PUBLIC (REDACTED) VERSION

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 190

In the Matter of:	)	
Biennial Consolidated Carbon Plan	)	**DIRECT TESTIMONY OF**
and Integrated Resource Plans of	)	**EVAN HANSEN ON**
Duke Energy Carolinas, LLC, and	)	**BEHALF OF**
Duke Energy Progress, LLC, Pursuant to	)	**APPALACHIAN VOICES**
N.C.G.S. § 62-110.9 and § 62-110.1(c)	)	

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I. INTRODUCTION AND OVERVIEW

Q: PLEASE STATE YOUR NAME, JOB TITLE, AND BUSINESS ADDRESS.

A: My name is Evan Hansen, and I am the founder and president of Downstream Strategies, LLC, a consulting firm based in West Virginia. My business address is 911 Greenbag Road, Morgantown, WV 26508.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A: I am testifying on behalf of Appalachian Voices.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION")?

A: No.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY OTHER STATE UTILITY COMMISSIONS OR REGULATORY BODIES?

A: Yes, I have testified before the West Virginia Public Service Commission. In 2024, I provided testimony on behalf Potomac Hills Energy, LLC regarding the local economic benefits from construction of a solar-powered generating facility.[1] In 2017, on behalf of the Sierra Club, I submitted testimony related to water quality impacts from the placement of coal combustion residuals from the Grant Town Power Plant on former mine sites. This case centered on a power purchase agreement between Monongahela Power Company, a regulated utility, and American Bituminous Power Partners, L.P., which operated the plant.[2] In 2014, on behalf of the West Virginia Public Service Commission's Consumer Advocate

[1] Potomac Hills Energy, LLC, No. 24-0075-E-SCS-PW (W.Va. P.S.C.).

[2] Am. Bituminous Power Partners, L.P., & Monongahela Power Co., No. 17-0631-E-P (W.Va. P.S.C.).

Division, I provided testimony related to source water protection in the Commission's General Investigation into West Virginia American Water Company, following a chemical spill that contaminated its water distribution system.[3] In 2007, I submitted testimony regarding Trans-Allegheny Interstate Line Company's application for a Certificate of Convenience and Necessity for a 500-kV transmission line.[4]

Q: PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A: In 1988, I earned a B.S. in Computer Science and Engineering from Massachusetts Institute of Technology. I then worked as a consultant through 1995 at Tellus Institute/Stockholm Environment Institute-Boston, where I developed, provided training on, and applied computer tools for strategic planning related to energy demand and supply, greenhouse gas emissions, and water resources. In 1997, I earned an M.S. in Energy and Resources from the University of California, Berkeley. This interdisciplinary program combines economics, environmental science, public policy, and engineering. I founded Downstream Strategies in 1997, and I serve as president, overseeing a wide range of science, policy, planning, and economic development projects. I manage interdisciplinary research teams, perform quantitative and qualitative analyses, provide litigation support, and

[3] Gen. Investigation Pursuant to W.Va. Code § 24-2-7 Into the Actions of WVAWC in Reacting to the Jan. 9, 2014 Chem. Spill., No. 14-0872-W-GI (W.Va. P.S.C.).

[4] Trans-Allegheny Interstate Line Company, Application for a Certificate of Convenience and Necessity authorizing the construction and operation of the West Virginia segments of a 500 kV electric transmission line and related facilities in Monongalia, Preston, Tucker, Grant, Hardy, and Hampshire Counties, and for related relief., No. 07-0508-E-CN (W.Va. P.S.C.).

communicate results with policymakers, local leaders, private companies, and nonprofit organizations. My work has included policy analyses related to renewable energy and fossil fuels, assessments of environmental impacts related to energy infrastructure, development of plans for watersheds impacted by energy development, and detailed permit analyses. A copy of my Curriculum Vitae is attached as **Hansen Exhibit 1**.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to outline certain risks that the Commission should take into account as it considers the natural gas build-out in the 2023–2024 Carbon Plan and Integrated Resource Plan ("CPIRP") proposed by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke Energy"). My testimony generally focuses on the P3 Fall Base Portfolio.

Q: PLEASE EXPLAIN HOW YOUR TESTIMONY IS ORGANIZED.

A: My testimony is organized into two primary sections: (1) regulatory risks related to implementation of the U.S. Environmental Protection Agency's ("EPA") Clean Air Act ("CAA") Section 111 Rule,[5] and (2) other risks that affect the Companies' ability to secure sufficient natural gas at affordable cost to fuel their proposed build-out of natural gas-fired power plants. Both sections of my testimony focus on the P3 Fall Base Portfolio and relate to the Companies' ability to significantly increase

[5] *See* New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39798–40064 (May 9, 2024) (to be codified at 40 C.F.R. pt. 60) [hereinafter "CAA Section 111 Rule" or "Final Rule"].

generation from natural gas-fired power plants and coal plants that co-fire with natural gas, and to phase out coal-fired power plants on schedule, while complying with the objectives of House Bill 951: Energy Solutions for North Carolina ("HB 951")[6] and minimizing impacts on ratepayers.

Q: PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS TO THE COMMISSION.

A: Regarding regulatory risks, I find that the Companies' proposed P3 Fall Base Portfolio, which includes a significant build-out of natural gas-fired power plants, is risky because it does not comply with the CAA Section 111 Rule, which has now been finalized. Absent court action, the CAA Section 111 Rule is no longer a potential regulatory risk; it is now a regulatory certainty. Because the P3 Fall Base Portfolio uses significantly different assumptions for the operation of natural gas-fired power plants than what is required under the Final Rule, and because it runs certain coal-fired units longer than allowed by the Final Rule, I recommend that the Commission require the Companies to develop one or more new portfolios that comply with the CAA Section 111 Rule. Further, because the Companies' calculation of ratepayer impacts of the P3 Fall Base Portfolio uses assumptions that are not consistent with the rule, the portfolio's true cost to ratepayers is unknown. Therefore, I further recommend that the Commission require the Companies to assess the ratepayer impacts associated with all candidate portfolios that comply with the CAA Section 111 Rule.

[6] Session Law 2021-165, enacted N.C. Gen. Stat. § 62-110.9.

Regarding other risks, I find that there are several beyond the Companies' control that may affect their ability to secure sufficient natural gas, at a cost that minimizes impacts to ratepayers, to fuel their proposed build-out of natural gas-fired power plants. I recommend that the Commission account for these risks—and compare them to risks in any alternative portfolios that may be presented by other intervenors—when making a decision in this CPIRP proceeding.

Q: PLEASE IDENTIFY THE DOCUMENTS AND FILINGS ON WHICH YOU BASE YOUR OPINIONS.

A: My findings rely primarily upon DEP and DEC's August 17, 2023, and January 31, 2024, CPIRP and Supplemental Planning Analysis, and the testimony, supplemental testimony, exhibits, modeling, and discovery responses of its witnesses in this proceeding. I also rely on certain industry publications and publicly available information. The exhibits to my testimony include the following:

Hansen Exhibit 1	Curriculum Vitae of Evan Hansen
Hansen Exhibit 2	DEC and DEP Response to Appalachian Voices' Data Request 4-1
Hansen Exhibit 3	DEC and DEP Response to Appalachian Voices' Data Request 4-2
Hansen Exhibit 4	DEC and DEP Response to Appalachian Voices' Data Request 4-4
Hansen Exhibit 5	DEC and DEP Response to Appalachian Voices' Data Request 2-1
Hansen Exhibit 6	Gas and Oil Association of West Virginia Presentation to Joint Standing Committee on Energy and Manufacturing
Hansen Exhibit 7	Confidential DEC and DEP Response to Appalachian Voices' Data Request 2-5

Hansen Exhibit 8 Confidential DEC and DEP Response to Appalachian Voices' Data Request 3-7

II. ISSUES: NATURAL GAS SUPPLY AND HYDROGEN AND NEAR-TERM ACTIONS: SUPPLY-SIDE DEVELOPMENT AND PROCUREMENT ACTIVITIES – NEW GAS[7]

A. Regulatory Risks Related to Implementation of EPA'S CAA Section 111 Rule

Q: PLEASE PROVIDE AN OUTLINE OF THIS SECTION OF YOUR TESTIMONY.

A: This section of my testimony focuses on EPA's CAA Section 111 Rule, which provides carbon pollution standards for new natural gas-fired and existing coal-fired power plants. This rule is critically important to this CPIRP proceeding because the P3 Fall Base Portfolio includes a build-out of new natural gas-fired power plants as well as a schedule for retiring or modifying existing coal-fired power plants—and, significantly, because the P3 Fall Base Portfolio does not comply with the rule. My testimony first focuses on impacts of the CAA Section 111 Rule on the new natural gas-fired power plants that the Companies propose to build. It then explains how the rule impacts the Companies' proposed retirement schedule for certain coal-fired power plants. Finally, this section of my testimony considers interactions between new natural gas-fired power plants and existing coal-fired power plants in relation to the CAA Section 111 Rule.

i. CAA Section 111: Impacts on New Natural Gas-Fired Power Plants

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[7] Description of issues correlate with Nos. 6 and 9(d) of the Companies' Corrected Attachment 2, Index of Designated Issues in Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Direct and Supplemental Direct Testimony and 2023-2024 Carbon Plan and Integrated Resource Plan, Docket No. E-100, Sub 190 (May 14, 2024).

Q: PLEASE SUMMARIZE THE PORTION OF THE CAA SECTION 111 RULE THAT IS MOST RELEVANT TO THE COMPANIES' PLAN TO BUILD NEW NATURAL GAS-FIRED POWER PLANTS.

A: The CAA Section 111 Rule includes best systems of emission reduction for new natural gas-fired power plants by subcategory. Base load units, which have capacity factors of 40 percent or greater, will immediately need to adopt highly efficient generation and will need to implement 90 percent carbon capture and sequestration/storage ("CCS") by 2032. Intermediate-load units, which have capacity factors of between 20 and 40 percent, will need to adopt highly efficient generation. Low-load units will need to burn lower-emitting fuels.

Q: WHEN DID EPA PUBLISH THE CAA SECTION 111 RULE?

A: The EPA announced the final CAA Section 111 Rule on April 25, 2024, and the Final Rule was published on May 9, 2024 in the Federal Register with an effective day of July 8, 2024. However, the agency published the proposed version of the CAA Section 111 Rule almost a year earlier, on May 23, 2023.[8]

Q: DID THE COMPANIES ACKNOWLEDGE THE PROPOSED RULE IN THEIR FILINGS AND TESTIMONY?

A: While several components of the Companies' filings acknowledge the Proposed Rule, their model of the P3 Fall Base Portfolio did not account for it. These acknowledgements include a section in CPIRP Chapter 3 (Portfolios) called

[8] *See* New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33240–33420 (May 23, 2023) (to be codified at 40 C.F.R. pt. 60) [hereinafter "CAA Section 111 Proposed Rule" or "Proposed Rule"].

"Proposed Environmental Protection Agency Regulations" that highlights the Companies' submittal of comments on the Proposed Rule to the EPA.[9] CPIRP Appendix C (Quantitative Analysis) includes a section called "Performance with Respect to Proposed Environmental Protection Agency's Clean Air Act Section 111 Proposed Rule."[10] CPIRP Appendix K (Natural Gas, Low-Carbon Fuels and Hydrogen) includes a section called "Environmental Protection Agency Clean Air Act Section 111 Proposed Rule and New Gas."[11] Mr. Snider also discusses the Proposed Rule in his direct testimony.[12] But again, while it was acknowledged, the Companies' model of the P3 Fall Base Portfolio did not account for the Proposed Rule.

Q: DO THE COMPANIES CONSIDER CCS TO BE FEASIBLE FOR THEIR PROPOSED BUILD-OUT OF NEW NATURAL GAS-FIRED POWER PLANTS?

A: No. The Companies stated:

> CCS has not been considered cost-effective due to the lack of suitable geology to sequester significant volumes of carbon in the Carolinas, and significant costs and challenges to develop interstate pipelines, including challenges related to permitting, property rights, and public acceptance, which would need to be overcome, to transport the captured CO_2 to other regions suitable for sequestration.[13]

[9] CPIRP Chapter 3 at 21–22.

[10] CPIRP Appendix C at 96–99.

[11] CPIRP Appendix K at 6–8.

[12] Direct Testimony of Glen Snider, Michael Quinto, Thomas Beatty, and Ben Passty on Behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket No. E-100, Sub 190 at 47–48 (Sept. 1, 2023).

[13] CPIRP Appendix C at 100.

They further stated: "The Companies will continue to investigate the feasibility and viability of CCS as a compliance pathway for the EPA CAA Section 111 Proposed Rule as further information becomes known and the proposed rule is finalized."[14]

Q: DID THE COMPANIES CONSIDER CO-FIRING WITH HYDROGEN TO BE FEASIBLE FOR THEIR PROPOSED BUILD-OUT OF NEW NATURAL GAS-FIRED POWER PLANTS?

A: No. The Companies discussed co-firing hydrogen, because the Proposed Rule included a second possible compliance pathway for new natural gas-fired power plants: the Hydrogen Pathway. The Hydrogen Pathway was not included as a compliance pathway in the Final Rule. However, because of its inclusion in the Proposed Rule, the Companies considered it and found that the Hydrogen Pathway was not feasible, raising concerns about cost and availability. According to the Companies, the present value of revenue requirements ("PVRR") would increase by $10.5 billion relative to the P3 Base scenario to produce sufficient clean hydrogen to co-fire with natural gas, as modeled in their "SP EPA 111 H_2" scenario. The Companies also stated: "Although the Companies believe hydrogen is an important and potentially transformational fuel for the future of the resource portfolio, the volumes necessary to utilize the hydrogen compliance pathway are not thought to be achievable on the timelines presented in the EPA CAA Section 111 Proposed Rule."[15]

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[14] *Id.*

[15] *Id.* at 101.

Q: HOW DID THE COMPANIES PLAN FOR THEIR NEW NATURAL GAS-FIRED POWER PLANTS TO COMPLY WITH THE CAA SECTION 111 RULE?

A: The Companies did not plan for the new combined cycle ("CC") natural gas-fired power plants proposed in the P3 Fall Base Portfolio to be compliant with the CAA Section 111 Rule. In the Companies' filings and testimony, the Proposed Rule was mentioned, and the Companies discussed running their natural gas-fired power plants at lower capacity factors to comply with the rule, because plants with lower capacity factors would fall into a different category with less stringent regulatory requirements. However, while the Companies discussed compliance with the Proposed Rule, their model of the P3 Fall Base Portfolio did not comply with the Proposed Rule—and does not comply with the Final Rule, which has since been released. In recent responses to discovery requests, the Companies acknowledge that they are currently in the process of analyzing the legal and technical implications of the Final Rule.[16]

Although the Companies did not plan for the new CC natural gas-fired power plants proposed in the P3 Fall Base Portfolio to be compliant with the CAA Section 111 Rule and their base assumptions for the portfolios did not include capacity factor limits, they did discuss running the plants with lower capacity factors. According to the Final Rule, baseload plants are defined as those that run at capacity factors of 40 percent and higher. Only these baseload plants must

[16] *See* **Hansen Exhibit 2**, DEC and DEP Response to Appalachian Voices' Data Request 4-1; *see also* **Hansen Exhibit 3**, DEC and DEP Response to Appalachian Voices' Data Request 4-2.

implement 90 percent CCS by 2032. By running their new plants at lower capacity factors, the Companies were therefore aiming to avoid the need to implement CCS at their new natural gas-fired power plants. To model this approach to complying with the Proposed Rule, the Companies created a scenario called "SP EPA 111 CF." This scenario was based on running plants at capacity factors of less than 50 percent, not 40 percent, because the threshold in the Proposed Rule was 50 percent.[17] This change in the capacity factor threshold from the Proposed Rule to the Final rule is significant and would require intermediate-load plants to sit idle approximately 37 additional days each year. It is also important to note that when modeling the P3 Fall Base Portfolio, the Companies did not use a capacity factor limit for their proposed CC natural gas-fired power plants.[18]

Q: WILL RUNNING CC PLANTS AT LOWER CAPACITY FACTORS TO QUALIFY AS INTERMEDIATE-LOAD PLANTS, RATHER THAN BASELOAD PLANTS, PRESENT CHALLENGES TO THE COMPANIES?

A: Yes. The Companies have run their existing fleet of CC plants as baseload plants. According to the Companies:

> Historically, the Companies' CC fleets have been designed and operated specifically for baseload operations and have faced a limited need to cycle given the flexibility of the remaining generators. As the energy transition progresses, the CC fleet will need to cycle on a more frequent basis. This operational approach will be new to the Companies' fleet and is likely to require changes to operations and maintenance practices and investments and upgrades to increase unit flexibility. The process of re-starting the majority (and in some seasons,

[17] CPIRP Appendix C at 101.

[18] *See* **Hansen Exhibit 4**, DEC and DEP Response to Appalachian Voices' Data Request 4-4.

> entirety) of the Companies' CC fleets within a few hours has not been tested, and coordination among all units and stages will be a challenge to precisely match the rapid increases in net load into the evening hours.[19]

Q: WOULD LIMITING THE CAPACITY FACTOR OF NATURAL GAS-FIRED POWER PLANTS INCREASE OR DECREASE COSTS TO THE UTILITY AND TO RATEPAYERS?

A: Limiting the capacity factor would increase the cost of electricity generated by the CCs compared to the costs that the Companies have modeled. The electricity that would have been generated most cost-effectively from a CC running at a higher capacity factor would need to be generated elsewhere, thus reducing the return on the capital investment for the plants running at lower capacity factors. As a result, more electricity would need to be generated from less cost-effective existing resources, or from new generating resources would need to be built. In addition, CCs running at lower capacity factors would likely increase that unit's cost per kilowatt-hour ("kWh") because (1) the units' fixed costs would be spread over fewer kWh, and (2) the units may generate electricity less efficiently.[20]

Q: DID THE COMPANIES INCLUDE THE INCREASED COSTS OF RUNNING THEIR PLANTS AT LOWER CAPACITY FACTORS IN THEIR CALCULATION OF RATEPAYER IMPACTS?

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[19] CPIRP Chapter 3 at 29.

[20] *See* EPA Office of Air and Radiation, *Efficient Generation: Combustion Turbine Electric Generating Units, Technical Support Document*, Docket ID No. EPA-HQ-OAR-2023-0072 (April 2024), https://www.epa.gov/system/files/documents/2024-04/tsd-efficient-generation-combustion-turbine-egus-april-2024.pdf.

A: No. Although the Companies did model the "SP EPA 111 CF" scenario, this scenario was one of several supplemental portfolios analyzed "for informational purposes only" because the CAA Section 111 Rule had not yet been finalized.[21]

Q: EVEN THOUGH THE COMPANIES DID NOT INCLUDE THESE INCREASED COSTS IN THEIR CALCULATION OF RATEPAYER IMPACTS, DID THEY ESTIMATE THE INCREASED COSTS?

A: Yes. According to the Companies, the capacity factor limitation would increase the PVRR by $3.6 billion relative to the P3 Base Portfolio.[22] This calculation was performed before the Companies presented the P3 Fall Base Portfolio in their Supplemental Planning Analysis.

Q: IS THE INCREASED PVRR OF $3.6 BILLION LIKELY TO UNDERESTIMATE THE COST OF IMPLEMENTING THE FINAL CAA SECTION 111 RULE?

A: Yes, the estimated increase of $3.6 billion is likely to underestimate the cost of implementing the Final Rule for two reasons. First, it was calculated based on the Proposed Rule, not the Final Rule. The Proposed Rule used a threshold of 50 percent to distinguish between baseload and intermediate-load plants, but the Final Rule lowered that threshold to 40 percent. Therefore, the Companies' CCs would need to be run even less often than was contemplated in the "SP EPA 111 CF" scenario. This further constraint would lead to even higher costs and ratepayer impacts. The second reason that the estimated increase of $3.6 billion is likely to

[21] CPIRP Appendix C at 101.

[22] *Id.* at 100.

be an underestimate is because the figure is a comparison with the P3 Base Portfolio, not the P3 Fall Base Portfolio.

Q: IF THE COMPANIES WERE TO RUN THEIR NATURAL GAS-FIRED POWER PLANTS AT A LOWER CAPACITY FACTOR, WOULD ADDITIONAL GENERATION BE NEEDED TO MAKE UP THE DIFFERENCE?

A: Yes. The Companies stated: "A capacity factor limitation on new resources will present additional challenges in meeting system energy requirements . . . ."[23] More detail is provided in the Companies' "SP EPA 111 CF" scenario, which found the need for an additional 1,600 MW of offshore wind by 2032 and an additional CC by 2035.[24] As mentioned above, the Proposed Rule used a threshold of 50 percent to distinguish between baseload and intermediate-load plants, and the Final Rule lowered that threshold to 40 percent. For this reason, additional generation—over and above the 1,600 MW of offshore wind and the additional CC—would be needed for the Companies to comply with the Final Rule. Also, when the Companies calculated the need for an additional 1,600 MW of offshore wind and an additional CC, they were considering the projected load in the P3 Base Portfolio, not the P3 Fall Base Portfolio. Due to the higher load forecast in the P3 Fall Base Portfolio, even more additional resources would be needed.

ii. <u>CAA Section 111: Impacts on Existing Coal-Fired Power Plants</u>

[23] CPIRP Appendix C at 98.

[24] *Id.* at 101.

Q: WHAT ARE THE RELEVANT REQUIREMENTS FOR EXISTING COAL-FIRED POWER PLANTS UNDER THE CAA SECTION 111 RULE?

A: For existing coal-fired power plants, the CAA Section 111 Rule establishes subcategories based on how far into the future the plant will stay open. Units that intend to operate on or after January 1, 2039 ("long-term" units) will have a numeric emission rate limit based on application of CCS with 90 percent capture, which they must meet on January 1, 2032. Units that have committed to cease operations by January 1, 2039 ("medium-term" units) will have a numeric emission rate limit based on 40 percent natural gas co-firing that they must meet on January 1, 2030. Units that are scheduled to permanently cease operation prior to January 1, 2032 will have no emission reduction obligations under the rule. States have some ability to grant variances or alternative standards.[25]

Q: HOW DID THE COMPANIES PLAN FOR THEIR EXISTING COAL-FIRED POWER PLANTS TO COMPLY WITH THE CAA SECTION 111 RULE?

A: The Companies documented which CAA Section 111 Rule requirements would be applicable to each coal-fired power plant based on its retirement year in the P1 Base, P2 Base, and P3 Base portfolios.[26] However, this was based on the Proposed Rule, not the Final Rule, and it did not consider the P3 Fall Base Portfolio. The Companies do not mention the CAA Section 111 Rule in their Supplemental Planning Analysis, in which the P3 Fall Base Portfolio is introduced, nor have the

[25] CAA Section 111 Rule.

[26] CPIRP Appendix C at 97–98 (Table C-72).

Companies explained how they will comply with the Final Rule, even in their recent discovery responses written after the Final Rule has been released.[27]

Q: WHEN DO THE COMPANIES PLAN TO RETIRE THEIR EXISTING COAL-FIRED POWER PLANTS?

A: The Companies plan to stagger their coal-fired power plant retirements from 2025 through 2036, with one exception. The exception, Cliffside 6, is scheduled for retirement in 2049; however, this unit is assumed to operate on 100 percent natural gas after 2035.[28]

Q: WOULD ANY OF THE EXISTING COAL-FIRED POWER PLANTS BE CONSIDERED MEDIUM-TERM UNITS UNDER THE CAA SECTION 111 RULE?

A: Yes, those that close between 2032 and 2038 would be considered medium-term units under the CAA Section 111 Rule. These include: Belews Creek 1 and 2, Marshall 3 and 4, and Roxboro 2 and 3.[29]

Q: BASED ON THE COMPANIES' MODELING RESULTS, WILL ANY OF THE MEDIUM-TERM UNITS BE NONCOMPLIANT WITH THE CAA SECTION 111 RULE?

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[27] *See* **Hansen Exhibit 2**, DEC and DEP Response to Appalachian Voices' Data Request 4-1; *see also* **Hansen Exhibit 3**, DEC and DEP Response to Appalachian Voices' Data Request 4-2.

[28] CPIRP Supplemental Planning Analysis at 34 (Table SPA 3-1).

[29] *Id.*

A: Yes. Model outputs for Roxboro 2 and 3 show generation from coal through 2033 but no co-firing of natural gas.[30] These units would not comply with the CAA Section 111 Rule, because they would need to have a numeric emission rate limit based on 40 percent natural gas co-firing by January 1, 2030.

iii. <u>CAA Section 111: Interactions Between New Natural Gas-Fired Power Plants and Existing Coal-Fired Power Plants</u>

Q: YOU STATED EARLIER THAT RUNNING NEW NATURAL GAS-FIRED POWER PLANTS AT A LOWER CAPACITY FACTOR WOULD RESULT IN THE NEED FOR ADDITIONAL GENERATION. COULD THE COMPANIES DELAY THE CLOSURE OF THEIR COAL-FIRED POWER PLANTS TO PROVIDE THIS ADDITIONAL GENERATION?

A: If the Companies tried to delay closure of their coal-fired power plants to generate this additional electricity, they would face two significant challenges. First, these delays would need to comply with HB 951. Second, these delays would need to comply with the CAA Section 111 Rule's requirements for existing coal-fired power plants.

Q: COULD THE COMPANIES FEASIBLY DELAY CLOSURE OF AN EXISTING COAL-FIRED POWER PLANT PAST 2038 AND COMPLY WITH THE CAA SECTION 111 RULE?

A: No. If the Companies delayed closure of an existing coal-fired power plant past 2038, then the plant would be considered a long-term unit under the CAA Section

[30] *See* the "Resource Annual Fuel" tab from the Companies' EnCompass Output Data, Supplemental CPIRP, PC Runs file named "P3 F23 Load - Base Load - 35Cap - 1 SC CC - P3 Retire - PC - 1.9.24." Due to the large file size of the referenced Excel spreadsheet, it is not included as a PDF exhibit in this testimony. Instead, it will be provided to the Commission in its native format.

111 Rule and would therefore be required to install CCS. As stated above, the Companies do not consider CCS to be feasible, raising issues related to the lack of suitable geology to sequester carbon in the Carolinas, the cost of developing interstate pipelines, and other challenges.[31]

Q: COULD THE COMPANIES FEASIBLY DELAY CLOSURE OF AN EXISTING COAL-FIRED POWER PLANT PAST 2031 AND COMPLY WITH THE CAA SECTION 111 RULE?

A: It would be unlikely to be feasible. If the Companies delayed closure of an existing coal-fired power plant past 2031, but not past 2038, then the plant would be considered a medium-term unit under the CAA Section 111 Rule and would be required to have a numeric emission rate limit based on 40 percent natural gas co-firing on January 1, 2030. Even if it were technically feasible to pipe sufficient natural gas to the plant and to upgrade the plant to co-fire 40 percent natural gas, it is unlikely to be economically feasible to make these large investments only to shut the plant down by 2038—which would be required to avoid being classified as a long-term unit with the requirement to install CCS.

iv. <u>CAA Section 111: Summary</u>

Q: PLEASE SUMMARIZE THE REGULATORY RISKS RELATED TO IMPLEMENTATION OF THE CAA SECTION 111 RULE.

A: The Companies' proposed P3 Fall Base Portfolio does not comply with the CAA Section 111 Rule. In fact, in a discovery response provided after the Final Rule was

[31] CPIRP Appendix C at 100.

published, the Companies stated: "The Companies are currently in the process of analyzing the legal and technical implications of the recently finalized EPA regulation under Section 111(b) and (d) of the Clean Air Act applicable to new gas combustion turbines and existing coal steam generators."[32]

The P3 Fall Base Portfolio does not comply with the CAA Section 111 Rule for two reasons. First, the P3 Fall Base Portfolio model does not limit the capacity factors for new natural gas-fired CCs—the only pathway that the Companies have discussed as viable for new CCs to comply with the CAA Section 111 Rule. Running plants at lower capacity factors will result in less efficient generation at these plants and the need for additional generation from other more expensive sources to make up the difference. Second, the P3 Fall Base Portfolio model does not comply with the Final Rule because it runs the coal-fired Roxboro 2 and 3 units through 2033 without co-firing natural gas. For medium-term coal-fired units that run past 2030, the Final Rule requires a numeric emission rate limit based on 40 percent natural gas co-firing by 2030.

Q: HOW DO YOU RECOMMEND THAT THE COMMISSION ADDRESS THE REGULATORY RISKS RELATED TO IMPLEMENTATION OF THE CAA SECTION 111 RULE.

A: Absent court action, the CAA Section 111 Rule is no longer a potential regulatory risk; it is now a regulatory certainty. I therefore recommend that the Commission require the Companies to develop one or more new portfolios that comply with the

[32] *See* **Hansen Exhibit 2**, DEC and DEP Response to Appalachian Voices' Data Request 4-1; *see also* **Hansen Exhibit 3**, DEC and DEP Response to Appalachian Voices' Data Request 4-2.

CAA Section 111 Rule. Because the P3 Fall Base Portfolio uses significantly different assumptions for the operation of natural gas-fired power plants than what is required under the Final Rule, and because it runs the coal-fired Roxboro 2 and 3 units longer than allowed by the Final Rule, the portfolio's true cost to ratepayers is unknown; therefore, I further recommend that the Commission require the Companies to assess the ratepayer impacts associated with all candidate portfolios that comply with the CAA Section 111 Rule.

B. Other Risks That Affect the Companies' Ability to Secure Sufficient Natural Gas at Affordable Cost to Fuel Their Proposed Build-Out of Natural Gas-Fired Power Plants

Q: PLEASE PROVIDE AN OUTLINE OF THIS SECTION OF YOUR TESTIMONY.

A: This section of my testimony focuses on non-regulatory risks that may affect the Companies' ability to secure sufficient natural gas at affordable cost to fuel their proposed build-out of natural gas-fired power plants. In this section, I first focus on the risk that increased natural gas demand in North Carolina and nearby states will cause natural gas prices to increase and/or become more volatile. Next, I turn to the risk that pipeline projects needed for the Companies' proposed build-out of natural gas-fired power plants will not be completed in time. Finally, I provide further data and analysis regarding the risk of increased volatility of natural gas prices.

i. Risk That Increased Natural Gas Demand in North Carolina and Nearby States Will Cause Natural Gas Prices to Increase and/or Become More Volatile

Q: GENERALLY, WHAT SECTORS HAVE SIGNIFICANT DEMAND FOR NATURAL GAS IN NORTH CAROLINA AND SURROUNDING STATES?

A: More than half of North Carolina's natural gas consumption is used to generate electricity, and a significant amount is used by the industrial, residential, and commercial sectors. In the surrounding states of Virginia, Georgia, and South Carolina, natural gas consumption follows similar patterns, while in Tennessee, the industrial sector accounts for the largest percentage of natural gas consumption.[33]

In addition to domestic consumption, the export market for liquified natural gas ("LNG") has recently started expanding. On the East Coast of the United States, this international market is accessed from the Cove Point facility in Maryland[34] and the Elba Island facility in Georgia.[35]

Q: HOW MUCH NATURAL GAS HAVE THE COMPANIES' NATURAL GAS-FIRED POWER PLANTS USED IN RECENT YEARS?

A: The Companies' generating assets include a fleet of 18 natural gas-fired power plants and three plants that co-fire natural gas with coal.[36] From 2019 through 2023, the natural gas-fired power plants alone used on average approximately 281,000

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[33] U.S. Energy Information Administration, *Natural Gas Consumption by End Use*, Area: North Carolina, https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SNC_a.htm*; see also* Area: Virginia; Area: Georgia; Area: South Carolina; and Area: Tennessee (last visited May 17, 2024).

[34] U.S. Energy Information Administration, *U.S. Natural Gas Exports and Re-Exports by Point of Exit*, Area: LNG Exports from Cove Point, MD, https://www.eia.gov/dnav/ng/ng_move_poe2_dcu_YCPT-Z00_a.htm (last visited May 17, 2024).

[35] U.S. Energy Information Administration, *U.S. Natural Gas Exports and Re-Exports by Point of Exit*, Area: LNG Exports from Elba Island, GA, https://www.eia.gov/dnav/ng/ng_move_poe2_dcu_YELBA-Z00_a.htm (last visited May 17, 2024).

[36] CPIRP Appendix B at 4 (Table B-1), at 5–7 (Table B-2), and at 8–9 (Table B-3).

million cubic feet ("MMcf") per year of natural gas.[37] Natural gas use in 2023 totaled approximately 276,000 MMcf.[38]

Q: HOW MUCH NATURAL GAS WILL THE COMPANIES REQUIRE TO FUEL THEIR PROPOSED NATURAL GAS BUILD-OUT?

A: The Companies propose an aggressive schedule to add approximately 9 GW of new natural gas-fired power plants and to co-fire natural gas at existing coal-fired power plants,[39] thereby increasing natural gas demand significantly. According to the Companies' model outputs, their natural gas demand is projected to peak in 2030 at approximately 601,000 MMcf.[40] Compared to the natural gas used by the Companies' natural gas-fired power plants in 2023, this represents an increase of approximately 325,000 MMcf.

Q: ARE ELECTRIC UTILITIES IN OTHER NEARBY STATES ALSO PROPOSING LARGE BUILD-OUTS OF NATURAL GAS-FIRED POWER PLANTS?

A: Yes. Earlier this year, Georgia Power was moving forward with a plan to fast-track 1.4 GW of new natural gas-fired power plants in the next three years. In South Carolina, legislation was advanced to fast-track construction of a 2-GW natural gas-fired power plant. And Tennessee Valley Authority is developing a plan that could

[37] *See* **Hansen Exhibit 5**, DEC and DEP Response to Appalachian Voices' Data Request 2-1. Here and elsewhere in my testimony, I use a conversion of 1.0 MMBtu per Mcf.

[38] *Id.*

[39] CPIRP Supplemental Planning Analysis at 8 (Figure SPA 1-2).

[40] *See* the "Company Annual Fuel" tab from the Companies' EnCompass Output Data, Supplemental CPIRP, PC Runs file named "P3 F23 Load - Base Load - 35Cap - 1 SC CC - P3 Retire - PC - 1.9.24." Due to the large file size of the referenced Excel spreadsheet, it is not included as a PDF exhibit in this testimony. Instead, it will be provided to the Commission in its native format.

include 6.6 GW of new natural gas-fired power plants.[41] Also, Virginia Electric and Power Company, a subsidiary of Dominion Energy, will submit an updated Integrated Resource Plan in October of this year. Their proposed 2023 IRP included two alternatives with 970 MW of new gas and two alternatives with 2,910 MW of new gas.[42]

Q: ARE OTHER SECTORS ALSO INCREASING DEMAND FOR NATURAL GAS?

A: Yes. In North Carolina, for example, industrial and commercial demand for natural gas has been rising in recent years. According to my analysis of publicly available data, if industrial and commercial demand continues to increase at the same rate as it has between 2013 and 2022, these sectors would demand an additional approximately 22,000 MMcf per year by 2035.[43]

Q: ARE EFFORTS UNDERWAY TO INCREASE EXPORTS OF LNG FROM THE EAST COAST OF THE UNITED STATES?

A: Yes. More than 100 million metric tons per year of increased LNG exports have been proposed in the United States.[44] Also, a recent presentation states a need by

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[41] Jeff St. John, *More demand, more gas: Inside the Southeast's dirty power push,* Canary Media (Apr. 11, 2024), https://www.canarymedia.com/articles/utilities/more-demand-more-gas-inside-the-southeasts-dirty-power-push.

[42] Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan, Virginia State Corporation Commission, Case No. PUR-2023-00066, and North Carolina Utilities Commission, Docket No. E-100, Sub 192 at PDF p. 24 (May 1, 2023), https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/company/2023-va-integrated-resource-plan.pdf?la=en&rev=6b14e6ccd15342b480c8c7cc0d4e6593.

[43] *See* U.S. Energy Information Administration, *Natural Gas Consumption by End Use*, Area: North Carolina, https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SNC_a.htm (last visited May 17, 2024).

[44] S&P Global Commodity Insights, *North American LNG project Tracker*, https://www.spglobal.com/commodityinsights/PlattsContent/_assets/_images/latest-news/110623-infographic-north-america-lng-projects-terminals-usgc-feedgas.svg (last visited May 17, 2024).

2030 for an additional 30 billion cubic feet per day (Bcfd) of LNG export capacity from the East Coast.[45]

Q: PLEASE SUMMARIZE YOUR FINDINGS RELATED TO RISKS RELATED TO INCREASED DEMAND FOR NATURAL GAS.

A: The Companies' proposed build-out of natural gas-fired power plants will significantly increase natural gas demand by the electric power sector in North Carolina, but this increase must be viewed within the context of other reasonably foreseeable increases in demand by other sectors and in nearby states. Increased demand by other utilities, industrial entities, commercial entities, and LNG export facilities are beyond the Companies' control and will put upward pressures on prices, reduce available supplies, and increase the risk of price volatility.

ii. <u>Risk That Pipeline Projects Needed for the Companies' Proposed Build-Out of Natural Gas-Fired Power Plants Will Not Be Completed in Time</u>

Q: IS ANY NATURAL GAS USED BY THE COMPANIES PRODUCED IN NORTH CAROLINA?

A: No. According to the Companies: ". . . other than small volumes of renewable natural gas, there is no Carolinas natural gas production or reservoir storage available to serve natural gas needs within the State."[46]

[45] **Hansen Exhibit 6** at 20, Gas and Oil Association of West Virginia, *West Virgnia Statistics – Serving All Aspects of the Oil and Natural Gas Industry*, Presentation to West Virginia Legislature, Joint Standing Committee on Energy and Manufacturing (April 15, 2024); *see also Joint Standing Committee on Energy and Manufacturing – Agenda*, West Virginia Legislature (April 15, 2024), https://www.wvlegislature.gov/committees/interims/agenda.cfm?recordid=5373&abb=ENERGY.

[46] (Public) Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Piedmont Natural Gas Company, Inc.'s Report on Management of Gas-Electric Dependencies and Inter-Dependencies During Extreme Cold Weather Events and Other Emergencies & Proposed Joint Planning Process to Prepare for and Respond to Natural Gas Transmission Vulnerabilities During Extreme Cold Weather Events, Docket No. M-100, Sub 217 at 6 (Mar. 21, 2024).

Q: HOW IS NATURAL GAS DELIVERED TO NORTH CAROLINA?

A: According to the Companies: ". . . the Duke Energy Electric Utilities [are] almost wholly dependent on Transco, which is a single source, fully subscribed, long-haul interstate natural gas pipeline accessing upstream and downstream Appalachia and Gulf Coast production regions."[47]

Q: IS THE TRANSCO PIPELINE ALREADY FULLY SUBSCRIBED?

A: Yes. According to the Companies, Transco is "fully subscribed."[48] Therefore, without additional pipeline projects, the Transco Pipeline cannot supply additional natural gas to meet increased natural gas demand in North Carolina.

Q: WHAT OTHER PIPELINE PROJECTS HAVE BEEN PROPOSED THAT MAY PROVIDE FOR THE DELIVERY OF ADDITIONAL NATURAL GAS TO NORTH CAROLINA?

A: The Mountain Valley Pipeline ("MVP"),[49] MVP-Southgate Extension,[50] Williams Southeast Supply Enhancement Project,[51] and Dominion T15 Reliability Project[52] have been proposed.

Q: ARE ANY OF THESE PROJECTS IN OPERATION?

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[47] *Id.* at 6–7.

[48] *Id.* at 6. This assertion may no longer be accurate if the Mountain Valley Pipeline and other proposed pipeline projects become operational.

[49] Mountain Valley Pipeline Project, https://www.mountainvalleypipeline.info/ (last visited May 13, 2024).

[50] *American Pipeline*, MVP Southgate, https://www.mvpsouthgate.com/ (last visited May 13, 2024).

[51] *Southeast Supply Enhancement*, Williams, https://www.williams.com/expansion-project/southeast-supply-enhancement/ (last visited May 13, 2024).

[52] *T15 Reliability Project*, Dominion Energy, https://www.dominionenergy.com/projects-and-facilities/natural-gas-projects/t15-pipeline (last visited May 13, 2024).

A: As of May 28, 2024, none of these projects are in operation, although the MVP may be in operation soon.[53]

Q: IS THE TIMING OF THESE PIPELINE PROJECTS WITHIN THE COMPANIES' CONTROL?

A: No. According to the Companies: "The project scope and in-service date of any additional interstate FT capacity accessible to the Carolinas region is not fully within the control of DEC and DEP."[54]

Q: WHAT IS THE RECENT TRACK RECORD IN THE EASTERN UNITED STATES FOR COMPLETING PIPELINE PROJECTS ON SCHEDULE?

A: Many pipeline projects in the Eastern United States have been canceled in recent years, including the Atlantic Coast Pipeline, Constitution Pipeline, PennEast Pipeline, and Northern Access Pipeline,[55] as well as the Northeast Supply Enhancement Project.[56] Other pipeline projects in the Eastern United States have been significantly delayed.[57] The original target in-service date for the MVP, for example, was 2018, and it is only now on the verge of completion, six years behind schedule.[58]

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[53] Curtis Tate, *Mountain Valley Pipeline completion again delayed*, VPM (May 22, 2024), https://www.vpm.org/news/2024-05-22/mountain-valley-pipeline-completion-delayed.

[54] CPIRP Appendix C at 45.

[55] Scott Disavino, *Explainer: U.S. Appalachian gas pipeline projects go by the wayside*, Reuters (Sept. 28, 2021), https://www.reuters.com/business/energy/us-appalachian-gas-pipeline-projects-go-by-wayside-2021-09-28/.

[56] Carlos Anchondo, *Pipeline company cancels Northeast gas project*, Energy Wire (May 8, 2024), https://www.eenews.net/articles/pipeline-company-cancels-northeast-gas-project.

[57] Disavino, *supra* note 55.

[58] Brad McElhinny, *Mountain Valley Pipeline, after years of delay and booming costs, is at the verge of completion*, MetroNews (May 5, 2024), https://wvmetronews.com/2024/05/05/mountain-valley-pipeline-after-years-of-delay-and-booming-costs-is-at-the-verge-of-completion/.

Q: BASED ON PUBLICLY AVAILABLE INFORMATION, WHEN ARE THESE PROJECTS PROJECTED TO BE OPERATIONAL?

A: The MVP is projected to be in operation this year,[59] and the MVP-Southgate Extension is projected to be completed in June 2028.[60] The target in-service date for the Williams Southeast Supply Enhancement Project is the end of 2027,[61] and the target in-service date for the Dominion T15 Reliability Project is the end of 2027.[62] However, many pipeline projects in the Eastern United States have been canceled or significantly delayed in recent years, so these dates are not certain to be achieved.

Q: HOW DO THESE DATES COMPARE TO THE DATES ASSUMED BY THE COMPANIES IN THIS PROCEEDING?

A: **[BEGIN CONFIDENTIAL]** [redacted][63] [redacted][64] [redacted]

[59] Tate, *supra* note 53.

[60] April 2024 Equitrans Midstream Investor Presentation: https://s22.q4cdn.com/743133753/files/doc_presentations/2024/Apr/30/q1-2024-investor-presentation-final.pdf.

[61] Williams, *supra* note 51.

[62] Dominion Energy, *supra* note 52.

[63] **Hansen Exhibit 7**, Confidential DEC and DEP Response to Appalachian Voices' Data Request 2-5-2.

[64] **Hansen Exhibit 7**, Confidential DEC and DEP Response to Appalachian Voices' Data Request 2-5-3.

[redacted][65] [redacted] **[END CONFIDENTIAL]**

Q: PLEASE CHARACTERIZE THE RISK FACED BY THE COMPANIES DUE TO RELIANCE ON THESE PIPELINE PROJECTS BEING COMPLETED ON TIME.

A: Because the Transco Pipeline is fully subscribed, the additional natural gas required to fuel the Companies' proposed build-out of new natural gas-fired power plants can only be delivered if new pipeline projects are built. Some of these projects, like the MVP and the MVP-Southgate Extension projects, would be needed to bring additional gas to the region. Other projects would be needed to provide natural gas to specific power plants. **[BEGIN CONFIDENTIAL]** [redacted][66] **[END CONFIDENTIAL]** The Commission should consider this risk, especially given that many pipeline projects in the Eastern United States have been canceled and delayed in recent years, and given that the Companies do not control the timeline for completing any of the pipeline projects required to fuel their build-out.

iii. Risk of Increased Volatility of Natural Gas Prices

[65] **Hansen Exhibit 7**, Confidential DEC and DEP Response to Appalachian Voices' Data Request 2-5-4.

[66] **Hansen Exhibit 8**, Confidential DEC and DEP Response to Appalachian Voices' Data Request 3-7.

Q: WHAT FACTORS IMPACT THE PRICE OF NATURAL GAS AND ITS VOLATILITY?

A: The price of natural gas and its volatility are affected by demand and supply in the broader Henry Hub market, with additional factors affecting the Transco Zone 5 market. Henry Hub, located in Louisiana, is where many interstate and intrastate natural gas pipelines interconnect, and Henry Hub prices are commonly used as a benchmark for natural gas pricing.[67] North Carolina is within Transco Zone 5, which is the portion of the Transco Pipeline that extends from the Georgia-South Carolina border to the Virginia-Maryland border, not including deliveries from the Cove Point LNG terminal.[68] Demand for natural gas has traditionally been only from domestic markets, but with increasing exposure of the U.S. gas supply to the international market via LNG exports, the dynamics of the natural gas market has changed. This change is reflected in both the price of natural gas and its volatility.

Q: HAVE THE COMPANIES RECENTLY RECEIVED APPROVAL FROM THE COMMISSION FOR FUEL-RELATED RATE INCREASES RELATED TO THE VOLATILITY OF NATURAL GAS PRICES?

A: Yes. In 2023, the Commission approved increased rates for DEC related in part to the volatility of natural gas prices that occurred in 2022 due to Winter Storm Elliot and geopolitical events. These increases of 1.4105, 1.0565, and 0.8312 ¢/kWh for

[67] *See* S&P Global, *What is Henry Hub?*, https://www.spglobal.com/commodityinsights/en/our-methodology/price-assessments/natural-gas/henry-hub-natural-gas-price-assessments (last visited May 24, 2024).

[68] *See* S&P Global, *Methodology and specifications guide US and Canada natural gas*, https://www.spglobal.com/commodityinsights/plattscontent/_assets/_files/en/our-methodology/methodology-specifications/na_gas_methodology.pdf.

the Residential, General Service/Lighting, and Industrial customer classes, respectively, equate to approximately $693 million on an annual basis in the rates and charges paid by the retail customers of DEC in North Carolina.[69] In a similar proceeding, the Commission approved increased rates for DEP related in part to the volatility of natural gas prices that occurred in 2022 due to Winter Storm Elliot and geopolitical events. These increases equate to approximately $208 million on an annual basis in the rates and charges paid by the retail customers of DEP in North Carolina.[70]

Q: IF THE COMPANIES PROCEED WITH THEIR BUILD-OUT OF NEW NATURAL GAS-FIRED POWER PLANTS, WILL MORE OF THEIR ELECTRICITY GENERATION BE SUSCEPTIBLE TO HIGHER NATURAL GAS PRICES AND NATURAL GAS PRICE VOLATILITY?

A: Yes. If the Companies proceed with their build-out of new natural gas-fired power plants, they will require significantly more natural gas in the future. As mentioned above, the Companies' natural gas demand is projected to peak in 2030 at approximately 601,000 MMcf, an increase of approximately 325,000 MMcf compared to the natural gas used the Companies' natural gas-fired power plants in 2023. Another way to quantify the Companies' susceptibility to natural gas price volatility is through their projected delivered cost of natural gas. In the P3 Fall Base

[69] Order Approving Notice to Customers of Change in Rates, Docket No. E-7, Sub 1281, 1282, 1283 at Appendix A (Sept. 6, 2023); *see also* Order Approving Fuel Charge Adjustment, Docket No. E-7, Sub 1282 (Aug. 23, 2023).

[70] Order Approving Notices to Customers of Change in Rates, Docket No. E-2, Sub 1320, 1321, 1323, 1324 at Appendix A (Nov. 28, 2023); *see also* Order Approving Fuel Charge Adjustment, Docket No. E-2, Sub 1321 (Nov. 17, 2023); *and* Errata Order, Docket No. E-2, Sub 1321 (Nov. 27, 2023).

Portfolio, the projected delivered cost of natural gas in 2030 is approximately $2.5 billion, which is approximately $720 million greater than the cost in 2024.[71] The $2.5 billion cost is based on an average annual natural gas price of $4.21 per MMBtu in 2030, but as illustrated below, recent volatility in natural gas prices have often raised the price much higher than $4.21 at Henry Hub—and prices at Transco Zone 5 have been more volatile and spiked much higher. If, for example, volatility raised the average price to $6.00 in 2030, the Companies' delivered cost of natural gas would increase from $2.5 billion to $3.6 billion in that year and ratepayers would presumably be left footing the bill.

Q: HOW VOLATILE HAVE NATURAL GAS PRICES BEEN IN RECENT YEARS?

A: Chart 1 below illustrates Henry Hub natural gas prices from 2010 through April 2024.[72] The chart begins in 2010 because shale gas production using horizontal drilling and hydraulic fracturing began to rapidly increase around that year.[73] The year 2016 is also important to note, because LNG exports from the United States began to increase then.[74] To account for this change in the natural gas market, I have divided the chart into two periods: 2010–2015 (before LNG exports began),

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[71] *See* the "Company Annual Fuel" tab from the Companies' EnCompass Output Data, Supplemental CPIRP, PC Runs file named "P3 F23 Load - Base Load - 35Cap - 1 SC CC - P3 Retire - PC - 1.9.24." Due to the large file size of the referenced Excel spreadsheet, it is not included as a PDF exhibit in this testimony. Instead, it will be provided to the Commission in its native format.

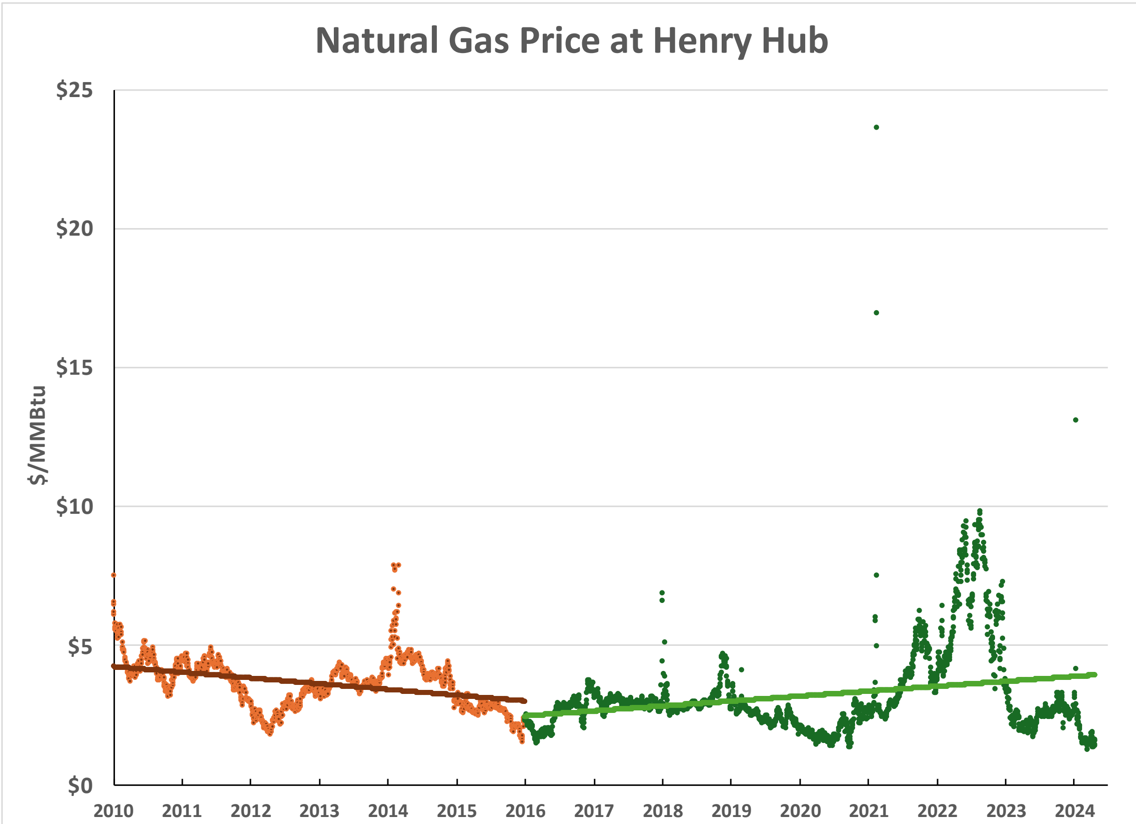
[72] U.S. Energy Information Administration, *Natural Gas – Henry Hub Natural Gas Spot Price*, https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm (last visited April 20, 2024).

[73] U.S. Energy Information Administration, *Natural gas explained Where our natural gas comes from*, https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php (last visited May 25, 2024).

[74] U.S. Energy Information Administration, *Natural Gas – Liquefied U.S. Natural Gas Exports*, https://www.eia.gov/dnav/ng/hist/n9133us2m.htm (last visited May 25, 2024).

and 2016 through 2024 (after LNG exports began). I have overlaid best-fit lines to illustrate the price trend in each period. The trend was for prices to decrease from 2010–2015 and to increase from 2016–2024.

Chart 1



Q: WHAT OBSERVATIONS CAN YOU MAKE ABOUT THE VOLATILITY OF HENRY HUB NATURAL GAS PRICES FOR THE TWO TIME PERIODS ILLUSTRATED IN THIS CHART?

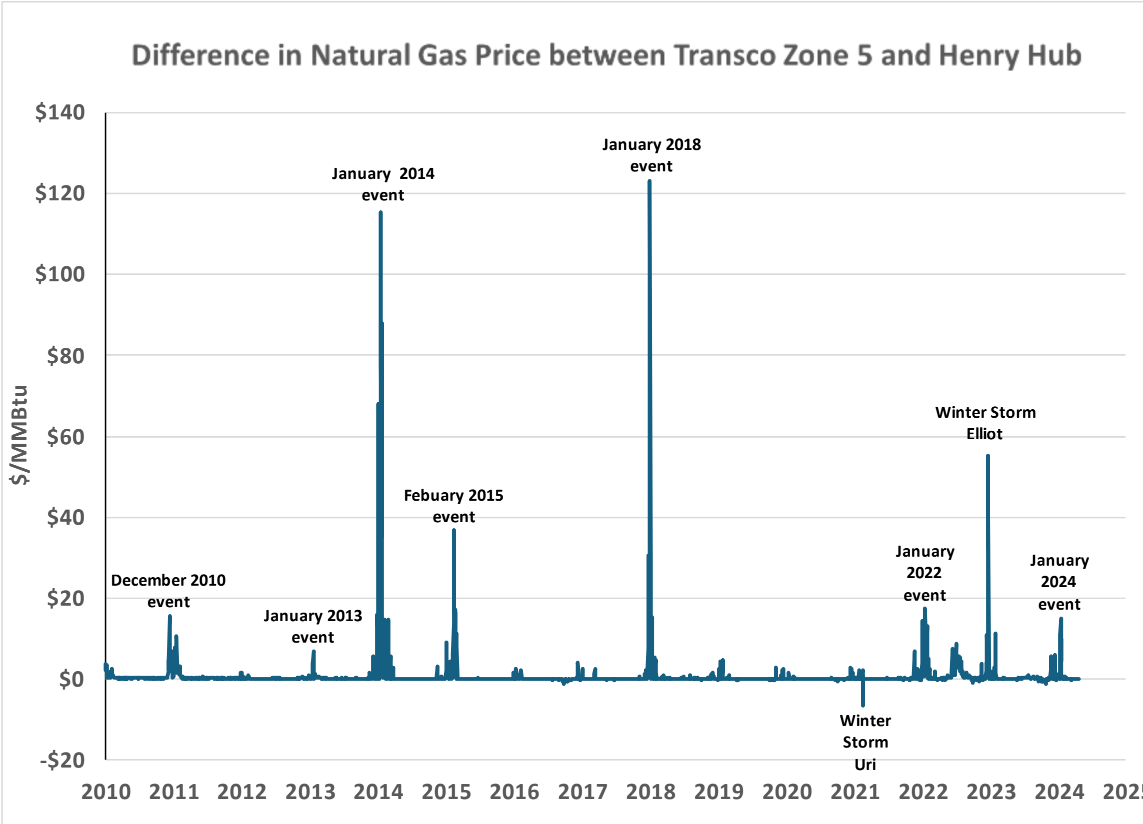
A: In the second period illustrated above (2016–2024), volatility increased. This increase can be quantified by the change in the standard deviation of prices. Standard deviation is a commonly used statistical test; for this analysis, it is the variation of the daily natural gas prices relative to the average natural gas price in the period. For the Henry Hub natural gas prices illustrated above, the standard deviation nearly doubled between the two periods: from $0.89 per MMBtu per day from 2010–2015 to $1.62 per MMBtu per day from 2016–2024. A higher standard deviation indicates that there is a higher volatility in the daily price of natural gas.

Q: HOW DOES TRANSCO ZONE 5 PRICING COMPARE TO HENRY HUB PRICING?

A: While Henry Hub prices are commonly used as a benchmark for natural gas pricing, the Companies are supplied natural gas from Transco Zone 5. Chart 2 below shows the difference between Transco Zone 5 prices[75] and Henry Hub prices since 2010. As illustrated in the chart, during many events, Transco Zone 5 prices exceeded Henry Hub prices by many dollars per MMBtu—and during four of these events, the price difference exceeded $20 per MMBtu.

[75] *See* Natural Gas Intelligence, *Daily Historical Data*, https://www.naturalgasintel.com/premium/daily-historical-data/ (last accessed on April 29, 2024).

Chart 2



Q: WHAT OBSERVATIONS CAN YOU MAKE ABOUT THE VOLATILITY OF TRANSCO ZONE 5 PRICES?

A: Prices at Transco Zone 5 are more volatile than prices at Henry Hub. From 2010–2015, the standard deviation of the Transco Zone 5 price was $5.43 per MMBtu per day, and from 2016–2024, the standard deviation of the Transco Zone 5 price was $4.20 per MMBtu per day. These values are much higher than the standard deviations during the same periods for the Henry Hub prices stated above. One reason is that, even before 2016, Transco Zone 5 prices have been impacted significantly by winter events.

Q: HAVE WINTER STORMS AND EXTREME WEATHER EVENTS LED TO INCREASED VOLATILITY?

A: Yes. Climate change has increased—and is predicted to continue to increase—the number and severity of extreme weather events.[76] The chart above, which illustrates the difference in natural gas prices between Transco Zone 5 and Henry Hub, identifies Winter Storm Elliot, and many other winter events, during which Transco Zone 5 prices increased substantially compared to Henry Hub prices, leading to higher price volatility.

Q: HAS THE U.S. NATURAL GAS MARKET'S EXPOSURE TO LNG EXPORTS ALSO LED TO INCREASED VOLATILITY?

A: Yes. In recent testimony before the U.S. Senate Committee on Energy and Natural Resources, U.S. Department of Energy Deputy Secretary David Turk noted that international markets have been about 50–100 percent more volatile than domestic markets, and that this volatility is likely to be reflected by higher volatility in domestic markets as they increase their exposure to those international markets.[77] Again, the U.S. market's exposure to international markets via LNG exports began around 2016.

Q: DID THE WAR IN UKRAINE LEAD TO VOLATILITY OF THE DOMESTIC MARKET FOR NATURAL GAS?

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[76] Rachel Licker, *How Is Climate Change Affecting Winter Storms in the US?*, Union of Concerned Scientists (Feb. 1, 2023), https://blog.ucsusa.org/rachel-licker/how-is-climate-change-affecting-winter-storms-in-the-us/.

[77] Testimony of David Turk, Deputy Secretary, U.S. Department of Energy, Before the Committee on Energy and Natural Resources, United States Senate, Regarding Liquefied Natural Gas Applications and Exports (Feb. 8, 2024), https://www.energy.senate.gov/services/files/12C4B00D-BFF3-4D11-9CD7-E462B156BF61.

A: Yes, the Ukraine War and its impacts on the European gas market as Russia reduced or stopped providing natural gas to countries in Western Europe resulted in significant changes in natural gas prices on the Henry Hub. These events were factors in the annual average price of natural gas on the Henry Hub rising to $6.41 per MMBtu in 2022. According to my observation and analysis of publicly available data, this is much greater than the average price of $3.87 in 2021 and $2.53 in 2023.[78]

Q: CAN YOU PROVIDE OTHER EXAMPLES OF THE IMPACT ON NATURAL GAS PRICES IN A DOMESTIC MARKET DUE TO OPENING THE DOMESTIC MARKET TO LNG EXPORTS?

A: When an explosion at the Freeport LNG export terminal in Texas caused the facility to shut down, U.S. prices fell and European prices increased.[79] This event clearly demonstrated the impacts of LNG exports on the U.S. market. Australia provides another example. In 2015 and 2016, three LNG export terminals started operating. Natural gas prices, which had averaged AU$4.21 per GJ between 2010 and 2015, doubled to AU$8.55 between 2016 and 2021. With the subsequent turmoil in Europe related to natural gas demand, contract prices rose in Australia to as high as AU$30 per GJ in 2023.[80]

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[78] U.S. Energy Information Administration, *Natural Gas – Henry Hub Natural Gas Spot Price*, https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm (last visited April 20, 2024).

[79] Kyra Buckley, *U.S. natural gas prices fell and those in Europe soared after this week's blast at Freeport LNG*, Houston Chronicle (June 13, 2022), https://www.houstonchronicle.com/business/energy/article/Natural-gas-prices-fall-after-Freeport-LNG-17230241.php.

[80] Kelly Neill, *Why Natural Gas Price Caps in Australia are Poor Policy*, Rice University's Baker Institute for Public Policy Center for Energy Studies (Feb. 7, 2023), https://www.bakerinstitute.org/research/why-natural-gas-price-caps-australia-are-poor-policy.

Q: HOW DO THE COMPANIES PROPOSE TO ADDRESS NATURAL GAS PRICE VOLATILITY?

A: The Companies' solution for addressing this volatility is to secure Appalachian gas: "The incremental Appalachian gas supply allows for supply diversity, increased fuel assurance, [and] decreased customer fuel cost volatility exposure . . . ."[81] However, as discussed above, securing an adequate Appalachian gas supply depends on the timely construction of pipeline expansion projects that are outside of the Companies' control. Further, during Winter Storm Elliot, Appalachian gas production from the Marcellus and Utica Shale formations decreased by 23 percent and 54 percent, respectively.[82] Decreases in natural gas production during winter storms are also beyond the Companies' control.

Q: PLEASE SUMMARIZE YOUR TESTIMONY RELATED TO THE VOLATILITY OF NATURAL GAS PRICES.

A: Natural gas prices at Henry Hub are volatile, and prices at Transco Zone 5, where North Carolina is located, are even more volatile. This volatility is impacted by factors outside of the Companies' control such as winter storms and geopolitical events. During periods of low supply or high demand, prices spike, increasing volatility. In North Carolina, this volatility was at the heart of hundreds of millions of dollars of recent fuel cost increases approved by the Commission. The Companies' proposed aggressive build-out of natural gas-fired power plants will

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[81] CPIRP Appendix C at 45.

[82] FERC, NERC and Regional Staff Report, *Winter Storm Elliot Report: Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*, FERC at 52 (Oct. 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

only increase their exposure, and their ratepayers' exposure, to the future volatility of natural gas prices.

iv. <u>Summary</u>

Q: PLEASE SUMMARIZE THE NON-REGULATORY RISKS THAT AFFECT THE COMPANIES' ABILITY TO SECURE SUFFICIENT NATURAL GAS AT AFFORDABLE COST TO FUEL THEIR PROPOSED BUILD-OUT OF NATURAL GAS-FIRED POWER PLANTS

A: To fuel the Companies' proposed aggressive schedule in the P3 Fall Base Portfolio to build out their fleet of new natural gas-fired power plants, a significant amount of additional gas will be needed. This increase must be viewed within the context of reasonably foreseeable increases in demand by other sectors and in nearby states—none of which are within the Companies' control. Also beyond the Companies' control is the completion of several pipeline projects that would be required to bring natural gas to North Carolina and to specific power plants according to the P3 Fall Base Portfolio. Winter storms and extreme weather events, geopolitical events, and exposure of the U.S. market to LNG exports are also beyond the Companies' control—and have increased the volatility of natural gas prices, leading to higher average prices.

Q: HOW DO YOU RECOMMEND THAT THE COMMISSION ADDRESS THESE NON-REGULATORY RISKS?

A: I recommend that the Commission account for these risks—and compare them to risks in any alternative portfolios that may be presented by other intervenors—when making a decision in this CPIRP proceeding.

III. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q: PLEASE SUMMARIZE YOUR TESTIMONY REGARDING REGULATORY AND NON-REGULATORY RISKS.

A: I have described several regulatory and non-regulatory risks. The most important regulatory risk, the CAA Section 111 Rule, is essentially now a regulatory certainty because it was recently finalized by the EPA. The Companies' P3 Fall Base Portfolio does not comply with the Final Rule, and its calculation of ratepayer impacts does not account for compliance. The primary non-regulatory risk is whether the Companies will be able to secure sufficient natural gas at affordable cost to fuel their proposed build-out of natural gas-fired power plants. This will have to be done in the context of increasing natural gas demand by other sectors and in nearby states, which are beyond the Companies' control, and can only be accomplished if several critical pipeline projects are completed. Completing these projects is also beyond the Companies' control, and many pipeline projects in the Eastern United States have been canceled or significantly delayed in recent years, so projected completion dates are not certain to be achieved. Adding to the challenge is that natural gas prices will likely continue to be volatile. I recommend that the Commission require the Companies to develop one or more new portfolios that comply with the CAA Section 111 Rule and that the Commission require the Companies to assess the ratepayer impacts associated with all candidate portfolios that comply with the CAA Section 111 Rule. I also recommend that the Commission account for the non-regulatory risks identified in my testimony—and compare them to risks in any alternative portfolios that may be presented by other intervenors—when making a decision in this CPIRP proceeding.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

Hansen
Exhibit 1

EVAN PAUL HANSEN

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Professional Profile

Downstream Strategies, LLC — Morgantown, W.Va.
President, 1997-present

Clients include AECOM; Allegany County, Md.; American Rivers; American Society of Civil Engineers; AmeriCarbon; Appalachian Center for the Economy and the Environment; Appalachian Mountain Advocates; Appalachian Regional Commission; Appalachian Stewardship Foundation; Appalachian Voices; Association of State Wetland Managers; Atkins North America; Aurora Lights; Blue Heron Environmental Network; Bill & Melinda Gates Foundation; Blue Moon Fund; Boggs Environmental Consultants; Bowden Faulkner Citizens Protective Response; Campbells Creek Watershed Improvement Association; Canaan Valley Institute; Center for Applied Environmental Law and Policy; Center for Applied Environmental Science; Center for Biological Diversity; Center for Economic Options; Center for Coalfield Justice; Center for Justice; Center for Watershed Protection; Central Appalachia Network; Central Hampshire Public Service District; Cheat River TMDL Stakeholder Group; City of Cumberland, Md.; Clean Water Network; Coal River Mountain Watch; Dominion Pipeline Monitoring Coalition; Earthjustice; Earthworks; Economic Development Research Group; Elk Headwaters Watershed Association; Fayette County Solid Waste Authority; Friends of Blackwater; Friends of the Cheat; Garrett County, Md.; Greenbrier Valley Economic Development Corporation; GridLab; Harpers Ferry Conservancy; Inter-American Development Bank; Jefferson County Planning Commission; Kent State University Center for Public Administration and Public Policy; Laurel Mountain/Fellowsville Area Clean Watershed Association; Laurel Run Community Watershed Association; Mary Reynolds Babcock Foundation; McDowell County Public Service District; Monongalia County Solid Waste Authority; Morgantown Utility Board; NAACP; National Environmental Services Center; National Fish and Wildlife Foundation; National Parks Conservation Association; Natural Capital Investment Fund; Natural Resources Defense Council; New River Conservancy; Oceana; Ohio River Valley Institute; Ohio Valley Environmental Coalition; Pendleton County Public Service District; Plateau Action Network; Potomac Headwaters Resource Alliance; Prairie Rivers Network; Public Justice; Region VI Planning and Development Council; Rise St. James; Robert & Patricia Switzer Foundation; Rockefeller Family Fund; Save the Tygart; Sierra Club; Solar United Neighbors; Solar Workgroup of Southwest Virginia; Solar Wind Storage; Stewards of the Potomac Highlands; Sun Tribe; Taylor Environmental Advocacy Membership; Tellus Institute/Stockholm Environment Institute-Boston; The Mountain Institute; The Nature Conservancy; Timberline Four Seasons Resort; Town of Harman; Trout Unlimited; US Department of Agriculture; US Department of Energy; US Environmental Protection Agency; University of Calif. Small Farm Center; University of Colorado Denver; University of Md. Francis King Carey School of Law, Environmental Law Clinic; Upper Guyandotte Watershed Association; W.Va. Center on Budget and Policy; W.Va. Conservation Agency; W.Va. Council of Trout Unlimited; W.Va. Department of Environmental Protection; W.Va. Highlands Conservancy; W.Va. Land Trust, W.Va. Public Service Commission Consumer Advocate Division; W.Va. Rivers Coalition; W.Va. Water Research Institute; W.Va. University Center for Energy and Sustainable Development; W.Va. University Industrial Assessment Center.

Natural Heritage Institute (NHI) — San Francisco, Calif.
Resource Scientist Assistant and Consultant, 1995-97

University of California Center for Biological Control — Berkeley, Calif.
Graduate Student Research Assistant, 1995-97

Tellus Institute and Stockholm Environment Institute-Boston (SEI) — Boston, Mass.
Research Analyst and Research Associate, 1988-95

Education

University of California, Berkeley Berkeley, Calif.
M.S. in Energy and Resources awarded 1997. The interdisciplinary Energy and Resources Group combines environmental science, public policy, economics, and engineering.

Massachusetts Institute of Technology Cambridge, Mass.
B.S. in Computer Science and Engineering awarded 1988.

Projects

Mr. Hansen founded Downstream Strategies in 1997. For a wide range of science, policy, planning, and economic development projects, he manages interdisciplinary research teams, performs quantitative and qualitative analyses, provides litigation support, and communicates results with policymakers, local leaders, private companies, and nonprofit organizations.

Policy and scientific analyses

Water resources and water quality

- Reviewing state policies regarding the placement of coal combustion residuals at coal mine sites in three states (Downstream Strategies, 2024, for Earthjustice).
- Updated an evaluation of the economic impacts of failing drinking water, wastewater, and stormwater infrastructure (Downstream Strategies, 2023, for EBP and American Society of Civil Engineers).
- Calculated the local economic benefits of water quality and habitat improvements in the West Branch Susquehanna River watershed, including abandoned mine drainage remediation, instream/riparian habitat restoration, and aquatic organism passage projects (Downstream Strategies, 2023, for Trout Unlimited).
- Assessed impacts of coal combustion residuals on water quality in Cambria County, Pennsylvania (Downstream Strategies, 2023-24, for Ohio River Valley Institute).
- For a Class VI Underground Injection Control permit under consideration for a carbon capture and sequestration project in California, assessed the potential for the injectate to pollute nearby sources of drinking water (Downstream Strategies, 2022, for Center for Biological Diversity).
- Combined disparate nonprofit and government agency water quality datasets and created online interactive map for stream samples near the New River Gorge National Park & Preserve (Downstream Strategies, 2022, for New River Conservancy).
- Assessed whether water withdrawal wells proposed by South Louisiana Methanol could impact the target aquifer—the Gramercy aquifer—and nearby wells (Downstream Strategies, 2022, for Rise St. James).
- Evaluated 19 coal ash disposal sites across the United States for compliance with the federal Coal Combustion Residual Rule (Downstream Strategies, 2022, for Center for Applied Environmental Law and Policy and Earthjustice).
- Quantified the populations potentially at risk from a new federal sewage blending rule, with a focus on low-income and minority populations (Downstream Strategies, 2019, for American Rivers).
- Analyzed regulatory and policy issues related to the deployment of new toilet technologies in the United States (Downstream Strategies, 2019, for Bill & Melinda Gates Foundation).
- Developed a Green Infrastructure Implementation Plan for Martinsburg, W.Va. to guide implementation of new stormwater management projects in an area with limited or no stormwater infrastructure (Downstream Strategies, 2018-19, for National Fish and Wildlife Foundation).
- Assessed potential water quality issues associated with coal combustion residue disposal in South Africa (Downstream Strategies, 2017-18, for Earthjustice).
- Assessed potential water quality issues associated with coal combustion residue disposal in Maryland (Downstream Strategies, 2017-18, for University of Md. Francis King Carey School of Law, Environmental Law Clinic).
- Assessed potential impacts to surface water and groundwater from the construction of natural gas pipelines in West Virginia, Virginia, and North Carolina (Downstream Strategies, 2018, for Natural Resources Defense Council).

- Investigated the use of Nationwide Permit 12 for the Atlantic Coast Pipeline in the Pittsburgh and Norfolk U.S. Army Corps of Engineers districts (Downstream Strategies, 2017, for Sierra Club).
- Provided suggestions for public participation in the permitting processes for the proposed Atlantic Coast Pipeline in West Virginia (Downstream Strategies, 2016, for Dominion Pipeline Monitoring Coalition).
- Supported an effort to integrate nature's values into coastal planning and management in Barbados, strengthen the capacity of the Coastal Zone Management Unit to map and value ecosystem services, and identify pathways for future coastal investment that incorporate climate impacts and the value of ecosystem services (Downstream Strategies, 2014-15, for Inter-American Development Bank).
- Wrote source water protection plans and implemented an ongoing source water protection program to protect drinking water intakes from contamination and to respond effectively if contamination should occur (Downstream Strategies, 2014-present, for Morgantown Utility Board. McDowell County PSD, Pendleton County PSD, Central Hampshire PSD, Town of Harman, and Timberline Four Seasons Resort).
- Providing expert testimony and support for litigation and permit appeals related to the Clean Water Act, Surface Mining Control and Reclamation Act, Safe Drinking Water Act, and water quality issues (Downstream Strategies, 2004-present, for various clients).
- Assessed water wells, streams, and soil for impacts from natural gas wells and coal mines (Downstream Strategies, 2009-15, for various individuals and attorneys).
- Assessed water quality, quantity, access, and value across Appalachia to inform local officials in making development decisions that account for local water assets (Downstream Strategies, 2009-14, for Appalachian Regional Commission).
- Wrote watershed-based plans for Muddy Creek and Pringle Run of the Cheat River to qualify the watersheds for 319 funds. These streams are impaired by acid mine drainage (Downstream Strategies, 2013-14, for Friends of the Cheat).
- Conducted a preliminary assessment of sites that, if improperly managed, could contaminate West Virginia American Water's drinking water intake on the Elk River in Charleston (Downstream Strategies, 2014, for W.Va. Rivers Coalition and W.Va. Land Trust).
- Provided policy recommendations necessary to protect drinking water sources and prevent future chemical spills, with a focus on key issues, information gaps, and policy remedies as they relate to the Clean Water Act, Safe Drinking Water Act, and Emergency Planning and Community Right-to-Know Act (Downstream Strategies, 2014, for W.Va. Rivers Coalition).
- Calculated water footprint for Marcellus Shale gas development in West Virginia and Pennsylvania. Researched sources of water used for hydraulic fracturing and the quality, quantity, and disposition of flowback (Downstream Strategies, 2012-13, for Earthworks and Robert & Patricia Switzer Foundation).
- Developed a new municipal separate storm sewer system (MS4) annual reporting form and MS4 in-lieu program guidance for the West Virginia Department of Environmental Protection (Downstream Strategies, 2011-13, for Center for Watershed Protection and W.Va. Department of Environmental Protection).
- Reviewed cost estimates for acid mine drainage treatment systems at bond forfeiture sites (Downstream Strategies, 2012, for Appalachian Mountain Advocates).
- Helped evaluate the economic impacts of failing drinking water, wastewater, and stormwater infrastructure (Downstream Strategies, 2011, for Economic Development Research Group and American Society of Civil Engineers).
- Wrote watershed-based plan for Sandy Creek of the Tygart Valley River to qualify the watershed for 319 funds. Sandy Creek is impaired by acid mine drainage (Downstream Strategies, 2011-12, for Save the Tygart and W.Va. Department of Environmental Protection).
- Wrote stakeholder- and science-driven comprehensive watershed plan for the Elk River headwaters, one of West Virginia's premier trout streams (Downstream Strategies, 2008-11, for local stakeholders).
- Researched TMDL implementation tracking conducted by state agencies and recommended indicators for future evaluation of progress (Downstream Strategies, 2009-11, for Kent State University Center for Public Administration and Public Policy).
- Helped write a comprehensive watershed plan for the New River, which quantified recreational use and estimated the impact of future development (Downstream Strategies, 2010-11, for National Parks Conservation Association and W.Va. Department of Environmental Protection).

- Project advisor for Jefferson County Blue Ridge Community Area Plan's stakeholder visioning effort and engineering recommendations, including best management practices for steep slope development (Downstream Strategies, 2010, for Jefferson County Planning Commission).
- Wrote watershed plan for metals impairments in Campbells Creek watershed of the Kanawha River (Downstream Strategies, 2010, for Campbells Creek Watershed Improvement Association and W.Va. Conservation Agency).
- Conducted assessment of economic impacts of acid mine drainage remediation efforts in the North Branch Potomac River watershed (Downstream Strategies, 2010, for Garrett County, Md.).
- Researched the potential of mine land reclamation for creating green jobs and diversifying the economy in Central Appalachia. (Downstream Strategies, 2010, for University of Colorado Denver).
- Researched policies that promote or hinder the use of green infrastructure stormwater practices and worked with local government officials to implement green infrastructure (Downstream Strategies, 2009-10, for Region VI Planning and Development Council).
- Wrote watershed-based plan for acid mine drainage and other pollutants for the Wolf Creek watershed (Downstream Strategies, 2009, for Plateau Action Network).
- Researched factors that lead toward successful implementation of total maximum daily loads in West Virginia and Ohio (Downstream Strategies, 2007-08, with Kent State University Center for Public Administration and Public Policy, for US Environmental Protection Agency).
- Analyzed sources of bacterial pollution in Pecks Run and provided recommendations for pollution reductions (Downstream Strategies, 2007-08, with WVRC, for W.Va. Department of Environmental Protection).
- Worked with nonprofit organizations to ensure that ORSANCO maintains strong water quality standards for the Ohio River (Downstream Strategies, 2005-08, for WVRC).
- Conducted technical analyses to support the development of new nutrient water quality criteria in W.Va. (Downstream Strategies, 2002-07, for WVRC).
- Analyzed trace metals in acid mine drainage treatment sludge from a mine that has received coal combustion waste, and assessed downstream drinking water well quality (Downstream Strategies, 2007-8, for Laurel Mountain/Fellowsville Area Clean Watershed Association).
- Calculated the local economic benefits of remediating abandoned mine drainage in the West Fork Susquehanna River watershed in Pennsylvania (Downstream Strategies, 2006-08, for Trout Unlimited).
- Helped improve implementation of West Virginia's Municipal Separate Storm Sewer System (MS4) permits (Downstream Strategies, 2007-08, with W.Va. Water Research Institute, for US Environmental Protection Agency).
- Provided expert testimony to the West Virginia Public Service Commission regarding stream and wetland impacts of a proposed transmission line (Downstream Strategies, 2007-08, for Laurel Run Community Watershed Association).
- Ensured that permitting decisions on a new wastewater treatment plant will preserve native trout habitat in the Upper Elk River watershed (Downstream Strategies, 2005-06, for W.Va. Council of Trout Unlimited).
- Wrote watershed-based plan for metals for the Upper Guyandotte watershed, so that the watershed will qualify for Clean Water Act 319 funds (Downstream Strategies, 2005-06, for Upper Guyandotte Watershed Association).
- Wrote watershed-based plan for acid mine drainage for the Three Forks watershed, so that the watershed will qualify for Clean Water Act 319 funds (Downstream Strategies, 2005-06, for Save the Tygart).
- Designed and implemented a telephone survey of residents and a mail survey of county leaders to help learn about the long-term community and watershed goals of residents of the Mid-Atlantic Highlands of Appalachia (Downstream Strategies, 2004-05, for Canaan Valley Institute).
- Wrote watershed assessment for the Robinson Run watershed, which is impaired by acid mine drainage (Downstream Strategies, 2005, for Region VI Planning and Development Council).
- Wrote watershed-based plan the North Fork Blackwater River watershed, which is impaired by acid mine drainage, so that the watershed will qualify for Clean Water Act 319 funds (Downstream Strategies, 2005, for Friends of Blackwater).
- Assessed whether trace metals have been found in surface and groundwater downgradient from coal mining sites on which coal combustion waste has been disposed (Downstream Strategies, 2005).

- Provided expert testimony on NPDES permits before the W.Va. Environmental Quality Board (Downstream Strategies, 2003-10, for Stewards of the Potomac Highlands, Blue Heron Environmental Network, and Bowden Faulkner Citizens Protective Response).
- Provided expert testimony on coal mine permit before the W.Va. Surface Mine Board (Downstream Strategies, 2004-09, for WVRC, W.Va. Highlands Conservancy, Trout Unlimited, and Taylor County Environmental Advocacy Membership).
- Wrote watershed-based plan for tributaries in the lower Cheat watershed impaired by acid mine drainage, bacteria, and sediment, so that the watershed will qualify for Clean Water Act 319 funds (Downstream Strategies, 2004-05, for Friends of the Cheat).
- Compiled matrix of past and upcoming Clean Water Act and Safe Drinking Water Act regulations that affect small communities (Downstream Strategies, 2004-05, for National Environmental Services Center).
- Drafted detailed technical comments on an NPDES permit for a wastewater treatment plant discharging into a major recreational river close to Harpers Ferry National Historical Park (Downstream Strategies, 2004, for Harpers Ferry Conservancy).
- Provided technical assistance related to the acid mine drainage total maximum daily loads being developed for the Cheat River watershed. Managed a US Environmental Protection Agency pilot project and helped draft a water quality trading framework to implement the TMDL (Downstream Strategies, 1999-2004, for the Cheat River TMDL Stakeholder Group).
- Created an instructional document to help local organizations assess state implementation of the Clean Water Act's antidegradation provisions (Downstream Strategies, 2001, for Clean Water Network).
- Assessed progress made toward implementing the pollutant reduction goals set forth in the West Virginia's TMDLs (WVRC, 2001).
- Edited white paper on computer modeling and TMDLs to help public interest organizations participate effectively in TMDL development (Downstream Strategies, 2001, for Clean Water Network).
- Assessed US Environmental Protection Agency's process for generating new nutrient water quality criteria, and the application of their process to Nutrient Ecoregion XI, where West Virginia is located (Downstream Strategies, 2001, for WVRC).
- Assessed a random set of West Virginia's NPDES water pollution control discharge permits, and the permitting process, based on a range of criteria. Provided recommendations to the state Department of Environmental Protection for improving public participation in the permitting process (WVRC, 2000-01).
- Assessed total maximum daily loads developed by US Environmental Protection Agency for acid mine drainage in two West Virginia rivers (Downstream Strategies, 1998, for WVRC, Ohio Valley Environmental Coalition, and W.Va. Highlands Conservancy).
- Assessed the data, assumptions, and computer model used by US Environmental Protection Agency to develop total maximum daily loads for fecal coliform in six rivers in the Potomac headwaters (Downstream Strategies, 1997, for Potomac Headwaters Resource Alliance and WVRC).
- Helped establish a modeling unit to evaluate state-wide conjunctive use programs. The unit consists of environmental groups, water supply districts, and state and federal agencies with jurisdiction over water in California (NHI, 1995-97).
- Analyzed global and national patterns of water supply, use, and scarcity (SEI, 1995).
- Modeled water supply and demand in the tributaries to the Aral Sea to predict future water level decline (SEI, 1992).

Energy and climate change

- Wrote community benefits plans for federal grant applications for new energy manufacturing facilities in West Virginia and Nevada (Downstream Strategies, 2023-present, for confidential client).
- For large-scale solar projects in West Virginia, performed economic benefits analyses and wrote testimony for solar siting certificates from the Public Service Commission (Downstream Strategies, 2020-23, for confidential clients).
- For a large-scale solar project in West Virginia, performed critical issues analysis of wetlands, waterbodies, floodplains, soils, threatened and endangered species, cultural resources, conservation easements, site contamination, and local ordinances and zoning (Downstream Strategies, 2022, for confidential client).

- Calculated the greenhouse gas reductions associated with a new carbon product as compared with imports from overseas (Downstream Strategies, 2021, for AmeriCarbon).
- Helped model the economic benefits of new advanced energy manufacturing tax credits (Downstream Strategies, 2021).
- Helped model the economic benefits of new federal investments in abandoned mine land reclamation (Downstream Strategies, 2021).
- Helped develop scenarios of West Virginia's energy future that would ramp up renewables, decrease costs, reduce risks, and strengthen economic opportunities (Downstream Strategies, 2020, for GridLab).
- In support of a coalition seeking to develop a solar cluster in the coalfield counties of Southwest Virginia, helped per form an economic impact assessment of solar development (Downstream Strategies, 2017, for Solar Workgroup of Southwest Virginia).
- Explored whether Marcellus Shale gas production has become more common near places essential for everyday life in West Virginia, increasing the potential for human exposure to contaminants associated with drilling and natural gas extraction (Downstream Strategies, 2017).
- Wrote a handbook for state regulators and consultants regarding state 401 certification of federal 404 permits for natural gas pipelines (Downstream Strategies, 2017-18, for Association of State Wetland Managers).
- Performed an economic analysis of a patented new technology to store hydrogen generated by solar and wind in underground chambers (Downstream Strategies, 2017-19, for Solar Wind Storage).
- Assessed opportunities and policies for developing large-scale solar projects on degraded lands in West Virginia (Downstream Strategies, 2018-19, for The Nature Conservancy).
- Analyzed economic resilience, documenting successful approaches to restructuring local economies, and compiling a set of strategies that can be implemented in communities throughout Appalachian Region impacted by the downturn of the coal industry. (Downstream Strategies, 2017-19, for Appalachian Regional Commission).
- Quantified the prospects for large-scale solar development on degraded land in West Virginia (Downstream Strategies, 2016-17, for Appalachian Stewardship Foundation).
- Assessed options for West Virginia to reduce greenhouse gas emissions from existing coal-fired power plants under the Clean Power Plan (Downstream Strategies, 2014-16, for W.Va. University Center for Energy and Sustainable Development and Appalachian Stewardship Foundation).
- Helped compile a community greenhouse gas inventory, survey residences, and develop and implement a program to increase energy efficiency and reduce energy costs and greenhouse gas emissions for Morgantown, West Virginia (Downstream Strategies, 2013-16, for Appalachian Stewardship Foundation).
- Facilitated the Mountain Maryland Energy Advisory Committee, a stakeholder group investigating energy opportunities in Garrett County (Downstream Strategies, 2013-15, for Garrett County, Md.).
- Analyzed the potential uses and benefits of a new coal severance tax in Illinois (Downstream Strategies, 2015, for Prairie Rivers Network)
- Advised a research project to assess the forest assets of Appalachia, including: quality, quantity, use, ownership patterns, and market and non-market valuation (Downstream Strategies, 2010-14, for the Appalachian Regional Commission).
- Wrote white paper that explains the benefits of solar energy and provides an overview of state policies needed to expand its deployment in West Virginia (Downstream Strategies, 2013-14, for The Mountain Institute and Blue Moon Fund).
- Oversaw energy audits for businesses across West Virginia (Downstream Strategies, 2011-14, for W.Va. University Industrial Assessment Center).
- Conducted a comprehensive analysis of the numerous market and regulatory influences that impact demand for Central Appalachian coal and identified which of the region's coal-producing counties are most vulnerable (Downstream Strategies, 2012-13, for Blue Moon Fund).
- Researched opportunities for renewable energy development across West Virginia and worked with local communities to implement these opportunities (Downstream Strategies, 2011-13, for The Mountain Institute and Blue Moon Fund).
- Analyzed potential impacts of a proposed surface mine in Pennsylvania on neighboring properties (Downstream Strategies, 2012, for private client).

- Helped research the impact of the coal industry on the Pennsylvania state budget, including the revenues, on-budget expenditures, tax expenditures, expenditures supporting coal-related employment, and legacy costs resulting from coal industry activity (Downstream Strategies, 2011-12, for Center for Coalfield Justice).
- Helped research the impact of the coal industry on the state budgets for West Virginia, Tennessee, and Virginia, including the revenues, on-budget expenditures, tax expenditures, expenditures supporting coal-related employment, and legacy costs resulting from coal industry activity (Downstream Strategies and West Virginia Center on Budget and Policy, 2010-13, for the Blue Moon Fund, Mary Reynolds Babcock Foundation, Natural Resources Defense Council, Rockefeller Family Fund, Sierra Club, and University of Colorado Denver).
- Researched market barriers to wind energy development in Central Appalachia and proposing strategies to overcome these barriers (Downstream Strategies, 2010-12, for The Mountain Institute and US Department of Energy).
- Researched the challenges to future coal production in Central Appalachia due to increased competition from other coal-producing regions and sources of energy; the depletion of the most accessible, lowest-cost coal reserves; and environmental regulations (Downstream Strategies, 2010).
- Compiled a variety of information to help guide the Central Appalachia Prosperity Project, an initiative to create a plan for the region’s transition to a clean energy economy built on green jobs and industries, healthy communities, protection of natural resources, and restoration of assets that have been depleted or damaged by past activities (Downstream Strategies, 2009, for University of Colorado Denver).
- Created Renewable Energy on Coal River Mountain theme, including maps, videos, and lesson plans, for the Journey Up Coal River Web site (Downstream Strategies, 2009, for Aurora Lights).
- Calculated the financial costs and benefits and the local economic benefits of building an industrial wind farm versus a mountaintop removal mine on Coal River Mountain in West Virginia (Downstream Strategies, 2008, for Coal River Mountain Watch).
- Compiled information on the use of greenhouse gas credits and renewable energy credits to help implement landfill gas-to-energy projects on small public landfills in West Virginia (Downstream Strategies, 2006-07, for The Mountain Institute).
- Assessed the prospects for landfill gas-to-energy projects in West Virginia (Downstream Strategies, 2005-06, for The Mountain Institute).
- Advised US Environmental Protection Agency on the development of a computer model and database for evaluating greenhouse gas emission scenarios based on the use of improved technologies (Downstream Strategies, 1998-2000, for the Air Pollution Prevention and Control Division of US Environmental Protection Agency).
- Projected agricultural energy use in Zimbabwe, Sudan, Senegal, Tanzania, and Egypt (SEI, 1995).
- Assessed the feasibility of a long-term transition toward a fossil-free energy future (SEI, 1993).
- Modeled alternative future energy strategies for Zimbabwe and Zambia (SEI, 1993).

Agriculture and the environment

- Identified barriers and proposed recommendations for the expansion of organic agriculture across the West Virginia, based on surveys and interviews of West Virginia farmers combined with economic, policy, and GIS analyses (Downstream Strategies, 2011-13, for US Department of Agriculture).
- Quantified the environmental benefits of a poultry litter baling facility in the eastern panhandle of West Virginia (Downstream Strategies, 2012-13, for Blue Moon Fund).
- Helped conduct a feasibility study for a poultry litter composting facility for the eastern panhandle of West Virginia, emphasizing potential economic benefit for farmers and environmental benefit of reduced nutrient run-off (Downstream Strategies, 2011-12, for Blue Moon Fund).
- Helped conduct regional food system assessment for the Greenbrier Valley, West Virginia (Downstream Strategies, 2010-11, for Greenbrier Valley Economic Development Corporation).
- Assisted the Tygart Valley Growers Association with understanding and influencing federal and state food safety policy (Downstream Strategies, 2011, for Center for Economic Options and Central Appalachia Network).

- Analyzed trends in family and corporate ownership of livestock and poultry farms across the United States (Downstream Strategies, 2000, for Clean Water Network).
- Advised US Department of Agriculture on opportunities to improve marketing assistance for small-scale farmers through a survey of small-scale produce farmers in the southeastern United States (Downstream Strategies, 1998-2000, for UC Small Farm Center).
- Calculated nutrient uptake capacities on cropland and pasture and compared these capacities with nutrients generated by poultry in West Virginia's major poultry-producing region (Downstream Strategies, 1998-99, for Potomac Headwaters Resource Alliance and WVRC).
- Assessed pest control strategies and information sources used by different groups of small-scale California farmers (MS Thesis, 1997).
- Performed economic analyses of successful biological control programs (UC Center for Biological Control, 1996-97).

Other
- Developing a manufacturing business attraction analysis, tourism business expansion analysis, regional strategic plan for business attraction, and marketing/sales pitch packet to retain and recruit outdoor recreation and lifestyle manufacturing businesses and employees to western Maryland (Downstream Strategies, 2022, for Allegany and Garrett counties, Md.).
- Provided recommendations for improving solid waste management and recycling throughout Fayette County, West Virginia (Downstream Strategies, 2022, for Fayette County Solid Waste Authority).
- Assessed the economic impacts and implementation pace of the Abandoned Mine Land Economic Revitalization Program (Downstream Strategies, 2022, for Appalachian Voices).
- Assisted in the development of a Comprehensive Economic Development Strategy for North-central West Virginia (Downstream Strategies, 2022, for Region VI Planning and Development Council).
- Estimated the economic benefits of Abandoned Mine Land Economic Revitalization Program projects and identified why many projects take longer than originally planned (Downstream Strategies, 2021-22, for Appalachian Voices).
- Updated Garrett County, Md.'s comprehensive plan (Downstream Strategies, 2018-19, for Garrett County, Md.).
- Developed a Blight Action Plan for vacant and dilapidated buildings (Downstream Strategies, 2018, for City of Cumberland).
- Assessed future scenarios for Monongalia County, West Virginia to reduce the amount of trash sent to landfills by increasing recycling and composting or by building a gasification plant (Downstream Strategies, 2016-18, for Monongalia County Solid Waste Authority).

Tool development

Water resources and water quality
- WEAP (Water Evaluation And Planning system). Used by nonprofit organizations, government agencies, and water supply districts to evaluate alternatives for meeting water supply, demand, and quality goals (SEI, 1991-95).
- RESULTS (Registry of Equipment Suppliers of Treatment Technologies for Small Systems). Used by community officials, state regulators, and consulting engineers to learn about technologies in use at small drinking water systems across the United States. (Downstream Strategies, 1999-2000, for National Environmental Services Center).
- BIB (NDWC Bibliographic Database). Used by technical assistants at NDWC to reference articles related to drinking water systems in small communities (Downstream Strategies, 1999-2000, for National Environmental Services Center).

Energy and greenhouse gases
- LEAP and EDB (Long-range Energy Alternatives Planning system and the accompanying Environmental Database). Used by more than 100 institutions in over 30 countries to model long-term energy and environmental scenarios (SEI, 1990-95).

- G2S2 (Greenhouse Gas Scenario System). Used by nonprofit organizations and government agencies to model current and future sources and sinks of greenhouse gases (SEI, 1993-95).

Other

- PoleStar. Used by policy analysts to model alternative development strategies by assessing interactions between economic growth, resource use, lifestyle choice, and the environment (SEI, 1994).
- P2/FINANCE (Pollution Prevention Financial Analysis and Cost Evaluation system). Used by the screen printing and metal finishing industries to weigh the profitability of pollution prevention investments (SEI, 1995).
- Congressional Correspondence Database. Used to track correspondence with congressional representatives related to services provided by ESTD (Downstream Strategies, 1999, for National Environmental Services Center).

Training

Water resources and water quality

- Conducted NPDES permit and TMDL training workshops for watershed organizations across West Virginia. Workshops include basic permitting issues, antidegradation, and stormwater (WVRC, 2000-10).
- Co-led a general Clean Water Act training workshop for a watershed organization in Morgantown, W.Va. (WVRC, 2000).
- Co-led a three-day integrated water resources planning and WEAP software training workshop for water planners at the Water Research Centre in Cairo, Egypt (SEI, 1994).
- Trained analysts from the Beijing Municipal Environmental Protection Bureau, China (SEI, 1994).

Energy and greenhouse gases

- Co-led a one-week integrated energy planning and LEAP software training workshop in Zimbabwe for energy planners from across sub-Saharan Africa (SEI, 1992).
- Trained analysts from the Energy for Development Research Centre, Cape Town, South Africa and the national Departments of Energy in Zimbabwe, Zambia, and Tanzania (SEI, 1992-95).

Publications

Peer-reviewed articles

Hoornbeek J, Hansen E. 2013. Integrated Water Resource Management (IWRM) in the United States: An Inquiry into the Role of Total Maximum Daily Loads (TMDLs). *International Journal of Water Governance.* 2013:339–360.

Hoornbeek J, Hansen E, Ringquist E, Carlson R. 2013. Implementing water pollution policy in the United States: Total maximum daily loads and collaborative watershed management. *Society and Natural Resources.* 26(4):420-436.

Collins AR, Hansen E, Hendryx M. 2012. Wind versus coal: Comparing the local economic impacts of energy resource development in Appalachia. *Energy Policy*, 50:551-561.

Hansen E, Hereford A, McIlmoil R. 2010. Orange water, green jobs. *Solutions*, 1(4):53-61.

Hansen E. 2007. Protecting West Virginia trout streams. *The West Virginia Public Affairs Reporter*. 24(3).

Dahlsten DL, Hansen EP, Zuparko RL, Norgaard RB. 1998. Biological control of the blue gum psyllid proves economically beneficial. *California Agriculture*, 52(1):35-40.

Raskin PD, Hansen E, Margolis RM. 1996. Water and sustainability: Global patterns and long-range problems. *Natural Resources Forum*, 20(1):1-15.

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Book chapters

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Hansen E, Christ M, Fletcher J, Herd R, Petty JT, Ziemkiewicz P. 2004. The potential for water quality trading to help implement the Cheat watershed acid mine drainage total maximum daily load in West Virginia. Downstream Strategies.

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Raskin P, Hansen E, Margolis R. 1995. Water and sustainability: A global outlook. SEI.

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Talbot N, Hansen E. 1993. Zambia: Resuming the energy transition. SEI and Zambia Department of Energy.

Talbot N, Hansen E. 1993. Zimbabwe: Energy end-uses and end-use efficiency. SEI and Zimbabwe Department of Energy.

Awards

- Morgantown Human Rights Commission Don Spencer Human Rights Day Award, 2016
- W.Va. Environmental Council's Don Gasper Science in the Public Interest Award, 2014.
- W.Va. Watershed Network Guiding Light Award, 2005.
- Switzer Environmental Leadership Grant, 2000 and 2002.
- Switzer Environmental Fellowship, 1996.
- Tau Beta Pi and Eta Kappa Nu honorary fraternities, 1988.

Public Service

- Elected to the West Virginia House of Delegates to represent the 51st and 79th districts in Monongalia County (2018, 2020, 2022).
- Board of Directors of Main Street Morgantown, 2023-present.
- US Environmental Protection Agency Local Government Advisory Committee, 2021-present.
- Board of Directors of Spark! Imagination and Science Center, 2017-present.
- Board of Directors of Canaan Valley Institute, 2016-present.
- Board of Directors of Morgantown Rotary Club, 2020-2023.
- Board of Directors of Monongalia County Read Aloud, 2018-2023.
- Board of Directors of West Virginia Center on Climate Change, 2018-2022.
- Board of Directors of Appalachian Headwaters, 2015-22.
- Invited presentation to Atlantic Council Millennium Leadership Program, Millennium Fellowship Program 2017 West Virginia Study Tour (June 2017, Energy-Water Nexus in West Virginia).
- Invited presentation to the U.S. Department of State International Visitor Leadership Program (June 2017, State and Federal Energy Issues).
- Invited testimony to the U.S. Senate Environment and Public Works Committee (March 2014, Preventing Potential Chemical Threats and Improving Safety: Oversight of the President's Executive Order on Improving Chemical Facility Safety and Security).
- Invited presentation to the W.Va. Legislature Judiciary Committee (February 2014, Potential Significant Contaminant Sources above West Virginia American Water's Charleston Intake: A Preliminary Assessment).
- Invited presentations to W.Va. Legislature Joint Legislative Oversight Commission on State Water Resources (January 2014, The Freedom Industries Spill: Lessons Learned and Needed Reforms; October 2013, Water Footprint and Water Resource Reporting from Marcellus Shale Drilling and Hydraulic Fracturing in West Virginia and Pennsylvania).
- Invited presentation to W.Va. Legislature Joint House Judiciary/House Health and Human Resources Committees (January 2014, The Freedom Industries Spill: Lessons Learned and Needed Reforms).
- Invited speaker for W.Va. University Davis-Michael Sustainability Fellows Program, W.Va. University Plant and Soil Sciences Club, W.Va. Geological and Economic Survey, W.Va. University Society of Environmental Professionals, W.Va. University Department of Public Administration, W.Va. University Pi Sigma Sigma Policy Studies Honorary, Oglebay Institute Living Green Lecture Series, Mountaineer Audubon Chapter, Friends of Deckers Creek, Yale School of Forestry and Environmental Studies, W.Va. Associated Press Legislative Lookahead, W.Va. University Institute for Public Affairs Local Government Leadership Academy, Robert and Patricia Switzer Foundation, Monongahela River Water Quality Forum, W.Va. University Fisheries Society, Downstream Alliance, Cheat Lake Environment and Recreation Association, W.Va. University Forestry Club, Tellus Institute, W.Va. Environmental Council, W.Va./Pa. Monongahela Area Watersheds Compact, and W.Va. Chapter of the Sierra Club.
- Morgantown Utility Board Technical Advisory Group, 2011.
- City of Morgantown City Manager's Green Team, 2007-10.
- W.Va. Environmental Quality Board Aluminum Study Review Team, 2002-03.
- W.Va. Environmental Quality Board/W.Va. Department of Environmental Protection Nutrient Criteria Committee, 2002-07.
- W.Va. Department of Environmental Protection Water Quality Trading Stakeholder Committee, 2002-04.

- Board of Directors of Friends of Deckers Creek, 2000-10. President, 2002-10.
- Morgantown Utility Board Storm Water Utility Stakeholder Group, 2002.
- US Environmental Protection Agency Peer Review Committee of the acid mine drainage functions of the Watershed Analysis Risk Management Framework (WARMF) TMDL computer model, 2000.
- US Environmental Protection Agency Peer Review Committee of the WARMF TMDL computer model, 1999-2000.
- W.Va. Department of Environmental Protection Total Maximum Daily Load Steering Committee, 1999-2001.
- Guest lecturer for W.Va. University courses in Science and Public Policy, Fisheries Management, Conservation Biology, Environmental Systems, Environmental Impact Assessment, Art and Environment, and Natural Resources of West Virginia.

Hansen
Exhibit 2

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please refer to Duke's response to Public Staff DR 10-3. In response to DR 10-3(b), the Companies state that "Incorporating the EPA 111d 50% CF limitation on new and existing CCs reduced the amount of energy available to meet system demand." Have the Companies performed modeling runs using a 40% capacity factor limit as outlined in the final Clean Air Act Section 111 rule? If not, please explain why.

Response:

The Companies are currently in the process of analyzing the legal and technical implications of the recently finalized EPA regulation under Section 111(b) and (d) of the Clean Air Act applicable to new gas combustion turbines and existing coal steam generators. The Companies are developing such analysis under privilege and will produce the final analysis of the Companies' compliance strategy to the Commission at the appropriate time.

Responder: Michael T. Quinto, Director, IRP Advanced Analytics

Hansen

Exhibit 3

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please explain whether the Companies expect the operation of its proposed combined cycle natural gas-fired power plants at a 40% capacity factor limit to affect the estimated amount of CO2 emissions over the expected lifespan of the power plants. If yes, please explain how a 40% capacity factor limit at the Companies' proposed combined cycle natural gas-fired power plants will affect the carbon reduction mandates outlined in HB 951 (N.C.G.S. § 62-110.9)?

Response:

As explained in the Companies' response to Appalachian Voices DR 4-1, the Companies are in the process of assessing the impacts of the recently finalized EPA rules and the impact on the resource portfolio. While this analysis is underway, it is premature to speculate on the impact of CO2 emission from selected new natural gas combined cycle resources.

Responder: Michael T. Quinto, Director, IRP Advanced Analytics

Hansen
Exhibit 4

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Regarding the modeling for Portfolio P3 Fall Base, what capacity factor limit was used for the proposed combined cycle natural gas-fired power plants?

Response:

The Companies did not include any capacity factor limit for proposed combined cycle natural gas-fired power plants in the modeling of Portfolio P3 Fall Base.

Responder: Thomas Beatty, Senior Engineer

Hansen
Exhibit 5

Appalachian Voices'
Docket No. E-100, Sub 190
2023 Carolinas Resource Plan
Appalachian Voices' Request No. 2
Item No. 2-1

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

For each existing combustion turbine and combined cycle natural gas-fired power plant across both the DEC and DEP service territories, please provide the following by year between 2019 and 2023:

Nameplate capacity (MW).

2-1-1 Nameplate capacity (MW).
2-1-2 Annual generation (MWh).
2-1-3 Annual capacity factor.
2-1-4 Amount of natural gas used.

Response:

Please see the attached file: "App Voices 2-1 - CT-CC Data.xlsx."

App Voices 2-1 - CT-CC Data.xlsx

Responder: David Julius, Initiative Management Manager

App Voices DR 2-1

2-1 For each existing combustion turbine and combined cycle natural gas-fired power plant across both the DEC and DEP service territories, please provide the following by year between 2019 and 2023

2-1-1 Nameplate capacity (MW).
2-1-2 Annual generation (MWh).
2-1-3 Annual capacity factor.
2-1-4 Amount of natural gas used.

				2-1-1	2-1-2	2-1-3	2-1-4
Jurisdiction	Generating Station	Generating Unit	Station-Unit	Name Plate	Net Annual MWh	Net Capacity Factor	Fuel Consumed MBTU
DEC	Buck CC	CC	Buck CC1-1	185.3	1,134,065	69.86%	13,222,363
DEC	Buck CC	CC	Buck CC1-2	185.3	1,134,559	69.90%	12,744,701
DEC	Buck CC	CC	Buck CC1-S	327.25	1,598,203	55.75%	4,624,834
DEC	Clemson CHP	CC	Clemson CHP1-1	13.4	5,300	4.51%	0
DEC	Dan River CC	CC	Dan River CC1-7	185.3	1,847,499	113.82%	4,759,736
DEC	Dan River CC	CC	Dan River CC1-8	185.3	1,311,548	80.80%	13,476,781
DEC	Dan River CC	CC	Dan River CC1-9	327.25	1,297,690	45.27%	13,212,069
DEC	Lincoln CT	CT	Lincoln CT-1	109.6	941	0.10%	29,768
DEC	Lincoln CT	CT	Lincoln CT-2	109.6	1,972	0.21%	26,382
DEC	Lincoln CT	CT	Lincoln CT-3	109.6	1,608	0.17%	30,506
DEC	Lincoln CT	CT	Lincoln CT-4	109.6	1,227	0.13%	38,242
DEC	Lincoln CT	CT	Lincoln CT-5	109.6	934	0.10%	23,814
DEC	Lincoln CT	CT	Lincoln CT-6	109.6	879	0.09%	30,506
DEC	Lincoln CT	CT	Lincoln CT-7	109.6	1,542	0.16%	26,690
DEC	Lincoln CT	CT	Lincoln CT-8	109.6	1,931	0.20%	30,127
DEC	Lincoln CT	CT	Lincoln CT-9	109.6	-1,132	-0.12%	20,553
DEC	Lincoln CT	CT	Lincoln CT-10	109.6	622	0.06%	22,440
DEC	Lincoln CT	CT	Lincoln CT-11	109.6	1,155	0.12%	21,868
DEC	Lincoln CT	CT	Lincoln CT-12	109.6	746	0.08%	17,189
DEC	Lincoln CT	CT	Lincoln CT-13	109.6	679	0.07%	21,814
DEC	Lincoln CT	CT	Lincoln CT-14	109.6	897	0.09%	25,114
DEC	Lincoln CT	CT	Lincoln CT-15	109.6	798	0.08%	25,372
DEC	Lincoln CT	CT	Lincoln CT-16	109.6	968	0.10%	23,020
DEC	Mill Creek CT	CT	Mill Creek CT-1	99.9	12,356	1.41%	148,893
DEC	Mill Creek CT	CT	Mill Creek CT-2	99.9	11,997	1.37%	137,225
DEC	Mill Creek CT	CT	Mill Creek CT-3	99.9	11,129	1.27%	117,976
DEC	Mill Creek CT	CT	Mill Creek CT-4	99.9	9,250	1.06%	117,385
DEC	Mill Creek CT	CT	Mill Creek CT-5	99.9	7,147	0.82%	127,583
DEC	Mill Creek CT	CT	Mill Creek CT-6	99.9	7,460	0.85%	118,153
DEC	Mill Creek CT	CT	Mill Creek CT-7	99.9	5,557	0.63%	119,736
DEC	Mill Creek CT	CT	Mill Creek CT-8	99.9	5,436	0.62%	117,006
DEC	Rockingham CT	CT	Rockingham CT-1	195.5	98,487	5.75%	1,975,972
DEC	Rockingham CT	CT	Rockingham CT-2	195.5	182,087	10.63%	2,000,280
DEC	Rockingham CT	CT	Rockingham CT-3	195.5	144,230	8.42%	2,200,262
DEC	Rockingham CT	CT	Rockingham CT-4	195.5	130,451	7.62%	1,894,004
DEC	Rockingham CT	CT	Rockingham CT-5	195.5	101,316	5.92%	2,279,418
DEC	W.S. Lee CC	CC	W.S. Lee CC1-10	362.1	2,443,026	77.02%	5,706,290
DEC	W.S. Lee CC	CC	W.S. Lee CC1-11	242.25	1,739,314	81.96%	16,070,182
DEC	W.S. Lee CC	CC	W.S. Lee CC1-12	242.25	1,853,394	87.34%	15,973,435
DEC	W.S. Lee CT	CT	W.S. Lee CT-07C	54	877	0.19%	47,415
DEC	W.S. Lee CT	CT	W.S. Lee CT-08C	54	834	0.18%	123,781
DEP	Asheville CC	CC	Asheville CC1-A	191.2	1,043,253	62.29%	1,077,761
DEP	Asheville CC	CC	Asheville CC1-S	102.8	490,224	54.44%	0
DEP	Asheville CC	CC	Asheville CC2-A	191.2	1,027,585	61.35%	311,268
DEP	Asheville CC	CC	Asheville CC2-S	102.8	399,681	44.38%	0
DEP	Asheville CT	CT	Asheville CT-3	211.7	80,761	4.35%	1,830,949
DEP	Asheville CT	CT	Asheville CT-4	211.8	97,407	5.25%	1,645,040
DEP	Blewett CT	CT	Blewett CT-1	17.5	-84	-0.05%	0
DEP	Blewett CT	CT	Blewett CT-2	17.5	-96	-0.06%	0
DEP	Blewett CT	CT	Blewett CT-3	17.5	-83	-0.05%	0
DEP	Blewett CT	CT	Blewett CT-4	17.5	-79	-0.05%	0
DEP	Darlington CT	CT	Darlington CT-12	158	1,540	0.11%	167,687
DEP	Darlington CT	CT	Darlington CT-13	158	38	0.00%	104,552
DEP	H.F. Lee CC	CC	H.F. Lee CC1-A	221	1,039,771	53.71%	12,291,243
DEP	H.F. Lee CC	CC	H.F. Lee CC1-B	221	1,157,910	59.81%	12,504,347
DEP	H.F. Lee CC	CC	H.F. Lee CC1-C	221	1,150,591	59.43%	12,543,802
DEP	H.F. Lee CC	CC	H.F. Lee CC1-S	405	2,305,740	64.99%	11,729,118
DEP	Smith Energy Complex	CT	Smith Energy Complex-1	199.4	270,210	15.47%	3,814,453
DEP	Smith Energy Complex	CT	Smith Energy Complex-2	199.4	279,818	16.02%	3,862,007
DEP	Smith Energy Complex	CT	Smith Energy Complex-3	199.4	242,674	13.89%	3,054,347
DEP	Smith Energy Complex	CT	Smith Energy Complex-4	199.4	180,149	10.31%	4,240,648
DEP	Smith Energy Complex	CC	Smith Energy Complex4-7	199.4	954,015	54.62%	13,961,246
DEP	Smith Energy Complex	CC	Smith Energy Complex4-8	199.4	938,673	53.74%	13,334,942
DEP	Smith Energy Complex	CC	Smith Energy Complex4-S	195.5	1,102,306	64.37%	0
DEP	Smith Energy Complex	CC	Smith Energy Complex5-10	191.2	1,314,306	78.47%	13,695,480

DEP	Smith Energy Complex	CC	Smith Energy Complex5-9	191.2	1,320,105	78.82%	13,564,372
DEP	Smith Energy Complex	CC	Smith Energy Complex5-S	271.1	1,720,801	72.46%	0
DEP	Smith Energy Complex	CT	Smith Energy Complex-6	199.4	258,014	14.77%	3,424,030
DEP	Sutton CC	CC	Sutton CC1-A	221	1,226,982	63.38%	15,968,286
DEP	Sutton CC	CC	Sutton CC1-B	221	1,237,878	63.94%	15,822,772
DEP	Sutton CC	CC	Sutton CC1-S	288	1,548,834	61.39%	0
DEP	Sutton FS CT	CT	Sutton FS CT-4	60.5	31,928	6.02%	946,416
DEP	Sutton FS CT	CT	Sutton FS CT-5	60.5	32,731	6.18%	971,296
DEP	Wayne CT	CT	Wayne CT-10	195.2	17,944	1.05%	102,930
DEP	Wayne CT	CT	Wayne CT-11	195.2	19,263	1.13%	55,776
DEP	Wayne CT	CT	Wayne CT-12	195.2	28,733	1.68%	207,926
DEP	Wayne CT	CT	Wayne CT-13	195.2	45,705	2.67%	389,774
DEP	Wayne CT	CT	Wayne CT-14	198.9	63,753	3.66%	795,215
DEP	Weatherspoon CT	CT	Weatherspoon CT-1	39.7	-33	-0.01%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-2	39.7	10	0.00%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-3	41.8	-13	0.00%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-4	41.8	-26	-0.01%	0

				2-1-1	2-1-2	2-1-3	2-1-4
Jurisdiction	Generating Station	Generating Unit	Station-Unit	Name Plate	Net Annual MWh	Net Capacity Factor	Fuel Consumed MBTU
DEC	Buck CC	CC	Buck CC1-1	185.3	1,134,065	69.67%	12,134,538
DEC	Buck CC	CC	Buck CC1-2	185.3	1,134,559	69.70%	11,688,807
DEC	Buck CC	CC	Buck CC1-S	327.25	1,598,203	55.60%	3,160,534
DEC	Clemson CHP	CC	Clemson CHP1-1	13.4	5,300	4.50%	62,924
DEC	Dan River CC	CC	Dan River CC1-7	185.3	1,297,690	79.73%	3,739,687
DEC	Dan River CC	CC	Dan River CC1-8	185.3	1,311,548	80.58%	14,054,447
DEC	Dan River CC	CC	Dan River CC1-9	327.25	1,847,499	64.27%	13,952,156
DEC	Lincoln CT	CT	Lincoln CT-1	109.6	941	0.10%	25,273
DEC	Lincoln CT	CT	Lincoln CT-2	109.6	1,972	0.20%	26,094
DEC	Lincoln CT	CT	Lincoln CT-3	109.6	1,608	0.17%	22,532
DEC	Lincoln CT	CT	Lincoln CT-4	109.6	1,227	0.13%	18,039
DEC	Lincoln CT	CT	Lincoln CT-5	109.6	934	0.10%	14,365
DEC	Lincoln CT	CT	Lincoln CT-6	109.6	879	0.09%	14,064
DEC	Lincoln CT	CT	Lincoln CT-7	109.6	1,542	0.16%	20,047
DEC	Lincoln CT	CT	Lincoln CT-8	109.6	1,931	0.20%	24,848
DEC	Lincoln CT	CT	Lincoln CT-9	109.6	(1,132)	-0.12%	14,671
DEC	Lincoln CT	CT	Lincoln CT-10	109.6	622	0.06%	12,501
DEC	Lincoln CT	CT	Lincoln CT-11	109.6	1,155	0.12%	18,592
DEC	Lincoln CT	CT	Lincoln CT-12	109.6	746	0.08%	13,120
DEC	Lincoln CT	CT	Lincoln CT-13	109.6	679	0.07%	12,293
DEC	Lincoln CT	CT	Lincoln CT-14	109.6	897	0.09%	14,534
DEC	Lincoln CT	CT	Lincoln CT-15	109.6	798	0.08%	14,106
DEC	Lincoln CT	CT	Lincoln CT-16	109.6	968	0.10%	14,687
DEC	Mill Creek CT	CT	Mill Creek CT-1	99.9	12,356	1.41%	163,055
DEC	Mill Creek CT	CT	Mill Creek CT-2	99.9	11,997	1.37%	155,882
DEC	Mill Creek CT	CT	Mill Creek CT-3	99.9	11,129	1.27%	143,856
DEC	Mill Creek CT	CT	Mill Creek CT-4	99.9	9,250	1.05%	117,727
DEC	Mill Creek CT	CT	Mill Creek CT-5	99.9	7,147	0.81%	95,234
DEC	Mill Creek CT	CT	Mill Creek CT-6	99.9	7,460	0.85%	102,058
DEC	Mill Creek CT	CT	Mill Creek CT-7	99.9	5,557	0.63%	74,193
DEC	Mill Creek CT	CT	Mill Creek CT-8	99.9	5,436	0.62%	72,131
DEC	Rockingham CT	CT	Rockingham CT-1	195.5	98,487	5.74%	1,073,252
DEC	Rockingham CT	CT	Rockingham CT-2	195.5	182,087	10.60%	1,964,024
DEC	Rockingham CT	CT	Rockingham CT-3	195.5	144,230	8.40%	1,573,865
DEC	Rockingham CT	CT	Rockingham CT-4	195.5	130,451	7.60%	1,437,893
DEC	Rockingham CT	CT	Rockingham CT-5	195.5	101,316	5.90%	1,106,134
DEC	W.S. Lee CC	CC	W.S. Lee CC1-10	362.1	2,443,026	76.81%	5,498,678
DEC	W.S. Lee CC	CC	W.S. Lee CC1-11	242.25	1,739,314	81.74%	18,322,630
DEC	W.S. Lee CC	CC	W.S. Lee CC1-12	242.25	1,853,394	87.10%	19,297,511
DEC	W.S. Lee CT	CT	W.S. Lee CT-07C	54	877	0.18%	65,135
DEC	W.S. Lee CT	CT	W.S. Lee CT-08C	54	834	0.18%	11,591
DEP	Asheville CC	CC	Asheville CC1-A	191.2	1,043,253	62.12%	10,527,267
DEP	Asheville CC	CC	Asheville CC1-S	102.8	490,224	54.29%	0
DEP	Asheville CC	CC	Asheville CC2-A	191.2	1,027,585	61.18%	10,156,452
DEP	Asheville CC	CC	Asheville CC2-S	102.8	399,681	44.26%	0
DEP	Asheville CT	CT	Asheville CT-3	211.7	80,761	4.34%	1,011,687
DEP	Asheville CT	CT	Asheville CT-4	211.8	97,407	5.24%	1,179,105
DEP	Blewett CT	CT	Blewett CT-1	17.5	(84)	-0.05%	0
DEP	Blewett CT	CT	Blewett CT-2	17.5	(96)	-0.06%	0
DEP	Blewett CT	CT	Blewett CT-3	17.5	(83)	-0.05%	0
DEP	Blewett CT	CT	Blewett CT-4	17.5	(79)	-0.05%	0
DEP	Darlington CT	CT	Darlington CT-12	158	1,540	0.11%	16,880
DEP	Darlington CT	CT	Darlington CT-13	158	38	0.00%	8,713
DEP	H.F. Lee CC	CC	H.F. Lee CC1-A	221	1,039,771	53.56%	10,635,248
DEP	H.F. Lee CC	CC	H.F. Lee CC1-B	221	1,157,910	59.65%	11,875,552
DEP	H.F. Lee CC	CC	H.F. Lee CC1-C	221	1,150,591	59.27%	11,699,254
DEP	H.F. Lee CC	CC	H.F. Lee CC1-S	405	2,305,740	64.81%	7,961,185
DEP	Smith Energy Complex	CT	Smith Energy Complex-1	199.4	270,210	15.43%	2,966,172
DEP	Smith Energy Complex	CT	Smith Energy Complex-2	199.4	279,818	15.98%	3,011,359
DEP	Smith Energy Complex	CT	Smith Energy Complex-3	199.4	242,674	13.85%	2,754,601
DEP	Smith Energy Complex	CT	Smith Energy Complex-4	199.4	180,149	10.29%	2,043,608
DEP	Smith Energy Complex	CC	Smith Energy Complex4-7	199.4	954,015	54.47%	11,092,903
DEP	Smith Energy Complex	CC	Smith Energy Complex4-8	199.4	938,673	53.59%	10,894,049
DEP	Smith Energy Complex	CC	Smith Energy Complex4-S	195.5	1,102,306	64.19%	0
DEP	Smith Energy Complex	CC	Smith Energy Complex5-10	191.2	1,314,306	78.26%	15,050,612

DEP	Smith Energy Complex	CC	Smith Energy Complex5-9	191.2	1,320,105	78.60%	15,284,488
DEP	Smith Energy Complex	CC	Smith Energy Complex5-S	271.1	1,720,801	72.26%	0
DEP	Smith Energy Complex	CT	Smith Energy Complex-6	199.4	258,014	14.73%	2,880,676
DEP	Sutton CC	CC	Sutton CC1-A	221	1,226,982	63.21%	14,377,769
DEP	Sutton CC	CC	Sutton CC1-B	221	1,237,878	63.77%	14,503,305
DEP	Sutton CC	CC	Sutton CC1-S	288	1,548,834	61.22%	0
DEP	Sutton FS CT	CT	Sutton FS CT-4	60.5	31,928	6.01%	313,507
DEP	Sutton FS CT	CT	Sutton FS CT-5	60.5	32,731	6.16%	322,201
DEP	Wayne CT	CT	Wayne CT-10	195.2	17,944	1.05%	198,002
DEP	Wayne CT	CT	Wayne CT-11	195.2	19,263	1.12%	192,922
DEP	Wayne CT	CT	Wayne CT-12	195.2	28,733	1.68%	344,231
DEP	Wayne CT	CT	Wayne CT-13	195.2	45,705	2.67%	533,626
DEP	Wayne CT	CT	Wayne CT-14	198.9	63,753	3.65%	737,973
DEP	Weatherspoon CT	CT	Weatherspoon CT-1	39.7	(33)	-0.01%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-2	39.7	10	0.00%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-3	41.8	(13)	0.00%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-4	41.8	(26)	-0.01%	0

				2-1-1	2-1-2	2-1-3	2-1-4
Jurisdiction	**Generating Station**	**Generating Unit**	**Station-Unit**	**Name Plate**	**Net Annual MWh**	**Net Capacity Factor**	**Fuel Consumed**
DEC	Buck CC	CC	Buck CC1-1	185.3	1,350,380	83.19%	14,257,740
DEC	Buck CC	CC	Buck CC1-2	185.3	1,370,919	84.46%	14,063,555
DEC	Buck CC	CC	Buck CC1-S	327.3	1,814,076	63.28%	3,555,503
DEC	Clemson CHP	CC	Clemson CHP1-1	13.4	15,739	13.41%	186,523
DEC	Dan River CC	CC	Dan River CC1-7	185.3	1,682,928	103.68%	2,852,940
DEC	Dan River CC	CC	Dan River CC1-8	185.3	1,228,210	75.66%	13,254,015
DEC	Dan River CC	CC	Dan River CC1-9	327.25	1,262,306	44.03%	13,479,401
DEC	Lincoln CT	CT	Lincoln CT-1	109.6	763	0.08%	17,789
DEC	Lincoln CT	CT	Lincoln CT-2	109.6	5,006	0.52%	25,796
DEC	Lincoln CT	CT	Lincoln CT-3	109.6	3,988	0.42%	21,774
DEC	Lincoln CT	CT	Lincoln CT-4	109.6	4,168	0.43%	28,130
DEC	Lincoln CT	CT	Lincoln CT-5	109.6	2,822	0.29%	19,697
DEC	Lincoln CT	CT	Lincoln CT-6	109.6	2,579	0.27%	18,881
DEC	Lincoln CT	CT	Lincoln CT-7	109.6	3,232	0.34%	19,273
DEC	Lincoln CT	CT	Lincoln CT-8	109.6	3,505	0.37%	11,774
DEC	Lincoln CT	CT	Lincoln CT-9	109.6	837	0.09%	14,708
DEC	Lincoln CT	CT	Lincoln CT-10	109.6	2,599	0.27%	10,120
DEC	Lincoln CT	CT	Lincoln CT-11	109.6	3,253	0.34%	20,018
DEC	Lincoln CT	CT	Lincoln CT-12	109.6	2,862	0.30%	16,883
DEC	Lincoln CT	CT	Lincoln CT-13	109.6	2,160	0.22%	16,791
DEC	Lincoln CT	CT	Lincoln CT-14	109.6	2,441	0.25%	16,467
DEC	Lincoln CT	CT	Lincoln CT-15	109.6	2,056	0.21%	15,553
DEC	Lincoln CT	CT	Lincoln CT-16	109.6	2,313	0.24%	12,392
DEC	Mill Creek CT	CT	Mill Creek CT-1	99.9	13,826	1.58%	84,566
DEC	Mill Creek CT	CT	Mill Creek CT-2	99.9	11,253	1.29%	115,517
DEC	Mill Creek CT	CT	Mill Creek CT-3	99.9	14,355	1.64%	95,827
DEC	Mill Creek CT	CT	Mill Creek CT-4	99.9	18,941	2.16%	136,808
DEC	Mill Creek CT	CT	Mill Creek CT-5	99.9	21,504	2.46%	79,569
DEC	Mill Creek CT	CT	Mill Creek CT-6	99.9	19,944	2.28%	128,367
DEC	Mill Creek CT	CT	Mill Creek CT-7	99.9	15,418	1.76%	93,220
DEC	Mill Creek CT	CT	Mill Creek CT-8	99.9	13,808	1.58%	88,883
DEC	Rockingham CT	CT	Rockingham CT-1	195.5	313,672	18.32%	960,139
DEC	Rockingham CT	CT	Rockingham CT-2	195.5	193,414	11.29%	1,344,614
DEC	Rockingham CT	CT	Rockingham CT-3	195.5	371,065	21.67%	2,049,552
DEC	Rockingham CT	CT	Rockingham CT-4	195.5	345,721	20.19%	1,816,969
DEC	Rockingham CT	CT	Rockingham CT-5	195.5	215,289	12.57%	1,630,617
DEC	W.S. Lee CC	CC	W.S. Lee CC1-10	362.1	1,948,119	61.42%	5,553,205
DEC	W.S. Lee CC	CC	W.S. Lee CC1-11	242.25	1,172,874	55.27%	18,345,854
DEC	W.S. Lee CC	CC	W.S. Lee CC1-12	242.25	1,533,260	72.25%	18,025,213
DEC	W.S. Lee CT	CT	W.S. Lee CT-07C	54	28,073	5.93%	30,983
DEC	W.S. Lee CT	CT	W.S. Lee CT-08C	54	27,774	5.87%	30,697
DEP	Asheville CC	CC	Asheville CC1-A	191.2	1,104,932	65.97%	11,038,965
DEP	Asheville CC	CC	Asheville CC1-S	102.8	560,321	62.22%	0
DEP	Asheville CC	CC	Asheville CC2-A	191.2	1,276,325	76.20%	12,791,408
DEP	Asheville CC	CC	Asheville CC2-S	102.8	649,734	72.15%	0
DEP	Asheville CT	CT	Asheville CT-3	211.7	126,242	6.81%	1,107,580
DEP	Asheville CT	CT	Asheville CT-4	211.8	74,189	4.00%	684,895
DEP	Blewett CT	CT	Blewett CT-1	17.5	(45)	-0.03%	0
DEP	Blewett CT	CT	Blewett CT-2	17.5	(59)	-0.04%	0
DEP	Blewett CT	CT	Blewett CT-3	17.5	80	0.05%	0
DEP	Blewett CT	CT	Blewett CT-4	17.5	55	0.04%	0
DEP	Darlington CT	CT	Darlington CT-12	158	2,905	0.21%	29,394
DEP	Darlington CT	CT	Darlington CT-13	158	953	0.07%	19,007
DEP	H.F. Lee CC	CC	H.F. Lee CC1-A	221	1,160,102	59.92%	11,256,478
DEP	H.F. Lee CC	CC	H.F. Lee CC1-B	221	977,180	50.48%	9,845,711
DEP	H.F. Lee CC	CC	H.F. Lee CC1-C	221	1,173,134	60.60%	11,476,521
DEP	H.F. Lee CC	CC	H.F. Lee CC1-S	405	2,168,045	61.11%	7,627,596
DEP	Smith Energy Complex	CT	Smith Energy Complex-1	199.4	210,683	12.06%	2,369,847
DEP	Smith Energy Complex	CT	Smith Energy Complex-2	199.4	294,048	16.83%	3,223,760
DEP	Smith Energy Complex	CT	Smith Energy Complex-3	199.4	227,058	13.00%	2,596,599
DEP	Smith Energy Complex	CT	Smith Energy Complex-4	199.4	302,130	17.30%	3,402,585
DEP	Smith Energy Complex	CC	Smith Energy Complex4-7	199.4	917,119	52.50%	10,678,493
DEP	Smith Energy Complex	CC	Smith Energy Complex4-8	199.4	947,271	54.23%	10,274,482
DEP	Smith Energy Complex	CC	Smith Energy Complex4-S	195.5	1,073,666	62.69%	0
DEP	Smith Energy Complex	CC	Smith Energy Complex5-10	191.2	1,247,102	74.46%	14,426,971

DEP	Smith Energy Complex	CC	Smith Energy Complex5-9	191.2	1,189,474	71.02%	13,141,509
DEP	Smith Energy Complex	CC	Smith Energy Complex5-S	271.1	1,571,982	66.19%	1,391,297
DEP	Smith Energy Complex	CT	Smith Energy Complex-6	199.4	285,986	16.37%	3,183,021
DEP	Sutton CC	CC	Sutton CC1-A	221	1,282,834	66.26%	14,774,040
DEP	Sutton CC	CC	Sutton CC1-B	221	1,308,340	67.58%	15,034,429
DEP	Sutton CC	CC	Sutton CC1-S	288	1,555,221	61.64%	0
DEP	Sutton FS CT	CT	Sutton FS CT-4	60.5	15,395	2.90%	150,242
DEP	Sutton FS CT	CT	Sutton FS CT-5	60.5	15,611	2.95%	145,072
DEP	Wayne CT	CT	Wayne CT-10	195.2	13,993	0.82%	91,102
DEP	Wayne CT	CT	Wayne CT-11	195.2	45,073	2.64%	460,666
DEP	Wayne CT	CT	Wayne CT-12	195.2	59,293	3.47%	661,003
DEP	Wayne CT	CT	Wayne CT-13	195.2	67,479	3.95%	727,554
DEP	Wayne CT	CT	Wayne CT-14	198.9	86,100	4.94%	938,723
DEP	Weatherspoon CT	CT	Weatherspoon CT-1	39.7	209	0.06%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-2	39.7	208	0.06%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-3	41.8	197	0.05%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-4	41.8	199	0.05%	0

				2-1-1	2-1-2	2-1-3	2-1-4
Jurisdiction	Generating Station	Generating Unit	Station-Unit	Name Plate	Net Annual MWh	Net Capacity Factor	Fuel Consumed MBTU
DEC	Buck CC	CC	Buck CC1-1	185.3	1,406,294	86.64%	14,727,412
DEC	Buck CC	CC	Buck CC1-2	185.3	1,403,629	86.47%	14,380,367
DEC	Buck CC	CC	Buck CC1-S	327.3	2,056,915	71.75%	4,911,143
DEC	Clemson CHP	CC	Clemson CHP1-1	13.4	91,218	77.71%	1,118,720
DEC	Dan River CC	CC	Dan River CC1-7	185.3	1,172,815	72.25%	4,428,714
DEC	Dan River CC	CC	Dan River CC1-8	185.3	1,158,153	71.35%	12,382,214
DEC	Dan River CC	CC	Dan River CC1-9	327.25	1,779,047	62.06%	12,454,440
DEC	Lincoln CT	CT	Lincoln CT-1	109.6	4,924	0.51%	6,233
DEC	Lincoln CT	CT	Lincoln CT-2	109.6	5,006	0.52%	7,778
DEC	Lincoln CT	CT	Lincoln CT-3	109.6	3,988	0.42%	4,416
DEC	Lincoln CT	CT	Lincoln CT-4	109.6	4,168	0.43%	6,127
DEC	Lincoln CT	CT	Lincoln CT-5	109.6	2,822	0.29%	5,103
DEC	Lincoln CT	CT	Lincoln CT-6	109.6	2,579	0.27%	9,876
DEC	Lincoln CT	CT	Lincoln CT-7	109.6	3,232	0.34%	4,638
DEC	Lincoln CT	CT	Lincoln CT-8	109.6	3,505	0.37%	6,584
DEC	Lincoln CT	CT	Lincoln CT-9	109.6	837	0.09%	3,577
DEC	Lincoln CT	CT	Lincoln CT-10	109.6	2,599	0.27%	3,640
DEC	Lincoln CT	CT	Lincoln CT-11	109.6	3,253	0.34%	6,710
DEC	Lincoln CT	CT	Lincoln CT-12	109.6	2,862	0.30%	6,773
DEC	Lincoln CT	CT	Lincoln CT-13	109.6	2,160	0.22%	14,048
DEC	Lincoln CT	CT	Lincoln CT-14	109.6	2,441	0.25%	14,036
DEC	Lincoln CT	CT	Lincoln CT-15	109.6	2,056	0.21%	6,312
DEC	Lincoln CT	CT	Lincoln CT-16	109.6	2,313	0.24%	10,142
DEC	Mill Creek CT	CT	Mill Creek CT-1	99.9	13,826	1.58%	131,755
DEC	Mill Creek CT	CT	Mill Creek CT-2	99.9	11,253	1.29%	119,313
DEC	Mill Creek CT	CT	Mill Creek CT-3	99.9	14,355	1.64%	142,764
DEC	Mill Creek CT	CT	Mill Creek CT-4	99.9	18,941	2.16%	189,879
DEC	Mill Creek CT	CT	Mill Creek CT-5	99.9	21,504	2.46%	203,172
DEC	Mill Creek CT	CT	Mill Creek CT-6	99.9	19,944	2.28%	183,358
DEC	Mill Creek CT	CT	Mill Creek CT-7	99.9	15,418	1.76%	157,004
DEC	Mill Creek CT	CT	Mill Creek CT-8	99.9	13,808	1.58%	124,535
DEC	Rockingham CT	CT	Rockingham CT-1	195.5	313,672	18.32%	3,323,020
DEC	Rockingham CT	CT	Rockingham CT-2	195.5	193,414	11.29%	2,088,685
DEC	Rockingham CT	CT	Rockingham CT-3	195.5	371,065	21.67%	3,954,298
DEC	Rockingham CT	CT	Rockingham CT-4	195.5	345,721	20.19%	3,776,376
DEC	Rockingham CT	CT	Rockingham CT-5	195.5	215,289	12.57%	2,253,830
DEC	W.S. Lee CC	CC	W.S. Lee CC1-10	362.1	1,948,119	61.42%	12,652,309
DEC	W.S. Lee CC	CC	W.S. Lee CC1-11	242.25	1,172,874	55.27%	16,080,163
DEC	W.S. Lee CC	CC	W.S. Lee CC1-12	242.25	1,533,260	72.25%	4,912,665
DEC	W.S. Lee CT	CT	W.S. Lee CT-07C	54	28,073	5.93%	269,402
DEC	W.S. Lee CT	CT	W.S. Lee CT-08C	54	27,774	5.87%	275,298
DEP	Asheville CC	CC	Asheville CC1-A	191.2	1,180,826	70.50%	11,699,256
DEP	Asheville CC	CC	Asheville CC1-S	102.8	573,117	63.64%	0
DEP	Asheville CC	CC	Asheville CC2-A	191.2	1,225,611	73.17%	12,462,875
DEP	Asheville CC	CC	Asheville CC2-S	102.8	624,741	69.37%	0
DEP	Asheville CT	CT	Asheville CT-3	211.7	215,840	11.64%	2,365,206
DEP	Asheville CT	CT	Asheville CT-4	211.8	194,798	10.50%	2,181,656
DEP	Blewett CT	CT	Blewett CT-1	17.5	(45)	-0.03%	0
DEP	Blewett CT	CT	Blewett CT-2	17.5	(59)	-0.04%	0
DEP	Blewett CT	CT	Blewett CT-3	17.5	80	0.05%	0
DEP	Blewett CT	CT	Blewett CT-4	17.5	55	0.04%	0
DEP	Darlington CT	CT	Darlington CT-12	158	51,552	3.72%	507,206
DEP	Darlington CT	CT	Darlington CT-13	158	43,590	3.15%	473,681
DEP	H.F. Lee CC	CC	H.F. Lee CC1-A	221	1,198,447	61.90%	11,139,378
DEP	H.F. Lee CC	CC	H.F. Lee CC1-B	221	1,284,836	66.37%	12,277,819
DEP	H.F. Lee CC	CC	H.F. Lee CC1-C	221	1,327,451	68.57%	12,612,745
DEP	H.F. Lee CC	CC	H.F. Lee CC1-S	405	2,230,312	62.86%	9,781,411
DEP	Smith Energy Complex	CT	Smith Energy Complex-1	199.4	463,835	26.55%	4,860,626
DEP	Smith Energy Complex	CT	Smith Energy Complex-2	199.4	355,404	20.35%	3,358,457
DEP	Smith Energy Complex	CT	Smith Energy Complex-3	199.4	362,906	20.78%	4,085,143
DEP	Smith Energy Complex	CT	Smith Energy Complex-4	199.4	351,691	20.13%	3,831,939
DEP	Smith Energy Complex	CC	Smith Energy Complex4-7	199.4	1,048,739	60.04%	11,463,209
DEP	Smith Energy Complex	CC	Smith Energy Complex4-8	199.4	1,070,984	61.31%	11,714,504
DEP	Smith Energy Complex	CC	Smith Energy Complex4-S	195.5	1,189,385	69.45%	0
DEP	Smith Energy Complex	CC	Smith Energy Complex5-10	191.2	1,374,781	82.08%	15,423,239

DEP	Smith Energy Complex	CC	Smith Energy Complex5-9	191.2	1,377,370	82.24%	15,612,491
DEP	Smith Energy Complex	CC	Smith Energy Complex5-S	271.1	1,906,354	80.27%	3,596,257
DEP	Smith Energy Complex	CT	Smith Energy Complex-6	199.4	418,962	23.99%	4,604,230
DEP	Sutton CC	CC	Sutton CC1-A	221	1,217,858	62.91%	14,041,659
DEP	Sutton CC	CC	Sutton CC1-B	221	1,210,479	62.53%	13,966,925
DEP	Sutton CC	CC	Sutton CC1-S	288	1,482,658	58.77%	0
DEP	Sutton FS CT	CT	Sutton FS CT-4	60.5	7,907	1.49%	56,142
DEP	Sutton FS CT	CT	Sutton FS CT-5	60.5	8,404	1.59%	61,140
DEP	Wayne CT	CT	Wayne CT-10	195.2	51,391	3.01%	391,224
DEP	Wayne CT	CT	Wayne CT-11	195.2	67,784	3.96%	589,630
DEP	Wayne CT	CT	Wayne CT-12	195.2	126,812	7.42%	1,293,201
DEP	Wayne CT	CT	Wayne CT-13	195.2	120,026	7.02%	1,241,412
DEP	Wayne CT	CT	Wayne CT-14	198.9	182,279	10.46%	1,990,848
DEP	Weatherspoon CT	CT	Weatherspoon CT-1	39.7	189	0.05%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-2	39.7	297	0.09%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-3	41.8	252	0.07%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-4	41.8	202	0.06%	0

				2-1-1	2-1-2	2-1-3	2-1-4
Jurisdiction	Generating Station	Generating Unit	Station-Unit	Name Plate	Net Annual MWh	Net Capacity Factor	Fuel Consumed MMBtu
DEC	Buck CC	CC	Buck CC1-1	185.3	1,111,803	68.49%	11,710,364
DEC	Buck CC	CC	Buck CC1-2	185.3	1,126,791	69.42%	11,762,967
DEC	Buck CC	CC	Buck CC1-S	327.25	1,581,365	55.16%	3,467,826
DEC	Clemson CHP	CC	Clemson CHP1-1	13.4	108,527	92.45%	1,239,434
DEC	Dan River CC	CC	Dan River CC1-7	185.3	1,096,342	67.54%	11,523,886
DEC	Dan River CC	CC	Dan River CC1-8	185.3	1,056,369	65.08%	11,769,819
DEC	Dan River CC	CC	Dan River CC1-9	327.25	1,576,101	54.98%	3,333,917
DEC	Lincoln CT	CT	Lincoln CT-1	109.6	(903)	-0.09%	6,489
DEC	Lincoln CT	CT	Lincoln CT-2	109.6	519	0.05%	8,154
DEC	Lincoln CT	CT	Lincoln CT-3	109.6	333	0.03%	5,832
DEC	Lincoln CT	CT	Lincoln CT-4	109.6	663	0.07%	10,306
DEC	Lincoln CT	CT	Lincoln CT-5	109.6	245	0.03%	4,628
DEC	Lincoln CT	CT	Lincoln CT-6	109.6	207	0.02%	4,838
DEC	Lincoln CT	CT	Lincoln CT-7	109.6	1,028	0.11%	13,135
DEC	Lincoln CT	CT	Lincoln CT-8	109.6	611	0.06%	9,703
DEC	Lincoln CT	CT	Lincoln CT-9	109.6	(819)	-0.09%	8,793
DEC	Lincoln CT	CT	Lincoln CT-10	109.6	507	0.05%	6,846
DEC	Lincoln CT	CT	Lincoln CT-11	109.6	524	0.05%	7,060
DEC	Lincoln CT	CT	Lincoln CT-12	109.6	572	0.06%	7,113
DEC	Lincoln CT	CT	Lincoln CT-13	109.6	84	0.01%	4,133
DEC	Lincoln CT	CT	Lincoln CT-14	109.6	63	0.01%	3,607
DEC	Lincoln CT	CT	Lincoln CT-15	109.6	311	0.03%	6,040
DEC	Lincoln CT	CT	Lincoln CT-16	109.6	205	0.02%	3,828
DEC	Mill Creek CT	CT	Mill Creek CT-1	99.9	3,948	0.45%	57,091
DEC	Mill Creek CT	CT	Mill Creek CT-2	99.9	3,452	0.39%	52,004
DEC	Mill Creek CT	CT	Mill Creek CT-3	99.9	4,284	0.49%	60,083
DEC	Mill Creek CT	CT	Mill Creek CT-4	99.9	4,054	0.46%	58,198
DEC	Mill Creek CT	CT	Mill Creek CT-5	99.9	6,731	0.77%	92,715
DEC	Mill Creek CT	CT	Mill Creek CT-6	99.9	6,814	0.78%	95,778
DEC	Mill Creek CT	CT	Mill Creek CT-7	99.9	4,792	0.55%	70,140
DEC	Mill Creek CT	CT	Mill Creek CT-8	99.9	4,421	0.51%	66,742
DEC	Rockingham CT	CT	Rockingham CT-1	195.5	152,551	8.91%	1,668,020
DEC	Rockingham CT	CT	Rockingham CT-2	195.5	207,995	12.15%	2,243,693
DEC	Rockingham CT	CT	Rockingham CT-3	195.5	146,929	8.58%	1,632,154
DEC	Rockingham CT	CT	Rockingham CT-4	195.5	132,284	7.72%	1,456,187
DEC	Rockingham CT	CT	Rockingham CT-5	195.5	156,035	9.11%	1,701,263
DEC	W.S. Lee CC	CC	W.S. Lee CC1-10	362.1	2,429,400	76.59%	18,606,853
DEC	W.S. Lee CC	CC	W.S. Lee CC1-11	242.25	1,736,246	81.82%	18,596,489
DEC	W.S. Lee CC	CC	W.S. Lee CC1-12	242.25	1,775,803	83.68%	5,831,863
DEC	W.S. Lee CT	CT	W.S. Lee CT-07C	54	5,235	1.11%	56,190
DEC	W.S. Lee CT	CT	W.S. Lee CT-08C	54	5,062	1.07%	54,158
DEP	Asheville CC	CC	Asheville CC1-A	191.2	1,366,017	81.56%	13,747,287
DEP	Asheville CC	CC	Asheville CC1-S	102.8	708,552	78.68%	0
DEP	Asheville CC	CC	Asheville CC2-A	191.2	1,108,276	66.17%	11,131,614
DEP	Asheville CC	CC	Asheville CC2-S	102.8	562,047	62.41%	0
DEP	Asheville CT	CT	Asheville CT-3	211.7	50,580	2.73%	616,687
DEP	Asheville CT	CT	Asheville CT-4	211.8	83,496	4.50%	971,874
DEP	Blewett CT	CT	Blewett CT-1	17.5	12	0.01%	0
DEP	Blewett CT	CT	Blewett CT-2	17.5	5	0.00%	0
DEP	Blewett CT	CT	Blewett CT-3	17.5	6	0.00%	0
DEP	Blewett CT	CT	Blewett CT-4	17.5	4	0.00%	0
DEP	Darlington CT	CT	Darlington CT-12	158	11,744	0.85%	128,111
DEP	Darlington CT	CT	Darlington CT-13	158	10,380	0.75%	125,325
DEP	H.F. Lee CC	CC	H.F. Lee CC1-A	221	1,297,243	67.01%	12,527,890
DEP	H.F. Lee CC	CC	H.F. Lee CC1-B	221	1,182,889	61.10%	11,671,748
DEP	H.F. Lee CC	CC	H.F. Lee CC1-C	221	1,305,936	67.46%	12,660,952
DEP	H.F. Lee CC	CC	H.F. Lee CC1-S	405	2,588,512	72.96%	10,059,660
DEP	Smith Energy Complex	CT	Smith Energy Complex-1	199.4	305,248	17.48%	3,429,761
DEP	Smith Energy Complex	CT	Smith Energy Complex-2	199.4	244,474	14.00%	2,423,333
DEP	Smith Energy Complex	CT	Smith Energy Complex-3	199.4	269,007	15.40%	3,134,723
DEP	Smith Energy Complex	CT	Smith Energy Complex-4	199.4	185,235	10.60%	2,025,304
DEP	Smith Energy Complex	CC	Smith Energy Complex4-7	199.4	947,721	54.26%	10,642,897
DEP	Smith Energy Complex	CC	Smith Energy Complex4-8	199.4	919,930	52.67%	10,346,078
DEP	Smith Energy Complex	CC	Smith Energy Complex4-S	195.5	1,056,254	61.68%	0
DEP	Smith Energy Complex	CC	Smith Energy Complex5-10	191.2	1,330,556	79.44%	15,304,387
DEP	Smith Energy Complex	CC	Smith Energy Complex5-9	191.2	1,326,984	79.23%	14,459,644
DEP	Smith Energy Complex	CC	Smith Energy Complex5-S	271.1	1,811,778	76.29%	2,279,888
DEP	Smith Energy Complex	CT	Smith Energy Complex-6	199.4	200,430	11.47%	2,294,272
DEP	Sutton CC	CC	Sutton CC1-A	221	1,182,767	61.09%	13,813,054
DEP	Sutton CC	CC	Sutton CC1-B	221	1,211,872	62.60%	14,155,711
DEP	Sutton CC	CC	Sutton CC1-S	288	1,493,765	59.21%	0
DEP	Sutton FS CT	CT	Sutton FS CT-4	60.5	792	0.15%	8,945

DEP	Sutton FS CT	CT	Sutton FS CT-5	60.5	901	0.17%	10,264
DEP	Wayne CT	CT	Wayne CT-10	195.2	8,972	0.52%	112,344
DEP	Wayne CT	CT	Wayne CT-11	195.2	7,401	0.43%	76,441
DEP	Wayne CT	CT	Wayne CT-12	195.2	16,884	0.99%	203,895
DEP	Wayne CT	CT	Wayne CT-13	195.2	36,963	2.16%	428,802
DEP	Wayne CT	CT	Wayne CT-14	198.9	20,528	1.18%	246,844
DEP	Weatherspoon CT	CT	Weatherspoon CT-1	39.7	47	0.01%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-2	39.7	28	0.01%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-3	41.8	(8)	0.00%	0
DEP	Weatherspoon CT	CT	Weatherspoon CT-4	41.8	37	0.01%	0

Hansen
Exhibit 6

GAS & OIL ASSOCIATION OF WEST VIRGINIA

West Virginia Statistics

Serving All Aspects Of The Oil And Natural Gas Industry

Top U.S. Natural Gas Producing States

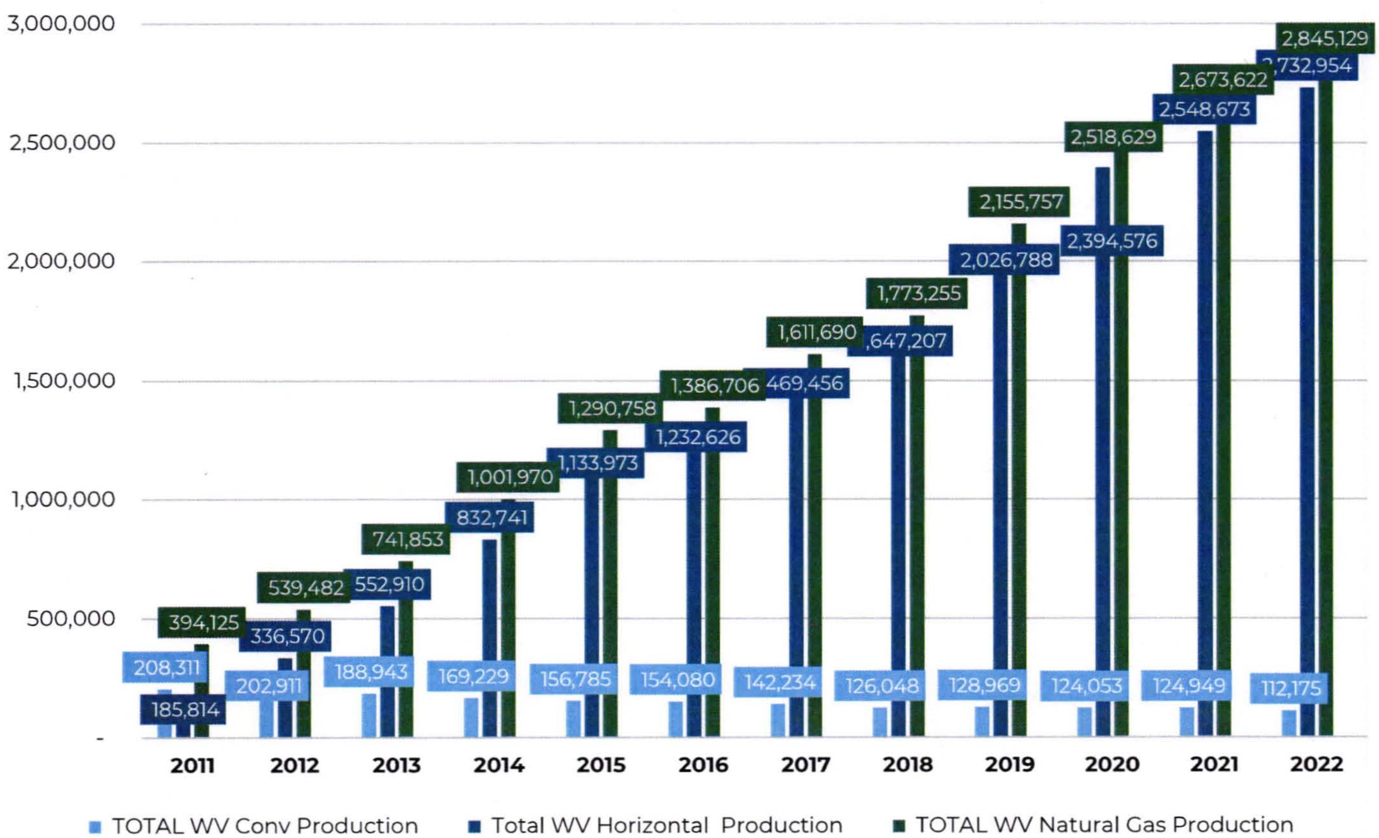
West Virginia Ranks 4th In total NG production (EIA)

West Virginia Ranks 5th In total energy production (EIA)

- Five of the 34 natural gas producing states accounted for about 70.4% of total U.S. dry natural gas production in 2021.
- The top five natural gas-producing states and their share of total U.S. natural gas production in 2021 were:

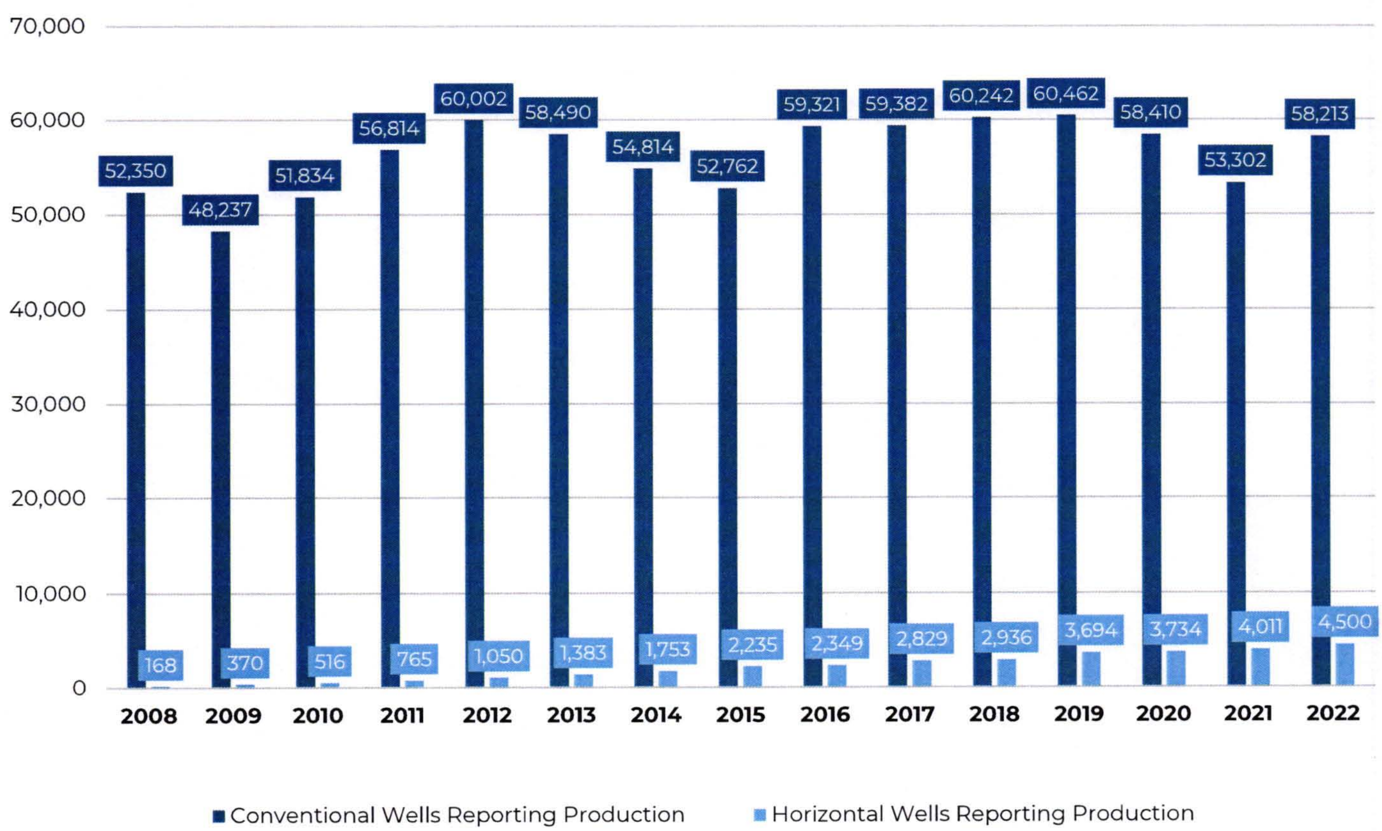
	Tcf	
Texas	8.7	24.6%
Pennsylvania	7.5	21.8%
Louisiana	3.4	9.9%
West Virginia	2.5	7.4%
Oklahoma	2.3	6.7%

Total WV Natural Gas Production (MMCF)



Total Number of Producing Wells

Source: WVDEP: 7-10-23



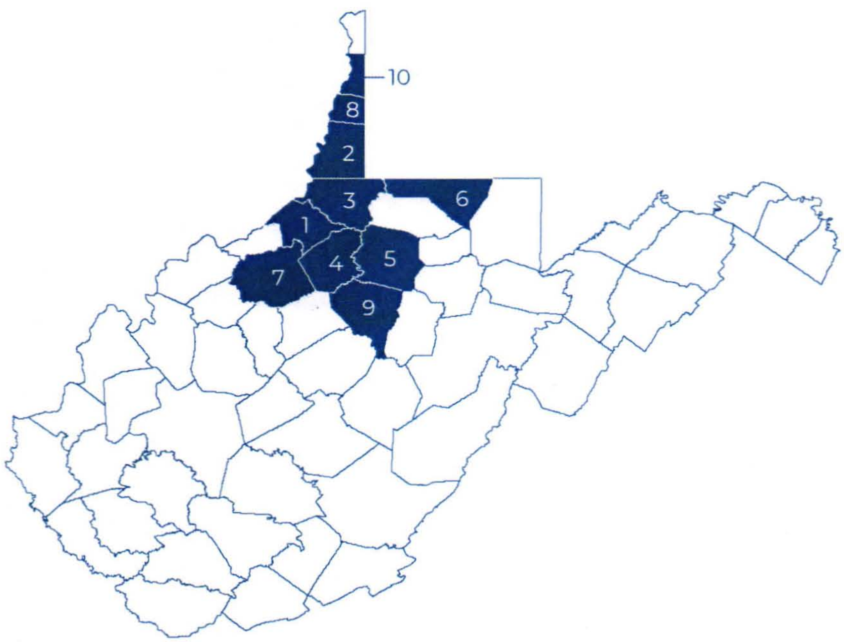
2022 Top Natural Gas Producing Companies

Source: WVDEP : 7-10-23

	Bcf
1. Antero Resources Corp.	1,051.9
2. SWN Production Co.	399.3
3. EQT Production Co.	306.7
4. Tug-Hill Operating	276.9
5. HG Energy II Appalachia	196.7
6. Northeast Natural Energy	165.8
7. Diversified Gas & Oil	87.5
8. CNX Gas Companies	68.5
9. Arsenal Resources	62.7
10. Jay-Bee Oil and Gas	58.6

2022 Top Natural Gas Producing Counties

Source: WVDEP: 7-10-23



	Bcf	Wells
1. Tyler	675.5	1,475
2. Marshall	487.3	773
3. Wetzel	306.7	1,741
4. Doddridge	300.1	4,382
5. Harrison	208.0	3,478
6. Monongalia	173.5	560
7. Ritchie	170.2	5,731
8. Ohio	95.5	202
9. Lewis	92.7	3,375
10. Brooke	89.1	161

2022 World's Largest Producers of Natural Gas – Plus Us!

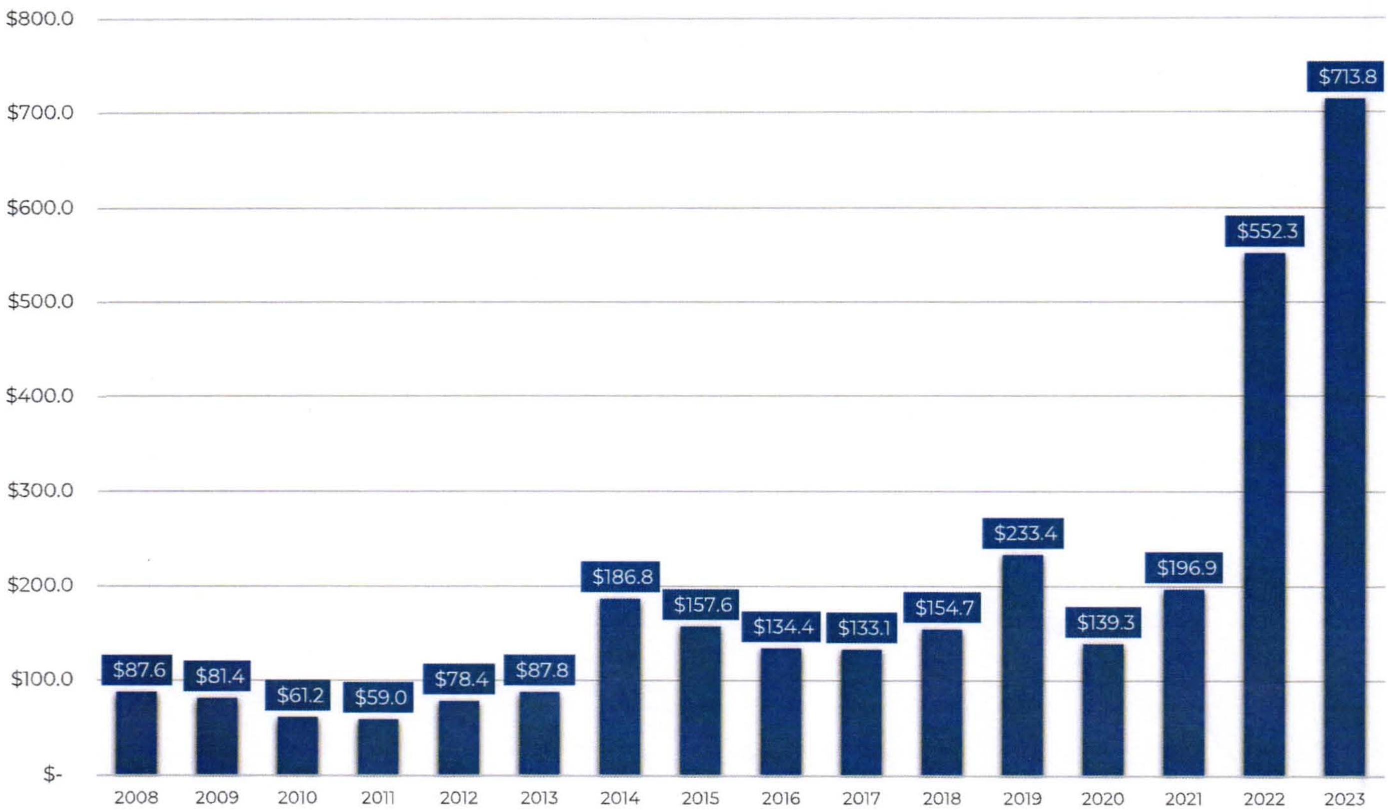
Source: www.worldometer.info (7-10-23)

	Tcf/yr
1. United States	32.9
2. Russia	22.7
3. OH – PA – WV	12.6
4. Iran	9.1
5. Canada	6.7
6. Algeria	6.5
7. Qatar	6.0
8. Norway	5.7
9. Australia	5.0
10. Saudi Arabia	4.2
11. UAE	3.2

GAS & OIL ASSOCIATION OF WEST VIRGINIA

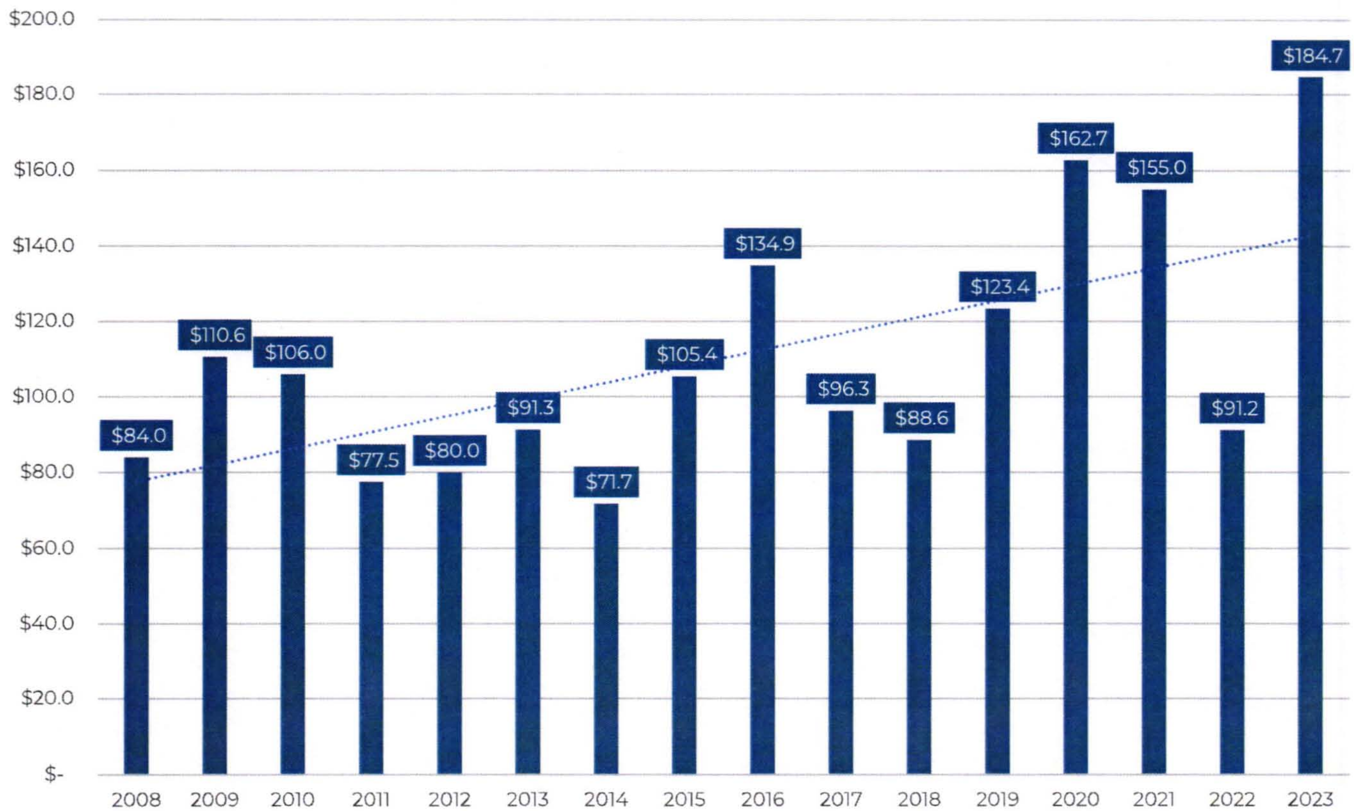
Annual Natural Gas, NGL's and Oil Severance Tax Collections

(millions) Source: WV State Department of Revenue (7-10-23)



Oil Natural Gas Property Tax Contributions $1.76 Billion since 2008

(millions) Source: WV State Department of Revenue (7-10-23)



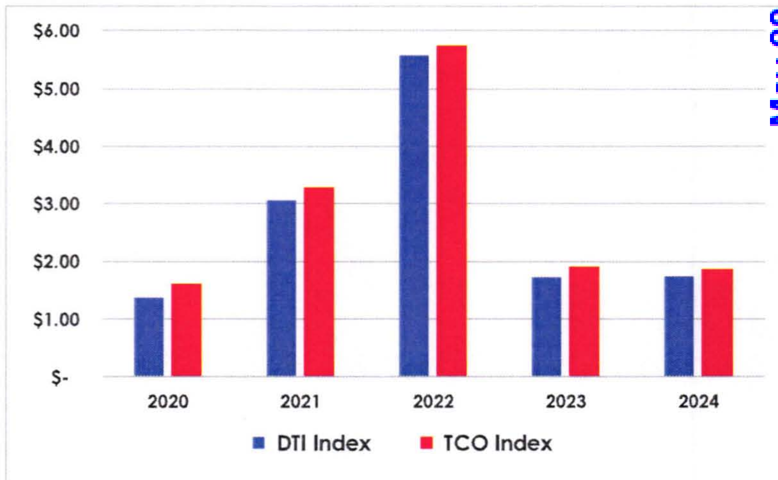
2023 Top 10 Counties: Estimated Oil & Natural Gas Property Tax

(millions) Source: WV State Department of Revenue (7-10-23)

	Million
1. Tyler	$ 51.44
2. Marshall	$ 32.42
3. Doddridge	$ 16.60
4. Ritchie	$ 14.30
5. Wetzel	$ 12.22
6. Ohio	$ 11.76
7. Harrison	$ 10.83
8. Brooke	$ 9.30
9. Monongalia	$ 7.43
10. Marion	$ 2.40

Nat Gas Price Outlook

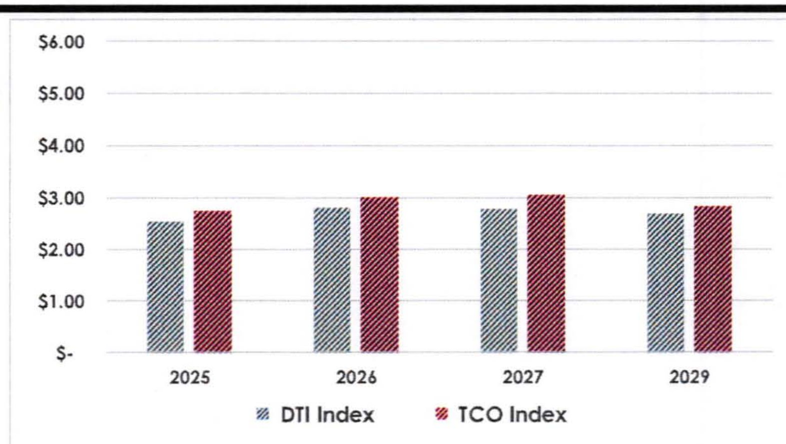
Historical Prices	NYMEX SETTLE	DTI Basis	DTI Index	TCO Basis	TCO Index
2020 Averages	$ 2.077	$ (0.708)	$ **1.369**	$ (0.461)	$ **1.616**
2021 Averages	$ 3.841	$ (0.777)	$ **3.064**	$ (0.561)	$ **3.280**
2022 Averages	$ 6.644	$ (1.057)	$ **5.587**	$ (0.911)	$ **5.733**
2023 Averages	$ 2.737	$ (1.004)	$ **1.733**	$ (0.829)	$ **1.908**
Jan-24	$ 2.619	$ (0.629)	$ **1.990**	$ (0.509)	$ **2.110**
Feb-24	$ 2.490	$ (0.780)	$ **1.710**	$ (0.450)	$ **2.040**
Mar-24	$ 1.615	$ (0.385)	$ **1.230**	$ (0.385)	$ **1.230**
Apr-24	$ 1.575	$ (0.315)	$ **1.260**	$ (0.255)	$ **1.320**
May-24	*$ 1.833*	*$ (0.415)*	*$ **1.418***	*$ (0.270)*	*$ **1.563***
Jun-24	*$ 2.089*	*$ (0.468)*	*$ **1.622***	*$ (0.355)*	*$ **1.734***
Jul-24	*$ 2.420*	*$ (0.553)*	*$ **1.868***	*$ (0.478)*	*$ **1.943***
Aug-24	*$ 2.516*	*$ (0.635)*	*$ **1.881***	*$ (0.535)*	*$ **1.981***
Sep-24	*$ 2.520*	*$ (0.900)*	*$ **1.620***	*$ (0.778)*	*$ **1.743***
Oct-24	*$ 2.610*	*$ (1.065)*	*$ **1.545***	*$ (0.915)*	*$ **1.695***
Nov-24	*$ 3.012*	*$ (0.980)*	*$ **2.032***	*$ (0.823)*	*$ **2.190***
Dec-24	*$ 3.514*	*$ (0.828)*	*$ **2.687***	*$ (0.700)*	*$ **2.814***
2024 YTD averages	**$ 2.401**	**$ (0.663)**	**$ 1.738**	**$ (0.538)**	**$ 1.863**



Observed Forward Prices on 4/10/24

....INDICATIVE FORWARD PRICES FOR THE NEXT FEW MONTHS

Futures	NYMEX	DTI Basis	DTI Indicative	TCO Basis	TCO Indicative
....INDICATIVE FORWARD PRICES					
Apr24-Oct24	*$ 2.22*	*$ (0.62)*	*$ **1.60***	*$ (0.51)*	*$ **1.71***
Nov24-Mar25	*$ 3.43*	*$ (0.79)*	*$ **2.64***	*$ (0.58)*	*$ **2.85***
Cal 2025	*$ 3.48*	*$ (0.93)*	*$ **2.55***	*$ (0.74)*	*$ **2.74***
Cal 2026	*$ 3.80*	*$ (1.00)*	*$ **2.80***	*$ (0.80)*	*$ **3.00***
Cal 2027	*$ 3.81*	*$ (1.03)*	*$ **2.78***	*$ (0.76)*	*$ **3.05***
Cal 2028	*$ 3.76*	*$ (1.01)*	*$ **2.75***	*$ (0.90)*	*$ **2.86***
Cal 2029	*$ 3.73*	*$ (1.03)*	*$ **2.70***	*$ (0.89)*	*$ **2.84***



All indicative forward prices shown above are taken entirely from publically available sources.

***Forwards sourced from CME & ICE**

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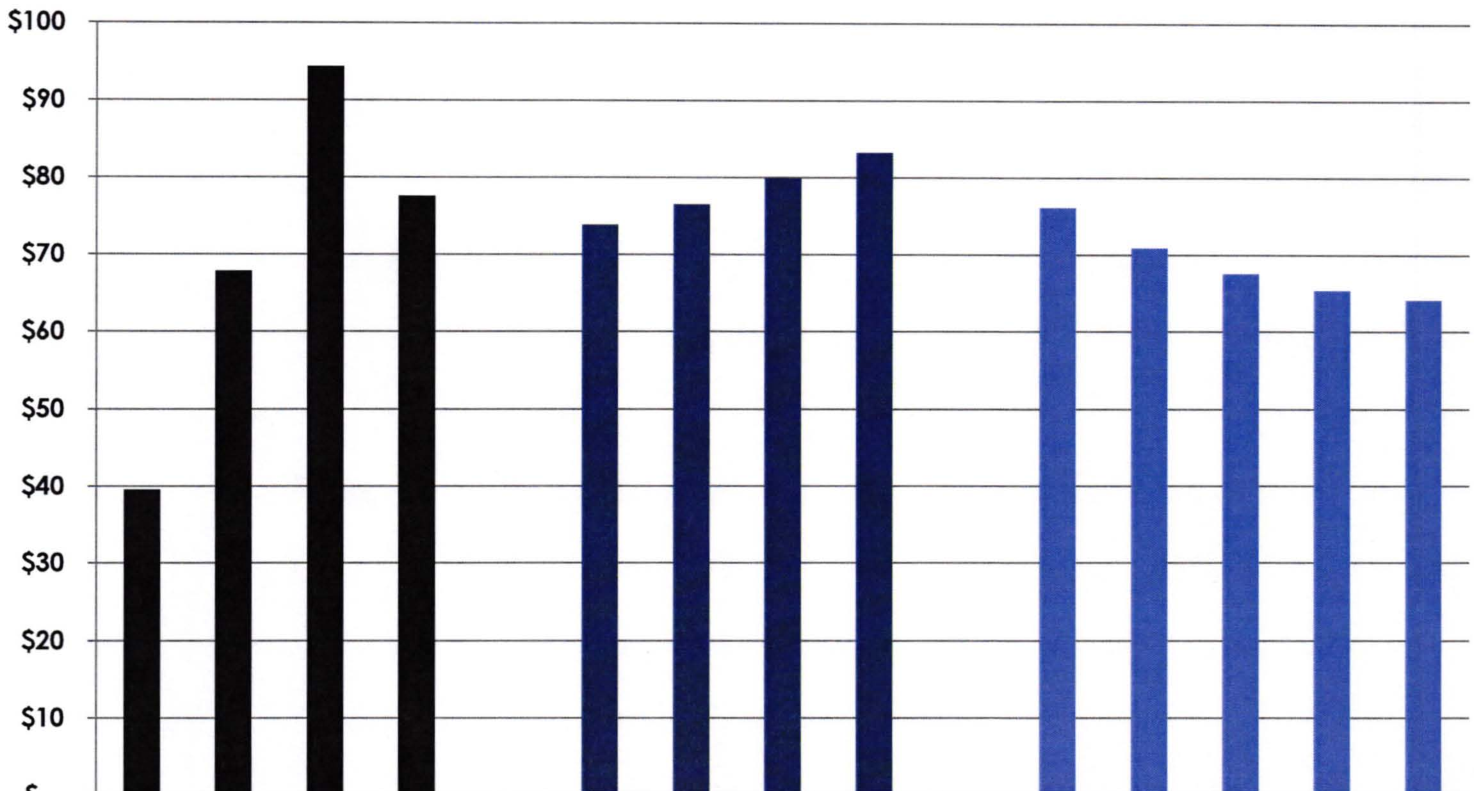
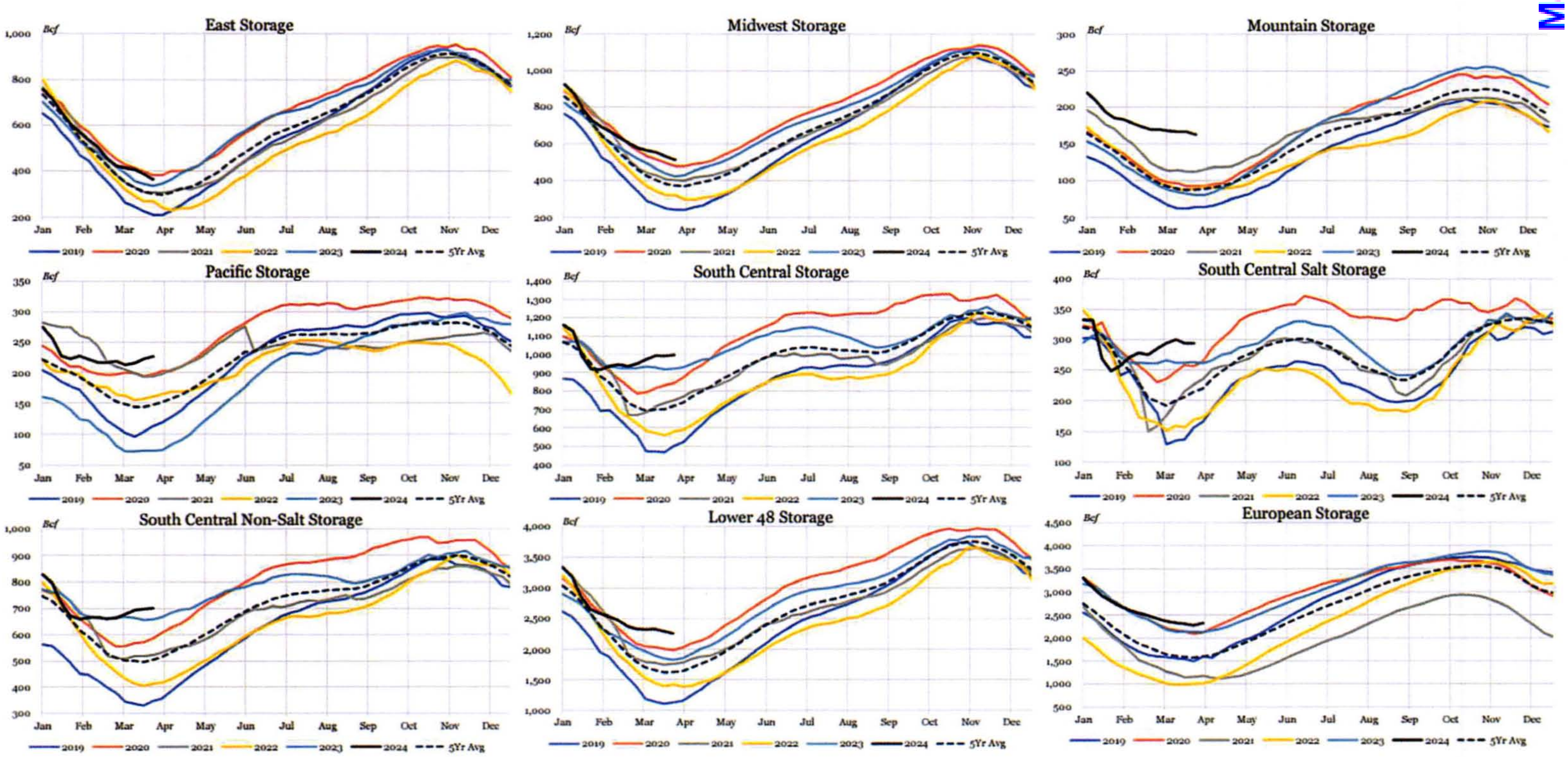
Oil Prices



	2020	2021	2022	2023		Jan-24	Feb-24	Mar-24	Bal 2024		2025	2026	2027	2028	2029
Series1	$40	$68	$94	$78		$74	$77	$80	$83		$76	$71	$68	$65	$64

Source: CME - as of April 10, 2024

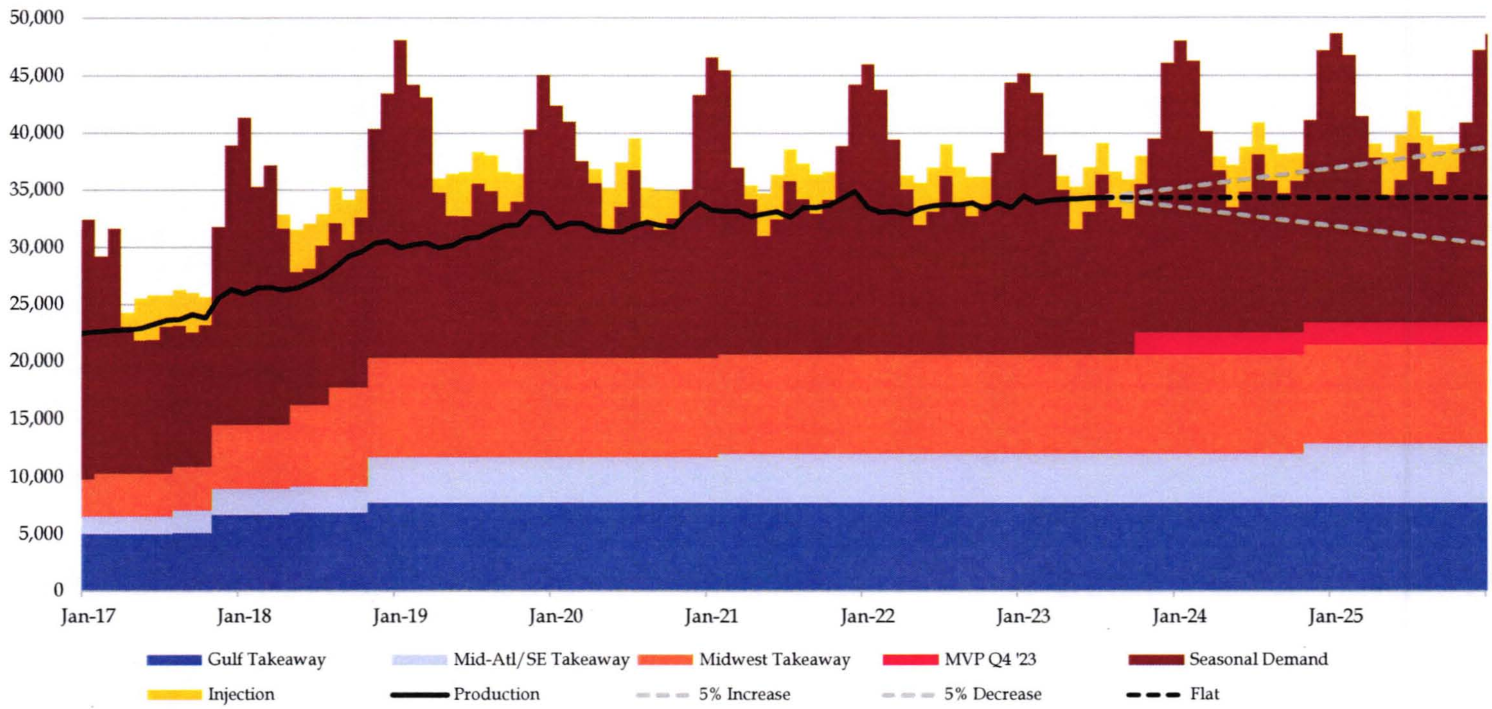
Regional, U.S. and European Storage



Sources: EIA / ARM Research

Appalachia Activity/Supply and Demand

- Appalachia remains relatively tight across the region as new projects are having a tough time reaching approval
- **MVP coming online in mid 2024 will help balance Supply and Demand for the Northeast. (2 Bcf/d)**
- Beyond MVP, no new pipelines are likely to be built effectively limiting new production out of the region



Sources: EIA / ARM Research

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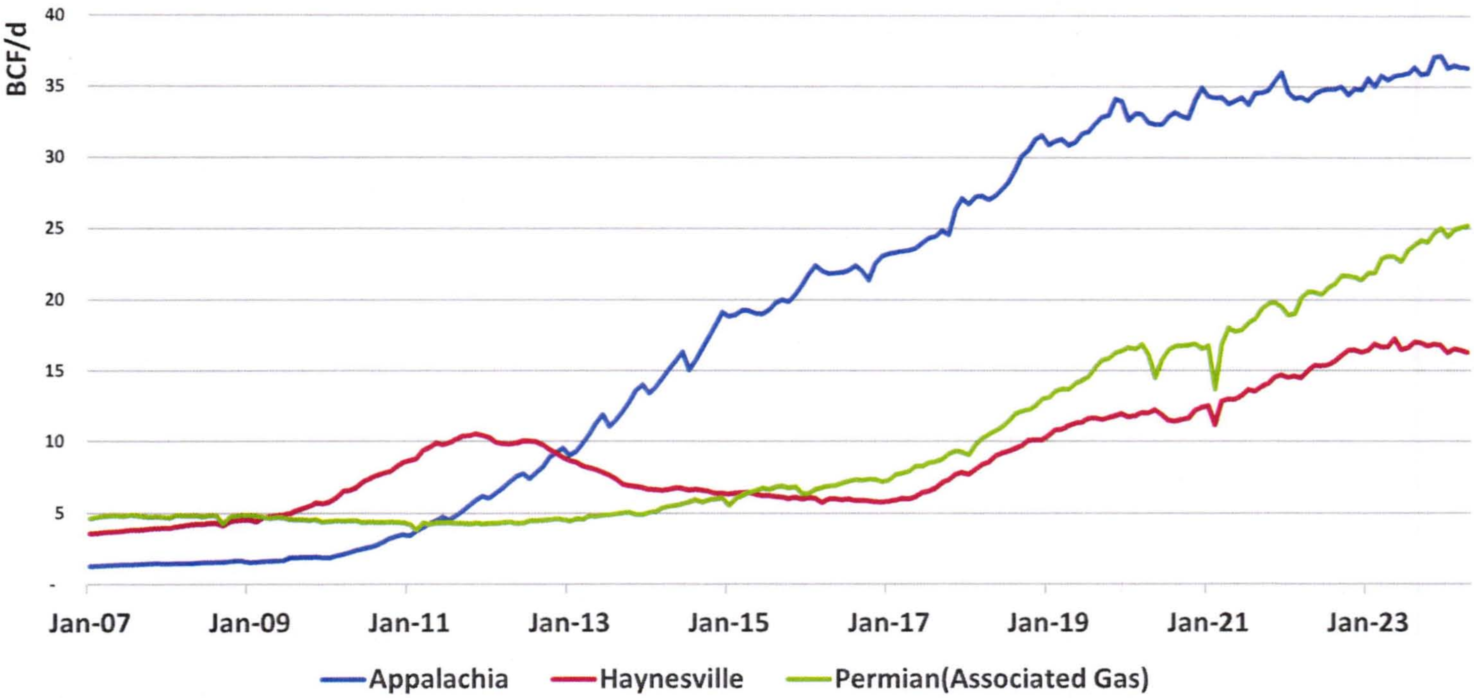
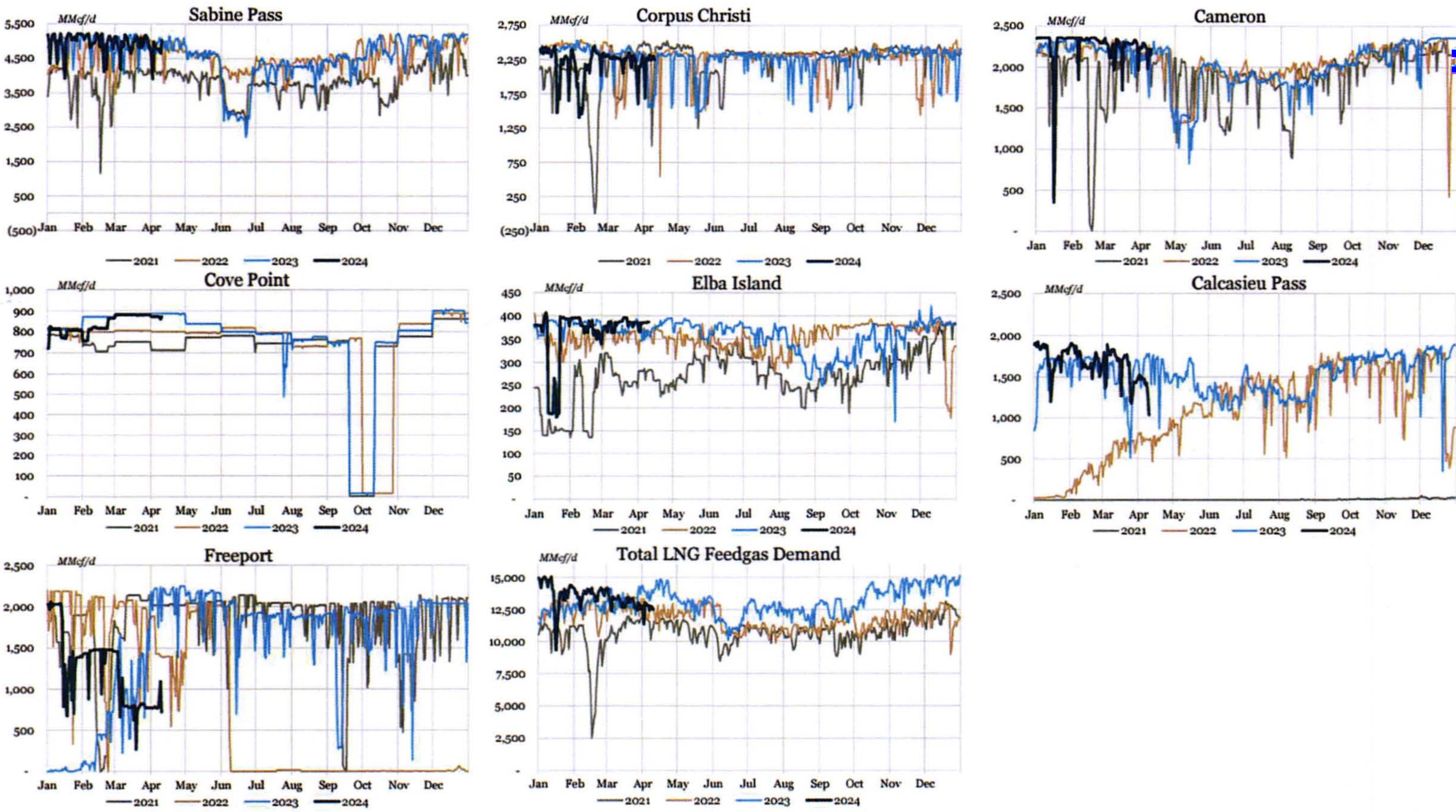
U.S. Gas Revolution

- Appalachia has been the leader in gas growth since the Shale Revolution.
- Inadequate pipeline infrastructure to other regions has bottlenecked Appalachia and allowed other regions to grow in recent years.



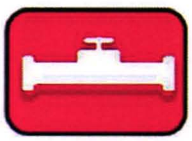
Sources: EIA / ARM Research

LNG Update



Sources: EIA / ARM Research

Top U.S. LNG Supplier Located in WV(Antero)

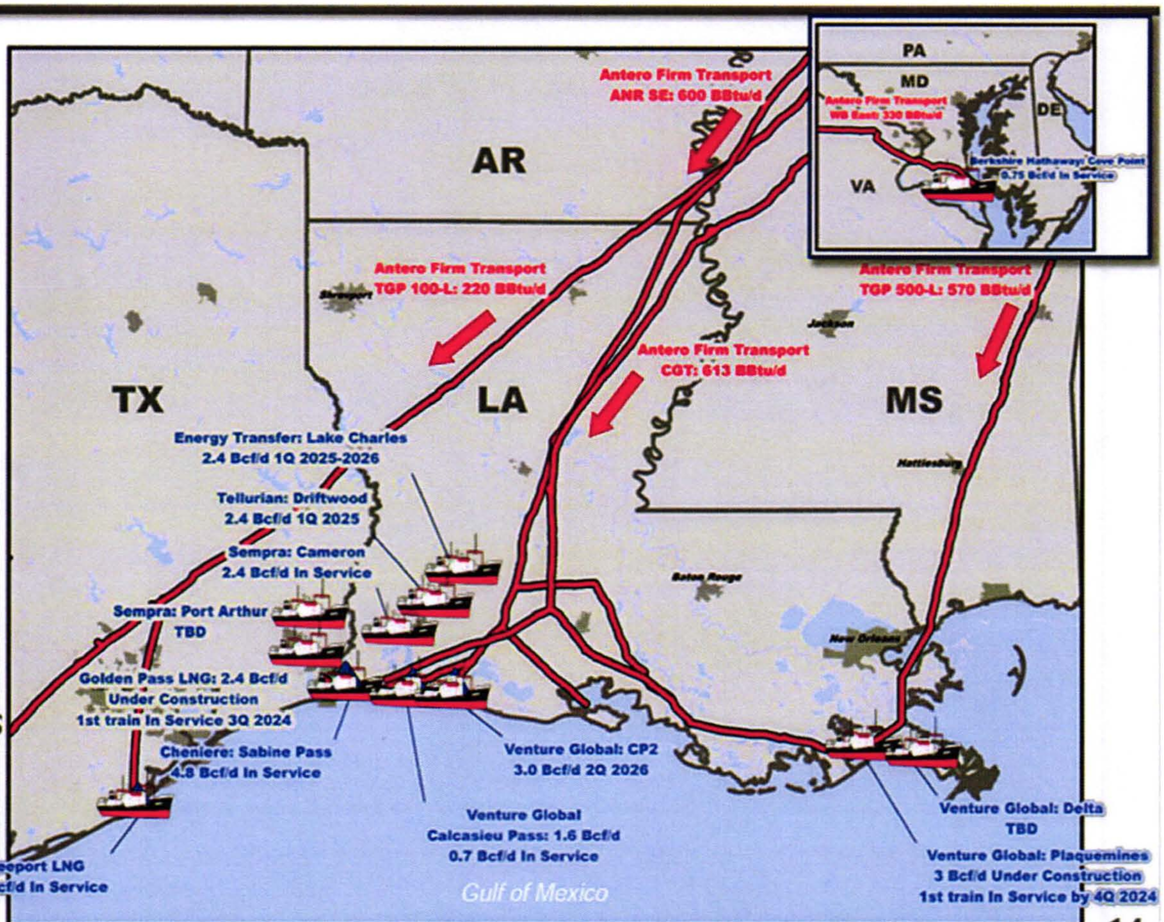


~2.3 Bcf/d

ANTERO FIRM TRANSPORT ACCESSES THE LNG FAIRWAY (1)

~26 Bcf/d

TOTAL LNG CAPACITY ACCESSIBLE BY ANTERO'S FIRM TRANSPORT,
~11 Bcf/d IN-SERVICE
~15 Bcf/d IN PROGRESS



1) Includes 330 MMcf/d of transport to Atlantic Seaboard (Cove Point).

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Unleashing LNG(EQT Slides)

- The U.S. natural gas industry stands ready to execute on this project today
- We have the resources, labor, capital, materials, and funding
- We need the green light: a prioritization of pipeline and LNG infrastructure

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Resource Development(EQT)

Step I: Develop the Resource

Deploying Just 50 Rigs Above Today's Levels

Remaining Inventory @ $3.75/mcf[1]

Basin	Region	Remaining Wells	BCF/Well	Total Resource (TCF)
Appalachia	Northeast	90,000	14.4	1,275
Haynesville	Gulf Coast	25,000	12.8	300
Eagle Ford (dry gas)	Gulf Coast	20,000	8.3	168
Woodford (dry gas)	Gulf Coast	8,000	10.9	82
Total Gas Shales		140,000	13.0	1,800+
Permian Associated Gas	Gulf Coast	50,000+	4.0	200+

Resource Summary

- 1,800 TCF from 4 basins to be developed from 140,000 wells
- All wells are economic at $3.75/mcf or below, in line with historical/current prices
  - Including LNG costs, U.S. natural gas is a cheap alternative to carbon intensive coal

Development Needed

- All basins have been developed for 15 years with 40,000 wells already drilled
  - 120 active rigs as of March '22
  - 50+ Rig Additions Needed for LNG Ramp

Production Ramp[2]

- Current rates of 4 gas plays: 45 Bcfd
- 2030 Rate: 90 Bcfd
  - Y/Y Growth rates of +5.5 Bcfd are in line with historical norms
  - 2022-2030 growth of +45 Bcfd is split roughly 60/40 Appalachia vs Gulf Coast
- 2040 Rate: 100 Bcfd
  - Appalachia constitutes 70% of total production, growing from 33 Bcfd to 70 Bcfd
- Able to hold these rates flat for 30 years to incentivize long term LNG buildout
- Permian associated gas would be additive (+8 Bcfd by 2030)

1. BCF/well is calculated from historical performance from existing wells in each basin, and remaining wells counts is estimated by well spacing and available acres in each basin. 2. Internal study assumes rig activity will ramp up to ~170 / year and stay relatively flat until 2030.

Source: Enverus, EQT analysis.

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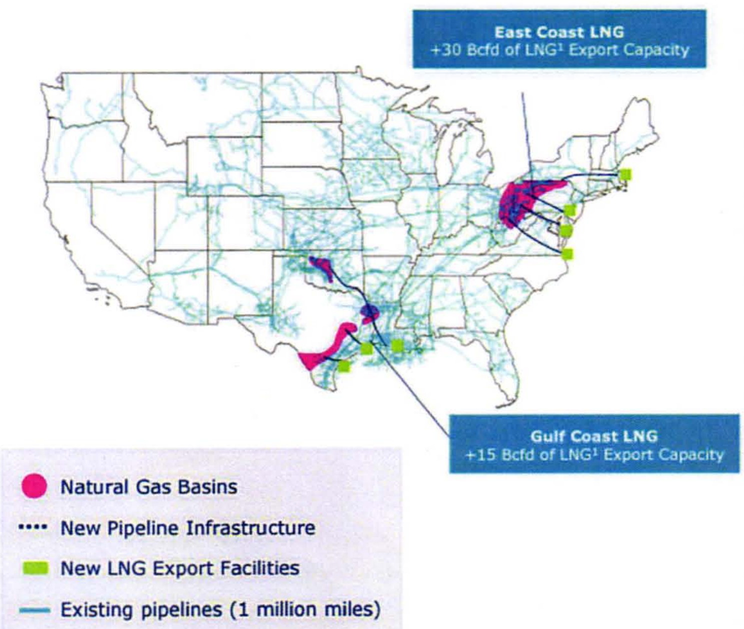
Infrastructure Outlook(EQT)

Step II: Connect Supply to Demand with Infrastructure



Pipelines

Need multiple, large diameter pipelines heading to both the East Coast and Gulf Coast

- Appalachia alone has the ability to reduce international emissions by ~750 million metric tons CO2/year (approximately 600 million metric tons CO2/year attributable to Pennsylvania)
  - 3x Germany's Energiewende project
- Pennsylvania pipelines are operating at capacity due to opposition and cancellation of proposed midstream projects
- Previously cancelled pipelines should be reconsidered, completed and deployed

LNG Facilities

Both the East Coast and Gulf Coast need to be major LNG export hubs

- East Coast
  - Current LNG Export Capacity[2]: 1 Bcfd
  - 2030 Needs: 31 Bcfd (+30 Bcfd)
  - Global CO2 Reductions From East Coast LNG[3]: -775 Million Metric Tons CO2/Year
- Gulf Coast
  - Current LNG Export Capacity[2]: 12 Bcfd
  - 2030 Needs: 27 Bcfd (+15 Bcfd)
  - Global CO2 Reductions From Gulf Coast LNG[3]: -725 Million Metric Tons CO2/Year

1. Internal analysis assume a 140-170 U.S rigs /year drill schedule // Based on internal study, 70% of total U.S. resource comes from near East coast and 30% from near the gulf coast, and the future additional capacity is allocated using a similar ratio. 2. Based on Jan / Feb 2022 data. 3. Electricity generated from LNG can be calculated using gas production multiplied by 1bcf = 136.3GWh conversion factor, CO2 emission saving from coal-to-LNG is 0.56 MtCO2e/TWh, and total emission saving can be derived from multiplying electricity generated by CO2 saving factor; includes emissions reduction due to LNG Export Facilities under construction.

Source: EIA Natural Gas Consumption by End-Use Sector and Census Division for local consumption, Enverus for gas production potential in U.S., EQT analysis.

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Blocked/Cancelled Pipelines

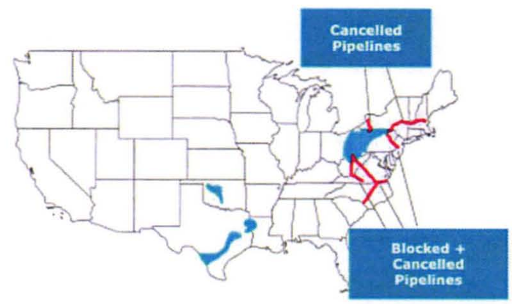
The Only Blockade to Unlocking the Largest Green Initiative

A Misguided Opposition to Infrastructure

Pillars for U.S. LNG Expansion	
Natural Gas Production	The U.S. natural gas industry is ready to ramp production now, but we cannot increase production without associated pipelines to LNG export facilities on the coasts because existing pipelines are largely full.
Infrastructure	Over the last 5 years, pipelines and LNG facilities have been cancelled or considerably delayed. Pipeline and LNG facility buildouts are currently being constructed at a pace 1/4th that of the level at which industry can provide the natural gas. **Cancellation/Delays of natural gas infrastructure has resulted in hundreds of millions of metric tons of unnecessary CO2 emissions at a time when rapid action is needed,** while also contributing to elevated regional and global inflation.

Example:

Locations of Blocked / Cancelled Natural Gas Pipelines



Project	Status	Gas Volumes (Bcfd)
Constitution	Cancelled	0.7
Penn East	Cancelled	1.1
Northern Access	Opposed	0.5
MVP	Opposed	2.0
Atlantic Coast	Cancelled	1.5
Northeast Direct	Cancelled	1.2
Total		7.0 Bcfd

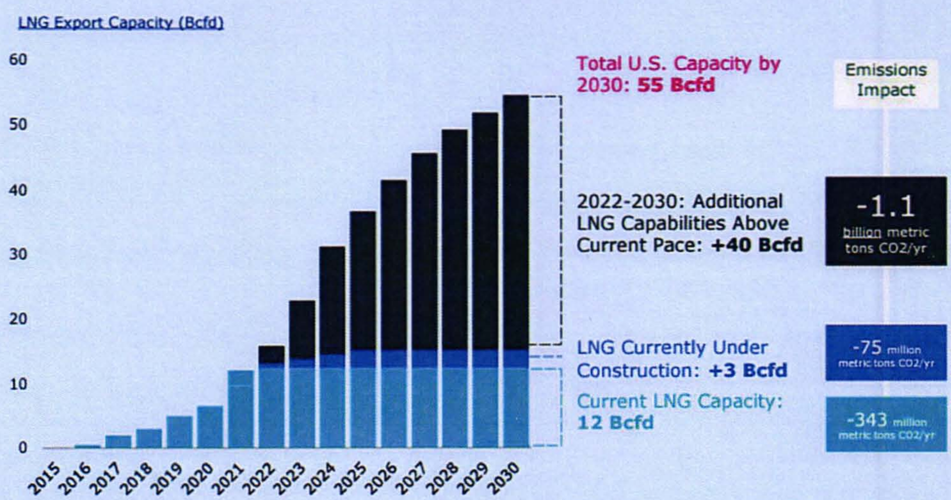
LNG Export Capacity Unleased(EQT)

Looking Forward: U.S. LNG Could Grow 6x the Current Obstructed Pace

Opposition to Natural Gas Infrastructure is Impeding What is Possible

- An unleashed U.S. LNG scenario assumes production increases in-line with historic rates and a prioritization of LNG and pipeline infrastructure build[2]
- The only barricade to expanding on what is *already* the largest green project → opposition to infrastructure

Projected LNG Export Capacity Through 2030[1]



1. Based on an internal study, U.S can produce 40 bcfd production surplus by 2030. 2. There is 3 bcfd capacity currently under construction, and another 3 bcfd anticipated. Therefore, projected incremental capacity is 6bcfd. To reach an additional 40 bcfd, the incremental needs to be 6x, which is in line with non-obstructed pace. 3. Assuming 3 bcfd under construction, and 40 bcfd additional capacity by 2030.

Source: ICF Update to the life-cycle analysis of GHG emissions for U.S. LNG exports analysis to calculate emissions saving from coal to gas; EQT analysis for additional production (based on Enverus data)

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Hansen
Exhibit 7

CONFIDENTIAL

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

[redacted]

[redacted]

Confidential Response:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Hansen
Exhibit 8

CONFIDENTIAL

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

[redacted]

Confidential Response:

[redacted]

[redacted]

CERTIFICATE OF SERVICE

I certify that the foregoing Direct Testimony and Exhibits of Evan Hansen, filed on behalf of Appalachian Voices in Docket No. E-100, Sub 190, has been served upon each of the parties and counsel of record in this proceeding either by electronic mail or by deposit of same in the U.S. Mail, postage prepaid.

This the 28th day of May, 2024.

LAW OFFICES OF F. BRYAN BRICE, JR.

By: /s/ Andrea C. Bonvecchio
Andrea C. Bonvecchio