cost) or will be obsolete before they are fully depreciated, translating to higher costs for ratepayers.
    a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis*** to examine whether an alternative portfolio that relies less on new gas plants and new modular nuclear plants would present a lower total cost with less uncertainty for ratepayers.

[2] See Motion for Extension of Time to File Comments and Expert Report, NCUC Docket No. E-100, SUB 179. (July 14, 2022)

2. ***Total ratepayer costs for the Duke Resources scenario are distributed unequally across ratepayer classes.*** Duke's gas-heavy and speculative-technology scenario would disproportionately saddle residential customers in Duke Energy Carolinas (DEC) territory, and industrial customers in Duke Energy Progress (DEP) territory, with larger average bill volatility. This finding is propelled by the current cost causation framework, which channels variable costs (driven by fuel prices) primarily to residential customers, while capital costs (which are proportionally higher relative to variable costs in cleaner scenarios) can be passed to commercial and industrial customers in the form of demand charges.
    a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis*** to explore whether an alternative portfolio more equitably distributes costs amongst the different ratepayer classes.
3. ***New gas capacity is not a cost-effective hedge against fuel price shocks — but accelerating renewable deployment could be.*** In the near and medium term, the Duke Resources scenario adds new gas combined cycle (CC) and combustion turbine (CT) generation capacity. While new CCs and CTs are more fuel-efficient than coal units converted to gas co-firing, the cost savings from greater efficiency do not exceed the incremental fixed capital and operating costs of the new build in any year — even in the event of a doubling in fuel prices. Factors beyond the scope of RMI's Optimus modeling analysis — such as the likely high cost of later conversion of CC and CT units to hydrogen, and the accelerated cost recovery of unneeded gas infrastructure upon conversion — will likely exacerbate this dynamic. However, the new proposed renewable portfolio in the Duke Resources scenario becomes cost-effective as a hedge against a fuel price doubling starting in 2032. Moreover, there is a strong correlation between increased deployment of renewable resources and decreasing ratepayer exposure to fuel price shocks in the Duke Resources scenario.
    a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis to investigate whether*** an accelerated deployment of solar, battery storage, and wind resources in the near and medium term would be a more cost-effective hedge against future fuel price volatility.
4. ***The Duke Resources scenario underutilizes securitization as a source of ratepayer relief to mitigate rate spikes from early retirement of coal.*** The later coal retirements occur, the smaller the potential savings that can be derived from securitization. Securitization is a low-cost refinancing mechanism that drives savings for ratepayers when applied to larger unrecovered balances. RMI estimates that the Duke Resources scenario would result in approximately $14.1 million in savings for ratepayers as a net present value (NPV) in 2022 dollars. 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 $446 million in savings (NPV, 2022$) for ratepayers. From this perspective, the Duke Resources scenario captures only 3% of the ratepayer savings available from securitization under H951. For informational purposes, 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 $1.26 billion (NPV, 2022$).

   a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis to review whether*** an alternative scenario that enables an earlier retirement of coal assets than Duke projected will translate into greater total ratepayer savings.

5. ***The Duke Resources scenario leaves ratepayers vulnerable to rate de-stabilization from large increases in load and fuel price.*** When higher loads associated with faster electrification are assumed and then combined with a fuel price shock, all ratepayers are worse off under more fuel-dependent and less energy-efficient resource portfolios. RMI's analysis shows that high load projections coupled with a fuel price shock increases the average retail monthly bill 3% for DEC and 4% for DEP on a present value basis under the Duke Resources scenario.
   a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis to understand*** whether a higher penetration of fuel-free resources will temper the impacts of a fuel price shock in a high load future scenario.
6. ***The implementation of multi-year rate plans (MYRPs) and revenue decoupling 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.*** The use of forecasted costs to set the revenue allowance in the H951 performance-based regulation (PBR) design may motivate the utility to conservatively estimate the costs associated with fuel- and variable cost-dependent resources to account for uncertainty and price volatility, which increases the cost to consumers. RMI's modeling of a MYRP and residential decoupling in Optimus reveals substantial risk to ratepayers from the concurrence of these factors. When coupled with higher load growth due to electrification and a prolonged fuel price increase, a MYRP and revenue decoupling mechanism cause the average retail bills associated with the Duke Resources scenario to rise approximately 9% for both DEC and DEP on a present value basis.
   a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis to examine whether*** PBR could provide a stronger incentive for

the utility to control operating costs when applied to an alternative resource portfolio.

7. ***If implemented, federal policy changes in the next decade will present significant cost savings opportunities that can be passed through to ratepayers; the Duke Resources scenario would capture $5.4 billion***. Using the policies outlined in the Build Back Better Act as a proxy for potential future policy changes, RMI asserts that cleaner energy portfolios possess an "option value" associated with the potential benefits of new or enhanced federal policies that will subsidize zero-emitting resources. The Duke Resources scenario has an estimated option value of $5.4 billion, which can be passed through to ratepayers in the form of savings. Conversely, portfolios with a higher concentration of emitting resources have a "risk value" for future policies that may penalize or increase the cost of emitting resources.
   a. ***Should the Commission allow, RMI can conduct a supplemental Optimus analysis to explore*** how much additional savings to ratepayers could be attained by an alternative resource portfolio.

<u>Key Caveats</u>

RMI's Optimus financial modeling is offered as a companion analysis to the modeling provided by Synapse and Duke. The Optimus financial modeling examines paths to achieve the State's carbon reduction requirements, as outlined in H951, with attention to how the utility service costs will be reflected in rates and bills. This analysis includes a broader set of drivers (including fuel price shock and federal policy reform) than is currently considered in Duke's Carbon Plan proposal. RMI recommends that that the NCUC consider making this approach to analyzing resource planning proposals a standard in future Carbon Plan processes to ensure that the full scope and measure of potential risks and benefits to ratepayers are considered when determining the least-cost path.[3]

As is true of all models, RMI's efforts cannot perfectly predict future impacts. However, the findings contained in this report are the product of a model with a high degree of resolution for data inputs and calculations. Nevertheless, it must be stressed that this analysis depended on a re-creation of Duke's Portfolio 1 scenario ("Duke Resources") as modeled by Synapse rather than Duke's EnCompass outputs themselves. As such, there are inevitable differences between certain RMI metrics and similar calculations conducted by Duke in its Carbon Plan proposal. In these instances, the difference is likely

[3] Optimus is an open-source tool developed by RMI. The LBNL FINDER tool has been deployed in a similar fashion in other settings.

due either to the use of a simplified rate and bill impact estimate in Duke's modeling or because RMI was unable to acquire the same data sources or formulas used by Duke.

A key example of the latter circumstance relates to RMI's calculation of rates for each ratepayer class. RMI's analysis is not as robust nor as accurate as Duke Energy's cost-of-service study. Through the discovery process, RMI requested the necessary information to replicate the cost-of-service cost allocation methodology but did not receive granular enough detail to replicate it in sufficient time for the July 15 filing deadline. Consequently, RMI employed a simplified approach using public data on historical revenue collection and assumptions that provide directional insight rather than precision.[4]

Although PBR and securitization may be outside the scope of the Carbon Plan proceeding, RMI simulated the impact of these mechanisms in this analysis because their impacts can vary greatly depending on composition and timing of the resource portfolio. To ignore the potential impact of these mechanisms, which are included in the same authorizing legislation, risks making costlier choices for ratepayers than are justified.

Some of the sensitivities and policy scenarios analyzed in this report are, concededly, speculative — as is any forecast and sensitivity analysis. For example, the enhanced federal policy sensitivity uses the Build Back Better Act provisions as a proxy for future policy changes. While it is impossible to definitively forecast the scope, form, and timing of future policies, this scenario is intended to provide an illustration of the possible scale and impact of benefit to ratepayers from future policy action.

Finally, RMI conducted this analysis on Synapse's EnCompass results before Synapse identified the EnCompass version 6.0.9 software bug. **The EnCompass bug is very unlikely to have affected the EnCompass 6.0.9 Duke Resources scenario.**

However, in light of the extension granted for the Synapse report, Synapse will run the Duke Resources scenario again in the same downgraded version of EnCompass that Duke utilized for its proposed Carbon Plan. Synapse's re-run of the Duke Resources Scenario is unlikely to result in portfolio changes; however, the two EnCompass versions likely contain other differences in model logic which will change dispatch of the portfolio to an uncertain degree relative to the dispatch projected by EnCompass 6.0.9. In turn, operating projections and costs will vary between the two versions of the Duke Resources scenario results, which impacts all the Optimus calculations and findings presented in this report.

Cognizant of these differences, RMI offers this report as an illustrative and directionally accurate analysis of the Duke Resources scenario.

[4] The simplified approach is described in detail in the appendix.

Introduction

About RMI

RMI is an independent, non-partisan, nonprofit organization of experts across disciplines working to accelerate the clean energy transition and improve lives. RMI's mission is to transform the global energy system to secure a clean, prosperous, zero-carbon future for all.

RMI's previous work in North Carolina was in support of the creation and implementation of the NC Department of Environmental Quality's Clean Energy Plan and the North Carolina Energy Regulatory Process (NERP). RMI appreciates the opportunity to provide this report in support of the implementation of the H951 legislation — specifically, the development of North Carolina's first Carbon Plan.

About Optimus

Optimus is an open-source financial modeling tool that quantifies the distribution of economic impacts of utility planning scenarios among ratepayers, the utility, and the utility's shareholders. RMI created Optimus because state policies across the country are increasingly requiring utility regulators to play a leading role in achieving decarbonization goals while simultaneously controlling expenses and allocating costs fairly. Optimus is designed to support the task of resource planning by providing robust and timely insights to inform decisions that balance decarbonization alongside fair distribution of risks and benefits to ratepayers.

Optimus leverages the outputs from capacity expansion modeling as inputs for further analyses that yield results for ratepayers, the utility, and utility shareholders.[5] Optimus was created to quantify the distributional impacts for a range of policy, regulatory, and market sensitivities, including, but not limited to:

- State and federal policies, such as expanded production tax credits for clean energy,
- Refinancing mechanisms, such as securitization,
- Performance-based regulatory mechanisms, such as multi-year rate plans and performance incentive mechanisms, and

[5] Though Optimus can assess utility earnings and shareholder impact, this analysis examines only the ratepayer impacts due to time and resource constraints as well as EnCompass output limitations.

- Unpredictable market dynamics, such as demand shocks or fuel cost spikes.

Purpose of this Analysis

SELC, and their clients, and NCSEA retained RMI to conduct an analysis using Optimus to quantify the allocation of economic impacts of differing Carbon Plan scenarios. The objective of this analysis 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."[6]

The law empowers the NCUC with the "discretion to determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals."[7] The Optimus analysis described herein supports the selection of the least cost resource portfolio by shedding light on the distributional economic impacts of a portfolio proposed by Duke Energy ("Duke") as modeled by Synapse Energy Economics ("Synapse"),[8] and how the distributional impacts might be further affected by plausible future events — such as fuel price shocks, state utility regulation reform, and the adoption of new federal policies. RMI is capable of producing a similar, comparative analysis for any other portfolios developed with EnCompass, should the NCUC allow a supplemental report.

Methodology

This section briefly represents the sensitivity scenarios modeled in Optimus and the differences between the Optimus and EnCompass analytical approaches. A full description of how Optimus works and the results from calibrating Optimus and EnCompass results can be found in the Appendix.

Duke Resources Scenario from EnCompass

The EnCompass scenario RMI modeled in Optimus for this report is described in ***Table A.*** RMI leveraged the Duke Resources portfolio from Synapse's forthcoming analysis,[9] which

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[6] North Carolina General Assembly, Session 2021, Session Law 2021-165, House Bill 951, 1.
[7] Ibid., 2.
[8] Synapse Energy Economics (2022). *Carbon-Free by 2050; Pathways to Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers*.
[9] Motion for Extension of Time to File Comments and Expert Report, NCUC Docket No. E-100, SUB 179. (July 14, 2022)

recreated Portfolio 1-Alternate (P1-Alt) from Duke Energy's proposed Carbon Plan. Should the Commission allow, RMI can conduct a supplemental Optimus analysis on alternative proposed Carbon Plan scenarios for which analysis of Synapse's Duke Resources scenario can serve as a comparable baseline.

Table A. Scenario Analyzed in Optimus[10]

Scenarios	Description
Duke Resources	This scenario was created by Synapse to replicate the resources selected in Duke's P1-Alt portfolio, which does not assume firm Appalachian gas capacity.[11]

It was RMI's intent to compare the ratepayer impact results of the Duke Resources scenario to those of alternative scenarios modeled by Synapse. Due to a significant software error discovered by Synapse in EnCompass model version 6.0.9, RMI did not have access to an alternative scenario from Synapse to analyze in time for the July 15 filing deadline.[12] RMI's analysis of Duke Energy's Carbon Plan proposal is based on Synapse EnCompass modeling of a scenario that replicates Duke's Portfolio 1 with no new Appalachian gas transmission. This scenario is referred to as "Duke Resources." Should the Commission allow, RMI can conduct an Optimus analysis of any alternative scenarios developed using EnCompass by Synapse or any party to this proceeding as a supplement to this report.

Optimus Policy and Sensitivity Scenarios Modeled

In this analysis, RMI used Optimus to model the impacts of a set of existing federal policy incentives, potential future policies, regulatory mechanisms from North Carolina's H951 legislation, and several macroeconomic sensitivities on the Duke Resources scenario.[13] Each of the policy and sensitivity scenarios RMI modeled is described in brief below. More detail on the assumptions and application of each scenario can be found in the appendix.

1. *High load projection:* This sensitivity explores how each scenario would fare in the event of an unexpected growth in load driven by electrification. This assumes the

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[10] Please see Synapse's Report for further description of this scenario and Synapse's revised assumptions.
[11] RMI conducted this analysis on Synapse's EnCompass results before Synapse identified the EnCompass version 6.0.9 software bug. The EnCompass bug is very unlikely to have affected the EnCompass 6.0.9 Duke Resources scenario.
[12] See Motion for Extension of Time to File Comments and Expert Report, NCUC Docket No. E-100, SUB 179. (July 14, 2022)
[13] The policies included in Optimus are primarily economic in nature and limited to those described here and in the Appendix. Other regulatory levers, such as existing and potential tightening of public health rules, were not analyzed.

load grows 2% faster than the projected trend in the baseline ("Duke Resources") scenario. This corresponds to a 25% higher load in 2050 when compared with the baseline.[14]

2. *<u>Fuel price sensitivities</u>:*[15] RMI explored two sensitivities to gauge how the Duke Resources scenario would fare in the event of an unexpected, temporary price spike — similar to the global gas market shock since Russia's invasion of Ukraine. The two fuel price sensitivities modeled include:
    a. <u>A single-year extreme fuel price shock</u> to assess the temporary impact of market turbulence. This sensitivity assumes doubling the fossil fuel prices for the entirety of one single calendar year, and the test year range is 2029-2035 because these are the peak years for generation from gas and co-firing units (and thus, consumption of gas) in the Duke Resources scenario. The metric used to evaluate the impact is the percentage increase of annual total ratepayer cost driven by the fuel price shock in that year, and by comparing the impact across the range of 2029-2035, RMI was able to identify the year where the portfolio is most susceptible to fuel price volatility.
    b. <u>A prolonged, multi-year increase in fuel price (2029 through 2035)</u> to assess the medium-term impact on prices of a longer-term shift in fuel market dynamics. This sensitivity assumes 50% higher fossil fuel prices for the entirety of calendar years 2029 through the end of 2035 on each resource scenario and is also coupled with a higher load projection as described above to analyze the effect of these two compounding risks.

3. *<u>Securitization</u>:* H951 allows for half of the costs associated with early retirement of subcritical coal-fired electric generating facilities to be securitized.[16] This scenario assumes that 50% of the remaining plant balance of all of Duke's subcritical coal units is securitized at the time of retirement, while the other 50% of the balance remains in the rate base and is turned into a regulatory asset.

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[14] Appendix A.5 provides a visual comparison of the application of the Optimus high load sensitivity in contrast to the high load assumption modeled in EnCompass.
[15] Fuel price volatility could reasonably be assumed to have a positive impact on the cost-effectiveness of energy efficiency (EE) as a resource. However, EE is treated as an exogenous resource in all scenarios and sensitivities modeled within EnCompass (rather than economically selected) -- thus an exogenous input into Optimus as well—as it is dependent on the potential prescribed by Duke's energy efficiency cost estimates.
[16] North Carolina G.A., Session Law 2021-165, House Bill 951, 2.

A brief description of *how* Securitization works

Securitization is a refinancing mechanism that uses low-cost debt backed by non-bypassable ratepayer charges to pay off undepreciated plant balances. When securitization bonds are issued, the utility receives funds allowing it to pay off existing creditors and equity contributors. The new securitized debt is an obligation neither of the state nor the company, but rather of all current and future utility customers over the life of the bonds. Securitization legislation typically includes valuable protections for creditors that result in extremely high credit ratings for the bonds — higher than any U.S. utility's current credit rating — and correspondingly low interest rates. Because ratepayers are paying lower interest rates when securitization is utilized, thereby avoiding paying for the higher returns demanded by equity providers, they ***realize savings that scale in proportion with the size of the refinanced balances*** and ***the duration of the avoided period*** of traditional utility finance.

For more on securitization, see Christian Fong and Sam Mardell, "Securitization in Action: How US States Are Shaping an Equitable Coal Transition," RMI (March 4, 2021).[17]

4. *PBR mechanisms:* This Optimus sensitivity scenario models the design elements of a MYRP described in statute (i.e., 36 months, 4% annual revenue adjustment, revenue requirement based on forecasted costs) and residential class revenue decoupling.

5. *Existing federal policy scenario:* Existing federal policies include the Production Tax Credit (PTC) for wind generation and the Investment Tax Credit (ITC) for utility-scale solar, which are currently available for facilities that enter service through the end of 2025 but subject to a gradual phase-out (PTC) or phase-down (ITC). Optimus modeled the benefit of these credits as a savings opportunity for scenarios that incorporate new wind and solar facilities within this timeframe. Of note, the benefits from PTC are not applicable to any of the Duke's Carbon Plan P1-P4 portfolios because those portfolios do not add new eligible capacity within the required timeframe.

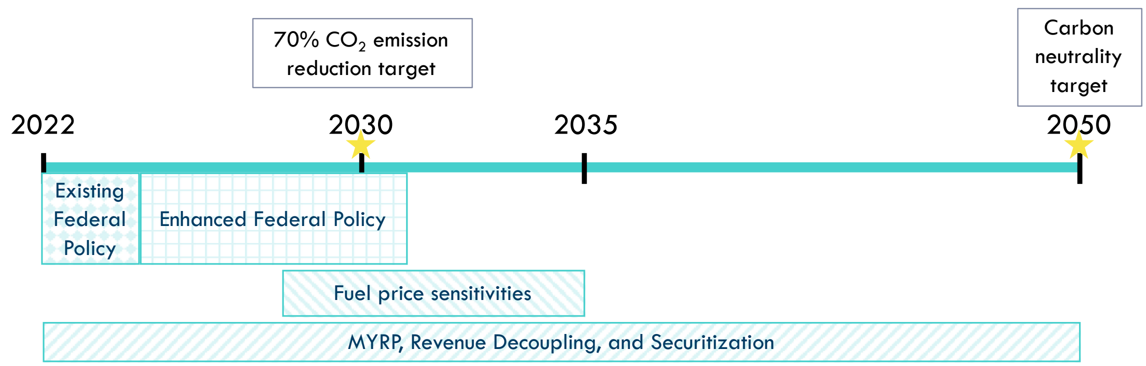
6. *Enhanced federal policy scenario:* Future federal policies may provide greater rewards for investment in clean electricity resources. Conversely, they may also introduce penalties (e.g., a carbon price) or regulatory requirements that increase the cost of investment in, and operation of, carbon-emitting resources. To

[17] Available at https://rmi.org/securitization-in-action-how-us-states-are-shaping-an-equitable-coal-transition/

approximate the potential savings that further federal action may implicate, this scenario modeled an extension of the scope and applicability of the current ITC and PTC policies through 2031, as conceived in the Build Back Better Act (H.R. 5376).

The scenarios and sensitivities are applied over the same timeframe as modeled by Duke in its Carbon Plan proposal (through 2050). RMI's analysis of the net present value for costs associated with scenarios and sensitivities are calculated for 2022-2050. RMI focused primarily on medium-term metrics and outcomes that are relevant to achieving the first of the state's two statutory emission reduction goals. RMI's modeling horizons within this timeframe are in ***Figure 1***.

Figure 1 1. Policy and sensitivity scenario application relative to Duke's Carbon Plan proposal



Key Differences between the EnCompass and Optimus Methodologies

Optimus is a utility financial model designed to assess the full ratepayer cost and shareholder impact of utilities' planning decisions.[18] There are several key factors that set it apart from the revenue requirement assessment in capacity expansion and production cost modeling tools like EnCompass. ***Table B*** outlines these key differences and briefly summarizes their implications for this analysis. Please see the appendix for a more complete description and discussion of these differences.

Table B. Key Differences Between EnCompass and Optimus Methodologies

Difference	Brief Description
Full revenue requirement	Duke estimated ratepayer cost using only the forward-looking incremental costs. This has the effect of treating expenses

[18] Though Optimus can assess utility earnings and shareholder impact, this analysis only examines the ratepayer impacts due to time and resource constraints and EnCompass output limitations.

vs. forward-looking incremental system cost	associated with the existing electric fleet as a foregone conclusion, ignoring potential changes in those costs from early retirement and securitization, and adjustments to the depreciation schedule of regulatory assets. In contrast, RMI calculated ratepayer costs using the full revenue requirement to better reflect the cumulative impact on ratepayers and help the utility, the Commission, and intervening parties identify opportunities to reduce the cumulative costs of each portfolio scenario through mechanisms such as securitization.
Full vs. incremental rates and bills impact assessment	Duke's approach to the residential bill impacts assessment represents an average impact of the incremental portfolio additions, which again ignores how the costs of the existing portfolio could change and also implies that the costs of the future portfolio would be spread evenly across retail customer classes. RMI's approach considers the evolution of the entire portfolio (both existing assets and additions) and estimates the differential impact amongst the four primary classes of customers (residential, commercial, industrial and wholesale).
Fixed O&M expenses vs. capitalization	In Duke's EnCompass modeling, transmission upgrade costs and the maintenance capital expenditures (or "CapEx") associated with existing assets are treated as fixed O&M cost adders. In Duke's EnCompass outputs, these costs are inextricably combined with other generation project-specific costs from the "Fixed Cost" category in EnCompass. As a result, Optimus's calculations of securitization benefits in this report represent an underestimate; moreover, utility earnings (though not calculated here) will similarly be challenging to calculate accurately.
Discount factor for Net Present Value calculation	In Duke's EnCompass modeling, the net present value (NPV) calculation uses a single discount factor: the Weighted Average Cost of Capital (WACC) for the entire planning horizon. RMI used the same constant WACC for the incremental NPV calculation. However, for the full revenue requirement assessment beyond incremental NPV, RMI used a hybrid, forward-looking ROR approach which provides a more nuanced picture of the value of different portfolio decisions. RMI's approach more accurately reflects the nature of the capital markets that utilities encounter and the costs they face and consequently right-sizes the NPV estimation.

Limitations of this Analysis

Important Disclaimer Regarding this Report

RMI conducted this analysis on Synapse's EnCompass results before Synapse identified the EnCompass version 6.0.9 software bug. **The EnCompass bug is very unlikely to have affected the EnCompass 6.0.9 Duke Resources scenario.**

However, in light of the extension granted for the Synapse report, Synapse will run the Duke Resources Scenario again in the same downgraded version of EnCompass that Duke utilized for its proposed Carbon Plan. Synapse's re-run of the Duke Resources Scenario is unlikely to result in portfolio changes, However, the two EnCompass versions likely contain other differences in model logic which will change dispatch of the portfolio to an uncertain degree relative to the dispatch projected by EnCompass 6.0.9. In turn, operating projections and costs will vary between the two versions of the Duke Resources scenario results, which impacts all the Optimus calculations and findings presented in this report.

Cognizant of these differences, RMI offers this report as an illustrative and directionally accurate analysis of the Duke Resources scenario.

In light of time and data constraints, RMI employed several workarounds and simplified assumptions in this modeling exercise. RMI acknowledges that these may have influenced the findings in this report to varying degrees. However, the influence is unlikely to materially change the direction of the findings in this report. RMI is open to revisiting these simplifying assumptions with the Commission, utilities, and other intervenors to examine the potential change in findings if sufficient time and interest exists.

For projects constructed over multiple years, RMI made a simplifying assumption to apply the total installed cost in the single year when construction is completed (i.e., when the project enters into service) rather than spreading the installation cost across multiple years. RMI did not use Construction Work in Progress (CWIP) or Allowance for Funds Used During Construction (AFUDC) to account for the difference in rate base and tax treatment, due to time constraints. This leads to a smaller NPV of the revenue requirements since the rate impact is added at later years.

RMI was unable to fully model Duke's Carbon Plan proposal P1 scenario using the EnCompass outputs Duke provided. This was infeasible because Duke's EnCompass outputs did not provide the installed cost associated with each asset, which is a necessary input for Optimus. As a workaround, RMI analyzed Synapse's "Duke Resources" scenario since it produced the same resource portfolio as Duke's proposed P1 buildout. However, this workaround complicates direct comparison of the ratepayer impacts calculated by Optimus with similar metrics included in Duke's Carbon Plan proposal.

Considering the above, RMI's findings in this report should be construed as an analysis of a scenario similar to, but not exactly the same as, Duke's P1 scenario. RMI's findings should not be interpreted as applicable to Duke's P2-P4 scenarios, though some findings may be directionally indicative.

Findings

This section presents seven high-level findings from RMI's analysis using the Optimus model to analyze the ratepayer impacts associated with the Duke Resources scenario. RMI calibrated its results from Optimus against those from Synapse's EnCompass run which resulted in NPVRR calculations that are less than 1% different from Synapse's numbers through 2030 and within 3% through 2050.

1. Expensive nuclear and gas units drive up the total ratepayer costs for the Duke Resources scenario throughout the planning period.

Disclaimer: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

The Duke Resources scenario contains gas combined cycle and combustion turbine generation capacity which together represent 12% and 9% of the of the total annual ratepayer cost in 2035 and 2050, respectively.[19] Nuclear, which is also a significant cost driver in the Duke Resources scenario, represents 13% and 36%, respectively. ***Table C*** demonstrates the Full Portfolio NPVRR as calculated by Optimus for the medium and long-term planning horizon.

Table C. Full Portfolio NPVRR Comparison across Scenarios, 2022-2050

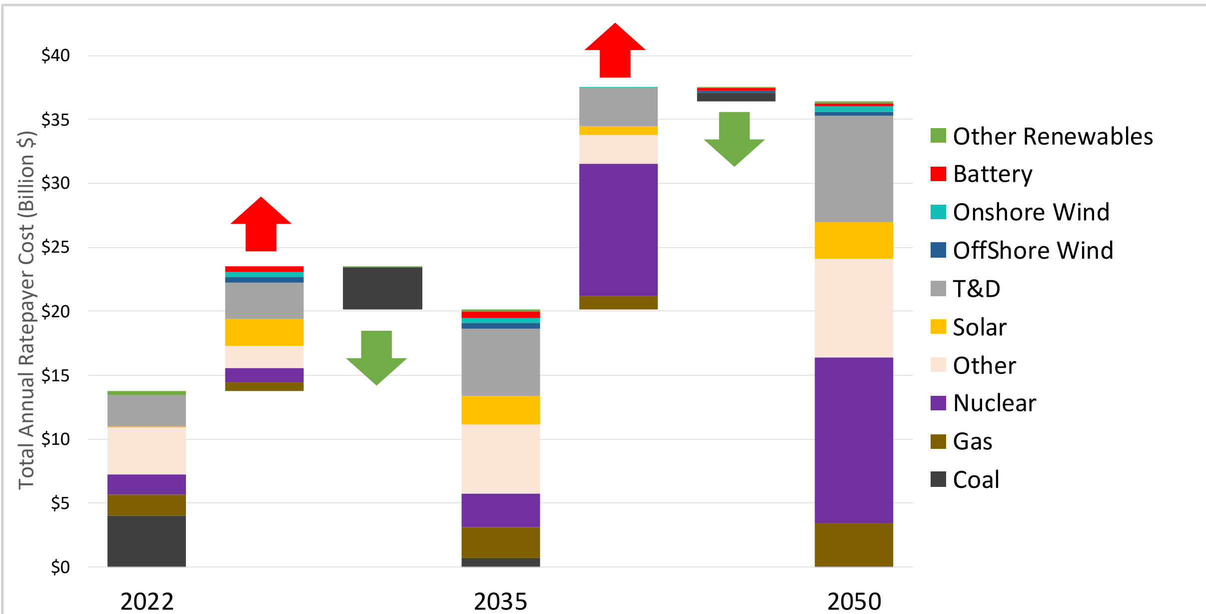
(Billion $)	**Duke Resources**
NPVRR through 2035	143.9
NPVRR through 2050	244.4

Figure 2 breaks down the annual ratepayer cost impact by technology and showcases the key drivers of the total cost increase. Gas and nuclear are significant drivers of the total

[19] This finding is agnostic of PBR policies enabled by H951 and potential federal policy enhancement but does reflect the current ITC and PTC federal policies.

ratepayer costs in the Duke Resources scenario.[20] This is a reflection of the generally high cost associated with these resources. ***Figure 2*** also shows factors that drive ratepayer cost reduction. Coal cost decreases over time are related to coal plant retirements, or to fuel switching for plants with co-firing capability. Battery cost decreases by the end of the modeling period are a result of battery storage deployed in 2030 reaching the end of its accounting life and being replaced by either much cheaper batteries (due to technology cost declines) or by other resources deployed before the batteries' end of life. Moreover, there is significant cost uncertainty associated with both small modular nuclear (SMR) technology and the conversion of gas to hydrogen given that neither has been commercially scaled to date, which is not reflected here.

Figure 2. Annual Ratepayer Cost Comparison of 2022/2035/2050 in the Duke Resources Scenario



In particular, near-term investment in gas capacity introduces significant risks to ratepayers by locking in significant capital costs that will either be converted to hydrogen (at uncertain cost) or, if the conversion does not pan out, will be depreciated more quickly, translating to higher costs for ratepayers. Should the Commission allow, RMI can conduct a supplemental Optimus analysis to examine **whether an alternative portfolio that relies less on new gas plants and new modular nuclear plants would present a lower total cost with less uncertainty for ratepayers.** RMI is able to analyze and compare

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[20] The "Other" category depicted in ***Figure 2*** includes investment in energy efficiency, purchases, and non-production expenses. Non-production expenses grow proportional to sales, load, and operational expenses. In a scenario where more efficiency and demand-side management are deployed, the Other cost category would decrease proportionally.

alternative portfolio scenarios to examine the differential total ratepayer impacts using Optimus once those alternative portfolio scenarios are completed.

2. Total ratepayer costs of the Duke Resources scenario are distributed unequally across ratepayer classes.

Disclaimer: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

Under the current cost causation framework,[21] the Duke Resources scenario disproportionately saddles residential customers in the DEC territory, and industrial customers in the DEP territory, with larger average bill volatility.

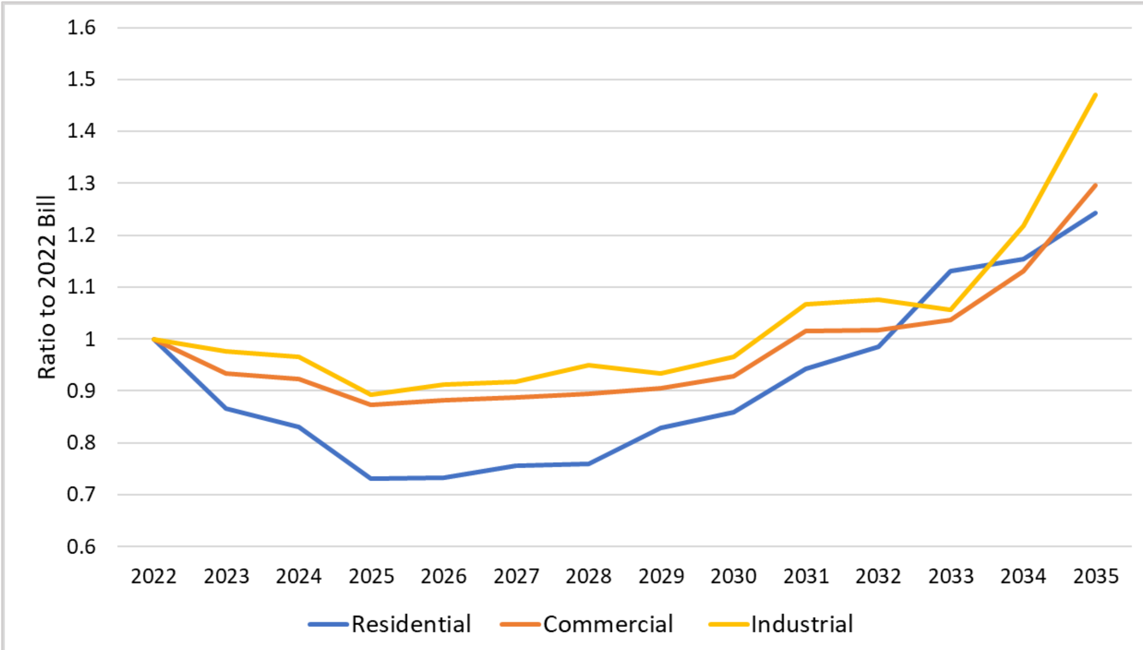
Figures 3 and 4 illustrate how DEC and DEP average monthly bills for each customer class would change over time relative to 2022 average bills under the current policy framework (absent PBR and securitization).

For DEC, the Duke Resources scenario maintains roughly parallel paths for average residential, commercial, and industrial bills through 2027. After that, the Duke Resources scenario results in a steeper "take-off" of residential charges relative to other classes' bills beginning in 2025. After 2032, when DEC sees generation increase from both gas-fueled and carbon-free resources, average commercial and industrial (C&I) bills also increase sharply. In 2035, average commercial, industrial, and residential bills, would be 48%, 30% and 24% higher than 2022, respectively.

The Optimus model shows a near-term decrease in bills, especially for the residential class. This results from (1) the cost allocation framework as exposed by Duke's rate structures, and (2) a precipitous decline in natural gas costs in the near term. In terms of cost allocation, the only additions to rate base between 2022 and 2027 are maintenance capex of existing transmission and distribution assets, which are costs heavily related to demand and thus borne more heavily by C&I customers. As for the natural gas price projection, the unit prices of the fuel drop to half of 2022 prices by 2025. Appendix A.9 provides further details on the natural gas price assumptions used in the model.

[21] *See* Appendix A.7, which lists the information sources that informed RMI's analysis in this section.

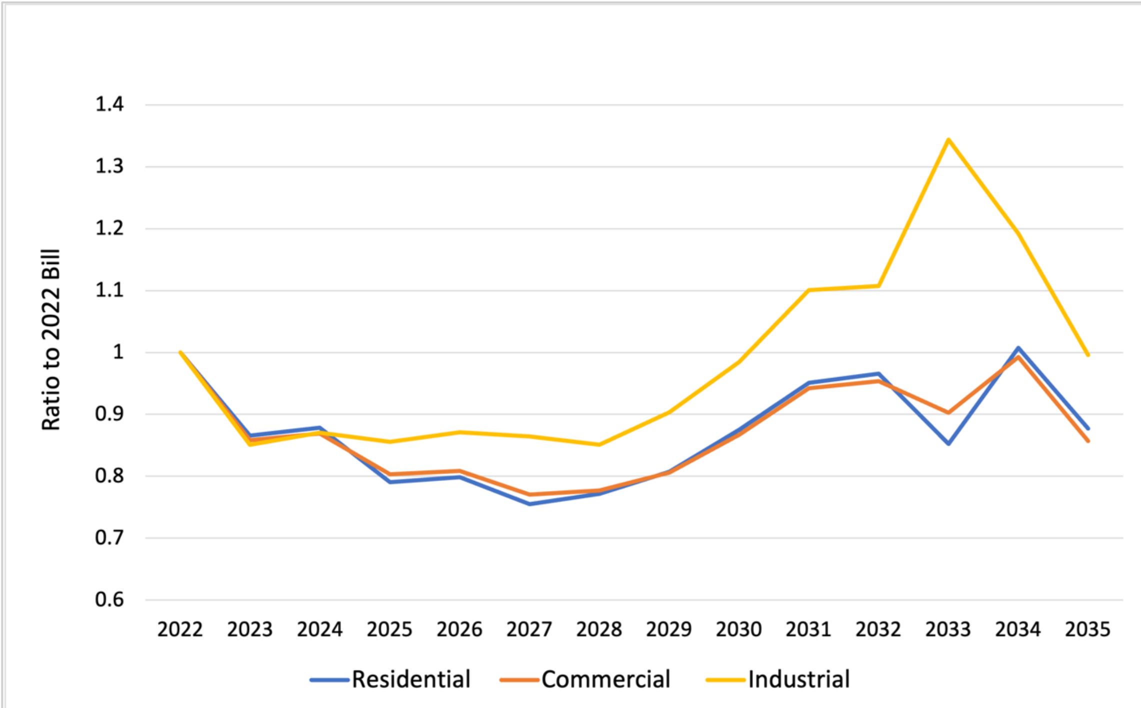
Figure 3. Average Monthly DEC Bill Change by Customer Group for Duke Resources Scenario



For DEP, the Duke Resources scenario yields rapidly increasing residential, commercial, and industrial average bills starting in 2028. In 2027, the paths for average bills between industrial, residential and commercial classes sharply diverge, with industrial customers disproportionately bearing the brunt of the total cost of the portfolio. Discrepancies in other specific years (for instance, 2033) result from costs incurred at the level of the whole balancing area or company included in EnCompass modeling that are hard to disaggregate with the limited information made available; the general trends in bills and the direction of the results are robust results regardless of single year discrepancies introduced by the quality of the data.

Between 2027 and 2032, when portfolio expansions are most crucial to meet carbon reduction requirements, different customer classes see larger increases in their average bills than others. In DEC, *residential* customers incur a disproportionate share of the portfolio expansion costs between 2027 and 2032. In DEP, *industrial* customers see the disproportionate share from 2024 onwards with increasing volatility over the years. After that, parallel trajectories are seen in most customer classes for both utilities. This inverse dynamic is driven by the interaction of resource portfolio differences and the cost allocation framework. In the Duke Resources scenario, DEC has more gas generators combined with slow retirement of coal units and addition of renewable resources. In contrast, DEP's resource portfolio sees faster renewable resource additions. Renewable resources are associated with a higher proportion of capital expenses whereas gas and coal-fired units have higher proportions of variable costs, largely attributable to fuel. The cost causation framework used by Duke (see the Appendix for an explanation of how this cost causation framework was derived using publicly available data) collects a higher proportion of capital expenses from industrial customers, through demand charges, whereas energy charges are paid for more by residential and commercial customers.

Figure 4. Average Monthly DEP Bill Change by Customer Group for Duke Resources Scenario



Given the disproportionate burden placed on residential customers in DEC and industrial customers in DEP associated with the Duke Resources scenario, RMI can conduct a supplemental Optimus analysis to explore **whether an alternative portfolio more equitably distributes costs amongst the different ratepayer classes**. RMI hypothesizes that a cleaner alternative portfolio would more equitably distribute costs to the extent that the breakdown of energy-, demand- and customer-cost components resulting from the alternative resource portfolio is parallel to Duke's rate structure allocation. Further analysis of alternative resource portfolios in Optimus can provide a substantive basis to explore whether Duke's cost allocation methodology should be adjusted to be closer to cost causation, while balancing the impact across classes through rate cases.

3. New gas capacity is not a cost-effective hedge against fuel price shocks – but accelerating renewable deployment could be.

Unlike the other findings, some of the key results in Finding 3 were verified against Duke Energy's own EnCompass results. As such, the disclaimer found in other sections does not apply here.

RMI's analysis shows that investing in new, more efficient gas combustion turbines (CT) and combined cycle (CC) units to replace existing fossil assets is not a cost-effective hedge against fuel price shocks for ratepayers. The incremental additional capital costs required for Duke's proposed near-term investment in gas generating capacity far outweighs the potential hedging value of more efficient gas capacity, relative to less efficient co-fired units, even in extreme high fuel-cost scenarios. However, RMI presents evidence that **deployment of additional solar, storage and wind to avoid fuel utilization is likely a no-regrets solution to limit ratepayer exposure** to the risks of:

1. Globally driven fossil fuel price volatility, particularly if natural gas supplies remain constrained over the near and medium-term,
2. Uncertain future cost and performance challenges associated with the potential conversion of gas CC and CT units to hydrogen, and
3. Accelerated cost recovery of any natural gas infrastructure that is no longer needed upon such conversion.

RMI modeled a fuel price "shock" in Optimus which assumed that fuel prices for gas and coal unexpectedly double (100% higher) for a single year relative to Synapse's assumed long-term fuel prices. Given recent global fuel market trends,[22] such a shock is well within the realm of possibility, even if Duke has implemented strategies to hedge against fuel price risks. A shock of the modeled magnitude will generally be difficult for a utility to contain with operational adjustments alone. With greater financial hedging of fuel risks, ratepayers might reduce volatility exposure in exchange for heftier insurance premia. But even if expanded hedging contracts could be secured,[23] counterparty default risk in the event of a major fossil fuel shock would be considerable.

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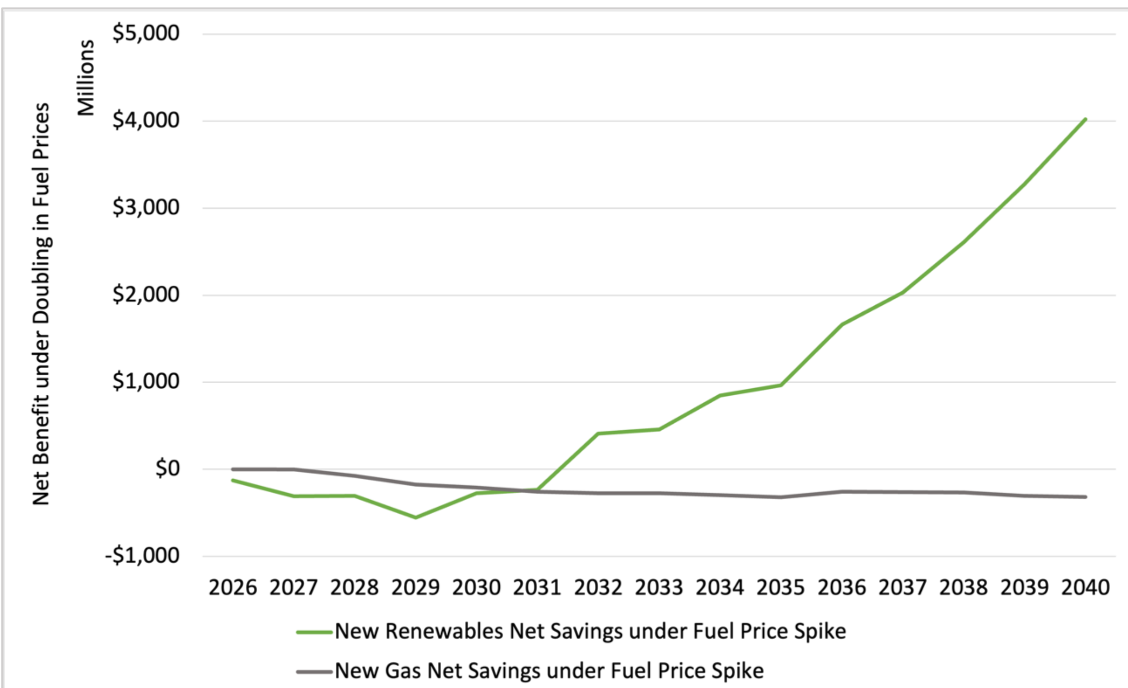
[22] See the coal and gas price chart included in Appendix A.8.

[23] See Direct Testimony and Exhibits of Gregory M. Lander on Behalf of The Sierra Club," In the Matter of: Application of Duke Energy Carolinas, LLC Pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities, DOCKET NO. E-7, SUB 1263, DOCKET NO. E-7, SUB 1263, 12.

In order to assess the cost-effectiveness of the deployment of more efficient gas CT and CC units to hedge against fuel price shocks, RMI compared the capital, fuel, and operating costs under a high fuel price sensitivity in the Duke Resources scenario to a counterfactual case without those units, instead utilizing existing, less efficient generators. RMI analysis of Duke's Encompass results show that the potential savings to ratepayers from the utilization of more efficient new gas generation in the event of a 100% price spike never exceeds the incremental capital and operating costs of the new gas facilities. Even in 2029, the year with the greatest potential savings from gas plant efficiency gains, a price spike of nearly 500% would be necessary to see a net hedging benefit from switching to new gas units. Thus, new gas units do not meaningfully provide a cost-effective hedge against high fuel prices.

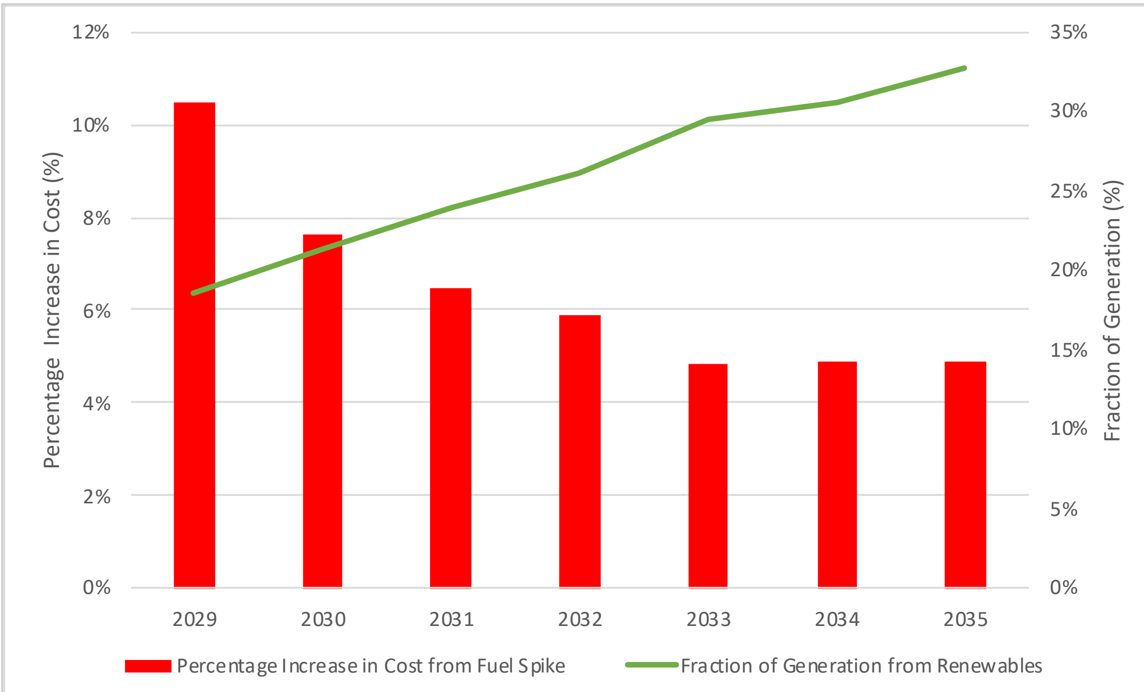
In contrast, when RMI performed a similar analysis of **all renewable assets deployed in the Duke Resources case from 2026 onwards, net hedging benefits in the event of a 100% price spike were seen for every year starting in 2032** (see ***Figure 5*** below**).**

Figure 55. Net savings or costs from the deployment of new gas or renewables relative to continued operation of existing fossil assets under a fuel price shock in each year



Moreover, RMI found evidence that the decrease in dependence on fossil fuels tied to greater deployment of renewable energy that fully displaces fossil fuel use is correlated over time with lower ratepayer exposure to fuel price shocks. Fossil fuel operating costs in the absence of a fuel shock represent roughly 7% of the total ratepayer costs in DEC for the Duke Resources scenario in 2029 through 2035 and 9% in DEP. When a single-year fuel cost spike is introduced in Optimus in each of the years from 2029 through 2035, there is a decreasing relative impact of the shock on ratepayer costs over time, roughly in direct proportion to the increase in the fraction of generation from renewable sources (see **Figure 6** below).

Figure 66. Annual Generation and Costs under Single-year Fossil Fuel Cost Spike Sensitivity (2029 through 2035)



Ultimately, these findings provide evidence that economic capacity expansion modeling alone falls short of tabulating the tradeoffs between capacity costs and risks of fuel price volatility.[24] Optimus modeling can provide support to inform consideration of the best resource composition to insulate ratepayers from fossil fuel price increases, hedging premia, and hedging counterparty default risk using alternative scenarios as a point of comparison. For example, should the Commission allow, RMI can conduct a supplemental Optimus analysis to investigate **whether an accelerated deployment of solar, battery storage, and wind resources in the near and medium term would be a more cost-effective hedge against future fuel price volatility**.

[24] This is true not just for EnCompass, but all traditional capacity expansion models.

4. The Duke Resources scenario underutilizes securitization as a source of ratepayer relief to mitigate rate spikes from early coal retirement.

Disclaimer: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

As described above, securitization mitigates the rate spikes that would otherwise be associated with retiring a coal plant early. It does so by avoiding the use of accelerated depreciation schedules to recover the remaining book value of a plant. In addition, securitization further lowers costs by replacing expensive equity with lower cost debt.

The Duke Resources scenario constrains the magnitude of potential cost savings from securitization that could be passed onto Duke's customers due to exogenous determinations Duke made in selecting the retirement year of certain plants in its proposed portfolios. RMI modeled a baseline for securitization savings aligned with Duke's proposed retirement schedule and issuing ratepayer-backed securitization bonds upon plant retirement for 50% of the unrecovered balances of subcritical plants not yet retired.[25] If not securitized, unrecovered balances were treated as regulatory assets and received the same rate of return as in-service assets.

RMI estimates that the Duke Resources scenario would result in approximately $14.1 million in savings for ratepayers as a net present value (NPV) in 2022 dollars. 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 $446 million in savings (NPV, 2022$) for ratepayers.[26] Of the total incremental securitization savings, $238.3 million would be attributable to DEC plants and $207.8 million to DEP plants. From this perspective, the Duke Resources scenario captures only 3% of the ratepayer savings available from securitization under H951.

For informational purposes, RMI also modeled a securitization scenario outside the limits of H951. If all unrecovered balances from all Duke coal plants, including the supercritical

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[25] The retirement years for each plant in the Duke Resources scenario are presented in the appendix.

[26] This calculation assumed "AA"-rated bonds priced off July 2022 US Treasury Yield Curves and issued in tranches for tenors stretching through the final recovery dates of the various coal asset balances as proposed by Duke.

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 $1.26 billion (NPV, 2022$).

The Duke Resources scenario leaves extremely large securitization benefits — which could be passed along to ratepayers to mitigate the cost of the transition — off the table. Should the Commission allow, RMI can conduct a supplemental Optimus analysis to review **whether an alternative scenario that enables an earlier retirement of coal assets than Duke projected will translate into greater total ratepayer savings** for the Commission's consideration.

5. The Duke Resources scenario leaves ratepayers vulnerable to rate de-stabilization from large increases in load growth and fuel prices.

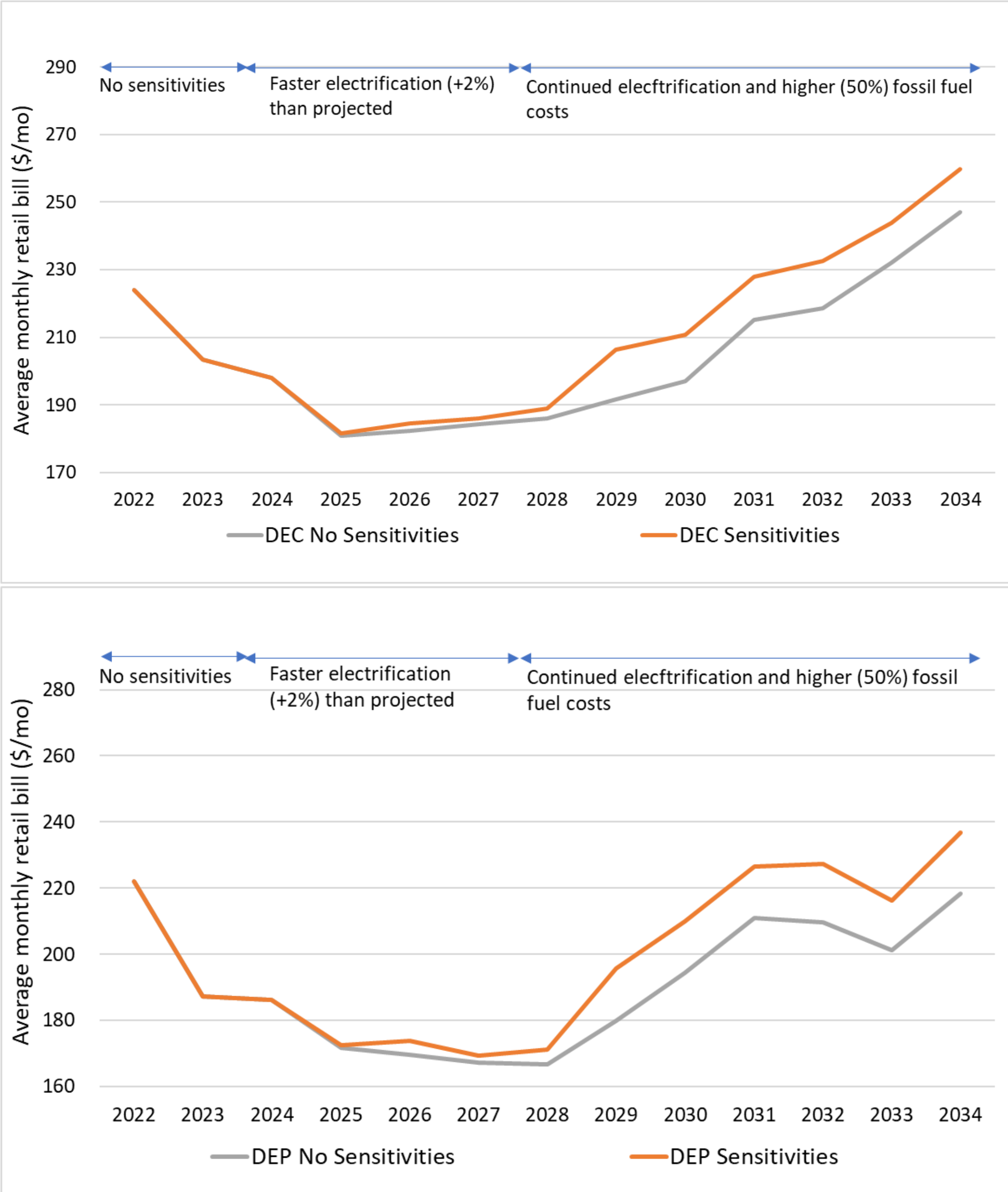
Disclaimer: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

Transportation and building electrification will be key drivers of load growth in the Duke territory, which reinforces the need to prepare the system for a higher penetration of demand-side resources. Unexpected and unprepared for higher load could drive up the cost for all ratepayers where more fuel-dependent resource portfolios are present. This finding is exacerbated when a fuel price increase sensitivity is layered in.

Figure 7 illustrates the average normalized rate over time when a prolonged, 50% increase in fuel price occurs from 2029 through 2035 along with a 2% faster load growth and compares it to the baseline Duke Resources scenario without Optimus sensitivities. [27] DEC, which has a significant proportion of fuel-consuming resources, sees average monthly bills increase steadily. In DEP, higher electrification coupled with fuel price sensitivity increases average ratepayer bills by 4% (in 2022$) on a present value basis.

[27] The 2% faster load growth sensitivity is roughly 0.5% higher than Duke's high-load projections and high EV adoption rates. RMI selected 2% faster load growth because of uncertainty in the timing of the adoption of EVs. See the section on load growth assumptions in Appendix A.5 for a full explanation and a plot comparing the load projections.

Figure 77. Normalized Ratepayer Bill Sensitivity to Higher Electrification and Fuel Price Shock



Should the Commission allow, RMI can conduct a supplemental Optimus analysis to understand ***whether a higher penetration of fuel-free resources will temper the impacts of a fuel price shock in a high-load future scenario.*** It is reasonable to assume that it would because a greater portion of demand would be satisfied with capital assets that are essentially fixed in cost and independent of the generation output. Optimus analysis of an alternative scenario can help to validate or disprove the extent to which this hypothesis is realistic and feasible for North Carolina.

Though not quantified in this analysis, there are also likely significant additional benefits from leveraging demand side resources, including demand response and energy efficiency, to mitigate the rate impact of higher load driven by EVs and building electrification. Compared to the fossil-dependent resource portfolios proposed by Duke, a portfolio of resources that can better leverage and realize the synergistic benefits of demand-side resources on the entire electric and gas distribution systems can add flexibility and lower the total cost of the portfolio.

6. The implementation of MYRPs and revenue decoupling 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.

Disclaimer: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

RMI's modeling of a multi-year rate plan (MYRP) and residential decoupling in Optimus for the Duke Resources scenario reveals that ratepayers are even more vulnerable to inflated rates in the medium and long term than they would be without these PBR mechanisms.

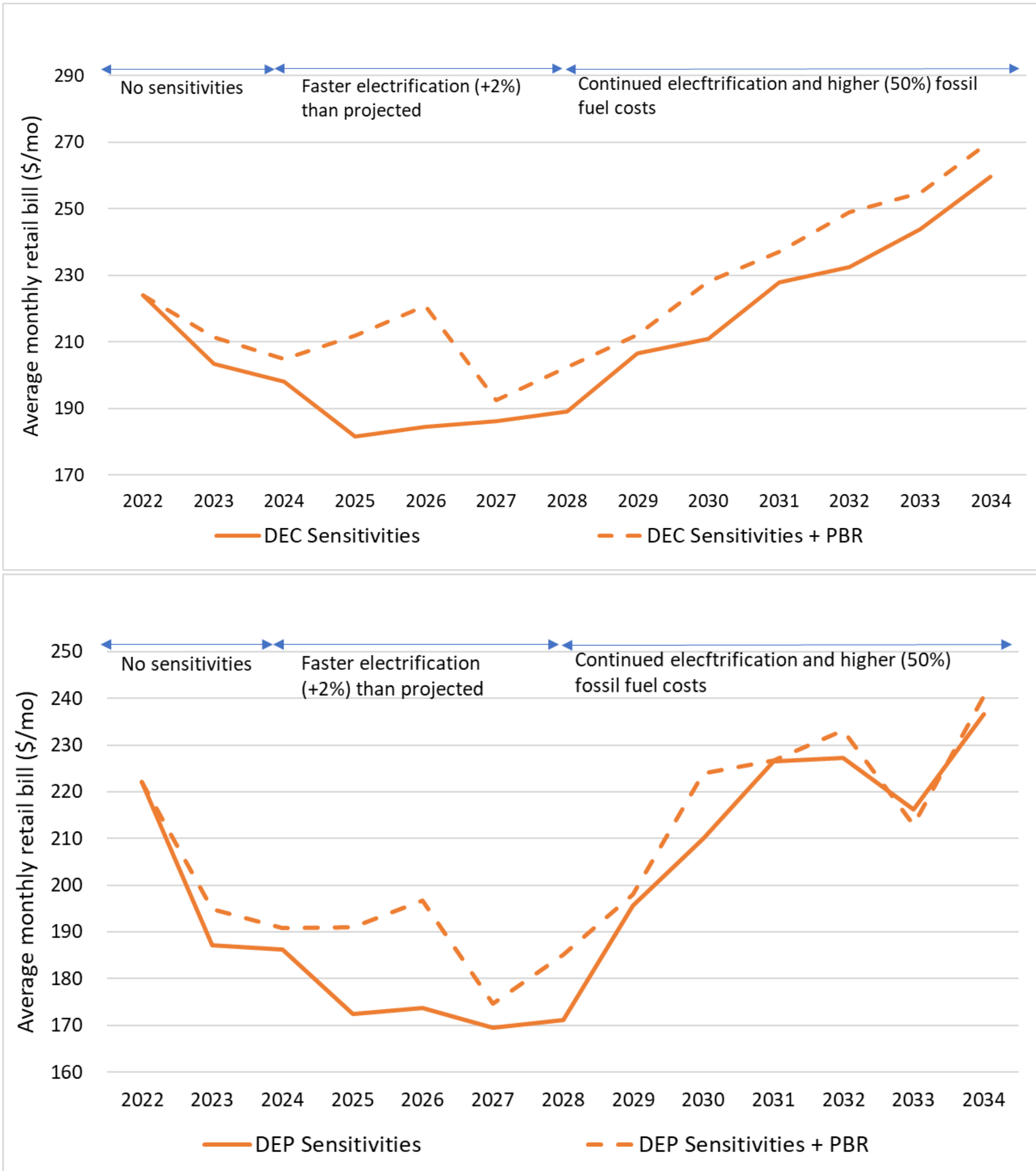
RMI modeled a MYRP and residential revenue decoupling applied to the higher load growth and fuel cost increase sensitivities. The results indicate that in 2035 the Duke Resources scenario would result in 26% and 16% higher average retail bills for DEC and DEP, respectively, compared to 2022 bills. Design parameters for a MYRP and decoupling mechanism that incentivize rates closer to the actual cost to serve customers would have resulted in an increase in average retail bills in 2035 of 16% and 7% for DEC and DEP, respectively, compared to 2022 baseline bills.

RMI attributes these cost increases to the H951 specifications regarding the use of forecasted costs to set the revenue allowance (instead of a historical base year). In MYRPs that use forecasts, portfolio scenarios that include higher mixes of fuel- or variable cost-dependent resources will motivate the utility to conservatively estimate costs in forecasts to account for fuel price uncertainty and volatility.

Figure 8 illustrates the effects of a MYRP and revenue decoupling mechanisms paired with high electrification and fuel cost increase sensitivities on average bills. In the DEC example, the MYRP 4% revenue adjustment mechanism[28] would compound an already higher level (50%) of fuel cost projection. Presumably, this phenomenon would occur to a much lower extent with a portfolio comprised of a higher proportion of renewables. This is yet another question that Optimus can explore with an alternative resource scenario as a counterfactual to the Duke Resources scenario; Should the Commission allow, RMI can conduct a supplemental Optimus analysis to examine ***whether PBR could provide a stronger incentive for the utility to control operating costs when applied to an alternative resource portfolio.***

[28] As prescribed in H951, the utility is allowed to increase revenues between years within a MYRP up to a maximum of 4% of the revenue requirement used to set rates during the first year of the rate plan. SL 2021-165 sec 4(c)1.a

Figure 88. Impact of MYRP and Decoupling under High Electrification and Fuel Cost Increase Scenarios



In addition to examining a less fuel-dependent portfolio for the Carbon Plan, the NCUC can leverage its discretionary authority to protect ratepayers from the potentially compounding effects of the MYRP design specified by H951. In the process that determines the justifiable costs for the MYRP, the Commission can foster transparency that will allow intervenors and the Commission the opportunity to closely examine proposed costs, including the effect of riders. Finally, the Commission could consider expanding targeted programs for low-income customers to mitigate any potential impacts on already burdened customers.

7. If implemented, federal policy changes in the next decade will present significant cost savings opportunities that can be passed to ratepayers; the Duke Resources scenario would capture $5.4 billion.

> **Disclaimer**: Given EnCompass v6.0.9 issues described in the Methodology section, this finding and discussion should be understood as an illustrative and directionally indicative analysis of the impact of the Duke Resources scenario if selected by the Commission.

The suite of enhanced federal policy levers for renewables, as detailed in Appendix A.2, could dramatically lower the costs associated with a cleaner scenario. The Duke Resources scenario could realize cumulative annual ratepayer savings of $7.7 billion in 2035, and net present value savings of $5.4 billion. It is unclear in relative terms how much additional ratepayer savings could be realized without comparison against an alternative scenario.

Assuming a non-zero probability of the policy enhancements RMI modeled, renewables have an "option value" for both Duke and ratepayers. No such value reasonably attaches to fossil plants since the likelihood of major new federal tax credits for these technologies is negligible. The option value of clean scenarios should be considered in Carbon Plan decision-making as a benefit to rate payers that would be lost or diminished if Duke's Carbon Plan proposals are selected.

Conversely, there is a "risk value" associated with the potential for policies that will penalize the utilization of, or investment in, fossil fueled resources. Though not analyzed in this report, the risk value of more stringent policies will similarly be passed along to ratepayers and should be considered alongside any portfolio that relies on fossil-fueled generation assets.

Figure 9 and ***Figure 10*** below show the annual and total ratepayer cost impact with and without state and federal policy changes for the Duke Resources scenario. Coal plant securitization on an annual and NPV basis, as discussed in Finding 4, yields limited savings under the requirement of H951. In ***Figure 9***, the difference between the annual ratepayer costs is negligible with and without securitization. Federal policy enhancements could be a more significant source of costs savings through provision of tax credits for deployment of zero-emission resources.

Figure 99. Annual Ratepayer Cost Impact with and without Federal Policy Changes

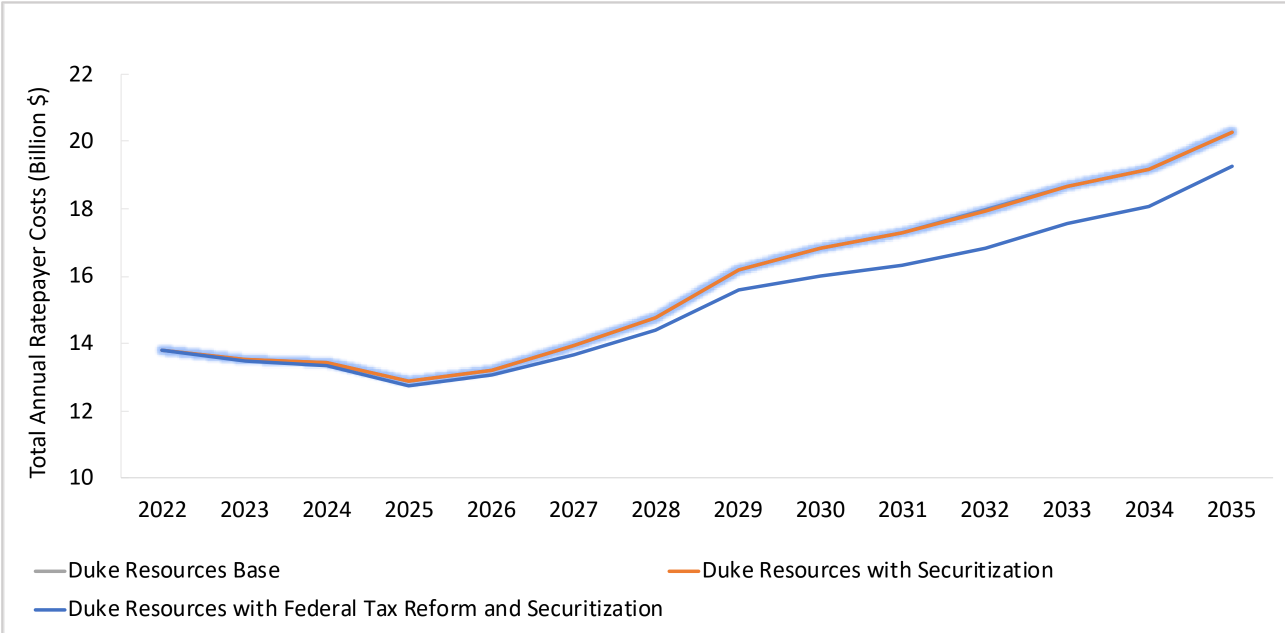
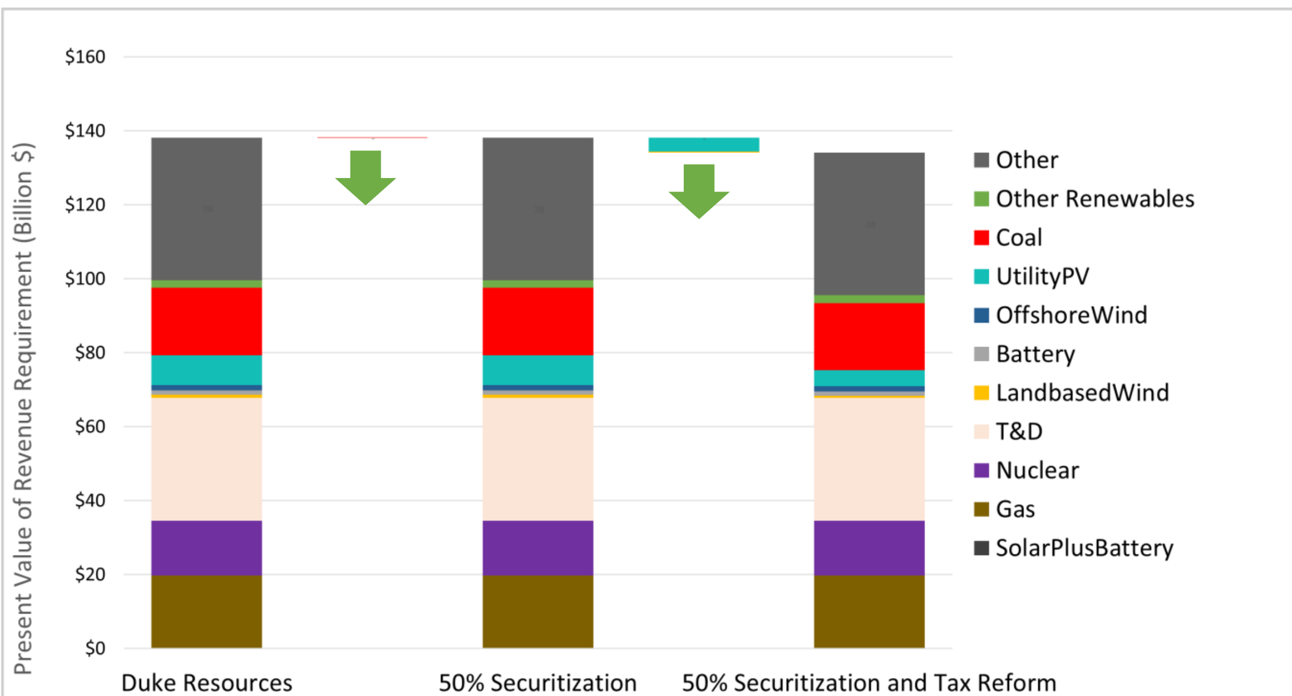


Figure 1010. Total Ratepayer Cost Comparison with Securitization and Federal Policy Changes



Implications and Recommendations for Future Carbon Planning Efforts

General Implications of this analysis

The analysis included in this report supports the conclusion that the P1-Alt scenario proposed by Duke Energy in its Carbon Plan presents considerable risks to ratepayers that are not captured by EnCompass modeling. This suggests that further analysis of alternative portfolio scenarios may be warranted to identify a different and more optimal least-cost Carbon Plan that can achieve both the 2030 and 2050 targets while better balancing the trade-offs of known capital costs with macro-economic, policy, and forecasting uncertainties. A variety of sensitivities modeled on the Duke Resources scenario provide a baseline for further analysis and comparison. Further analysis should explore whether an alternative cleaner resource portfolio that relies more on solar, storage, and wind than the ones proposed by Duke Energy could be more resilient from a ratepayer cost perspective to the uncertainty of future fuel prices, electricity demand, and policy and regulatory changes.

Conventional wisdom has long held that the CapEx intensity associated with portfolios that contain higher concentrations of zero-emitting resources makes them more costly relative to gas-heavy portfolios. However, this truism may be at an inflection point considering the following dynamics:

- Existing and increasing future price risks for the entire fuel requirement may outweigh the efficiency gains of new gas-fueled assets, undermining the rationale for the incremental CapEx costs for these carbon-emitting resources;
- Securitization and PBR can smooth out the cost of the transition for ratepayers and encourage cost efficiency on the part of the utility, but investment in fuel-dependent resources may diminish the efficacy of these cost-containment mechanisms; and
- Existing federal policy provides the opportunity for near-term savings associated with new wind and solar capacity that the Duke Carbon Plan scenarios largely bypass, while potential future federal policy enhancements are more likely than not to degrade the economics for fuel-dependent resources.

This analysis suggests that it would be unwise for the NCUC to determine North Carolina's Carbon Plan without:

- Analyzing 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 uncertainty);

- Considering 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;
- Examining the impact of a fully economic 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
- Weighing the potential benefits and risks posed by federal policy changes, and downstream ramifications for ratepayers (in terms of lost or accrued "option" and "penalty" values).

With further study of alternative scenarios, RMI analysis using Optimus can support the exploration of the above considerations holistically and contribute to the selection of a Carbon Plan that appropriately balances near-term investment decisions with their associated risks, thereby achieving a more optimal, cost-effective path from a ratepayer perspective. Additional time would also enable an exploration of the impact to the utilities' earnings from the Duke Resources scenario compared to alternatives.

The consequences of PBR as stipulated by H951 *may* mitigate costs to ratepayers but could possibly inflate them. Commission scrutiny, provision of a transparent process, and leveraging all discretionary tools within its disposal can be used to ensure that multi-year rate plans are mutually beneficial for ratepayers and the utilities.

Recommendations for Future Carbon Planning Efforts

To better improve upon and replicate the analysis contained herein for future iterations of the Carbon Plan, RMI offers the following recommendations for the Commission's consideration:

1. The Commission should require Duke to use ***the full revenue requirement to estimate ratepayer costs*** (instead of just the forward-looking incremental costs, which treats expenses associated with the existing electric fleet as a foregone conclusion). This will better reflect the cumulative impact on ratepayers and help the utility, the Commission, and intervening parties identify opportunities to reduce the cumulative costs of each portfolio scenario, including early retirement with refinancing options such as securitization or depreciation schedule adjustments of regulatory assets.

2. The Commission should require Duke to ***provide disaggregated cost projections associated with both existing assets and incremental additions for each portfolio scenario***. Such disaggregation must differentiate maintenance capital expenditures and transmission-related levelized fixed charge rates from fixed O&M costs. This will enable Duke, intervenors, and the Commission to understand and accurately reflect projected rates and bills trajectories, as well as the full potential benefits of mechanisms such as securitization.
3. Using Duke's cost-of-service methodologies, functional allocation of costs results in marked differences in impacts across customer classes for different resource portfolios. The Commission and interested parties should be aware of these varying impacts across classes. As such, ***the Commission should require Duke to estimate rate impacts for each customer class*** in addition to an average value (across all ratepayer classes) in its carbon plan filings.
4. The use of the weighted average cost of capital (WACC) in net present value (NPV) calculations does not holistically reflect the impact of regulatory accounting and utility finance. The Commission should ***consider requiring Duke to utilize a more nuanced approach to discounting the NPV and apply a rate of return on the full revenue requirement*** to yield more accurate NPV estimates for each portfolio.
5. The Commission should consider requiring Duke to ***make each of the following financial line items available in a disaggregated format*** to intervenors in future Carbon Plan updates:
    a. For incrementally added assets, for each scenario:
        i. The associated installed costs before and after AFUDC and CWIP are considered
        ii. A breakdown of how the company expects to spend the installed cost associated with each incrementally added asset over its construction period
        iii. Book depreciation, tax depreciation, book values, accumulated deferred incomes taxes (ADIT), and property taxes over time, by asset
        iv. Any cost adders that should be considered capital expenditures per accounting principles, but are incorporated as O&M costs for EnCompass modeling purposes
    b. For existing assets:
        i. Most current net plant balance, and any capex that will add to the book value of these over the planning period
        ii. Book depreciation, tax depreciation, book values, ADIT, and property taxes over time, by asset
        iii. Decommissioning and asset retirement costs
    c. Separate fixed and variable charges for purchased power for current contracts, with an indication of which of these would be incurred regardless of the dispatch of resources associated with the purchased power (i.e., "take-or-pay")

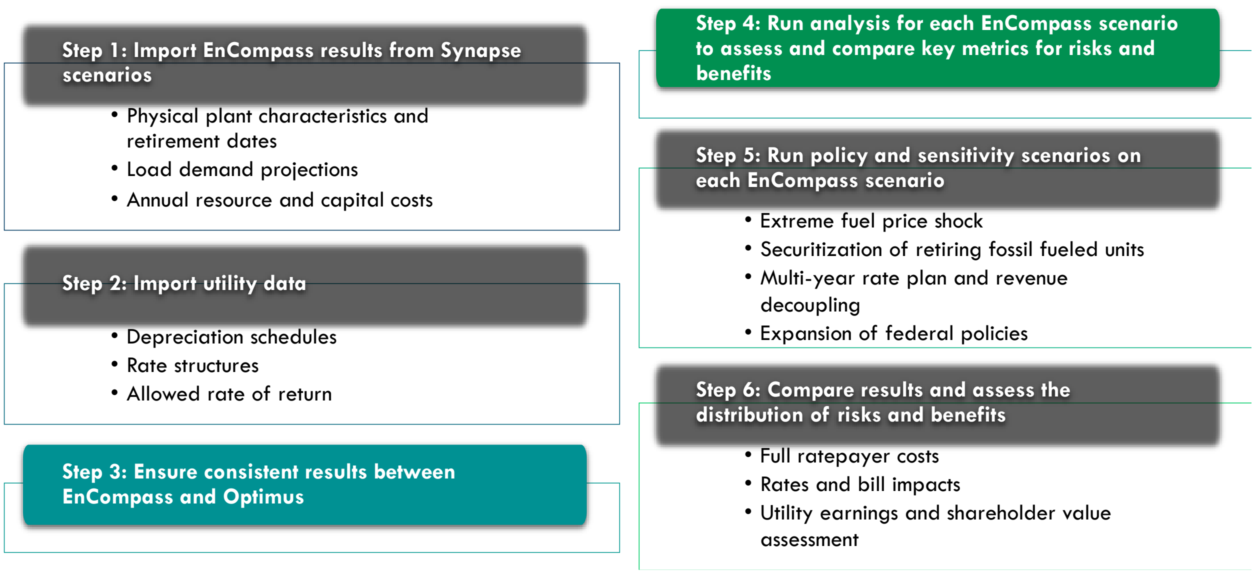
d. For purchased power additions (such as 3rd-party-owned solar), a separate calculation of costs utilizing project finance (as opposed to utility finance) methodologies, and earmarked as such
e. A breakdown of any costs incurred at any level above a resource (for instance, costs at a balancing area level or at a company level like contract costs or ancillary purchases) included in the capacity expansion or production cost modeling, and how these relate to the resource selection
f. A detailed calculation and associated breakdown of any costs bucketed as "Other Costs" in EnCompass modeling

Appendix

A.1 Optimus Modeling Steps & Key Metrics

RMI imported the EnCompass results from Synapse's replication of Duke's P1 scenario, the Duke Resources.[29] Optimus was then used evaluate Duke's P1 scenario on a variety of metrics for measuring ratepayer cost, utility earnings, and utility shareholder impacts for the Carbon Plan planning period of 2022-2050. ***Figure 11*** below provides an overview of the analytical steps in Optimus.

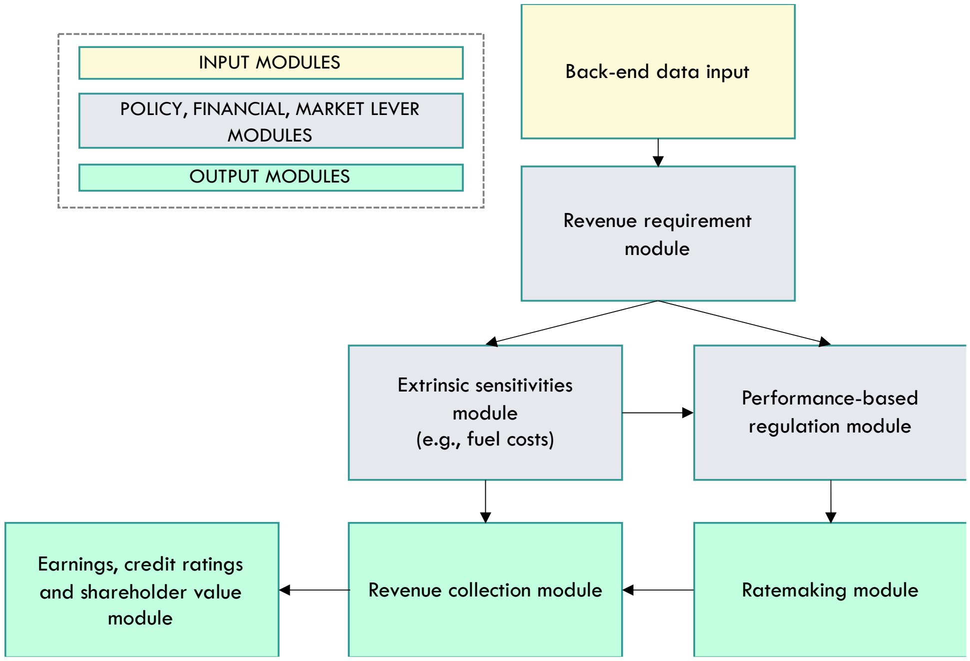
Figure 11 11. Optimus Analytical Steps



Optimus is comprised of a series of modules that post-process data and perform financial calculations as illustrated in ***Figure 12***.

[29] Optimus takes in the most granular level of Encompass results made available for each scenario: full production cost runs, if performed, or capacity expansion runs otherwise.

Figure 12 12.The Optimus model's high-level architecture



The modules depicted in green in ***Figure 12*** provide data outputs for metrics calculation. The metrics that can be derived from Optimus analysis are provided in ***Table D*** Metric results for resource scenarios and sensitivities analyzed for this report are presented in the ***Findings*** section of the report.

Table D. Optimus Analytical Metrics

Categories	Metrics
Ratepayer cost	• Total ratepayer cost ($) • Average ratepayer cost per MWh consumption ($/MWh) • Average ratepayer cost by residential, commercial, and industrial classes and by fixed, demand, and energy rates ($/MWh) • Incremental average bill impact by residential, commercial, and industrial classes compared to a baseline scenario ($/month)
Utility earnings	• After-tax earnings ($) • Incremental change in earnings compared to a baseline scenario (%)
Utility shareholder impact	• Incremental change in shareholder value compared to a baseline year (% accretion or dilution) • Credit rating impact (Moody's Financial Strength Metrics, Implied Rating, Aggregated Grid Rating Scores)

A.2 Policy and Sensitivity Scenario

The following table describes in greater detail the policy and sensitivity scenarios RMI run in service of this analysis.

Table E. Optimus Policy & Sensitivity Assumptions

Modeled Policies/Scenarios	Description
Existing Federal Policies	The federal Production Tax Credit (PTC) for wind generation is earned for each MWh sold for ten years after facility enters service. The last cohort of facilities eligible for the PTC must enter service by the end of 2025 and have begun construction by the end of 2021. These facilities will be credited with \$15/MWh (subject to inflation adjustment from 2019\$). Utility-scale solar and associated battery storage facilities are eligible for an Investment Tax Credit (ITC) of 30% of the asset cost if they enter into service by the end of 2023 and 10% if entering service after 2025, with incremental phasedowns of credit percentages for facilities entering service in 2024 and 2025. Stand-alone storage is not eligible for the ITC. The ITC may be claimed for assets owned by regulated utilities but must be normalized. Where Duke and Synapse resource portfolios include facilities that met the criteria for the PTC, the credits were applied as a cost reduction passed through to customers as soon as claimed for tax purposes. For the ITC, the credits for utility-owned assets are passed through to customers over the life of the relevant asset, or "normalized," as required by federal law.
Potential Federal Policy Enhancements	Federal policies are already an influential force on the competitiveness of resources today. As recognition of the necessity to decarbonize the US economy become increasingly mainstream, future federal policies may provide greater rewards for investment in clean electricity resources or introduce penalties (e.g., a carbon price) and/or regulatory requirements that increase the cost of investment in, and operation, of carbon-emitting electric resources. Such new policies could result in significant costs and benefits that for the utility, its shareholders, and ratepayers and thus cannot be ignored, despite their uncertainty. As a proxy for a tangible set of future federal policies that extend existing federal policies in terms of both applicability and duration, RMI modeled key elements of Build Back Better Act (BBBA), or H.R. 5376, that was passed by the House of Representatives in the 117th Congress but which did not secure approval in the Senate. BBBA enhancements modeled in Optimus include: (1) Extend applicability of PTC-type credit to include solar facilities. (2) Wind and solar facilities are eligible for PTC if they begin construction by the end 2031 and are valued at \$25/MWh (\$10 higher than current and still subject to inflation adjustment from 2019\$). (3) Stand-alone battery storage facilities are eligible for 30% ITC if they begin construction by the end of 2031.

	(4) Transmission investments newly eligible for 30% ITC. (5) PTC and ITC are made available as direct pay awards from the US Treasury to entities without sufficient tax capacity to monetize credits in the year earned. (6) Normalization of ITC would not be required. Note: This suite of policy enhancements has been supported by the Edison Electric Institute (EEI), the association of U.S. investor-owned utilities, of which Duke is a member.[30]
PBR Mechanisms	H951 authorized the Commission to approve performance-based regulation applications upon application by an electric public utility. As such, Duke Energy has ability to file multi-year rate plans (MYRP) inclusive of an earnings sharing mechanism, revenue decoupling for residential rate class, and performance incentive mechanisms. Additionally, the same legislation enables securitization of 50% of unrecovered balances when subcritical coal plants are retired early. The consequences of these mechanisms — for ratepayers and the utility — will vary based on the composition of the resource portfolio. RMI modeled the impact of securitizations occurring at the time of a unit's retirement as prescribed in the Duke Baseline. To operationalize the MYRP, RMI assumed application by the utility of the maximum (4%) increase of the base year revenue requirement in each year of the MYRP. For the cost forecast in between rate plans, RMI used capital costs and associated expenses and fixed costs corresponding to the first year of the MYRP, and unit variable costs from one year before the rate plan takes effect applied to the projected system load in the first year of the MYRP. The MYRPs were modeled as taking effect in 2023 and recurring at three-year intervals. H951 gives Duke the *option* to exclude rate schedules/riders for EV charging from the decoupling mechanism. However, EV load in Duke's load projection is combined with other load for each customer classes. Without disaggregation, RMI cannot model EV load decoupling discretely. Instead, our decoupling analysis will focus on two edge cases: • decoupling all load, including EV load, and • decoupling all residential load, including home EV chargers.
Securitization	H951 allows for half of the costs associated with early retirement of subcritical coal-fired electric generating facilities to be securitized.[31] Briefly described, securitization is a refinancing mechanism that uses low-cost debt backed by non-bypassable ratepayer charges to pay off undepreciated plant balances. The utility receives funds

[30] EEI news release from 19 November 2021, available at https://www.eei.org/resources-and-media/energy-talk/Articles/2021-11-eei-welcomes-house-passage-of-the-build-back-better-act

[31] North Carolina G.A., Session Law 2021-165, House Bill 951, 2.

	when the securitization bonds are issued, allowing it to pay off existing creditors and equity contributors. The new securitized debt is an obligation neither of the state nor the company, but rather of all current and future utility customers over the life of the bonds. Securitization legislation typically includes valuable protections for creditors that result in extremely high credit ratings for the bonds — higher than any U.S. utility's current credit rating — and correspondingly low interest rates. Because ratepayers are paying lower interest rates when securitization has been utilized, thereby avoiding paying for the higher returns demanded by equity providers, they realize savings that scale in proportion with the size of the refinanced balances and the duration of the avoided period of traditional utility finance. Securitization transactions have fixed and variable transaction fees, as well as ongoing servicing costs, all of which RMI includes in its modeling. When transaction fees would exceed savings from a securitization, Optimus is designed to use regulatory assets to warehouse plants balances over time in order to reduce the number of bond issuances with their fixed fees. If securitization cannot provide net ratepayers savings, Optimus rejects the transactions. The RMI securitization sensitivity scenario assumes that 50% of the remaining plant balance of each Duke subcritical coal plant/unit is securitized upon future retirement, while the other 50% of the balance remains in the rate base and is turned into regulatory asset. Since EnCompass is not easily adapted to model the impacts of securitization endogenously, sensitivity analysis in Optimus is used to identify scenarios where securitization can deliver significant net benefits for ratepayers, as well as scenarios where the benefits of securitization are left unrealized.
Fuel Price Sensitivity	RMI modeled two types of fuel price sensitivities in Optimus: (1) A single-year extreme fuel price shock to assess the temporary impact of market turbulence. This sensitivity assumes doubling the fossil fuel prices for the entirety of one single calendar year, and the test year range is 2029-2035 because these are the peak years for generation from gas and co-firing units (and thus, consumption of gas) in the Duke Resources scenario. The metric used to evaluate the impact is the percentage increase of annual total ratepayer cost driven by the fuel price shock in that year, and by comparing the impact across the range of 2029-2035, it enables identification of the year where the portfolio is most susceptible to fuel price volatility. (2) A prolonged, multi-year increase in fuel price (2029 through 2035) to assess the medium-term impact on prices of a longer-term shift in fuel market dynamics. This sensitivity assumes 50% higher fossil fuel prices for the entirety of calendar years 2029 through the end of 2035 on each resource scenario and is also coupled with a higher load projection as described above to analyze the effect of these two compounding risks.

	See Appendix A.8 below for an overview of recent fuel price for justification of the fuel price assumptions.

A.3 Further Explanation of the Key Differences Between the EnCompass and Optimus Calculations

1) Full revenue requirement vs. forward-looking incremental system cost

In its Carbon Plan proposal, Duke employed the traditional approach of using capacity expansion optimization to estimate ratepayer impacts. This approach considers only the capital expense components of capacity additions and the operational expenses of the full generation portfolio.[32] This implies that Duke has assumed capital and other expenses of the current generation fleet to be sunk costs, constant (in real dollars), and independent of future factors.

In contrast, RMI used Optimus to estimate ratepayer impacts utilizing the full revenue requirement, including *all cost components* of both existing assets and incremental resources added to the portfolio by EnCompass, as well as capital and operating costs associated with non-production assets.[33] Finance and accounting principles were applied to the full revenue requirement to derive total ratepayer costs.

The primary rationale for this approach is that a more comprehensive set of costs must be modeled to capture the potentially important impacts of regulatory and financing options such as securitization and PBR mechanisms on the distribution of costs and risks of potential resource scenarios. RMI believes this approach enables a wholistic examination of the impacts of future resource portfolios — in addition to the economic, policy, and regulatory dynamics described above — on all cost components, all of which can translate to ratepayer costs (and savings).

2) Full vs. incremental rates and bills impact assessment

The full revenue requirement approach also allows RMI to conduct forward-looking estimates of rates and bills differentiated by class in Optimus. To do this, the model employs a functional allocation methodology that classifies and assigns all cost components in the projected revenue requirement using cost causation principles and

[32] Duke, *Carolinas Carbon Plan*, Appendix E, Page 44.

[33] Non-production assets include transmission and distribution operating costs, Selling, General and Administrative (SG&A) expenses (which are the operating costs associated with utility operation), pension obligations, etc.

the historical allocation across customer classes (as observed in collected revenue and rate schedules).[34] The result is a differentiated average bundled rate and average monthly bill for the residential, commercial, industrial, and wholesale classes.

In contrast, Duke calculated the incremental impact per MWh of a residential bill of each scenario in its Carbon Plan proposal. Duke did this by applying their average cost allocation to all retail sales, without differentiating how costs would be allocated amongst ratepayer classes. Additionally, Duke assumed that the 2021 year-end average bundled price per MWh for the residential class will stay constant such that any cost allocated to residential customers from the incremental resources added by EnCompass would be in addition to the baseline. This approach effectively eliminates consideration of how the baseline costs will inevitably change due to depreciation of existing assets, evolution of fuel costs, and changes in capacity factors across time, among others.

In sum, Duke's approach to the residential bill impacts assessment represents an average impact of the incremental portfolio additions, omits consideration of how such additions change the costs of the existing portfolio, and implies the impact would be spread evenly across customer classes. RMI's approach tries to bridge the gap between capacity expansion analyses and the realities of cost-of-service studies and rate cases by considering the evolution of the entire portfolio (both existing assets and additions) and differentiating its impact to the main four classes of customers (residential, commercial, industrial and wholesale).

3) Fixed O&M expenses vs. capitalization

In Duke's EnCompass modeling, transmission upgrade costs and the maintenance capital expenditures (or "CapEx") associated with existing assets are treated as fixed O&M cost adders. In Duke's EnCompass outputs, these costs are inextricably combined with other generation project-specific costs from the "Fixed Cost" category in EnCompass. Duke's approach forced Synapse to do the same in its own scenarios. As a result, RMI was unable to disentangle the maintenance CapEx to incorporate it into Optimus's calculation of securitization benefits, which means that this analysis likely represents an underestimate of this potential value.

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[34] RMI's calculations of bill impacts using the cost causation framework were informed by a variety of sources: A RAP publication titled, *Electric Cost Allocation for a New Era: A Manual* (2020) by Lazar, Chernick, Marcus, and LeBel; National Renewable Energy Lab's Utility Rates Data Base; FERC Form 1 tables: sales by schedule and sales by customer class; and, NCUC Dockets E-2 Sub 1219 DEP Cost of Service Studies & Cost of Service Manual, and E-7 Sub 1026 DEC Cost of Service Study.

If sufficient breakdown of cost data had been provided, RMI's ideal approach would be to (1) treat the transmission and maintenance CapEx cost as an upfront capital expense (as it commonly would in cost-of-service regulation), and (2) estimate the impact of annual depreciation and rate of returns based on the depreciation schedule of each asset. In theory, both approaches will yield similar ratepayer cost outcomes *if* the fixed O&M cost adders incorporate the levelized impact of annual depreciation and authorized returns. However, the following factors would cause the outcomes to be different:

- Given the circumstances, the maintenance CapEx cost of existing assets was not subject to the Optimus securitization calculations. This reduces the potential savings of securitizing coal plants because the significant costs of maintenance CapEx are not added to net plant balances and included in the rate base calculation. Consequently, the overall securitization benefits are underestimated. RMI recommends revisiting the approach in future EnCompass modeling to reflect the benefits of mechanisms like securitization more accurately.
- Since fixed O&M cost adders are treated as direct pass-throughs in the EnCompass analysis, it would not be reflected in the earnings calculation. Consequently, the utility earnings are underestimated. RMI recommends revisiting the approach in future EnCompass modeling to allow for a comprehensive assessment of earnings and shareholder value.

4) Discount factor for Net Present Value calculation

In Duke's EnCompass modeling, the net present value (NPV) calculation uses a single discount factor: the Weighted Average Cost of Capital (WACC) for the entire planning horizon. This is the commonly used approach across capacity expansion modeling analysis to estimate the system costs when the analysis focuses more on the operational impact rather than the detailed financing structure.

To ensure comparable and consistent NPV estimate with EnCompass results, RMI used the same constant WACC for the incremental NPV calculation. For the full revenue requirement assessment beyond incremental NPV, RMI used a hybrid, forward-looking ROR approach which provides a more nuanced picture of the value of different portfolio decisions. RMI's forward looking ROR approach considers two factors:

- The dynamic nature of the cost of debt as captured in forward interest rate curves, which directly affects the company's cost of capital and tax deductibility of interest
- The continuous need to incorporate new equity and new debt into the capital structure of the Companies depending on the deployed capital to build the capacity expansion

These factors attempt to reflect the nature of the capital markets that utilities would face in the future, and thus affect the costs they bear. In a stricter sense (and if the data were available), different components of the revenue requirement should be discounted at different rates, depending on which group bears the risk associated with each cost component. For instance, direct pass throughs to ratepayers ought to be discounted at a lower rate, similar to a social discount rate.

The Optimus analysis and findings described in the next section indicate that the hybrid, forward-looking ROR has an upward trajectory (starting at 6.4% in 2022 and growing to 7.1% by 2050), which would yield lower NPV numbers compared to the EnCompass approach. RMI recommends the Commission revisit this methodology in future Carbon Plan EnCompass modeling.

A.4 Optimus & EnCompass Calibration Results

Before starting the full revenue requirement impact assessment, RMI calibrated its model with EnCompass to ensure Optimus yielded consistent baselines. ***Table A.3*** below lays out Optimus's estimate of the forward-looking incremental system cost, which is equivalent to the Incremental net present value for the *total* revenue requirement (NPVRR) calculated by Synapse.

Optimus's incremental NPVRR results are less than 1% different from Synapse's numbers through 2030 and within 3% difference through 2050. The difference is driven by the caveats laid out in the methodology section above; primarily the simplified treatment of the AFUDC account. RMI believes that the close agreement between the EnCompass and Optimus models provides strong evidence that the results from Optimus can be viewed as faithfully providing complementary analyses and metrics for the scenario that will be presented in Synapse's replication of Duke P1 scenario.

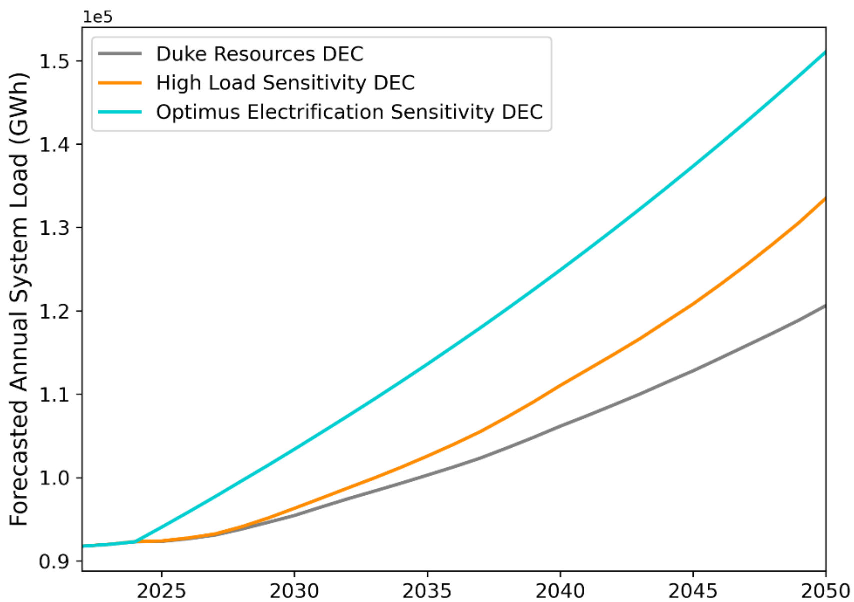
Table F. Incremental NPVRR Results from Optimus for all Scenarios, 2022-2050

(Billion $)	Duke Resources
NPVRR through 2030	36.5
NPVRR through 2040	77.8
NPVRR through 2050	120.7

A.5 Load Growth Assumptions

RMI compared the load growth assumptions under the Duke Resources scenario and the Optimus electrification sensitivity scenario against the ones under Duke's own High Load sensitivity scenario. RMI only compared the DEC region as Duke only provided the load projection data under the High Load sensitivity for DEC and DEP-East, and as a result RMI is not able to provide a complete comparison of the entire DEP region. ***Figure 14*** below shows a comparison of those assumptions, indicating that Duke's High Load scenario, which reflects "commitments made by vehicle manufacturers to achieve 40% to 50% of new vehicle sales being EVs by 2030,"[35] is roughly 0.4% faster growth than the base load projection. This is relatively conservative compared with the high electrification assumptions used in Optimus sensitivity, which is roughly reflecting 2% annual growth (1.5% faster than Duke's baseline).

Figure 14 13. DEC load growth scenarios for the baseline Duke Resources scenario (grey), Duke's high load and high EV sensitivity (orange), and the Optimus 2% load growth assumption (cyan).



A.7 Rates & Bills Impact Methodology

The first step in projecting the impacts to rates and bills is to model a typical ratemaking process, including a certain rate case frequency, a regulatory lag, a type of test year, and any PBR mechanisms that might be in effect. As standard assumptions, Optimus assumes rate cases will happen every other year, with a regulatory lag of one year, and use historical costs ("actuals") except for the MYRP. The result is a certain level of "revenue allowance" that the utility will seek to allocate and collect across its customers that differs slightly from the EnCompass revenue requirement due to ratemaking dynamics.

[35] Duke, *Carolinas Carbon Plan*, Appendix E, Page 18.

The second step is applying functional allocation to this "revenue allowance." The following table describes the data sources and references that RMI used to reconstruct a functional allocation methodology that follows cost causation principles and Duke's revenue collection parameters from publicly available data:

Table G. Data sources for functional allocation

Calculation	Data Sources	Assumption derived	Methodology
Collected revenue	FERC Form 1 Sales by Rate Schedule table	$ amounts and kWh sold under each rate schedule	Paired with the URDB to calculate collected revenue from each bill component per customer class
	FERC Form 1 Sales by Customer Class table	$ amounts and total kWh sold to each customer class	To calculate the fraction of revenues and load that each customer class represents
	NREL's Utility Rate Database (URDB) in conjunction with EIA 714 load information	Bill components in each rate schedule ($/kWh, $/kW-month and $/month)	Paired with FF1 Sales by Rate Schedule table to calculate collected revenue from each bill component per customer class
Cost allocation	Regulatory Assistance Project's Utility Cost Allocation for A New Era manual	Best practice guidance and average industry observations on functional classification percentages per asset type	To allocate cost components of each asset to fixed, demand or volumetric rates on a forward-looking basis
	Publicly available functionalized cost of service studies	Cost allocation of functions (generation, T&D, etc.) to each rate schedule	Calibration of functional allocation results
Cost baseline	FERC Form 1 revenues by cost component	Revenue $ amounts attributed to utility cost components	To get a historical breakdown of cost functionalization and classification as baseline

Functional allocation results in a matrix that specifies what percentage of each cost component in the revenue requirement would be collected from each customer class when applying cost causation principles and the current rate structure.

When applying said matrix to the asset level breakdown of costs, three main metrics can be obtained:

- Normalized average rates: total "revenue allowance" divided by total net load served
- Average bundled rate per customer class: fraction of the "revenue allowance" to be collected from each customer class (per the functional allocation matrix) divided by the net load of each customer class
- Average monthly bill: fraction of the "revenue allowance" to be collected form each customer class (per the functional allocation matrix) divided by the average annual customer count and then by 12

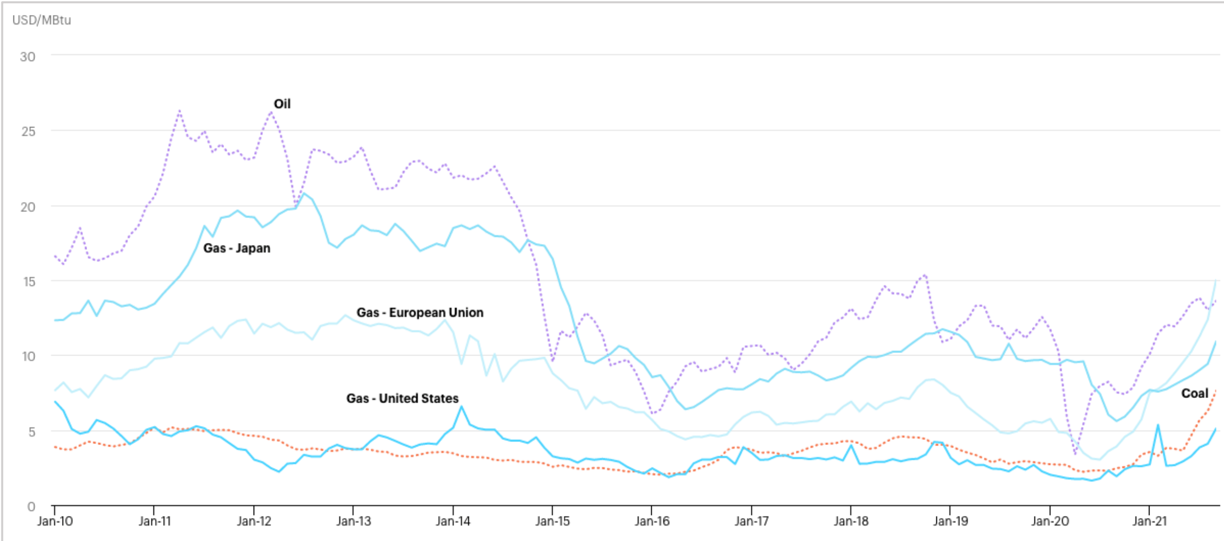
Since the analysis used a wide range of publicly available data, results are not expected to be exact. Rather, their intent is to provide medium to long-term directional insights into the distributional impacts of different resource selections. For the bills trajectory analysis under the Duke P1 scenario presented above, the results for 2022 are set as the baseline, and the changes relative to such baseline are plotted over time. According to NCSEA-SACE DR 2-23, Duke used 2022 bills estimates as baseline and projected bill impacts using changes relative to this baseline as well.

A.8 Recent Fuel Price Trajectories

Figure 15 below shows the recent historical price trajectory of global oil, gas, and coal prices, demonstrating the linkage in price amongst these energy sources.[36]

[36] IEA, *Oil, natural gas and coal prices by region, 2010 - 2021*, IEA, Paris https://www.iea.org/data-and-statistics/charts/oil-natural-gas-and-coal-prices-by-region-2010-2021

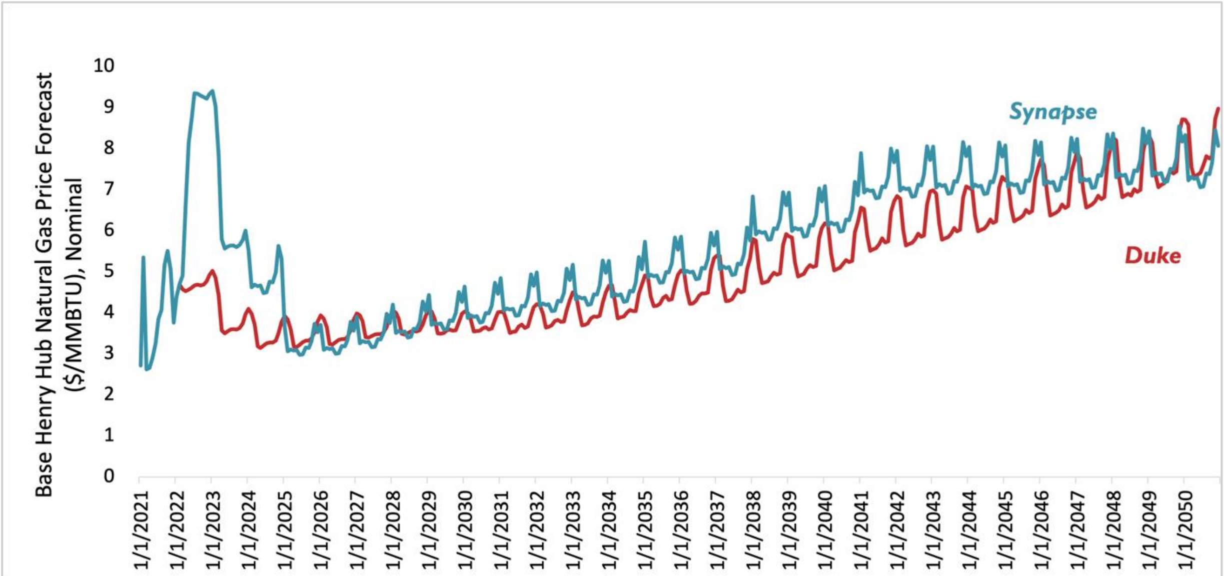
Figure 1145. IEA Oil, natural gas, and coal prices by region, 2010 - 2021 ($USD/MBtu)



A.9 Comparison of Synapse and Duke Natural Gas Price Forecast

Figure 16 below shows the forecast Henry Hub natural gas prices used by both Synapse and Duke. A notable deviation occurs between 2022 – 2025 where both forecasts predict a temporary price spike. Although the shape of the spike is similar in both forecasts, Synapse predicts that prices will peak about twice as high as the maximum forecast used by Duke in its proposed Carbon Plan. This big spike in 2022-2023 is reflected in the operating cost projection and results in a sharp incline in the following years, which explains the near-term bill decline particularly seen by the residential customers in the DEC territory given the cost allocation assumptions described in Appendix A.7 above.

Figure 16. Henry Hub Natural gas price forecast from Synapse and Duke (Source: Synapse)



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Oct 06 2022

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 179

In the Matter of: Duke Energy Progress, LLC and Duke Energy Carolinas, LLC 2022 Biennial Integrated Resource Plans and Carbon Plan	))))))	Verification of Gennelle Wilson

VERIFICATION

I, Gennelle Wilson, first being duly sworn, say that I am employed as a Senior Associate at RMI and have read the foregoing Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal, and know the contents thereof; and that the contents are true, accurate and correct to the best of my knowledge, information, and belief.

Gennelle Wilson

Signature

STATE OF Colorado

COUNTY OF Boulder

Signed and sworn to (or affirmed) before me this 14th day of July, 2022.

Paras Patel

Signature of Notary Public

Paras Patel

Printed or Typed Name of Notary Public

My Commission Expires: June 4, 2025

[Official Seal or Stamp]

PARAS PATEL
NOTARY PUBLIC - STATE OF COLORADO
NOTARY ID 20214021632
MY COMMISSION EXPIRES JUN 4, 2025

Transmission Issues and Recommendations for Duke's Proposed Carbon Plan

Jay Caspary

Vice President

Grid Strategies LLC

OVERVIEW

Transmission assumptions in the North Carolina Utilities Commission's Carbon Plan are critically important given the flexibility and optionality provided by increased grid connectivity that cannot be realized by generation and demand response resources. A strong electric transmission network provides significant options that will benefit customers; these options will not be realized by relying on incremental expansion planning, especially if those planning models are based on known commitments and do not reflect expected conditions for the future.

As discussed further below, I recommend that the North Carolina Utilities Commission ("NCUC" or "Commission") incorporate the following into its Carbon Plan and direct Duke to do the same in future proposed Carbon Plans:

1. Multi-Value Transmission Planning: Proactive, scenario-based, multi-value portfolios of transmission expansion projects, including Grid-Enhancing Technologies and advanced conductors, to identify bulk transmission upgrades to enable better integration of the DEC and DEP, as well as integration of renewable resources, particularly offshore wind. Transmission expansion upgrades need to be identified and vetted that would accelerate the effective integration, consolidated operations, and joint dispatch of DEC and DEP resources. New and upgraded transmission infrastructure should be "rightsized" in anticipation of future needs.[1]

2. Collaborative Planning Studies: Leverage the results of improved collaborative planning efforts with neighboring systems such as the ongoing Southeastern Regional Transmission Planning (SERTP) process, future North Carolina Transmission Planning Collaborative (NCTPC) studies, as well as the Atlantic Offshore Wind Transmission Study.

[1] In transmission planning, "rightsizing" generally refers to upsizing to a higher voltage class, multiple circuits, or higher capacity equipment when it comes to the bulk power system given the large economies of scale.

3. Advanced Transmission Technologies: Planning decisions regarding long range transmission expansion need to take full advantage of existing assets and corridors. Further, these asset management planning practices should be informed by transparent assumptions. The Duke electric power systems in the Carolinas have an opportunity to capture benefits for both DEC and DEP customers with effective planning and strategic decisions regarding the upcoming replacement of aging assets in, around and between the two systems.

4. Regional Integration: Rigorous analysis and assumptions regarding projects and costs to support future resource needs; in particular, imports and offshore wind developments that may be best addressed in partnership with neighboring systems. Collaborative planning between Duke and its neighbors, such as Dominion, can lead to efficient and resilient transmission infrastructure for new renewable resources such as offshore wind to serve the needs of both systems.

In addition, I recommend that the Commission synchronize development of its Carbon Plan with transmission planning processes in the interests of efficient least-cost planning. Furthermore, the NCUC should direct Duke in its next proposed Carbon Plan to make changes to existing processes to expand the planning horizon and scope of the SERTP process and NCTPC studies to address 20-year holistic planning studies with due consideration of transmission expansion to mitigate system stress associated with extreme weather, physical or cybersecurity threats. In addition, the NCUC should direct Duke to make changes to existing processes to incorporate non-traditional solutions such as system reconfiguration alternatives and other Grid-Enhancing Technologies (GETs). Duke need not wait on mandates from FERC, but should rather work with neighbors and stakeholders to revise its planning processes in a proactive manner.

STUDY ASSUMPTIONS

Transmission cost assumptions for new resources as part of the Duke proposed Carbon Plan vary significantly. As expected, the transmission integration cost assumptions for every resource option in the portfolio of Duke's expansion plan are a very small portion of the total resource costs. While the cost of transmission is small compared to capital requirements associated with resource development as expected, the flexibility and optionality provided by robust transmission expansion to grid operations and future expansion must be considered in any long-term plan.

While the transmission cost assumptions associated with solar and hybrid solar/storage in DEC and DEP are identical, substantial differences are noted for onshore wind with incremental transmission expansion costs for DEC compared to DEP, but that can be expected due to the relative proximity of offshore resources.

Transmission expansion costs for offshore wind in DEP show significant economies of scale beyond 1600MW of resource expansion, which is expected given the lumpy nature of transmission expansion.

The assumptions regarding transmission expansion costs for all other resources, e.g., batteries, pumped storage, SMRs, Advanced Nuclear with Internal Storage, and CTs, are constant with DEP costs being about 10% higher than DEC costs, which is unremarkable.

Transparency is critical for long range transmission expansion planning to be effective. Terminology needs to be used consistently for transmission expansion projects. Terms such as “Reconductor,” “Upgrade,” and “Rebuild” to describe projects which increase capabilities of existing assets must be standardized across all processes. For example, the four upgrades shown on slide 35 from the TAG Meeting June 27, 2022, appear to be complete rebuilds, rather than simply reconductoring which is noted in the “Upgrade” column.

The inputs and results of the NCTPC 2021 Public Policy Study published May 23, 2022, were reviewed to validate the transmission expansion assumptions for the onshore, offshore and large battery projects in Duke’s proposed Carbon Plan.

As demonstrated by recent studies as well as experience in other jurisdictions, proactive transmission planning is a necessary component of any plan to support integration of renewable resources to achieve decarbonization goals and mandates for the bulk power system. Commitments to proactively expand transmission capacity will result in the timely and efficient procurement of the highest quality renewable resources at the lowest cost to consumers. Even though past practices iterate between resource plans and transmission plans, it would be much more efficient to plan resources and transmission at the same time to develop optimal plans.

In conclusion, the cost assumptions for transmission expansion associated with new resources in Duke’s proposed Carbon Plan appear to be reasonable, with transmission being a small fraction of the total costs for new resources. The costs reflect economies of scale which should be expected for large offshore wind developments due to the lumpy nature of major transmission expansion projects. Major transmission projects show tremendous economies of scale in terms of power density in corridors, as well as the design and small incremental costs for structures to support adding a second circuit or even higher voltage ultimate operation in the long term without considering the advantages of advanced transmission technologies which are proven and being used more regularly to maximize the value of assets.

GENERAL RECOMMENDATIONS

Decisions regarding transmission must be part of co-optimization of integrated long term planning efforts that are pro-active and holistic, rather than an afterthought or an add-on to otherwise isolated power supply resource plans. An iterative approach may be required to identify optimal expansion plans given the lack of software tools and robust algorithms to solve these complex issues.

Electric power transmission is a critical component of the bulk power system whose value is too frequently discounted. A coordinated and collaboratively planned transmission network is a tremendous asset that can enable efficient and effective decisions regarding future supply options. Transmission enables and defines markets. The lack of robust transmission capability can be very costly, not only in terms of limiting supply choices, but also in limiting the flexibility that such robust capability provides for system operations to accommodate necessary rebuilds to replace aging infrastructure as transmission lines approach the end of life. The insurance value of robust transmission can be very significant during extreme weather, physical or cybersecurity events.

Transmission is lumpy with tremendous economies of scope and scale that need to be leveraged by utilities who may be reluctant to work with neighboring systems to achieve the potential benefits of larger regional network solutions.

Based on my observations of resource plans that follow best practices, it seems clear that significantly more clean energy developments will provide better solutions regarding resource plans and that would result in the ability to realize even better economies of scale with more efficient and effective bulk transmission expansion projects. To that end, the NCUC should take actions to accelerate Duke's efforts regarding better regional integration.

The interfaces between power systems are sometimes referred to as "seams." Coordination between transmission service providers to manage flows on the power system network can be a challenge. Seams issues and affected system study costs can be very large and must be considered in any resource planning decisions. Yet, the Duke Carbon Plan gives seams issues and related costs very little consideration, other than a short section regarding the cost to import resources from PJM based only on approved transmission service rates.[2] While these other costs can be difficult to quantify absent detailed studies, assessments can be made in collaboration with neighbors. The cost of affected system studies can very well drive business decisions for projects. The challenges with planning generation interconnection upgrades as well as cost responsibilities for network upgrades on or around the seam of adjacent systems may be difficult problems to solve, but they can be addressed if transmission service providers are willing to work together. Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) are providing some leadership on effective joint planning to displace reactive affected system impact studies with the proactive identification of backbone upgrades to fix their long-standing seam issues.[3] Addressing seams issues can be difficult between grid operators with different tariffs, business practices, market designs, etc. Merging Balancing Authorities provides a foundation for grid operators to capture significant benefits between systems that have struggled due to seams issues and the lack of diversity in resources, loads, etc.

Import and export limitations are critical, and it is important that these assumptions are reasonable when it comes to assessments to support integrated resource planning decisions.

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[2] Duke Proposed Carbon Plan, Appendix P, pp. 22-23.

[3] *See* https://www.misoenergy.org/stakeholder-engagement/committees/miso-spp-joint-targeted-interconnection-queue-study/.

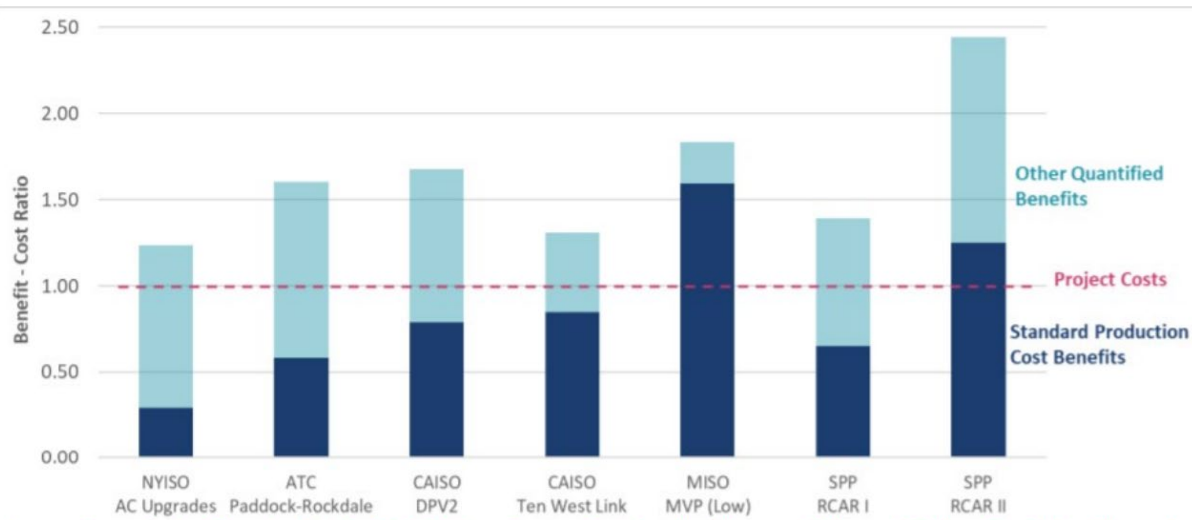
While it may not be appropriate to extrapolate historical imports/exports for planning purposes, that historical data can provide insights regarding the system's capability that may not be reflected in planning assumptions. EIA historical transactions data is posted separately for Duke Energy Carolinas, and the eastern and western systems of Duke Energy Progress. This data can help with investigating the merits of improved connections between the separate systems within Duke's North Carolina territory and help determine if they need to be considered as one unit for long range planning purposes. A quick analysis of the aggregate data demonstrates that the Duke systems in the Carolinas have been able to import more than 2,000MW in periods near peak winter demand in mid-January of 2018. Extreme weather events are easy to predict many days in advance and power system operations commit resources well in advance of need to ensure availability of critical resources during peak consumption periods. It is no surprise that Duke was importing significant amounts of power near peak demands as weather fronts move across the southeast and mid-Atlantic states, because utilities pre-position their fleets in advance to accommodate forecasted peak demands. Neighboring utilities typically have excess capacity in periods adjacent to their own coincident peaks. This fact provides opportunities for adjacent systems to exchange capacity and energy, which will improve system reliability and resilience and allow a reduction in reserves and capacity sharing which should lower customer costs. The bulk power system is a very valuable asset to move capacity and energy.

Seasonal diversity exchanges were commonplace decades ago to leverage the resources in power supply fleets and achieve load diversity. An efficient and effective bulk power system should take advantage of that diversity, but it's only available as a result of adequate transmission planning and expansion projects to capture those benefits. The flexibility provided by extra high voltage (EHV) transmission capability is extremely valuable for the interconnected system during periods of stress. That applies within the Duke North Carolina systems, as well as with its neighboring systems in PJM, TVA, Southern Company and others. Indeed, FERC is expected to draft a methodology to determine minimum interregional transmission capabilities in the upcoming NOPR on interregional planning. Duke could provide some leadership in this area and be proactive in driving these efforts to the benefit of its customers and decarbonization of the future grid. The NCUC should anticipate the impacts of the FERC NOPR and its impact on the final Carbon Plan and should participate in the FERC rulemaking process to the extent appropriate and feasible. At a minimum, the NCUC should not rush to adopt a Carbon Plan in this proceeding that relies too heavily on assuming very low regional integration.

Robust transmission expansion provides operational benefits which are not captured with traditional planning models and tools. Traditional planning models reflect all lines in service, normalized load patterns, and units dispatched at maximum generating capabilities which create unrealistic models of the future. These "pristine" models--that are overly optimistic in terms of facility availabilities--are typically the basis for long-term reliability and economic transmission expansion planning simulations. Reliability and economics are inseparable when it comes to the value proposition of prudent transmission expansion planning. Today's transmission expansion project to address a reliability need, based on existing reliability standards, provides economic benefits to support grid operations. Conversely, economic upgrades in the near term will also provide reliability benefits that are difficult to quantify since operating conditions rarely mirror planned scenarios. The benefits associated with the flexibility and optionality provided by a strong electric transmission network are significant and will not be realized if incremental least cost planning is performed with limited planning horizons, particularly if those do not align with corporate, institutional, state and municipal commitments to decarbonize their electric power supply resources by a date certain, as is the case following enactment of HB951.

The actual benefits of transmission expansion are typically much larger than those projected in economic planning assessments. It's important that due consideration be given to all the benefits that can be provided from an optimally-designed transmission network to customers as part of any long-range system plan. The following graph from the "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs" report[4] published by Brattle and Grid Strategies demonstrates how quantifying benefits above typical adjusted production costs are critically important to realize effective planning decisions:

FIGURE 5. BENEFIT-COST RATIOS OF TRANSMISSION PROJECTS WITH AND WITHOUT A BROAD SCOPE OF BENEFITS



Source: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (brattle.com)

The NCUC must capture the value of transmission in its Carbon Plan, and can leverage recent frameworks and case studies presented by Telos for ESIG,[5] as well as the Brattle/Grid Strategies findings for ACORE. In the recent FERC NOPR in Docket RM21-17, FERC has identified 12

[4] https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf

[5] https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf

(twelve) benefit metrics that could be considered as part of prudent transmission expansion planning.[6] Assessments to quantify the value of transmission expansion understate the actual value of those investments. As demonstrated by SPP's latest "The Value of Transmission" study, every dollar spent on transmission expansion in SPP returns at least $5.24 in actual benefits, despite planning studies which justified those projects resulting in their approvals only identifying a fraction of that value.[7] While the benefits of effective regional planning include the capital savings from avoiding and/or deferring local reliability upgrades due to better, long term solutions, there are operational savings such as reductions in reserves, lower system losses, as well as the ability to accommodate better maintenance and rebuild schedules to name a few. These considerations are important attributes of a portfolio of least-regrets, transmission expansion projects which maximize net benefits for consumers.

Asset replacement has become a major issue as it now drives capital budgets for transmission projects in most, if not all, utilities. The Duke electric power systems in the Carolinas have an opportunity to capture benefits for both DEC and DEP customers with effective planning and strategic decisions regarding the upcoming replacement of aging assets in, around, and between the two systems. Planning for infrastructure must have a long-term focus and incorporate reasonable assumptions regarding the remaining life of transmission lines, particularly those in critical corridors. Transmission planning to address future needs must take advantage of asset management information to better inform investment decisions. Planning should not just incorporate asset management decisions as an input into its studies, but rather those efforts need to work together in a proactive, holistic manner to identify opportunities for "rightsizing" aging assets that can defer or displace traditional transmission expansion needs from conservative planning assessments done in isolation. A particular focus on critical corridors is warranted to ensure that transmission expansion plans are not short-sighted, focusing only on local needs, but also support the long-term needs for a decarbonized grid in and around Duke's system in the Carolinas.

Effective interregional planning is a critical success factor for efficient offshore wind development and integration. The economic benefits of proactive, coordinated interregional planning for significant offshore wind development scenarios warrant investigation and understanding to ensure that resource plans are prudent. Coordinated planning with Duke and Dominion to integrate offshore wind resources in southern VA and northern NC can be expected to result in large benefits to customers of both systems. Cost effective, collaborative plans should be encouraged for both the optimal wet and dry network designs to harvest and integrate offshore resources for coordinated transmission expansion developments in southern VA and northern NC. Investing in the transmission infrastructure to support offshore wind

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[6] See Paragraph 185+ starting at page 161 of NOPR for RM21-17 that is posted at https://www.ferc.gov/media/rm21-17-000

[7] See "The Value of Transmission" (2021) SPP Study reviewed by the Brattle Group. https://www.spp.org/value-of-transmission

developments in southern VA and northern NC will provide tangible benefits to the larger transmission grid. Even if offshore wind developments are not part of the near-term resource plans, increased connectivity between Duke and Dominion will provide tremendous value by capturing operating efficiencies that will set up for longer term optionality regarding supply options.

FUTURE PLANNING

The FERC NOPR on **Building for a Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection**[8] in Docket RM21-17 issued April 21, 2022, has important implications for optimal system planning. As proposed, the NOPR will require 20-year holistic planning studies which are proactive, scenario-based and consider low-frequency, high-impact events such as extreme weather events. To that end, the NCUC should direct Duke to engage in the SERTP planning process to identify more efficient, cost-effective regional transmission solutions to facilitate meeting the Carbon Plan targets. In addition, to improve the planning process, the NOPR will require the incorporation of Dynamic Line Ratings (DLR) and Power Flow Controllers into planning processes to leverage proven technology and maximize the utilization of existing transmission assets without sacrificing reliability. While the use of DLR can improve operational efficiencies, allowing grid operators to better manage congestion and minimize curtailments of non-dispatchable renewable resources, it will take time to deploy sensors and collect data to update parameters used in static normal and emergency ratings to reflect actual and expected ambient conditions for long range planning studies. The NOPR will also adopt enhanced transparency between local and regional transmission planning to allow "rightsizing" of replacement facilities. Given the broad benefits of robust transmission that facilitates markets, FERC has identified 12 benefit metrics that could be considered in decisions regarding future transmission expansion.

Although comments to this FERC NOPR are not due until mid-August, it would be useful to understand Duke's initial reaction to some of the above key provisions to reform transmission planning. The NCUC should direct Duke to, in its next proposed Carbon Plan, make changes to existing processes to expand the planning horizon and scope of NCTPC to address 20-year holistic planning studies with due consideration of transmission expansion to mitigate system stress associated with extreme weather, physical or cybersecurity threats.

In the NOPR on **Improvements to Generator Interconnection Procedures and Agreements**[9] in RM22-14 released June 16, 2022, FERC is proposing that Transmission Service Providers evaluate Alternative Transmission Technologies. FERC expects that Grid-Enhancing Technologies (GETs) be considered to facilitate the timely integration of new resources stuck in existing generator-interconnection queues. GETs are advanced transmission technologies such as dynamic line ratings, advanced power flow controllers and topology optimization that

[8] https://www.ferc.gov/media/rm21-17-000
[9] https://www.ferc.gov/media/rm22-14-000

leverages sensors and algorithms to better manage flows and congestion of the bulk power system. GETs can also include "Storage as Transmission" that may be a preferred solution as part of an optimal portfolio of transmission expansion projects. The NCUC should direct Duke to, in future proposed Carbon Plans, make changes to existing processes to incorporate non-traditional solutions such as system reconfiguration alternatives and other GETs.

These recent FERC NOPRs will establish minimum study requirements for future planning and generation interconnection studies that are expected to improve and accelerate development of the future grid. Duke need not wait on mandates from FERC but should rather work with its neighbors and stakeholders to revise its current planning processes in a proactive manner. Duke and its stakeholders need to ensure that any revisions to future planning and tariff service processes are not merely "checking a box" to comply with new requirements but are necessary enhancements to improve long term system planning and operational needs of the future grid.

Affected system studies are important, and Duke notes that the potential cost impacts associated with affected system study costs have not been considered in these analyses. Plans must consider alternatives based on holistic assessments of options and those must consider affected system impacts. While it is difficult to address cost allocation given current processes, progress can be made determining "no regrets" solutions in effective joint planning studies such as the Joint Transfer Interconnection Queue (JTIQ) study[10] which is being finalized now between MISO and SPP after a 2-year study process. NCUC should consider JTIQ as a template for future joint long-range planning studies that can replace, or at least mitigate, the uncertainties and risks to developers associated with affected system studies, which identify long range backbone upgrades that will benefit everyone and not just the generators that are currently being assigned cost responsibilities based on tariff processes. The current transmission planning process in almost all regions, or as demonstrated in the proposed Carbon Plan, will never identify a portfolio of backbone transmission expansion projects to address long term needs because it will always proceed incrementally with smaller projects triggered by the next tranche of resource procurements. Unlike past joint planning efforts which were driven by affected system study provisions in existing tariffs and joint operating agreements, the JTIQ was a forward-looking collaborative, joint planning effort to identify major transmission expansion projects which benefit both SPP and MISO and will help to address decarbonization efforts for both systems and their customers.

Duke needs to lead the way for collaborative planning with neighbors through the North Carolina Transmission Planning Collaborative, SERTP, and other appropriate forums to create an efficient and effective long-range plan to address future planning needs.

Beyond local and regional planning needs, Duke needs to expand its engagement in the NREL-led Atlantic Offshore Wind Transmission Study[11]. The Atlantic Offshore Wind Transmission

[10] https://www.spp.org/engineering/spp-miso-jtiq/
[11] https://www.nrel.gov/wind/atlantic-offshore-wind-transmission-study.html

Study is evaluating coordinated transmission solutions to enable offshore wind resource deployment along the US Atlantic Coast from Maine to South Carolina. Duke should be working with Dominion and others in this study effort to determine optimal offshore developments near the Carolinas to support potential collaborative and coordinated plans to address future needs. Duke needs to provide transparency regarding input into key study assumptions for stakeholders to support the study findings and conclusions, and then determine how to incorporate those results into future proposed Carbon Plans. In addition to study inputs, scenarios and sensitivities should be studied as part of this study and other collaborative efforts to help frame future Duke proposed Carbon Plans and inform decisions regarding the merits and timing of offshore wind development to support Duke's needs.

Synchronizing the inputs, findings and conclusions of planning studies can be a challenge, but it is an important step in making sure that planning evolves and that we can apply the key findings from related efforts, even if assumptions and scenarios do not align. The NCUC could facilitate more transparency and active engagement by all stakeholders in the planning process by sponsoring a workshop to better understand current processes regarding maintenance and rebuild practices. The objective of that initial effort would be to establish a common understanding of existing utility practices and identify reforms which would create a solid foundation for rightsizing select facilities in key corridors. The findings in the **Report on the NC 2021 Public Policy Study May 23, 2022 FINAL REPORT** will need to be incorporated into the next Duke proposed Carbon Plan. Affected system studies are problematic and reforms in that regard are expected from FERC, given recent developments as well as the progress of the MISO-SPP JTIQ study. For its Carbon Plans, the NCUC should direct Duke to incorporate the results of long-range joint studies with other utilities and stakeholders to determine optimal expansion plans in lieu of affected system studies. It is important for plans of alternative portfolios of resource options to reflect a reasonable range of costs to collect and deliver 1600MW of offshore wind into the New Bern 230kV Substation. It appears that existing 230kV facilities are in a key corridor from Duke's backbone transmission system near Raleigh into New Bern and that those lines would be good candidates for "rightsizing" that might address future long term needs and support integration of offshore wind, as well as the DEC and DEP systems. The condition of those facilities (and the long-term plan regarding their replacement/upgrade) needs to be part of any future Carbon Plan.

From **Appendix P of the Carolinas Carbon Plan, Transmission System Planning and Grid Transformation**, pages 14-15, the status of the initial set of "red zone" upgrades shown in Table P-3 needs to be resolved as soon as possible. These upgrades seem to be a reasonable start to provide some certainty for developers to submit competitive proposals so that Duke can be expected to achieve its decarbonization goals within the next decade. Risks regarding proposed project developments translate to higher price offerings, which can be mitigated to a large extent with respect to interconnection costs for renewable projects, especially as it relates to high quality resources in relatively weak portions of the bulk power system. Although Duke is proposing to incorporate Red-Zone Transmission Expansion Plan (RZEP) projects "into the Local

Transmission Plan by mid-year 2022" and they represent an important first step towards resolving constraints, it's critically important to note that these upgrades will not address long term needs. It's important to understand which of these RZEP should be candidates for "rightsizing" and how much incremental capacity at what incremental cost can be expected to result. The ability to "rightsize" key facilities will depend upon many factors including the size of existing ROWs as well as the potential consideration of transmission designs to increase power densities. The existing 230kV facilities from Robinson Plant – Rockingham – West End – Cape Fear, especially given the parallel Robinson Plant – Rockingham 115kV line that also is projected to overload, transverse the high-quality solar zones and appear to be an excellent candidate for "rightsizing."

In addition to "rightsizing" upgrades to address long term needs to support decarbonization targets, Duke needs to give serious consideration to the use of advanced conductors to increase the capability of existing lines without upgrading existing structures, if appropriate. Regarding "reconductoring" projects, Duke needs to give serious consideration to the use of high temperature, low sag composite core conductors ("Advanced Conductors"), such as ACCC or TS Conductor, as an alternative to traditional ACSR. While reconductoring with Advanced Conductors has a cost premium, the ability to leverage existing towers can greatly accelerate renewable project integrations as reported in **Advanced Conductors on Existing Transmission Corridors to Accelerate Low Cost Decarbonization.**[12] In some cases, existing structures, not just conductors, need replacement. Then, a rebuild using Advanced Conductors needs to be considered since that design can be expected to result in fewer and shorter structures that can more than offset the cost premium associated with the conductor choice. Advanced Conductors provide greater efficiency/lower losses and higher loadability to help with extreme weather/resilience events, which are notable benefits that may not be considered as part of conductor selection.

In the recent Order in Dockets NO. E-2, SUB 1297 and E-7, SUB 1268, the NCUC has asked parties to comment in the Carbon Plan proceeding on the need for the inclusion of the RZEP projects to achieve the goals of the Carbon Plan and H951. Proactive planning has been a demonstrated success in transmission expansion to support renewable project integration in several jurisdictions, e.g., ERCOT CREZ, MISO MVPs, etc. Most recently, the Colorado Public Service Commission approved the high-capacity, backbone Power Pathway 345kV double circuit project to support efficient and effective wind/solar development and integration to realize decarbonization mandates in that state. That major transmission expansion project will allow Xcel Energy's Public Service of Colorado to address the challenge of the "chicken or the egg" to the benefit of its customers and the ability to achieve carbon reduction targets. Timing can be a challenge given tariff processes, but the fact that Duke's analyses continue to show these facilities as upgrades in numerous generation interconnection studies provides evidence that

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[12] https://gridprogress.files.wordpress.com/2022/03/advanced-conductors-on-existing-transmission-corridors-to-accelerate-low-cost-decarbonization.pdf

these RZEP should be considered “no regrets” projects that will facilitate decarbonization of the grid. As appropriate, the scope of these projects should consider “rightsizing” in initial design to support longer term needs. One of the key lessons from the approved portfolios of transmission expansion projects in many jurisdictions is that new facilities are oversubscribed upon energization and clearly inadequate for long term needs.

Duke notes that there is no available import capability from DEC to DEP on page 16 of the Appendix P. Transmission expansion upgrades need to be identified and vetted which could accelerate the effective integration, consolidated operations and joint dispatch of DEC and DEP. In addition to rightsizing and future-proofing select lines in key corridors, Duke needs to give serious consideration of the effective deployment of GETs or Advanced Conductors to facilitate grid decarbonization efforts. Duke should evaluate the merits of deploying GETs, such as Dynamic Line Ratings, Advanced Power Flow Controls or Topology Optimization, to address project system overloads/congestion and/or accelerate the integration of renewable resources in advance of planned transmission expansion projects. As a next step, Duke should consider the merits of deploying GETs in lieu of $200M+ for 100kV upgrades identified on 5 lines in the 2021 Public Policy Study. Similarly, Advanced Conductors should be considered for future reconductors, as well as uprates of existing lines to higher operating temperatures to address known clearance issues.

GETs can also enhance the value of, and provide operational flexibility to complement, major transmission expansion projects too. For example, lower voltage facilities tend to limit the value of major backbone projects in operations that may not even be considered in planning efforts. This is especially true given outages to replace/rebuild aging facilities that create congestion for existing and proposed resources. GETs can be deployed and redeployed as the grid evolves to manage system flows and congestion. GETs can even become part of permanent solutions too, as appropriate. RZEP identifies the need to rebuild both the 115kV and 230kV circuits between Robinson Plant and Rockingham. Duke and the NCUC should consider non-traditional solutions not only because they are likely to lead to a least-cost path to the HB951 carbon-reduction targets in the near term, but also provide benefits in addressing longer term needs and leveraging those facilities in that key corridor.

NEW OPPORTUNITIES TO DRIVE CHANGE

As a result of the Bipartisan Infrastructure Law, significant resources are now available to Duke and others to support future grid developments. Further, on July 6th the DOE released the first $2.3 Billion Formula Grant under the Building a Better Grid Initiative. Duke needs to work with DOE and other partners to fully capitalize on the grants and other programs in the new Building a Better Grid Initiative. Additional provisions to enhance transmission expansion such as a large Investment Tax Credit (ITC) for qualifying major transmission expansion projects are being considered in current budget reconciliations. An ITC would be expected to have a profound impact on the payback for major transmission expansion projects which could easily justify “rightsizing” and future proofing select projects in critical corridors. For example, in select corridors such as the 230kV upgrades shown for the path from Robinson Plant – Rockingham – West End – Cape Fear Plant on slide 44 from the TAG Meeting June 27, 2022 meeting, Duke needs to assess the feasibility and value of future optionality in building initial structures that can support a second 230 or even 500kV circuit in the same corridor to support long term planning needs. DOE resources may be available to support non-traditional transmission expansion solutions which would provide long-term benefits to Duke and its customers.

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Experience

- **Sept 2020 – present Grid Strategies LLC**
- **Vice President**

Leveraging 40+ years of utility and RTO experience to assist clients in realizing a clean energy future grid that is efficient, effective, secure and resilient

Co-author Brattle and Grid Strategies report filed in FERC RM21-17 entitled "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs"

Participated at North Carolina Utility Commission technical conference on Duke's 2020 IRP

Filed answer testimony in support of Clean Power Pathway in Colorado PUC CPCN docket

Filed testimony in support of Gateway South CPCNs at the Wyoming and Utah commissions

Co-author ACEG papers including "Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure" regarding FERC Order 1000 reforms and "Disconnected: The Need for New Generator Interconnection Policy"

WATT Coalition support including lead role in "Unlocking the Queue" which was a Grid Enhancing Technologies (GETs) case study in KS and OK for 2025

Team leader for ESIG workshops and white paper on "Transmission Planning for 100% Clean Electricity"

- **2001 - 2020 Southwest Power Pool**
- **Director – Research, Development & Tariff Services (RDTS)**

Manage research projects and funding priorities for SPP while providing strategic consulting for SPP executives and management

Direct RDTS staff in support of programs and projects to support strategic objectives of SPP - Dynamic Line Rating pilot projects with AEP and Sunflower Electric, PMU deployment roadmapping, special studies like High Priority Incremental Load Study (HPILS), Value of Transmission, WAPA/Basin IS integration

Direct all customer requested service studies including generation interconnections, transmission service and congestion hedging

Co-lead for Technical Review Committee for DOE-funded, NREL-led Interconnections Seam Study

Member of EPRI Grid Operations, Planning and Renewable Integration Leadership Team

Steering Committee for TransGrid-X 2030 Symposium at Iowa State University

U.S. Representative on CIGRE C1.35 and C1.44 evaluating merits of a global electric grid

2012 – 2013 Senior Policy Advisor – U. S. Department of Energy in Electricity Delivery and Energy Reliability (OE)

Educate DOE and agency staff on grid operations and planning
Serve on Grid Tech Team
Recommend changes in research priorities and organizational structure of OE
Member of WAPA Joint Outreach Team to facilitate grid modernization

Director – Transmission Development / Engineering

Led transmission expansion policy development within SPP and beyond, as well as strategic and other benefit assessments for EHV transmission.
Led inter-regional coordinated and collaborative planning studies, Eastern Interconnection Planning Collaborative (EIPC), WECC TEPPC, SWAT, SIRPP, etc.
Represent SPP on the Technical Review Committees for the Eastern Wind Integration and Transmission Study (EWITS) sponsored by DOE/NREL, as well as Nebraska Power Association Wind Integration Study, and several ARRA funded projects for EPRI, et al.
Chair EPRI Program 173: Enabling Transmission for Large Scale Renewables
Staff Secretary for SPP's Design Best Practices and Performance Criteria Task Force which led to SPP's design standards including 3,000 Amps for new 345kV regionally funded lines
Direct activities of the Technical Studies & Modeling, Planning and Tariff Studies Sections of t Engineering Department at SPP
Direct development of SPP's EHV Overlay plan, as well as Wind Penetration Study
Develop/Manage Engineer-In-Rotation program for all engineering groups at SPP
Led implementation of Economic Upgrades within SPP, e.g., Westar's Wichita – Reno Co – Summit 345 kV and KETA's Spearville – Knoll – Axtell EHV projects
Chair ISO/RTO Council Planning Committee
Development and implementation of the SPP Transmission Expansion Plan (STEP)
Develop process and template for economic transmission expansion planning
Initiate and direct coordinated planning activities, e.g., ERCOT/SPP Joint Study
Represent SPP on NERC Transmission Issues Subcommittee (TIS) and RAS

- **1981 – 2000** **Illinois Power**

Increasing levels of responsibility beginning with System Planning, and expanding expertise in Energy Supply, Regulatory Services, and Retail Marketing. Began career in Transmission Planning performing technical analyses as well as serving as IP's representative on the MAIN Engineering Committee, supporting Research & Development, negotiating and implementing the nation's first retail wheeling pilot program with industrial customers and transitioning interruptible customers to real time pricing tariffs, and then working with utilities and legislatures to get approval of retail choice in Illinois prior to developing and implementing marketing plans for commercial and industrial customers.

Education

University of Illinois	Bachelor of Science in Electrical Engineering with a Power Systems emphasis
Iowa State University	Course requirements for a Masters of Engineering

Memberships

2009 – Present Institute of Electrical and Electronics Engineers
2009 - Present Power and Energy Society
2016 – Present CIGRE

Awards

2011 UWIG Achievement Award for the advancement of transmission planning and markets in the SPP footprint, *Utility Wind Integration Group*

2012 Technology Transfer Award for DOE Integration of Southwest Power Pool Wind by Southeast Utilities, *Electric Power Research Institute*

2017 UVIG Service Award for 11 years of service to the UVIG Board of Directors, *Utility Variable-generation Integration Group*

2019 Sullivan Alumni Association Hall of Fame Award, Sullivan Illinois

2020 Honorable Mention Energy Central's Leaders in Innovation in the Electric Power Industry

2020 Electric Power Research Institute Power Delivery and Utilization Sector Transmission Operations and Planning Advisory Leadership award for outstanding contributions to the Transmission Operations and Planning Advisory Leadership Team from 2010 to 2020

Service Activities

2009 – 2012 NERC Integrating Variable Generation Task Force, Task 2.3 BA Services and Coordination Chair

2009 – 2020 Industry Advisory Board for Power Systems Engineering Research Center (PSERC) and GRid-connected Advanced Power Electronics Systems (GRAPES), including Chair for each organization

2009 – 2020 Member of Electric Power Research Institute Grid Planning & Operations Leadership Team

2016 – 2018 U. S. Department of Energy, Electricity Advisory Committee

2021 NSF Innovation-CORPs Midwest Cohort Industry Mentor for Bastazo

2021 - Present Member of SPP Independent Expert Panel (IEP)

2022 Chair of EUCI's GETs Fundamentals symposium, February 2022

2022 Chair of Infocast's Transmission Planning and Interconnection Summit, Arlington VA, June 2022

2022 Member of ESIG Transmission Benefits Valuation Task Force which published *Multi-Value Transmission Planning for a Clean Energy* report

Publications

Jay Caspary et al, *Unlocking the Queue with Grid-Enhancing Technologies: Case Study of the Southwest Power Pool,* CIGRE Paris, August 2022

Jay Caspary and Ted Bloch-Rubin, *A transatlantic perspective: unlocking the queue for renewables*, European Energy & Climate Journal, February 2022

Michael Goggin, Rob Gramlich, Jay Caspary, Jesse Schneider, *Fleet Failures: How Interregional Transmission Keeps the Lights on When Generation Fails*, November 2021

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Rob Gramlich, Michael Goggin, Jay Caspary, Jesse Schneider, Johannes Pfeifenberger, Kasparas Spokas, J. Michael Haggerty and John Tsoukalis, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, October 2021

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Bowman, D., McCann, R., Subramanian, D., Farantatos, E., Gaikwad, A., and Caspary, J., *SPP Grid Strength Study with High Inverter-Based Resource Penetration*, North American Power Symposium, 2019

Caspary, J., Bowman, D., Dial, K., Schoppe, R., Sharp, Z., Cates, C., Tanner, J., Ruiz, P. A, Li, X., and Tsuchida, T.B., *Application of Topology Optimization in Real-Time Operations*, CIGRE US National Committee 2019 Grid of the Future Symposium, 2019

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Caspary, J., and Waldele, B., *Leveraging Technology: Maximizing Value in the Bulk Power Industry [In My View]*, IEEE Power and Energy Society Magazine, November/December 2016

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Caspary, J., Power Engineer Profile, *IEEE-USA Today's Engineer*, June 2011

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 179

In the Matter of: Duke Energy Progress, LLC and Duke Energy Carolinas, LLC 2022 Biennial Integrated Resource Plans and Carbon Plan	))))))	Verification of Jay Caspary

VERIFICATION

I, Jay Caspary, first being duly sworn, say that I am employed as the Vice President of Grid Strategies, LLC and have read the foregoing **Transmission Issues and Recommendations for Duke's Proposed Carbon Plan**, and know the contents thereof; and that the contents are true, accurate and correct to the best of my knowledge, information, and belief.

Jay Caspary
Signature

STATE OF Arkansas

COUNTY OF Cleburne

Signed and sworn to (or affirmed) before me this 14 day of July, 2022.

Vicki Morgan
Signature of Notary Public

Vicki Morgan
Printed or Typed Name of Notary Public

My Commission Expires: 08/22/2024

[Official Seal or Stamp]

Vicki Morgan
State of Arkansas
County of Cleburne
Commision #12401918
Expires 08/22/2024