Docket No. RP22-__-000
Exhibit No. ANR-0001

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22 -___-000

Summary of the Prepared Direct Testimony of Joshua Gibbon

Mr. Gibbon is the Vice President of Rates and Regulatory for TransCanada USA Services, Inc. His testimony provides a broad overview of ANR Pipeline Company's ("ANR") system as well as a high-level description of the current market situation facing ANR. To that end, Mr. Gibbon explains when ANR filed its last rate case and provides a summary of the industry and market changes that have occurred since that rate case. Mr. Gibbon then discusses the significant commercial and business risks that ANR faces as a result of these changes. Finally, Mr. Gibbon provides an overview of certain elements of ANR's filing and introduces ANR's other witnesses.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22-___-000

PREPARED DIRECT TESTIMONY OF JOSHUA GIBBON ON BEHALF OF ANR PIPELINE COMPANY

January 28, 2022

<u>Glossary of Terms</u>

ANR	ANR Pipeline Company
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
CPG	Columbia Pipeline Group
Commission	Federal Energy Regulatory Commission
EFP	Eligible Facilities Plan
FERC	Federal Energy Regulatory Commission
LDCs	Local Distribution Companies
LNG	Liquified natural gas
Modernization Policy Statement	*Cost Recovery Mechanisms for Modernization of Natural Gas Facilities*, 151 FERC ¶ 61,047 (2015)
NGA	Natural Gas Act
PHMSA	Pipeline and Hazardous Materials Safety Administration
ROE	Return on Equity
RP16-440 Settlement	The FERC-approved 2016 settlement in Docket No. RP16-440-000
SBOs	Storage by Others
SIMM	System Improvement Modernization Mechanism
SE Mainline	Southeast Mainline
SW Mainline	Southwest Mainline
TC Energy	TC Energy Corporation

Tie Line	A line from Defiance, Ohio to Bridgman, Michigan that connects ANR's SE and SW Mainlines

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-___-000

Prepared Direct Testimony of Joshua Gibbon

Q: What is your name and business address?

A: My name is Joshua Gibbon. My business address is TC Energy Corporation ("TC Energy"), 700 Louisiana Street, Houston, Texas 77002.

Q: What is your occupation?

A: I am presently employed by TransCanada USA Services Inc., an indirect subsidiary of TC Energy, as the Vice President of Rates and Regulatory. TransCanada USA Services Inc. employs all personnel in the United States who are involved in the operation and maintenance of TC Energy's U.S. energy systems and facilities, including ANR Pipeline Company ("ANR"). I am filing testimony on behalf of ANR.

Q: Please describe your educational background and your occupational experience as they are related to your testimony in this proceeding.

I earned a Bachelor of Business Administration degree in Finance from Texas A&M University. I began my employment with Columbia Pipeline Group ("CPG") as a Market Analyst in June 2007. While at CPG, I served in the role of Marketing, Business Development, Strategy, and Project Coordination. Upon acquisition of CPG by TC Energy, formerly TransCanada Corporation, I was named Director of Business Development for our regulated natural gas business. After that, I was promoted to Vice President, Midstream, where I was responsible for the management and growth of our unregulated natural gas assets. In my current role of Vice President of Rates and

Regulatory. I am responsible for the regulatory matters of the U.S. natural gas business including rate cases, certificate filings, and modernization initiatives.

Q: Have you ever testified before the Federal Energy Regulatory Commission ("FERC" or the "Commission") or any other energy regulatory commission?

A: Yes. I have filed testimony before the Commission in *Columbia Gas Transmission, LLC*, Docket No. RP20-1060-000.

Q: What is the purpose of your testimony in this proceeding?

A: I provide a broad overview of the ANR system, a high-level description of the current market situation facing ANR, and a description of the major components that underlie this filing. I also introduce ANR's other witnesses.

Q: Please generally describe the ANR system.

A: ANR is a corporation organized and existing under the laws of the State of Delaware, and has its principal place of business at 700 Louisiana Street, Houston, Texas, 77002. ANR is a "natural-gas company" as defined by the Natural Gas Act ("NGA"), 15 U.S.C. § 717a(6), and is engaged in the business of transporting natural gas in interstate commerce, subject to the jurisdiction of the Commission.

As ANR witness Lakhani explains, ANR's system consists of approximately 9,000 miles of pipeline and nearly 203 billion cubic feet ("Bcf") of storage, including storage by others, and delivers more than 1 trillion cubic feet of natural gas annually. ANR's facilities include two main pipelines: the Southwest Mainline ("SW Mainline"), extending from Texas north through Oklahoma, Kansas, Missouri, Iowa, Illinois, and into Wisconsin with a segment extending through Indiana and into Michigan, and the Southeast Mainline ("SE Mainline"), extending from Louisiana north through Arkansas, Mississippi, Tennessee, Kentucky, Indiana, Ohio, and into Michigan. A segment of pipeline through northern Indiana, Ohio, and Michigan connects the two main branches ("Tie Line").

As ANR witness Lakhani testifies, the SW Mainline connects the production entering ANR's SW Area in Texas, Oklahoma, and Kansas to Midwest markets in Illinois, Wisconsin, and Michigan. The SE Mainline historically was designed to connect traditional Louisiana offshore production to the Midwest; however, today it functions very differently. The SE Mainline is now a bifurcated system flowing gas both north to the Midwest and south to markets on the Gulf Coast including liquified natural gas ("LNG") and industrial customers. The Tie Line connects the two mainlines.

Q: When were ANR's rates last reviewed?

A: ANR's current rates were established as part of the FERC-approved 2016 settlement in Docket No. RP16-440-000 ("RP16-440 Settlement"). As part of that settlement, ANR is obligated to file a general section 4 rate case with rates to be effective no later than August 1, 2022.

Q: Can you briefly describe the current overall market situation ANR faces?

A: Yes. As described in greater detail by ANR witness Lakhani, ANR has experienced significant changes in the natural gas marketplace since ANR's last rate case was resolved by settlement in 2016. Since 2016, production growth from the Marcellus and Utica supply basins has continued at a rapid pace resulting in several interstate pipeline companies constructing and putting into service new pipelines to transport this ever-increasing supply to market, thereby directly reducing ANR's contracting and market share to its Michigan markets in ANR's Northern Area. In ANR's SW Area, a boom-bust production cycle in the Rocky Mountain, Mid-Continent, and Permian basins has left this area overbuilt and under-supplied, resulting in significantly decreased supply on ANR's SW Mainline. Lastly, the ever-increasing LNG exports along the Gulf Coast have altered demand for transportation services, increased pipeline competition, and resulted in major market changes along ANR's Southeast Mainline.

Q: In general, how have these supply and market changes that have taken place over the last several years impacted ANR?

A: These changes have had profound impacts on ANR's current and projected business and operations, as ANR witness Lakhani explains. These impacts include but are not limited to: continued new supply and pipeline competition into ANR's Northern Area markets, particularly Michigan, resulting in significant declines in ANR's market share in these areas; significant reductions in supply in ANR's SW Area resulting in a substantial drop in utilization on ANR's SW Mainline; growing demand for capacity to transport gas supplies to the Gulf Coast for liquefaction as LNG exports; major investments by ANR to modernize its system; and increasing power generation-related deliveries.

Q: How has ANR invested in modernizing its system?

A: As ANR witnesses Lakhani, Parks, and Linder explain, ANR's system is on average older than other FERC-regulated interstate natural gas pipelines, and as a result, ANR has faced the ongoing need to modernize its system to enhance the efficiency, reliability, and safety of its system. As ANR witness Linder explains, pursuant to the RP16-440 Settlement, ANR made $837 million in modernization capital expenditures for these purposes. As explained further by various ANR witnesses, however, ANR continues to face the need to engage in modernization work, including to comply with new and anticipated Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulations. Therefore, ANR is proposing to implement a modernization program, as described below.

Q: Does ANR face particular sources of business risk in the current market?

A: Yes. ANR is facing several business risks in the current market. As explained by ANR witnesses Lakhani and Thapa, ANR is facing business risk associated with its contract profile, including a high concentration of producer-shippers, which has resulted from changes in ANR's natural gas markets. In addition, ANR is facing business risk associated with the supply changes in ANR's SW Area as well as competition from renewable generation coupled with state and federal net-zero carbon emission goals. ANR has also experienced heightened risk with respect to competition for its transportation services in the markets that it serves, particularly in the Northern Area, as well as increased regulatory and operating risk.

Q. How have market changes impacted ANR's customer profile and associated shipper credit risk?

A. As discussed by ANR witness Lakhani, a significant portion of ANR's forward haul capacity, and all of the backhaul capacity, on the SE Mainline is held by a small number of producers, who are particularly susceptible to changes in market conditions. Given current competitive conditions, ANR would face significant risk for remarketing this capacity in the event that one or more of the shippers were to turn the capacity back as a result of bankruptcy. As discussed by ANR witnesses Lakhani and Thapa, the recent increase in energy price volatility has affected producers more than others, resulting in an increased risk to ANR due to those shippers' evolving credit challenges. As ANR witness Thapa demonstrates, ANR has a significantly higher proportion of long-term contractual commitments from higher risk producer-shippers than most of its peer group pipelines. Given the significant financial pressure shale gas producers can face – and have faced as recently as last year – ANR's higher degree of exposure to this class of shippers results in

ANR facing a higher degree of business risk because of the risk that these shippers may default on their long-term contractual commitments to ANR.

Q: Please discuss the increased competition ANR is facing.

A: As ANR witness Lakhani explains, ANR has experienced significantly increased competition from new pipeline builds as a result of the continued production in the Utica and Marcellus region as well as along its SW Mainline. With respect to its Northern Area markets, Rover Pipeline and NEXUS Gas Transmission collectively provide an incremental 4.75 Bcf/d of supply capacity into the state of Michigan. The traditional markets that ANR served directly and indirectly in the state including power plants, local distribution companies ("LDCs"), and storage facilities, have become far more competitive to serve. As for the SW Mainline, following the boom-bust cycle associated with several SW Area basins, the resulting greenfield expansions during this time has placed ANR at a competitive disadvantage to its direct competitors in the region. As a result, ANR faces re-contracting risk, particularly in the SW Area where the effects of the supply changes have led to a decline in contracting of firm service. Lastly, while ANR has seen year-over-year growth in power plant deliveries on its system, this growth will be under pressure into the future as coal-fired unit retirements plateau, more renewable generation comes online, and state, federal, and even individual LDC net-zero carbon emission goals are pursued.

Q: Is ANR facing increased operating risk?

A: Yes. As described by ANR witnesses Lakhani and Linder, the size and age of ANR's pipeline system puts ANR at greater risk than other pipelines with respect to modernization costs and the impact of new regulations imposed by PHMSA, and potentially by the

Environmental Protection Agency, which would require substantial investment by ANR for compliance. These increased costs impose significant risks on ANR.

Q: Is ANR experiencing increased regulatory risk?

A: Yes, as ANR witness Lakhani explains, ANR is facing increased regulatory risk as a result of increasingly successful opposition to the development of new pipeline infrastructure, which opposition is being pressed at FERC, in courts, and before environmental and land use regulators. Mr. Lakhani also explains how ANR is facing increased regulatory risk associated with federal and state policy and legislative initiatives that impact ANR's ability to expand its system to serve new and existing markets, including the Commission's recent changes to its approach to assessing environmental impacts of new construction, including greenhouse gas impacts, and state efforts to deny needed permits and, as further explained by ANR witness Kirk, development of Renewable Portfolio Standards that limit the participation of natural gas in a state's resource mix.

Q: Do you see these new risks continuing in the foreseeable future?

A: Yes. In my view, these risks will remain the same or become even more significant over the next several years.

Q: What rate and rate design changes does ANR propose in this filing to reflect and address its new market and operational realities?

A: To address these issues, ANR is revising its rates to reflect an updated cost-of-service of more than $1.125 billion and, as noted, is proposing a system modernization program. ANR is also proposing certain rate design changes. First, as described in greater detail by ANR witnesses Linder and Miller, ANR is proposing to eliminate the term-differentiated rates for FSS service that were agreed to in the RP16-440 Settlement. Second, as discussed by Ms. Linder and ANR witness Barry, ANR proposes to reduce the existing 2x multiplier within the rate design for Rate Schedule ETS service to a 1.5x multiplier to reflect a more appropriate allocation of costs to that service, and further proposes to eliminate the access charge for service under Rate Schedules PTS-2 and PTS-3.

Q: Is ANR proposing a modernization cost recovery mechanism as a part of this filing?

A: Yes, ANR is proposing a System Improvement Modernization Mechanism ("SIMM") to recover costs associated with its continuing and necessary work to modernize its system. As ANR witness Linder explains, the SIMM is designed to allow ANR to recover specified costs associated with modernization of its system, as well as ANR's ongoing efforts to address numerous complex issues arising out of recent and anticipated changes in pipeline safety, reliability, integrity, and environmental requirements. As Ms. Linder explains, ANR's SIMM proposal is consistent with Commission policy governing cost recovery mechanisms for modernization of natural gas pipeline facilities, as set forth by the Commission in its Modernization Policy Statement issued in Docket No. PL15-1-000, *Cost Recovery Mechanisms for Modernization of Natural Gas Facilities*, 151 FERC ¶ 61,047 (2015) ("Modernization Policy Statement").

Q: Can you provide a summary description of ANR's SIMM proposal?

A. Yes. The tariff records included with this filing reflect initial SIMM rates of $0.00. The SIMM sets forth procedures pursuant to which ANR will make annual limited NGA section 4 filings to implement an additive surcharge to recover ANR's cumulative revenue requirement for capital investments made in certain defined Eligible Facilities as identified in the Eligible Facilities Plan ("EFP"). ANR is proposing a $900 billion cap, subject to a 15% tolerance, on the total amount of prudent investment for which revenue requirements are eligible for recovery through the five-year term of the SIMM.

Q: How do ANR's various proposals in this case affect the maximum recourse rate for firm transportation service?

A: As a result of the changes proposed herein, ANR's maximum recourse rate for firm transportation service (FTS-1, FTS-3, ETS, and NNS) will, on a revenue-based, weighted average basis, increase approximately 89.7 percent.

Q: How do ANR's various proposals in this case affect the maximum recourse rate for storage service?

A: As a result of the changes proposed herein, ANR's maximum recourse rate for firm storage service under Rate Schedule FSS will, on a revenue-based, weighted average basis, increase approximately 25.2 percent.

Q: Please describe the other significant aspects of ANR's filing, and the responsible witness for each.

A: A total of 16 witnesses (including me) are sponsoring direct testimony in this proceeding.

- ANR witness Sorana Linder provides an overview of ANR's existing rate design and supports ANR's proposed rate design modifications affecting the allocation of costs to the SE Area and SW Area. Ms. Linder provides policy support for ANR's proposals to eliminate term-differentiated rates from its storage services and to modify the design of ANR Rate Schedules ETS, PTS-2, and PTS-3. Ms. Linder also describes ANR's proposed modernization program, and supports the SIMM surcharge by which ANR proposes to recover the costs of its modernization program. Ms. Linder further explains how the proposed modernization program is consistent with the Commission's Modernization Policy Statement.
- ANR witness Adam Lakhani provides an overview of the ANR pipeline system, including system operations and storage assets. Mr. Lakhani also provides a detailed assessment of various market changes that have occurred since ANR's last rate case and how those

changes have affected ANR's sources of natural gas supply and its markets. Mr. Lakhani also provides a current and forward-looking discussion of the commercial environment and business risks that ANR is facing.

- ANR witness Bente Villadsen provides testimony describing the appropriate range of return on equity ("ROE") for ANR. Dr. Villadsen supports the proxy group that is used in determining the ROE and that is also used by ANR witness Thapa in his comparative business risk evaluation. Based on Dr. Villadsen's analysis and Mr. Thapa's business risk testimony, Dr. Villadsen recommends an ROE of 15.70%.
- ANR witness Anul Thapa reviews the business risk facing ANR and evaluates how ANR's business risk compares with a proxy group of other U.S. pipelines regulated by the Commission. Based on that analysis, Mr. Thapa concludes that ANR has greater business risks than those of the proxy group.
- ANR witness Scott Currier provides an overview of PHMSA regulations and their implications for ANR's modernization program.
- ANR witness Garrett Word provides the basis for the well abandonment and replacement projects that ANR proposes to include in the modernization program.
- ANR witness Matt Parks describes the EFP associated with ANR's proposed modernization program.
- ANR witness Alexander Kirk provides an assessment of gas supplies available to ANR, as well as demand factors for ANR's services, to determine the economic life of the ANR system, in support of depreciation rates sponsored by ANR witness Crowley. Based on his analysis, Mr. Kirk recommends that ANR's economic life be truncated at 2050 for ratemaking purposes.

- ANR witness Steven Fall testifies regarding the cost of retiring and removing facilities for development of a net negative salvage rate, in support of ANR witness Crowley.
- ANR witness Patrick Crowley addresses depreciation and negative salvage. Based on the economic life of ANR's facilities, Mr. Crowley recommends various depreciation rates and interim retirement negative salvage and terminal decommissioning negative salvage rates for each category of plant.
- ANR witness Nada Siddik discusses ANR's third-party transportation and storage contracts and explains how all ANR shippers benefit from these contractual arrangements.
- ANR witness Burton Cole addresses and supports ANR's cost-of-service. Mr. Cole establishes ANR's overall cost-of-service for the twelve-month base period ending October 31, 2021, adjusted for known and measurable changes for the test period ending July 31, 2022.
- ANR witness Greg Barry addresses the methodology used to functionalize, classify, and allocate costs in the development of ANR's reservation and delivery rates for its transmission, storage, and gathering services. Mr. Barry also discusses the impact of discount adjustments and the development of rates for each of ANR's services.
- ANR witness Eric Miller addresses billing determinants and revenues. As part of his testimony, Mr. Miller addresses known and measurable changes to billing determinants in the test period. Mr. Miller also describes the competitive environment which led ANR to enter into the negotiated rate contracts for which ANR is seeking a discount-type adjustment in this case, and supports ANR's proposal to eliminate term-differentiated rates from its storage services.

- ANR witness Nara Houy addresses ANR's proposal to roll in the costs and revenues of two expansion projects and demonstrates that doing so would be consistent with Commission policy.

Q: Does this conclude your testimony?

A: Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-____-000

State of Texas)
) ss.
County of Harris)

AFFIDAVIT OF JOSHUA GIBBON

Joshua Gibbon, being first duly sworn, on oath states that he is the witness whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of Joshua Gibbon"; that, if asked the questions which appear in the text of said testimony, he would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as Joshua Gibbon's sworn testimony in this proceeding.

DocuSigned by:
Joshua Gibbon
EF363EE2B0F449A...

Joshua Gibbon

SWORN TO AND SUBSCRIBED BEFORE ME THIS 19th DAY OF January, 2022. This notarial act was an online notarization.

Notary Seal

NOTARY PUBLIC STATE OF TEXAS
SHELIA O. COPUS
Notary ID
976876
My Commission Expires
2/22/2023

Digital Certificate

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Shelia Copus
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22 -___-000

Summary of the Prepared Direct Testimony of Sorana M. Linder

Ms. Linder is the Director, Rates, Tariffs, and Modernization for TransCanada USA Services Inc. Her testimony discusses several rate design changes being proposed by ANR Pipeline Company ("ANR") relating to ANR's ETS and PTS rate schedules as well as the elimination of ANR's term-differentiated storage rates for firm storage service under Rate Schedule FSS. Ms. Linder also supports the System Improvement Modernization Mechanism ("SIMM") that ANR is proposing in this instant proceeding as part of its modernization program. Ms. Linder explains how the proposed SIMM is consistent with the Commission's policy statement addressing cost recovery mechanisms for modernization of natural gas facilities ("Modernization Policy Statement").

Ms. Linder's testimony is divided into five sections. The first section provides an overview of ANR's existing seven-zone rate design and provides support for certain rate design changes related to rate schedules ETS, PTS, and FSS. The second section discusses the prior modernization work that ANR has completed pursuant to its immediately prior settlement and the benefits that such modernization work has yielded for ANR's system and its shippers.

In the third section, Ms. Linder discusses ANR's plan to continue to modernize its system over the next five years. To that end, she explains that ANR's planned future modernization work is designed to allow ANR to continue improving the reliability, integrity, safety, and efficiency of its system as well as to address compliance with existing and emerging regulatory requirements.

In section four, Ms. Linder provides details concerning ANR's proposed SIMM that will implement an additive surcharge designed to recover ANR's cumulative revenue requirement for capital investments made in certain defined Eligible Facilities and certain other costs. Ms. Linder explains how ANR will calculate the SIMM rate, and further, that such investments will not exceed $900 million plus a 15 percent tolerance through the proposed five-year term of the SIMM.

Finally, in section five, Ms. Linder details how ANR's proposed SIMM and overall modernization program is consistent with the Commission's Modernization Policy Statement.

Docket No. RP22-___-000
Exhibit No. ANR-0002

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-___-000

PREPARED DIRECT TESTIMONY
OF SORANA M. LINDER ON BEHALF OF
ANR PIPELINE COMPANY

January 28, 2022

Glossary of Terms

A&G	Administrative and General
ANR	ANR Pipeline Company
Columbia	Columbia Gas Transmission, LLC
Commission	Federal Energy Regulatory Commission
CS	Compressor Station
CPG	Columbia Pipeline Group
CS	Compressor Station
Dth-mile	Dekatherm-mile
EA	Environmental Assessment
EFP	Eligible Facilities Plan
EIS	Environmental Impact Statement
ETS	Rate Schedule ETS
FERC	Federal Energy Regulatory Commission
GPMC	General Plant Maintenance Capital
LAUF	Lost and Unaccounted for Gas
Mega Rule	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines
Modernization Policy Statement	*Cost Recovery Mechanisms for Modernization of Natural Gas Facilities*, 151 FERC ¶ 61,047 (2015)
NGA	Natural Gas Act
PHMSA	Pipeline and Hazardous Materials Safety Administration

PTS-2	Rate Schedules PTS-2
PTS-3	Rate Schedules PTS-3
RCC	Reservation Charge Credits
RP16-440 Settlement	The FERC-approved 2016 settlement in Docket No. RP16-440-000
SIMM	System Improvement Modernization Mechanism
SE Area	Southeast Area
SW Area	Southwest Area
System	ANR's Interstate Natural Gas Pipeline System
Tariff	FERC Gas Tariff, Third Revised Volume No. 1
TC Energy	TC Energy Corporation
TOIT	Taxes Other than Income Taxes

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company Docket No. RP22-___-000

Prepared Direct Testimony of Sorana M. Linder

Q: What is your name and business address?

A: My name is Sorana M. Linder. My business address is TC Energy Corporation ("TC Energy"), 700 Louisiana Street, Houston, Texas, 77002.

Q: What is your occupation?

A: I am presently employed by TransCanada USA Services Inc., an indirect subsidiary of TC Energy, as Director, Rates, Tariffs, and Modernization. TransCanada USA Services Inc. employs all personnel in the United States who are involved in the operation and maintenance of TC Energy's U.S. energy systems and facilities, including ANR Pipeline Company ("ANR"). I am filing testimony on behalf of ANR.

Q: Please state your education and professional background.

A. I earned a Bachelor of Science in Organic Chemistry from Sam Houston State University in 2002. I began my employment with Columbia Pipeline Group ("CPG") as a Senior Rates & Regulatory Analyst in March 2008. I was promoted to Manager, Rates & Regulatory Affairs in January 2011 and subsequently to Director, Rates & Regulatory Affairs in March 2016. While employed at CPG, I led the effort on the preparation of Columbia Gulf Transmission Company's general Natural Gas Act ("NGA") section 4 rate case in Docket No. RP11-1435-000, primarily managing issues related to the pipeline's cost-of-service. In addition, I led the effort on the preparation and negotiation of Columbia Gas Transmission, LLC's ("Columbia") Modernization I and II Settlements filed with and approved by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Docket Nos. RP12-1021-000 and RP16-314-000, respectively. I also was primary lead in the preparation of Columbia's subsequent modernization program filed in Columbia's 2020 NGA section 4 rate case filing in Docket No. RP20-1060-000. Finally, I have overseen numerous tariff filings and certificate applications submitted to the Commission. Upon acquisition of CPG by TC Energy, I was named Director of Regulated Services and, in 2017, I was named as Director, Modernization & Certificates. In this role I was responsible for ensuring that Columbia implements, and complies with, the Commission-approved Modernization Settlements and charged with directing all certificate applications and reporting pursuant to Part 157 of the Commission's regulations. Lastly, on July 1, 2021, I was appointed to my current position as Director, Rates, Tariffs, and Modernization. In this role, I am responsible for overseeing the Regulatory department, which maintains TC Energy's pipeline subsidiaries' FERC gas tariffs and submits and administers rate filings.

Q: Have you ever testified before FERC or any other regulatory commission or agency?

A: Yes. I have filed testimony with the Commission in *Columbia Gas Transmission, LLC*, Docket No. RP16-353-000, and *Columbia Gas Transmission, LLC*, Docket No. RP20-1060-000.

Q: What is the purpose of your testimony in this proceeding?

A: My testimony is divided into five sections. In Section I, I will provide an overview of ANR's existing seven-zone rate design including support for certain rate design modifications affecting the allocation of costs to the Southeast Area ("SE Area") and Southwest Area ("SW Area") of ANR's interstate natural gas pipeline system ("System"), including non-mileage cost allocation (Account No. 858 costs, A&G costs, and system balancing costs) to these zones. I will also discuss the policy support for ANR's proposal, as described by ANR witness Miller, to eliminate term-differentiated rates from its storage services. Finally, I will discuss proposed modifications to the way Rate Schedules ETS, PTS-2, and PTS-3 rates are designed.

Sections II through V of my testimony support the System Improvement Modernization Mechanism ("SIMM") that ANR is proposing in the instant proceeding. The SIMM is designed to allow ANR to recover specified costs associated with the modernization of its System and ANR's continued efforts to address the numerous complex issues arising out of recent and additional anticipated changes in pipeline safety, reliability, integrity, and environmental requirements. Section II will also provide background on ANR's prior modernization work pursuant to the prior settlement approved in Commission Docket No. RP16-440 ("RP16-440 Settlement") and Section III will provide an overview of how ANR intends to continue its modernization efforts going forward. Section IV will include a description of the proposed SIMM and the projects that ANR intends to undertake as part of its modernization efforts. Finally, Section V will explain how the proposed SIMM is consistent with the policy statement addressing cost recovery mechanisms for modernization of natural gas facilities that the Commission issued in its Docket No. PL15-1, *Cost Recovery Mechanisms for Modernization of Natural Gas Facilities*, 151 FERC ¶ 61,047 (2015) ("Modernization Policy Statement").

Q: Are you sponsoring any exhibits in addition to your testimony?

A: Yes. I am sponsoring the following exhibits:

Exhibit No. ANR-0003	SIMM Revenue Requirement Illustrative Calculation
Exhibit No. ANR-0004	SIMM Pre-Tax Return Calculation

Q: Are you sponsoring any Statements or Schedules?

A: Yes, I am sponsoring the following Statement:

Exhibit No. ANR-0132 Statement O (Description of Company Operations)

I. RATE DESIGN OVERVIEW & PROPOSED MODIFICATIONS

Q: Please provide an overview of ANR's seven-zone rate design.

A: The ANR system is divided into seven different zones as described by ANR witness Lakhani. Under the current rate design, ANR employs a zone-gate approach to assign costs directly to the SE and SW Areas while the costs associated with the Mainline Area are allocated to the other five zones using a dekatherm-mile ("Dth-mile") allocation. Under such Dth-mile rate design, costs are allocated to zones based upon the receipt and delivery quantities multiplied by the associated miles of haul. ANR proposes to continue designing its rates utilizing the Dth-mile allocation but proposes to allocate costs to all of the seven zones. Application of the Dth-mile allocation method across all zones ensures consistency to the allocation of mileage-related transmission costs and eliminates the potential for discrimination. In addition, as reflected in ANR witness Barry's testimony, ANR will allocate non-mileage transportation costs such as transmission function Account No. 850, Account No. 858, system balancing, and administrative and general ("A&G") costs to all of ANR's seven rate zones, consistent with Commission policy regarding cost responsibility for non-mileage, access-related costs.

Q. Please explain how the Commission views the classification of costs as non-mileage.

A: The Commission has previously found that A&G, Account Nos. 850 and 858, and storage balancing costs do not vary with distance and are therefore properly classified as non-mileage and can be collected through an access charge. In addition, it is my understanding that the Commission does not limit the costs that may be classified as non-mileage to only these specific costs, and that pipelines are permitted to demonstrate that other costs are also not distance sensitive.

Q: Please explain what other rate design modifications are being proposed in this filing.

A: As part of the RP16-440 Settlement, ANR implemented term-differentiated rates for firm storage service under Rate Schedule FSS. This proposal introduced firm rates that varied depending upon the term of the customer's firm storage contract. As supported by ANR witness Miller, ANR is proposing to eliminate term-differentiated rates from Rate Schedule FSS. ANR's experience with term-differentiated rates over a period of years has revealed that they have not been effective at lengthening the average FSS contract term – the original objective of implementing them in the first place.

Q: Please describe Rate Schedule ETS ("ETS").

A: ETS is a firm transportation service designed specifically for local distribution shippers. ETS service is similar to FTS-1 service, although it provides two additional service enhancements. One is the ability to aggregate multiple delivery points under a single ETS contract, thereby providing an ETS shipper the ability to move delivery point volumes among multiple gate stations. The second enhancement provides ETS shippers the right to deliver up to 1/16th of their Maximum Daily Quantity on an hourly basis. The ETS rate has been designed, and approved as part of ANR's Order No. 636 restructuring proceeding in Docket No. RS92-1, as a derivative of the FTS-1 rate, with ETS receiving a double allocation of mileage reservation costs in the zone of delivery. This 2x multiple of the mileage reservation costs in the zone of delivery was intended to recognize the cost of the additional capacity required for ETS service flexibility.

Q: Will ANR continue the double allocation of zone of delivery mileage reservation costs in the design of ETS rates?

A: No. While the double allocation of mileage reservation costs has been approved by the Commission previously, applying the existing 2x multiplier within the ETS rate design methodology would result in an ETS premium relative to the FTS-1 rate that is far in excess of the premium reflected in current rates. For example, ANR's currently effective ETS reservation rate for a Northern Segment to Northern Segment path is approximately 14% higher than the comparable rate for FTS-1. Under ANR's proposed 1.5x multiplier methodology, the ETS reservation rate for the same path is approximately 34% higher than the comparable rate for FTS-1, whereas under a 2x multiplier methodology the ETS reservation rate for the same path is approximately 68% higher than the comparable rate for FTS-1. Therefore, as reflected in ANR witness Barry's testimony, ANR proposes to utilize a 1.5x multiplier in the design of its ETS rates.

Q: Please describe Rate Schedules PTS-2 ("PTS-2") and PTS-3 ("PTS-3").

A: PTS-2 is a firm pooling transportation service that allows shippers to aggregate gas from various points within a pooling area and deliver the gas to a pooling headstation at either Greensburg, Kansas, or Eunice, Louisiana. PTS-2 shippers are not entitled to deliver gas to points other than these two headstations. PTS-3 is the interruptible form of PTS-2 service.

Q: Do you propose to continue to assess an access charge to PTS-2 shippers?

A: No. Downstream shippers that receive gas that is delivered to a headstation by means of a PTS-2 or PTS-3 agreement will pay an access charge that recovers all costs classified as non-mileage. Because all PTS-2 and PTS-3 gas must be delivered to an on-system headstation, rather than to an off-system delivery point, assessment of the access charge to PTS-2 or PTS-3 shippers would essentially serve to apply the access charge twice to any transaction involving a PTS-2 or PTS-3 contract, thereby disadvantaging any shipper that pooled its gas under a PTS-2 or PTS-3 agreement. Therefore, I have advised ANR witness Barry that the access charge should not be applied to PTS-2 or PTS-3 service.

II. BACKGROUND OF ANR'S MODERNIZATION PROGRAM

Q: Please explain the background behind ANR's RP16-440 Settlement.

A: The RP16-440 Settlement was the product of a NGA section 4 general rate case filing that ANR made on January 31, 2016. As part of the RP16-440 Settlement, which was a global settlement that resolved all issues set for hearing in that case, ANR and the settling parties agreed that ANR would commit to making capital expenditures of at least $837 million for Reliability and Modernization Projects over a three-year period commencing January 1, 2016. The RP16-440 Settlement stipulated that "Reliability and Modernization Projects" include "all capital projects that enhance the efficiency, reliability, and/or safety of ANR's system and do not include expansion projects or projects that otherwise increase the capacity of ANR's system." RP16-440 Settlement, Article IX.A. ANR was also required to provide written notification to all participants within thirty (30) days after it had made $837 million in capital expenditures for Reliability and Modernization Projects. Notice was provided on March 27, 2019 that ANR met its commitment to spend the agreed upon $837 million of modernization capital.

Q: Please summarize the modernization work included and completed by ANR under the RP16-440 Settlement.

A: Under the RP16-440 Settlement, ANR committed to perform modernization work on its System by undertaking work at critical stations and addressing aging portions of the System. The work included compression upgrades, integrity and measurement upgrades and replacements, including upgrades to gas quality monitoring equipment, balance of plant restoration, and technology and automation modernization by replacing obsolete control systems.

Q: Please provide examples of ANR's modernization accomplishments under the RP16-440 Settlement.

A: In achieving ANR's system modernization commitments under the RP16-440 Settlement, ANR has, among other things, completed compression upgrades by performing overhauls at 115 units across 43 stations and replacing units at LaGrange, Jena, and Brownsville. ANR also performed significant integrity work including five miles of class change remediation to ensure the pipeline is operating with safety factors commensurate to the surrounding population density. ANR's integrity work also included the installation of bi-directional pigging facilities to assess System integrity, and replacements of and/or upgrades to critical valves at strategic locations on the System. Additional work related to plant restoration addressed obsolete station power equipment upgrades, main gas filtration upgrades, and critical valve replacements. Also, in accordance with these commitments, ANR installed meter upgrades and updated gas quality monitoring equipment. Finally, in the technology and automation category, ANR installed a state-of-the-art real-time system and critical station control panel upgrades at seven stations.

These modernization projects have yielded tremendous benefits for the System and its customers, allowing ANR to significantly increase the safety, reliability, and efficiency of its System. For example, the measurement upgrades installed via the modernization program helped reduce lost and unaccounted for gas ("LAUF"), with LAUF levels trending down since 2018, which benefits customers across the System. Replacing critical units at Jena, Brownsville, and LaGrange ensured less unplanned outages associated with those specific units thereby ensuring reliability. In fact, Jena and Brownsville (HP replacement facilities) unplanned outages have decreased over 80 percent when comparing 2021 to 2016. In 2016, prior to replacement of this unit at Brownsville, unplanned outages at Brownsville were at approximately 26 percent, and at Jena prior to the unit replacement they were at approximately 30 percent. In 2020, unplanned outages at Brownsville were at less than approximately 4 percent, and at Jena they were less than approximately five percent. The modernization work performed by ANR has also had a positive environmental impact, reducing methane emissions through replacement of legacy facilities that were prone to methane leaks with new low-emission facilities.

III. UPCOMING MODERNIZATION WORK

Q: Does ANR plan to continue to modernize its system even after it has spent the $837 million contemplated in the RP16-440 Settlement?

A: Yes. As discussed in the testimony of ANR witness Parks, ANR further intends to modernize its facilities beyond the end of the RP16-440 Settlement. Although the RP16-440 Settlement addressed significant modernization needs, ANR's system still requires substantial modernization and ANR plans to continue to undertake modernization projects to meet that need based on risk prioritization.

Q: Please describe ANR's planned modernization work.

A: ANR's planned modernization projects are designed to allow ANR to continue improving the reliability, integrity, safety, and efficiency of its System and to address compliance with existing and emerging regulatory requirements. ANR witness Parks sponsors the Eligible Facilities Plan ("EFP"), which describes the transmission- and storage-related projects that ANR plans to execute over the proposed five-year term of its modernization program. Ongoing evaluation of the System has determined that the vintage and condition of the facilities listed in the EFP require facility upgrades and replacements to ensure that ANR can meet its firm service obligations in a safe and reliable manner. As ANR witness Parks testifies, the projects listed in the EFP were selected based on ANR's prioritization of its modernization needs such that each of the projects is associated with a facility that meets one or more of the following criteria: (1) it operates at a relatively high level of risk; (2) it requires upgrades for ANR to meet current or emerging regulations; and/or (3) its reliability is lower than necessary to meet current or future service requirements.

Q: Please describe the types of transmission- and storage-related projects that are included in the EFP.

A: The transmission projects described in the EFP are similar in character and scope to certain transmission-related modernization projects ANR performed in connection with the RP16-440 Settlement. ANR will complete projects such as replacements of vintage pipe with low cathodic protection, performance capabilities and poor adhesion properties, installations of permanent launchers, receivers, and any modification points such as mainline valves, fittings, or other ancillary piping to make the line piggable, as well as projects necessary for compliance with the Pipeline and Hazardous Materials Safety Administration ("PHMSA") Mega Rule. In addition to the Mega Rule-required work, certain launcher and receiver projects, such as the 1-501 Sardis Compressor Station ("CS") to Brownsville CS project, have been identified to further ANR's objective of strengthening the integrity of its system by making lines piggable in order to identify and address concerns promptly. Finally, ANR intends to undertake the 0-501 Southeast Mainline pipeline replacement project, as that pipeline was originally installed in the late 1950s and there are significant integrity concerns with the pipeline today due to external corrosion.

ANR will also replace existing vintage compression with more reliable, sustainable, energy efficient units and retain existing units for standby purposes, where applicable, to provide standby compression for use during both planned and unplanned outages. As detailed in the EFP, critical units have been identified for replacement at the Delhi CS, Jena CS, and St. John CS. Additional proposed work includes automation and control upgrades on compressor units allowing remote monitoring, advanced analysis, and preventative maintenance, as well as measurement upgrades, meter enhancements, and modernization of gas quality monitoring.

ANR's proposed storage-related work consists of projects in compliance with the PHMSA Storage Final Rule (Docket 2016-0016), as well as projects to modernize the gas processing and gas handling equipment, as supported by ANR witness Word. In addition, ANR has identified storage line-related launcher and receiver projects to further ANR's objective of making lines piggable to identify and address concerns promptly.

Q: Does ANR plan to undertake the modernization projects discussed above regardless of whether the proposed SIMM mechanism is approved as part of this proceeding?

A: Yes, ANR intends to assess and complete projects identified in the EFP, based on priority and risk, regardless of whether the proposed SIMM is approved. As noted above, the projects listed in the EFP were selected based on ANR's prioritization of its modernization needs such that each of the projects is associated with a facility that meets one or more of the following criteria: (1) it operates at a relatively high level of risk; (2) it requires upgrades for ANR to meet current or emerging regulations; and/or (3) its reliability is lower than necessary to meet current or future service requirements. As such, these projects are critical to the continued modernization of the System and ANR's ability to not only provide reliable and efficient service to its customers, but also to ensure compliance with existing and emerging regulations. If the SIMM is not approved as part of this proceeding, given the magnitude of the expenditures that ANR plans to incur for these modernization projects, ANR will be required to file multiple overlapping rate cases to recover its prudently-incurred expenditures as these facilities go into service. If approved, the SIMM will avoid the significant costs and resources that would otherwise be expended by the pipeline, its shippers, and the Commission to litigate multiple, simultaneous rate cases. Moreover, approval of the SIMM will also allow ANR and its shippers to continue collaborating in a cooperative and effective manner as ANR selects and executes projects during this next phase of modernization of the System.

IV. THE PROPOSED SIMM

Q. Please briefly describe the System Improvement Modernization Mechanism that ANR is proposing in this proceeding.

A. ANR proposes that the SIMM become effective through provisions added to Sections 4.20 and 6.26 of the General Terms and Conditions of its FERC Gas Tariff, Third Revised Volume No. 1 ("Tariff"). The SIMM Tariff provisions set forth procedures pursuant to which ANR will make limited NGA section 4 filings to implement an additive surcharge ("SIMM Rate(s)") to recover ANR's cumulative revenue requirement for capital investments made in certain defined Eligible Facilities (as such term is defined below) and associated cost with these Eligible Facilities as described below.

Q. Please describe what cost thresholds are associated with the SIMM during the proposed five-year term.

A: ANR has identified and scoped Eligible Facilities projects for which the revenue requirement may be recovered through the SIMM. Such investment will not exceed $900 million plus a 15 percent tolerance through the proposed five-year term of the SIMM.

While project cost estimates have been provided in the EFP, they are likely to fluctuate as engineering work proceeds and projects are adjusted or reprioritized based on risk assessment, reliability and safety needs, and potential regulatory delays.

Q: Please describe the costs that are eligible for recovery under the SIMM.

A. Under ANR's SIMM proposal, modernization projects defined as "Eligible Facilities" are eligible for cost recovery under the SIMM. These projects are specifically identified in the EFP sponsored by ANR witness Parks. In addition to modernization projects specifically identified in the EFP, certain categories of modernization projects that ANR may undertake at its discretion, as described below, are also eligible for cost recovery under the SIMM. ANR is also proposing to recover costs associated with Reservation Charge Credits ("RCC") and costs associated with alternatives to mitigate and/or avoid firm service outages directly related to construction of Eligible Facilities projects. ANR is further proposing to include a Tariff mechanism in the SIMM that would allow ANR to recover the costs of unanticipated modernization projects via the SIMM upon obtaining either a consensus of ANR's customers or approval by the Commission. I discuss each of these below.

Q: Please describe the additional categories of discretionary projects that ANR proposes to include in the SIMM.

A: ANR proposes to retain the discretion to recover its revenue requirement associated with the following types of projects via the SIMM regardless of whether the individual project is specified in the EFP: (1) projects to address issues that ANR believes could lead to imminent unsafe conditions; and (2) projects that ANR deems necessary to comply with new legislative and/or regulatory requirements. ANR is proposing to have the discretion to include the revenue requirements of these projects in the SIMM, subject to the overall cost limit for SIMM recovery that is discussed later in my testimony.

Q: Why is ANR proposing to have the discretion to recover the costs of these additional project categories via the SIMM?

A: ANR witness Parks explains that ANR applies integrity management principles under which it performs ongoing risk assessments of the System. To the extent that the risk factors associated with specific facilities increase, ANR may determine it is necessary to undertake a modernization project to address those risk factors. While the specific projects may not be known at this time, allowing ANR to include the costs of such modernization projects in the SIMM will help provide cost recovery certainty during the term of the SIMM for ANR without the need to litigate multiple rate cases. Shippers will retain the right to challenge the prudence of any such proposed costs at the time ANR files to recover the costs via the SIMM.

Q. Please generally describe the RCC and alternative costs that ANR is proposing to recover via the modernization surcharge.

A: ANR is proposing to recover RCC costs incurred as a result of firm service outages associated with Eligible Facilities. ANR witnesses Parks and Siddik describe the anticipated disruption to primary firm services associated with the proposed construction of Eligible Facilities projects and any potential alternatives associated with mitigating outages related to the construction of these Eligible Facility projects. I will describe later in my testimony how those costs will be included as part of the modernization surcharge cost-of-service calculation and how the inclusion of those costs in the modernization surcharge complies with the Commission's Modernization Policy Statement.

Q: Please generally describe the Tariff mechanism that ANR is proposing that would allow it to recover unforeseen modernization costs via the SIMM.

A: ANR is also proposing Tariff mechanisms within the SIMM that would allow ANR to include any unforeseen modernization costs that are not identified in the EFP or included in the discretionary categories above in the SIMM. The Tariff mechanism would permit recovery via the SIMM for projects that fall within one or both of the following categories: (1) projects to address issues that ANR believes could lead to imminent unsafe conditions; and (2) projects that ANR deems necessary to comply with new legislative and/or regulatory requirements provided such construction projects do not result in exceeding the established program cost limits cost limits. For projects that are not listed in the EFP and that do not fall into one of the above-mentioned categories, ANR would be permitted to include the costs of the projects in the SIMM upon ANR either obtaining the consent of a majority of shippers subject to the SIMM Rates or approval by the Commission. This mechanism will ensure that, if unforeseen events occur, ANR has the ability include the costs or to seek the consent of its shippers or approval by the Commission to include such costs in the SIMM Rate rather than be forced to file a general rate case that would be costly to all parties involved.

Q: How does ANR propose to implement the SIMM?

A: As part of ANR's instant rate case filing, ANR is proposing Tariff records to implement the SIMM in Sections 4.20 and 6.26 in Appendix A. ANR's filing includes "live" Tariff records to implement the SIMM.

Q: What is the proposed term for the SIMM?

A: ANR proposes that the SIMM be in effect for a five-year term beginning with Eligible Facilities placed into service from August 1, 2022, through November 30, 2023. On the initial tariff records for the rate case effective date, the SIMM Rates would be $0.00, and the SIMM Rates would be adjusted over time to reflect the capital costs of the Eligible

Facilities and associated costs of the type discussed herein. ANR would retain the right to seek removal of the SIMM provisions prior to the expiration of the full five-year term by filing a general NGA Section 4(e) rate case.

Q: Why is ANR proposing a five-year term for the SIMM?

A: Based on its experience with projects previously undertaken, ANR has determined that large modernization projects typically require approximately 29 to 35 months from pre-filing to notice to proceed and could take even longer due to various factors, including permitting delays. Based on recent project work, more and more applications are required to go through an Environmental Impact Statement ("EIS") versus an Environmental Assessment ("EA"), even where such a project would historically not have warranted that level of National Environmental Policy Act review. The greater use of EISs versus EAs adds additional time to the process and review of projects. Also, earlier this year, FERC issued Order No. 871, amending its regulations to preclude the issuance of authorizations to proceed with construction activities with respect to natural gas projects approved pursuant to section 7 of the Natural Gas Act until either the time for filing a request for rehearing of such order has passed with no such request being filed or the Commission has acted on the merits of any rehearing request. Such delays can add up to an additional 150 days to a project and therefore having a five-year term for the SIMM ensures that ANR can plan accordingly and be successful in placing these projects in service on a timely basis.

Q: Is ANR proposing an overall spending cap for the five-year SIMM term?

A: Yes, the total amount of prudent investment for which revenue requirements are eligible for recovery through the SIMM for the proposed five-year term will not exceed $900 million, plus a 15 percent tolerance.

Q: **Is ANR proposing to recover all of its modernization expenditures through the SIMM Rates during the five-year term?**

A: No, ANR's SIMM proposal provides that ANR will incur substantial additional expenditures that are not recoverable via SIMM Rates. ANR proposes to maintain a general plant maintenance capital ("GPMC") level equal to the sum of its base system transmission and storage plant depreciation expense of $100 million per year, as detailed in Schedule H-2 pages 1-2.[1] If ANR does not maintain this level of GPMC expenditures on an annual basis, then the amount eligible for recovery through the SIMM will be reduced by the amount of the GPMC shortfall. Setting the GPMC level in this manner ensures that ANR will continue to invest to preserve its base system investment in addition to its extensive modernization work.

Q: Please elaborate on the filing process to implement the SIMM Rates.

A: As I noted above, the Tariff records that accompany ANR's filing reflect initial SIMM Rates of $0.00. Consistent with the proposed Tariff provisions implementing the SIMM, ANR will have the right to seek, through limited NGA section 4 filings, to establish SIMM Rates for the recovery of the revenue requirement associated with Eligible Facilities. ANR will have the ability to file to increase the SIMM Rates via an annual filing to be made by March 1 of each year for an effective date of April 1 of each year.

Q: Please explain how ANR will calculate the SIMM Rates.

A: As shown in the proposed Tariff records in Section 6.26 in Appendix A, the revenue requirements underlying each increase in the SIMM Rates will be based on ANR's investment in Eligible Facilities, RCC(s), and other applicable costs associated with

[1] The base system transmission and storage plant depreciation expense amount reflected in Schedule H-2 is $99.849 million. ANR has rounded this number to $100 million.

alternatives to mitigate and/or avoid firm service outages directly related to construction of Eligible Facilities projects during the prior period. Each investment will be functionalized to the appropriate transmission and storage SIMM Rates. The period for costs to be included in the initial SIMM Rates will include the revenue requirements of Eligible Facilities placed into service beginning August 1, 2022, through November 30, 2023, in ANR's first SIMM Rate filing including any trailing costs associated with Eligible Facilities placed in service during SIMM prior periods. Subsequent SIMM Rates will include revenue requirements related to Eligible Facilities RCC(s), and other applicable costs associated with alternatives to mitigate and/or avoid firm service outages directly related to construction of Eligible Facilities projects placed into service from December 1 through November 30 of each subsequent year including any trailing costs into the annual SIMM Rate filing.

ANR will recover the revenue requirement associated with Eligible Facilities utilizing the following calculation to determine each applicable SIMM Rate. The first factor in the calculation is net rate base. Net rate base is calculated by taking the sum of the gross plant, accumulated depreciation, accumulated deferred income taxes, and regulatory assets associated with the listed Eligible Facilities that have been placed in and remain in service. The net rate base is then multiplied by two factors, a pre-tax return of 15.13 percent and taxes other than income taxes ("TOIT") of 2.26 percent. The TOIT calculation will record a regulatory asset or regulatory liability to track the over- or under-collection compared to actuals. ANR will then take the identified gross plant and multiply it by the appropriate depreciation and negative salvage rates, as reflected in the cost-of-service schedule H-2, pages 1-2, to calculate the depreciation and negative salvage expenses. Finally, ANR will sum the amounts associated with the regulatory asset amortization, pre-tax return, TOIT, depreciation expense, and negative salvage expense, to show the proposed revenue requirement by function. In Exhibit No. ANR-0003, ANR provides an illustrative calculation of the revenue requirement associated with Eligible Facilities by function and the RCC(s) and costs associated with alternatives to mitigate and/or avoid firm service outages. ANR will follow the Dth-mile cost allocation as described by ANR witness Barry to allocate the transportation cost of service between the seven zones.

To safeguard shippers against losses in billing determinants, ANR will calculate SIMM Rates by utilizing the greater of: (i) for each SIMM period, projected reservation billing determinants, reflecting discount adjustments for both discounted and negotiated rate contracts, based on the most recently available 12-month actual billing determinants, for all system customers, including billing determinants associated with non-incremental negotiated rate contracts and anticipated contract expirations, but exclusive of contracts for capacity on incrementally-priced projects; or (ii) billing determinant transmission or storage floors, as applicable, which are discussed below. For purposes of this calculation, a “non-incremental negotiated rate contract” is an agreement for capacity that would be subject to the base system recourse rate but for the parties’ mutual agreement to apply a negotiated rate instead. ANR proposes to define its billing determinant floors as the totals reflected in Schedule J-1, by zone, adjusted for: (1) 25 percent on transmission to reflect the risk associated with potential shipper bankruptcy risk as discussed in the testimony of ANR witness Lakhani; and (2) 10 percent on storage to reflect the downward pressure for continued discounting on ANR’s storage contracts. If actual billing determinants are lower than these billing determinant floors, ANR shall impute billing determinants and the revenues that would be associated with such billing determinants at the maximum applicable Tariff rate to reflect the above-stated billing determinant floors in the calculation of the SIMM Rates.

Q: Please describe the pre-tax return that ANR is using in its calculation of SIMM Rates.

A: ANR is using the same pre-tax return for the SIMM Rates calculation that it is proposing to use for all rates in this rate case filing, as shown on Exhibit No. ANR-0004. This pre-tax return of 15.13 percent is utilizing the inputs reflected in Schedules F-2, H-3, and H-3(1).

Q: Please explain what depreciation rates ANR is proposing to use in the calculation of SIMM Rates?

A: ANR is proposing to utilize the same depreciation rates of 2.59 percent for transmission plant and, 2.24 percent for storage plant, in the calculation of SIMM Rates that is reflected in the cost of service Statement H-2.

Q: Please explain what negative salvage rates ANR is proposing to use in the calculation of SIMM Rates?

A: ANR is proposing to utilize the same negative salvage rates of 1.41 percent for transmission plant and 1.08 percent for storage plant, in the calculation of SIMM Rates that is reflected in the cost of service Statement H-2.

Q: Please describe how ANR will allocate Eligible Facilities costs for purposes of calculating the transmission and storage SIMM Rates?

A: ANR will classify each Eligible Facility and associated costs as transmission or storage, based on the function of the facility. The transmission SIMM zone Rates will be calculated by deriving the transmission cost of service allocated utilizing the Dth-mile allocation method and using the transmission billing determinants as described above.

In calculating the storage SIMM Rates, ANR will use the Equitable Method related to storage cost allocation, where 50 percent of the costs are allocated to the deliverability component and 50 percent of the costs are allocated to the capacity component. The storage deliverability-related SIMM Rate component will be calculated by dividing the sum of 50 percent of the storage function cost of service by the greater of the projected storage reservation billing determinants or the proposed annual storage billing determinant floor.

Q: Please describe how ANR will calculate costs associated with RCC(s) and alternative arrangements for purposes of calculating the transmission and storage SIMM Rates?

A: ANR is proposing to recover costs associated with RCC(s) provided to shippers associated with firm service outages resulting from construction of Eligible Facilities projects proposed in the EFP, and costs associated with alternative arrangements to mitigate and/or avoid such firm service outages. ANR is proposing to track such costs, and include them as a regulatory asset to be amortized over the remaining life associated with the modernization program term. These costs will be recovered through the appropriate transmission or storage SIMM Rate(s) based on the functionalization of the corresponding Eligible Facility project.

Q: Which rate schedules will be assessed the SIMM Rates?

A: The SIMM Rates will apply to the following ANR rate schedules: ETS, STS, FTS-1, FTS-4, FTS-4L, FTS-2, FTS-3, ITS, ITS-3, and FSS.

Q: Will the SIMM filings make adjustments for over- or under-recoveries?

A: Yes, following the initial SIMM filing, any over- or under-recovery of the prior calculated revenue requirements associated with Eligible Facilities placed in service under the SIMM will be trued up in the next succeeding SIMM filing. The over- or under-recovery will be calculated, by function, in each filing by comparing ANR's actual revenue requirements against the revenues received during the preceding recovery period. Any over- or under-recovery will be applied, by function, to the subsequent SIMM calculation.

Q: Please describe the treatment of incrementally-priced expansion projects in the SIMM.

A: Billing determinants associated with contracts for capacity on expansion projects with incremental recourse rates will not be included in the SIMM Rate calculation nor will they be subject to the SIMM Rates.

Q: Please describe the treatment of rolled-in projects or projects that have been granted a predetermination for roll-in in the SIMM.

A: Contracts for capacity on expansion projects for which the Commission has approved the use of the base system rate as the recourse rate rather than an incremental recourse rate are considered to be rolled-in projects that will be subject to the SIMM Rates.

Q: Please describe the cost allocation for a project that is part Eligible Facility and part expansion?

A: If such an expansion is identified and constructed then the costs will be allocated between the base system and the expansion project consistent with FERC policy.

V. COMPLIANCE WITH MODERNIZATION POLICY STATEMENT

Q. Is ANR's proposal consistent with the Commission's Modernization Policy Statement?

A. Yes. The Modernization Policy Statement provides five flexible criteria that the Commission will use to evaluate a modernization cost tracker. Those criteria are:

- The pipeline's base rates must have been recently reviewed through a NGA general section 4 rate proceeding, a cost and revenue study, or through a collaborative effort between the pipeline and its customers;

- Eligible costs must generally be limited to one-time capital costs incurred to meet safety or environmental regulations or other capital costs shown to be necessary for the safe, reliable, and/or efficient operation of the pipeline, and the pipeline must specifically identify each capital investment to be recovered by the surcharge;
- Captive customers must be protected from cost shifts if the pipeline loses shippers or increases discounts to retain business;
- The pipeline must include some method to allow a periodic FERC review to ensure rates remain just and reasonable; and
- The pipeline must work collaboratively with shippers to seek their support for any surcharge proposal.

As set forth below, ANR's proposal satisfies each of these criteria.

Q. How is ANR meeting the first Modernization Policy Statement criteria that the proposing pipeline establish that its base rates are just and reasonable?

A. The Commission will evaluate ANR’s proposal and will establish just and reasonable base rates in this NGA section 4 proceeding. Additionally, ANR meets this requirement because the SIMM will recover future costs as no Eligible Facilities that would be recovered by this mechanism are included in base rates in this proceeding.

Q. Explain how the SIMM is generally limited to recovery of one-time capital costs incurred to meet safety or environmental regulations or other capital costs necessary for the safe, reliable, and/or efficient operation of ANR's system.

A. The Commission stated in the Modernization Policy Statement that it expects a pipeline to conduct a review of its existing system to determine what investments are necessary to ensure the safe and efficient operation of its system in order to determine what projects to include in a cost recovery mechanism. As explained in greater detail by ANR witness

Parks, ANR has conducted and continues to conduct ongoing assessments of its existing system and has identified projects in the above categories in the EFP.

Q. Explain how ANR's proposal to also recover certain RCC(s) and other costs associated with mitigating and/or avoiding firm service interruptions via the SIMM fits within the Commission's Modernization Policy Statement.

A. In the Modernization Policy Statement, the Commission permitted pipelines to propose to recover within its modernization mechanism the costs of RCC(s) provided to shippers associated with firm service outages resulting from construction of eligible modernization projects, and costs associated with alternative arrangements to mitigate and/or avoid such firm service outages. The Commission noted that in its filing to establish a modernization mechanism, a pipeline "should state the extent to which it anticipates that any particular project will disrupt primary firm service, explain why it expects it will not be able to continue to provide firm service, and describe what arrangements the pipeline intends to make to mitigate the disruption or provide alternative methods of providing service." Modernization Policy Statement at P 109.

The costs discussed above related to RCC(s) and alternative arrangements that ANR proposes to recover via the SIMM are consistent with the costs that the Commission has permitted pipelines to propose to recover via a modernization mechanism. ANR witnesses Parks and Siddik identify those Eligible Facilities projects that, when constructed, are most likely to result in planned outages of primary firm service or will require ANR to incur costs to make alternative arrangements to mitigate and/or avoid such outages. ANR's limited section 4 filings will seek to recover through the SIMM such costs related to RCC(s) and/or alternative arrangements.

Q: Please discuss how ANR has identified the Eligible Facilities Costs it proposes to recover through the SIMM.

A: ANR witness Parks supports the EFP, which identifies specific Eligible Facilities and associated costs that ANR intends to undertake over the five-year term of the SIMM. These Eligible Facilities in the EFP were identified and included because they meet one or more of the following criteria: (1) they involve facilities that operate at a relatively high level of risk, (2) the existing facilities require upgrades to meet current or emerging regulations, and/or (3) the existing facilities have reliability that is lower than necessary to meet current or future service requirements. In each SIMM filing, ANR will provide a narrative explanation demonstrating why each of the projects for which it seeks cost recovery falls within at least one of the aforementioned categories.

Additionally, as discussed above, ANR also proposes to retain the discretion to recover its revenue requirement associated with certain categories of projects that are not specifically identified in the EFP, subject to the cost cap set forth herein, including: (1) projects to address issues that ANR believes could lead to imminent unsafe conditions; and (2) projects that ANR deems necessary to comply with new legislative and/or regulatory requirements. As further discussed by ANR witness Parks, these additional categories are necessary to provide ANR with the ability to continually assess the risk of its pipeline system and address increases in risk associated with particular facilities during the term of the SIMM. Such flexibility is necessary to ensure the safe, reliable, and/or efficient operation of the pipeline.

Q: Is ANR proposing a mechanism to ensure that a representative level of ordinary system maintenance capital costs are excluded from the SIMM?

A: Yes. The Commission suggested in the Modernization Policy Statement that parties consider including in modernization cost recovery trackers a mechanism to ensure that "a representative level of ordinary system maintenance capital costs are excluded from the tracker." Consistent with the Modernization Policy Statement, ANR proposes to establish its base system GPMC level, as described in my testimony above, of $100 million annually. ANR's GPMC commitment will ensure that maintenance costs are separate from modernization costs and guarantees that ANR will continue to expend significant capital to maintain its system outside the scope of the SIMM.

Q. Explain how ANR's proposal will prevent cost shifting onto captive customers.

A. ANR has included proposed billing determinant floors for transmission and storage to ensure that SIMM costs will not be shifted onto captive customers. In the Modernization Policy Statement, the Commission stated that a pipeline must design the modernization surcharge in a manner that protects the pipeline's captive customers from cost shifts if the pipeline loses shippers or must offer increased discounts to retain customers and noted that this could be accomplished through the use of a billing determinant floor, which would require the pipeline to design the modernization surcharge based on the greater of its actual billing determinants or the floor.

In the proposed SIMM, ANR includes a transmission and a storage billing determinant floor as described above. If actual billing determinants are lower than the described floors, ANR will impute billing determinants and the revenues that would be associated with such billing determinants at the maximum applicable rate to reflect the billing determinant floors in the calculation of the SIMM Rates. This is consistent with the standard established in the Modernization Policy Statement.

ANR has chosen to utilize these transmission billing determinant zone floors because they prevent cost shifting to ANR's customers while also balancing the market risks faced by ANR. These market risks, which are described by ANR witnesses Lakhani and Thapa, could result in de-contracting during the proposed five-year term of the SIMM.

Q. Does ANR propose to adjust the transmission billing determinant floors during the term of the SIMM?

A: Yes. ANR proposes to reduce the transmission billing determinants reflected in Schedule J-1 by 25 percent. In accordance with the significant business risk that ANR witnesses Thapa and Lakhani have identified with respect to ANR's particular exposure due to potential shipper default on the transmission contracts, the transmission billing determinant floor should be adjusted if ANR experiences contract terminations due to a current customer filing for Chapter 11 bankruptcy. Once a customer files for Chapter 11 bankruptcy and capacity under its contract(s) with ANR is returned to ANR as generally available capacity, the pipeline will try to remarket that capacity to another interested party. However, to the extent that ANR is not able to recontract that capacity within six months of such occurrence, the billing determinant floor should be adjusted in the next respective SIMM filing by the determinants associated with the respective contract.

Q: Does ANR also propose a billing determinant floor for the storage function?

A: Yes. ANR's proposed storage billing determinant floor is described above.

Q: How will ANR's proposal assure that ANR's rates will remain just and reasonable?

A. Under the proposed SIMM Tariff language, as I explained previously, ANR will be required to make an annual limited NGA section 4 filing with the Commission to place into effect the SIMM Rates to recover the Eligible Facilities revenue requirement. ANR's proposal to make only one limited section 4 filing per year is in direct response to shipper feedback. Any over- or under-recoveries would be trued-up in the next SIMM filing. Shippers would have the right to question the prudency of any proposed Eligible Facilities and associated costs contained in the filing, as well as review in detail the SIMM Rates calculations. In addition, ANR is proposing that the SIMM expire no later than five years from the effective date. To the extent that not all costs included in the SIMM have been recovered, ANR reserves the right to seek recovery of such costs subsequently in a NGA section 4 rate case. Therefore, ANR's proposed SIMM satisfies the Commission's requirement for periodic review of the modernization surcharge and base rates.

Q. Does ANR's proposal satisfy the Commission's requirement for collaboration with shippers?

A. Yes. ANR held customer meetings on September 30, 2021 and December 7, 2021, at which ANR formally provided an overview regarding the potential projects to be included in a future modernization program. Additionally, ANR sought input from its customers on what types of projects and what categories should be considered for any modernization program that ANR would include when it files its NGA section 4 rate case. Although these efforts did not ultimately result in a comprehensive resolution of all matters related to the modernization mechanism, ANR was able to incorporate additional information based on shipper feedback, such as committing to make a single annual SIMM filing. ANR and the stakeholders were also able to discuss the projects included in the EFP and the drivers behind them.

ANR has not filed a general section 4 rate case in six years and is in fact required by the RP16-440 Settlement to make this filing at this time. Given this requirement, and the continued evolution of the natural gas market resulting in significant changes to the ANR system, the filing presents a host of interrelated and complex issues. However, it is ANR's view that this NGA section 4 proceeding, including the proposed modernization program, will provide ANR and its shippers a further opportunity to collaborate on its proposal.

In addition, ANR proposes significant controls that promote transparency and shipper input, which will provide meaningful oversight to the SIMM Rates on an ongoing basis. ANR proposes meetings and webcasts in which parties will discuss upcoming Eligible Facilities projects; Eligible Facilities projects from the prior year; proposed additions, removals, or substitutions of Eligible Facilities; and anticipated outages resulting from Eligible Facilities projects. Consistent with its current practices, ANR will post planned outages and associated information to the Electronic Bulletin Board.

Finally, ANR proposes to allow parties the opportunity to review the proposed SIMM Rates and supporting workpapers prior to ANR's SIMM filings and to intervene and comment once the filings are made. Thus, the parties will have sufficient opportunities to fully review and challenge the SIMM Rates, to the extent necessary, and the interests of all parties will continue to be fully protected over the five-year term of the proposed SIMM.

Q: Does this conclude your testimony?

A: Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-____-000

State of Texas)
) ss.
County of Harris)

AFFIDAVIT OF SORANA M. LINDER

Sorana M. Linder, being first duly sworn, on oath states that he is the witness whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of Sorana M. Linder"; that, if asked the questions which appear in the text of said testimony, he would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as Sorana M. Linder's sworn testimony in this proceeding.

DocuSigned by:
Sorana Linder
23711DEBE837440...

Sorana M. Linder

SWORN TO AND SUBSCRIBED BEFORE ME THIS 18th DAY OF January, 2022. This notarial act was an online notarization.

Notary Seal **Digital Certificate**

NOTARY PUBLIC STATE OF TEXAS
SHELIA O. COPUS
Notary ID
976876
My Commission Expires
2/22/2023

DocuSigned by:
Shelia Copus
6B60C3597ADE4AD...

ANR Pipeline Company
SIMM Revenue Requirement
Illustrative Calculation

Line No	Description	Reference		Transmission Amount	Storage Amount
		(1)		(2)	(3)
				$	$
1	Gross SIMM Plant		1/	100,000,000	100,000,000
2	Accumulated Depreciation			-	-
3	Net Plant			100,000,000	100,000,000
4	Accumulated Deferred Taxes			(607,007)	(695,161)
5	SIMM Regulatory Asset		2/	200,000	
6	SIMM Net Rate Base	Lines 3 + 4 + 5		99,592,993	99,304,839
7	Pre-Tax Return	Line 6 x 15.13%	3/	15,071,227	15,027,621
8	Depreciation Expense on SIMM Transmission Plant	Line 1 x %	4/	2,590,000	2,240,000
9	Negative Salvage Expense on SIMM Transmission Plant	Line 1 x %	5/	1,410,000	1,080,000
10	Amortization of Regulatory Asset		2/	65,000	
11	Annual Other Tax Expense on SIMM Plant	Line 6 x 2.26%	6/	340,610	339,624
12	Current Transmission SIMM Revenue Requirement	Lines 7 + 8 + 9 + 10+11		19,476,837	18,687,246
13	Cumulative Over/Under Recovery		7/	-	-
14	Total SIMM Revenue Requirement	Lines 11 + 12		19,476,837	18,687,246

1/ Illustrative capital spend.
2/ Regulatory asset will be amortized over the remaining term of modernization program.
3/ See Pre-Tax Return Calculation on Page 3, Line 9.
4/ As filed depreciation rates shown on Statement H-2 Pg 1-2 - Transmission 2.59% and Storage 2.24%.
5/ As filed negative salvage rates shown on Statement H-2 Pg 1-2 - Transmission 1.41% and Storage 1.08%.
6/ For illustrative purposes ANR utilized an other tax of 2.26%.
7/ Reflects $0 for the first filing calculation.

ANR Pipeline Company
SIMM Revenue Requirement - Allocation
Illustrative Calculation

				Transmission							Storage	
Line No	Description		Reference	Zone 1 Amount	Zone 2 Amount	Zone 3 Amount	Zone 4 Amount	Zone 5 Amount	Zone 6 Amount	Zone 7 Amount	Deliverability Amount	Capacity Amount
			(1)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(10)
				$	$	$	$	$	$	$	$	$
1	Transmission Cost of Service		Page 1, Line 14	19,476,837	19,476,837	19,476,837	19,476,837	19,476,837	19,476,837	19,476,837		
2	Dth-Mile Allocation Percentage	1/	Schedule I-3	3.61%	2.23%	30.48%	16.21%	5.49%	5.91%	36.07%		
3	Total Zone Transmission Cost of Service		Line 1 x Line 2	703,114	434,333	5,936,540	3,157,195	1,069,278	1,151,081	7,025,295		
4	Storage Cost of Service		Page 1, Line 14								18,687,246	18,687,246
5	Equitable Allocation	2/									50.00%	50.00%
6	Total Storage Cost of Service		Line 4 x Line 5								9,343,623	9,343,623

1/ As filed Dth-Mile/d ratio shown on Schedule I-3
2/ Per ANR witness Linder testimony, ANR will use the Equitable Method related to storage cost allocation.

ANR Pipeline Company
Pre-Tax Return Calculation

Line No.	Description	Schedule Reference	Capitalization Percentage	Cost of Capital	Weighted Cost and Claimed Return
		(1)	(2)	(3)	(4)
1	Debt cost	F-2	34.00%	4.110%	**1.40%**
2	Equity Return	F-2	66.00%	15.700%	**10.36%**
3	Total		100.00%		
4	State Income Taxes	H-3(1)	4.50%		
5	Federal Income Tax	H-3	21.00%		
6	**Taxable Income Before Income Taxes**		**24.56%**		
7	Debt		1.40%		
8	Equity		13.74%		
9	**Pre-Tax Return**		**15.13%**		

Docket No. RP22-__-000
Exhibit No. ANR-0005

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22 -___-000

Summary of the Prepared Direct Testimony of Adam Lakhani

Mr. Lakhani is Senior U.S. Pipeline Marketing Representative for TransCanada USA Services Inc. He provides an overview of the ANR Pipeline Company ("ANR") system and describes changes that have occurred on the system since ANR filed its last general section 4 rate case in 2016.

First, Mr. Lakhani describes ANR's system, including its seven-zone rate structure and explains how ANR's system consists of two mainlines: the SE Mainline, that transports gas primarily from the Appalachia region to markets in ANR's Northern Area as well as to the Gulf Coast, and the SW Mainline, that transports gas primarily from the Mid-Continent, Rockies, and Permian basins to markets in ANR's Northern Area. Mr. Lakhani also discusses ANR's storage assets and operations.

Second, Mr. Lakhani describes several significant supply and market changes that have impacted ANR's system since its last rate case. Specifically, Mr. Lakhani describes: (1) the continued prolific natural gas production from the Marcellus and Utica basins and the resulting increase in pipeline competition transporting from these basins to ANR's Northern Area ; (2) the boom-bust production cycle in producing areas in the Rockies, Mid-Continent, and Permian basins and the resulting impact of this on ANR's SW Mainline; (3) the increasing LNG export market along the Gulf Coast; and (4) the increased demand from power generators and the potential impact on this demand from net-zero emissions goals.

Third, Mr. Lakhani describes major business risks that ANR faces. He discusses the risk associated with the boom-bust production cycle in the supply basins that serve the SW Mainline and the consequences of those supply changes to future long-term contracting on the SW Mainline. With respect to the SE Mainline, Mr. Lakhani details the business risks ANR faces due to its reliance on riskier producer contracts for its SE Mainline and the risk that potential defaults by those shippers pose. Additionally, he addresses the increase in supply mix serving ANR's Michigan market that will continue to reduce the contracting ability of the SE Mainline flowing northbound. Next, he addresses the operational risk that ANR faces, largely as a result of the age of its system and the ongoing need for ANR to expend significant capital in modernizing its system. Finally, he discusses the risk associated with a regulatory environment that is increasingly difficult for development of natural gas infrastructure.

Docket No. RP22-___-000
Exhibit No. ANR-0005

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22-___-000

PREPARED DIRECT TESTIMONY OF ADAM LAKHANI ON BEHALF OF ANR PIPELINE COMPANY

January 28, 2022

Glossary of Terms

ANR	ANR Pipeline Company
Bcf	Billion cubic feet
Commission	Federal Energy Regulatory Commission
DOT	U.S. Department of Transportation
Dth	Dekatherm
Dth/d	Dekatherms per day
EIS	Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
GLGT	Great Lakes Gas Transmission Limited Partnership
KMLP	Kinder Morgan Louisiana Pipeline
LDC	Local distribution company
LNG	Liquified natural gas
Midship	Midship Pipeline
MISO	Midcontinent Independent System Operator
ML-2	Southeast Southern Segment
ML-3	Southeast Central Segment
ML-5	Southwest Southern Segment
ML-6	Southwest Central Segment
ML-7	Northern Market Zone 7
NGPL	Natural Gas Pipeline Company of American

NEXUS	DTE Energy’s and Enbridge’s NEXUS Gas Transmission
NGA	Natural Gas Act
NNG	Northern Natural Gas Company
PEPL	Panhandle Eastern Pipe Line Company, LP
Permian Highway	Permian Highway Pipeline
PHMSA	Pipeline and Hazardous Materials Safety Administration
Rockies Express	Tallgrass Energy's Rockies Express Pipeline LLC
Rover	Energy Transfer Partners’ Rover Pipeline Project
RP16-440 Settlement	The FERC-approved 2016 settlement in Docket No. RP16-440-000
RTO	Regional Transmission Officer
SBO	Storage by Others
SE Mainline	Southeast Mainline
SW Mainline	Southwest Mainline
TBO	Transportation by others
TC Energy	TC Energy Corporation
Transco	Williams’ Transcontinental Pipeline
Tie Line	A line from Defiance, Ohio to Bridgman, Michigan that connects ANR’s SE and SW Mainlines
WEC	WEC Energy Group

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22-___-000

Prepared Direct Testimony of Adam Lakhani

Q: What is your name and business address?

A: My name is Adam Lakhani. My business address is TC Energy Corporation ("TC Energy"), 700 Louisiana Street, Houston, Texas 77002.

Q: What is your occupation?

A: I am employed by TransCanada USA Services Inc., an indirect subsidiary of TC Energy, as a Senior U.S. Pipeline Marketing Representative. TransCanada USA Services Inc. employs all personnel in the United States who are involved in the operation and maintenance of TC Energy's U.S. energy systems and facilities, including ANR Pipeline Company ("ANR"). I am filing testimony on behalf of ANR.

Q: Please describe your educational background and your occupational experience as they are related to your testimony in this proceeding.

A: I earned a B.S. degree in Economics from Texas A&M University in 2011. I have spent the last nine years working at TC Energy in a variety of roles with increasing responsibility, including Pricing and Analytics, Scheduling and Nominations, and the last seven years as a Marketing Representative for our U.S. Natural Gas Pipelines and Storage assets. In this role, I am responsible for understanding current and longer-term energy market fundamentals, as well as optimizing the short- to medium-term pipeline capacity and storage sales for several of our assets, including ANR.

Q: Have you ever testified before the Federal Energy Regulatory Commission ("Commission") or any other energy regulatory commission?

A: No.

Q: What is the purpose of your testimony in this proceeding?

A: My testimony is divided into three sections. In the first section I will provide an overview of the ANR system. In the second section I will detail the evolution of the ANR system, including a synopsis of the factors that have impacted the system as well as certain changes in market and supply dynamics that have continued to evolve since ANR's last general Natural Gas Act ("NGA") section 4 rate case in 2016.

Finally, in the third section I will describe ANR's current business risk. The majority of these risks affect ANR's two mainline segments, the Southwest Mainline ("SW Mainline") and the Southeast Mainline ("SE Mainline"). I will detail the current and long-term headwinds to supply that serves the SW Mainline and its negative effects on future contracting. In addition, with respect to the SE Mainline, I will address (1) ANR's reliance on riskier producer contracts for its SE Mainline and the risk that defaults by those shippers pose and (2) the increase in supply mix serving ANR's Michigan market that will continue to reduce the contracting ability of the SE Mainline flowing northbound.

Q: Are you sponsoring any exhibits in addition to your testimony?

A: No.

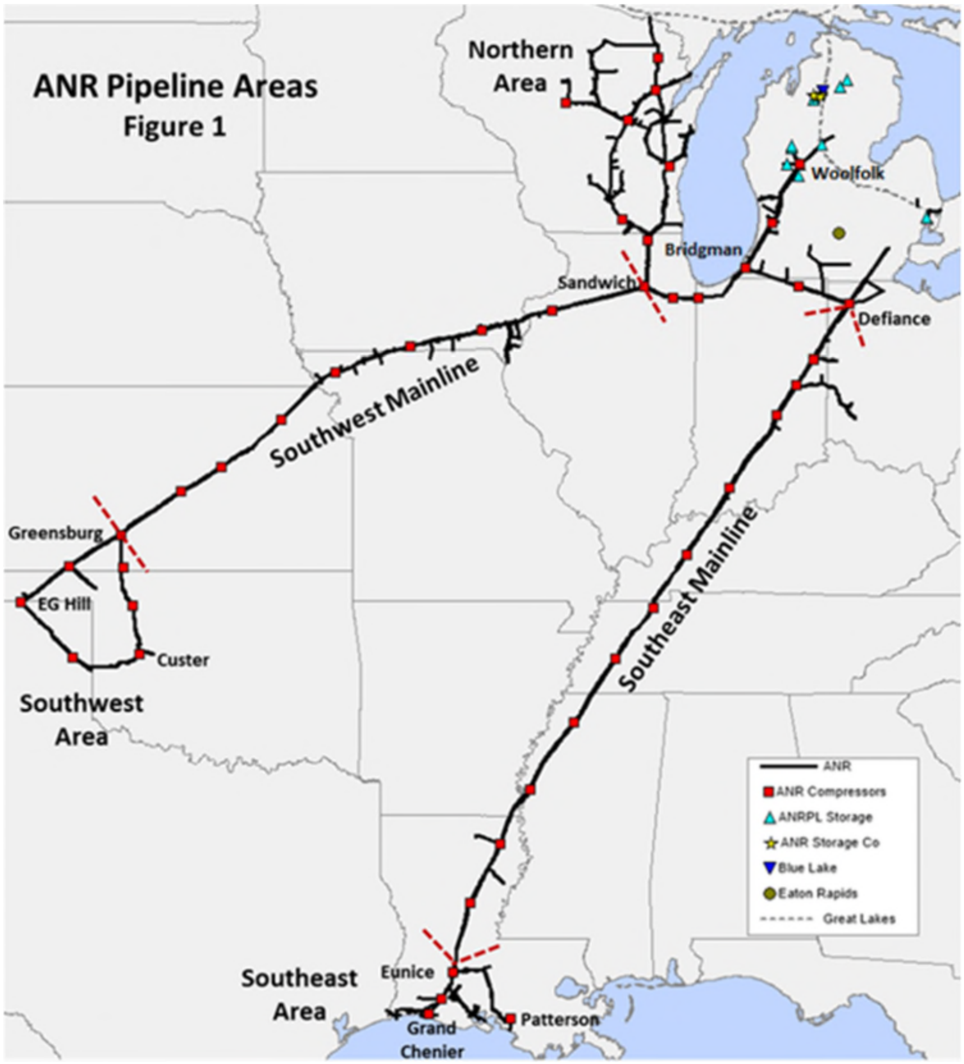
I. OVERVIEW OF THE ANR PIPELINE SYSTEM

Q. Please provide a general description of the ANR pipeline system.

A: ANR's system consists of approximately 9,000 miles of pipeline and nearly 203 billion cubic feet ("Bcf") of storage, including storage by others ("SBO"), with a withdrawal capacity in the winter of 3.5 Bcf/d. ANR delivers more than 1 trillion cubic feet of natural gas annually. ANR consists of two mainlines that are joined in the ANR Northern Market Zone 7 ("ML-7") in the Midwest. These two mainline pipelines are known as the SW Mainline and the SE Mainline. The SW Mainline connects the production entering its SW Area in Texas, Oklahoma, and Kansas to Midwest markets in Illinois, Wisconsin, and Michigan. The SE Mainline extends from Louisiana north through Arkansas, Mississippi, Tennessee, Kentucky, Indiana, Ohio, and into Michigan. A segment of pipeline, the Tie Line, runs through northern Indiana, Ohio, and Michigan and connects the two main branches.

The SE Mainline historically was designed to connect traditional Louisiana offshore production to the Midwest, however, now it serves a much different role. The SE Mainline is now a bifurcated system flowing gas both north to the Midwest and south to markets on the Gulf Coast including liquified natural gas ("LNG") and industrial customers. ANR also owns storage facilities located in Michigan and purchases additional SBO capacity from third-party storage providers. As discussed more fully by ANR witness Siddik, ANR has purchased transportation capacity on third-party systems (referred to as "transportation by others" or "TBO") to integrate its storage facilities and to ensure the reliability of ANR's firm transportation services. A map depicting these areas is shown in Figure 1 below.

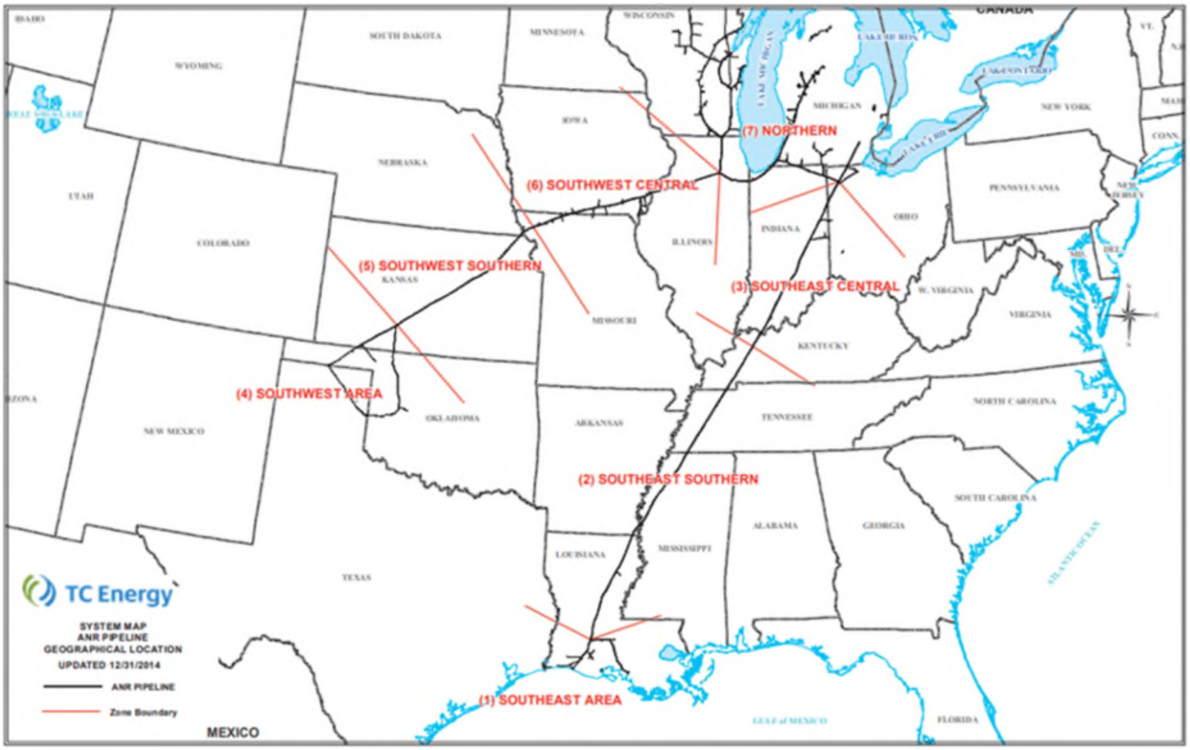
Figure 1



Q: How is ANR's system currently divided into zones for ratemaking purposes?

A: ANR consists of a seven-zone rate structure. The SW Area and SE Area each constitute a separate rate zone, and ML-7 in the Northern Area constitutes a separate zone. The SW Mainline is divided into two separate segments, the SW Southern Segment ("ML-5") and the SW Central Segment ("ML-6"), and the SE Mainline likewise is divided into two segments, the SE Southern Segment ("ML-2") and the SE Central Segment ("ML-3"). Figure 2 depicts the current zone boundaries.

Figure 2



Q: Can you describe the general characteristics of the facilities for each of the major areas/rate zones on ANR's system?

A: Yes, I will begin with the SE Area. This portion of ANR's system includes the pipelines and laterals that extend east and south of ANR's compressor station near Eunice, Louisiana, a compressor facility that has become known as the Southeast Headstation or simply Eunice. The Eunice compressor station is the demarcation point between the SE Area and the SE Mainline. The SE Area is composed of two operational areas: the Louisiana System – East, commonly referred to as the Patterson System, and the Louisiana System – West, generally known as the Grand Chenier System.

Supply into the Patterson System comes primarily from the Eugene Island Operating Area through Kinetica Energy Express, with additional supply from other natural gas processing plants delivering into the system near Patterson, Louisiana. There is no longer a substantial amount of supply that comes into the Grand Chenier system from Offshore production. As I discuss more fully in my testimony, the decline in receipts from the Gulf of Mexico, coupled with continued increasing LNG demand for deliveries into the SE Area, has resulted in the SE Area becoming a mature market area on ANR's system.

Q. Please describe the SE Mainline.

A: The SE Mainline traverses eight states and includes two separate rate zones: ML-2 and ML-3. The SE Mainline is the primary source of gas for deliveries to the SE Area and contributes significantly to deliveries in the Northern Market Area. There are a number of local distribution companies ("LDCs"), power plants, and interstate pipelines in ML-2 and ML-3 that receive gas supply from the SE Mainline. Geographically, the SE Mainline extends from Eunice, Louisiana to Defiance, Ohio and includes a total of eight compressor stations. The demarcation boundary between ML-2 and ML-3 is the Madisonville, Kentucky compressor station site.

Gas supply from production basins in Arkansas, Louisiana, Oklahoma, and Texas are delivered to the SE Mainline within the ML-2 rate zone, while supply from the Rockies and Appalachian regions are delivered to the ML-3 rate zone. As I will discuss further in my testimony, the SE Mainline is a 1,228-MMcf/d south to north bound pipeline that has historically had very limited backhaul contracts. This flow pattern began to evolve as Appalachian producers contracted for primary paths with a receipt in ML-3 and a delivery in the SE Area. The SE Mainline became a net north to south directional pipeline in July of 2017 with up to 1,156-MMcf/d continuously sold through the Eunice compressor station with natural gas destined for markets in the Gulf.

Q. Please describe the SW Area.

A: The SW Area is a triangle-like set of facilities, at the top of which is the ANR compressor station located near Greensburg, Kansas (generally referred to as the Southwest Headstation or Greensburg). The west side of the triangle extends from Greensburg to ANR's E.G. Hill compressor station that straddles the Oklahoma-Texas border. The eastern side of the triangle extends from Greensburg to a compressor station located in Custer County, Oklahoma. The base of the triangle extends from E.G. Hill southeast through ANR's Gageby Creek Compressor Station, and then to Custer as shown in Figure 1.

The SW Area is primarily a supply gathering system that aggregates together supply from pipelines coming out of the Rockies basin, local supply from the Mid-Continent, and Permian production that enters via pipelines out of Texas. These supplies are then transported to various markets in the Midwest. As I discuss below, significant increases in production in these basins, followed by substantial pipeline development, and a subsequent collapse in production has resulted in significant supply and market challenges for ANR.

Q. Please describe the SW Mainline.

A: The SW Mainline traverses seven states and includes two separate rate zones: ML-5 and ML-6. Geographically, the SW Mainline extends from Greensburg, Kansas to Sandwich, Illinois and functions using a total of nine compressor stations. The demarcation boundary between ML-5 and ML-6 is the Maitland, Missouri compressor station site. The SW Mainline design capacity is 708,000 dekatherms ("Dth")/day ("Dth/d") of northbound flows from the Greensburg compressor station, which includes gas supply from the SW

Area and ML-5, and to markets along the SW Mainline and beyond the Sandwich compressor station to the Northern Market Area.

Unlike the SE Mainline, the SW Mainline has limited market outlets along the mainline path, save a few scattered municipalities and end users in ML-6. Nearly all of the gas sourced from the SW Area flows northbound on the SW Mainline to serve the Northern Market Area.

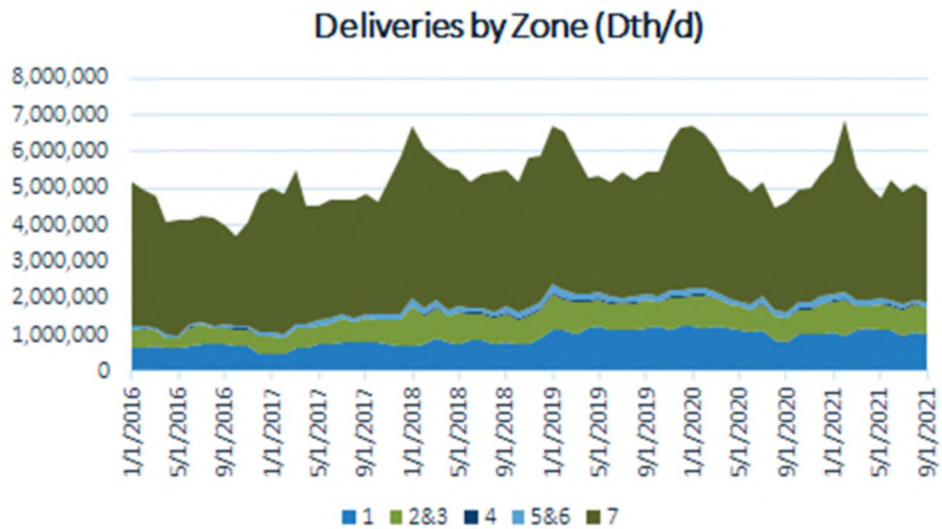
Q. Please describe the Northern Area.

A: ANR's Northern Area, ML-7, is a network of pipelines, compressor stations, and storage facilities that provide reliable natural gas to LDCs, power plants, and end users in Illinois, Indiana, Michigan, Ohio, and Wisconsin. ANR's Northern Market Area is a critical piece of infrastructure that serves high population centers across the Midwestern U.S.

The ML-7 fuel segment includes all points downstream of the Sandwich, IL (SW Mainline) and the Defiance, OH (SE Mainline) compressor station sites. Both the SW Mainline and SE Mainline were originally constructed to serve demand in ML-7, and that supply is augmented with gas supply from Canada (Western Canadian Sedimentary Basin) and ANR's network of storage facilities in Michigan.

In order to serve each of the geographically disperse markets in the Northern Area, ANR relies on third-party TBO agreements and SBO agreements with pipeline and storage operators in ML-7 to accommodate firm obligations. The Northern Area is ANR's largest market area as shown in Figure 3 below.

Figure 3



Q: How does ANR use its storage assets?

A: Storage plays a significant role on ANR's system, representing peak day winter deliverability of up to 3.5 Bcf. ANR owns and operates six storage fields that are directly connected to the system and four that are connected to Great Lakes Gas Transmission Limited Partnership ("Great Lakes"). ANR contracts for additional storage capacity with other storage service providers; one is directly connected to ANR's system with the remainder connected to other pipelines. Nine of the storage fields ANR operates are discontiguous to its system (meaning they are not directly connected to ANR's transmission system), and approximately 70 percent of ANR's storage deliverability is discontiguous to its system. ANR provides storage and related transportation services that rely upon integrated storage facility operations rather than limiting customers to allocated capacity in individual storage facilities, which is both beneficial for customers and more efficient for ANR system operations. Therefore, ANR relies upon service agreements with other pipelines to operationally balance and integrate ANR's operated storage network with its contracted storage services provided by others. As ANR witness Siddik explains in greater detail, these contracted service agreements provide essential operational flexibility necessary for the integrated storage and transportation operations on ANR's system consistent with ANR's historical practice.

II. EVOLUTION OF THE ANR SYSTEM SINCE ITS LAST RATE CASE

Q. What is the basis for ANR's currently effective rates?

A: ANR's current generally effective system rates are the result of a settlement of ANR's last general Section 4 rate case in Docket No. RP16-440 ("RP16-440 Settlement"). ANR filed that rate case on January 31, 2016, and the RP16-440 Settlement was filed in September 2016, and the Commission approved it in an order dated December 15, 2016. The rates established by the RP16-440 Settlement became effective on August 1, 2016. Under the terms of the RP16-440 Settlement, ANR is required to file a general rate case with rates to be effective no later than August 1, 2022.

Q. Since ANR filed its last rate case, have there continued to be changes in the natural gas marketplace that have affected ANR's operations and competitive environment?

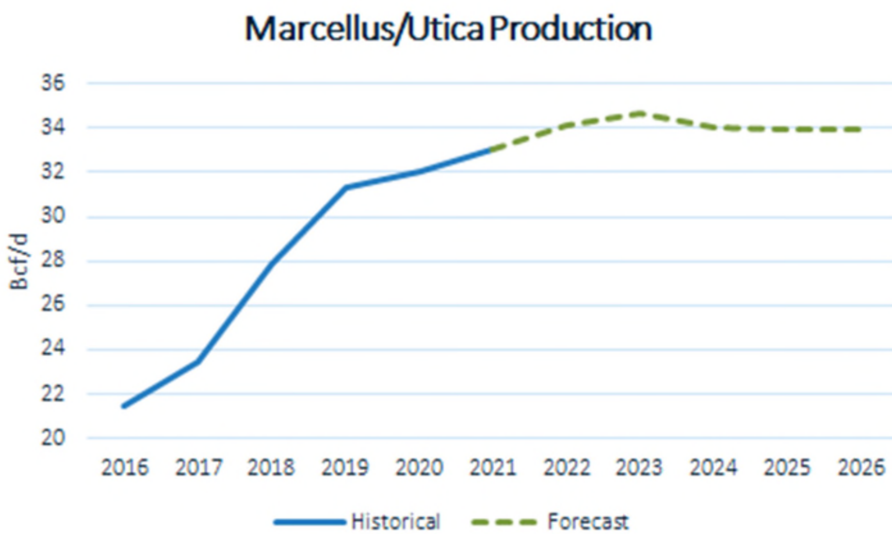
A: Yes, even over the last six years, there have continued to be significant changes in the natural gas marketplace that have had substantial impacts on ANR's operations. In particular, the continued prolific natural gas production out of the Eastern Utica/Marcellus region, a boom-bust production cycle in producing areas in the Rockies, Mid-Continent, and Permian basins that supply the SW Area, and ever-increasing LNG exports along the Gulf Coast have altered demand for transportation services, increased pipeline competition, and resulted in major market and supply changes for ANR.

<u>Supply Changes</u>

Q: Please describe the impact of the continued development of Marcellus and Utica shale on the pipeline industry in general since 2016.

A: Since 2016, production growth from the Marcellus and Utica supply basins has continued at a prolific pace, increasing from approximately 21 Bcf/d to an average of 33 Bcf/d through October 2021 as seen in Figure 4 below. This increase of more than 12 Bcf/d has led to Eastern production filling nearly every available pipeline with transport capacity out of the region as production has far outpaced demand growth in the East region. As a direct result of this continued production growth, several interstate pipeline companies have constructed and put into service new pipelines to transport this ever-increasing supply to market. Notably, Energy Transfer Partners' Rover Pipeline Project ("Rover"), which went into service in August 2017 with a capacity of 3.25 Bcf/d, and DTE Energy's and Enbridge's NEXUS Gas Transmission ("NEXUS"), which went into service in October 2018 with a capacity of 1.5 Bcf/d, both transport Marcellus/Utica production to the Midwest, and Michigan in particular. Production growth from the Marcellus/Utica basins is expected to continue to modestly grow through 2023 before stabilizing as seen below in Figure 4, which is derived from S&P Global Platts, 2021 data.

Figure 4



To put this in context, production from the Marcellus and Utica region combined in 2021 to produce nearly 35 percent of all production in the United States, by far the largest producing region in the United States.

Q: How have these developments specifically affected ANR?

A: The increase in production from the Eastern producing basins has increased supply onto ANR via its interconnect with Rover and Tallgrass Energy's Rockies Express Pipeline LLC ("Rockies Express") in ANR's Zone ML-3. This new supply has enabled ANR to fill its southbound capacity to serve increasing LNG load in its Southeast Area. However, this relentless increase in production has also pushed an abundant source of new supply into ANR's traditional Michigan and West Ohio markets via the two new pipelines I mentioned previously, Rover and NEXUS. This has directly reduced ANR's contracting and market share to Michigan as I will detail below.

Q: Please describe how ANR has been affected by developments related to Rocky Mountain, Mid-Continent, and Permian supplies since 2016.

A: Production in these areas rose prolifically from 2016 until late 2019, accounting for a combined increase of nearly 922 Bcf/d in production, before the Mid-Continent and Rockies basins started declining at the beginning of 2020, and the Permian growth flattened out. Figures 5-7 below show the gross natural gas production volumes as reported by S&P Global Platts, 2021 for their defined regions for the Mid-Continent, Rockies, and Permian from 2016 through 2021.

Figure 5

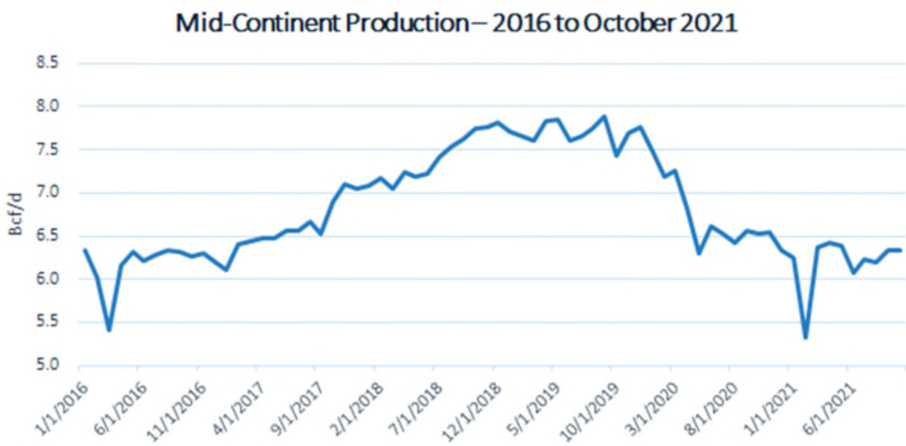


Figure 6

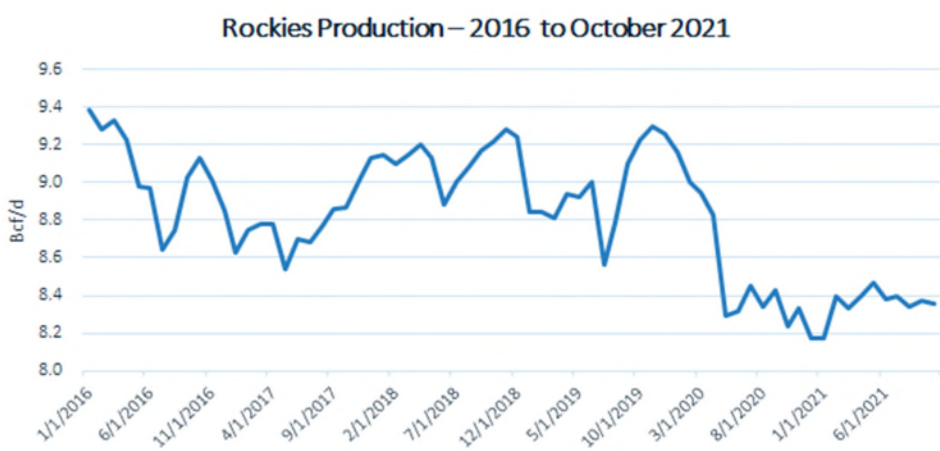
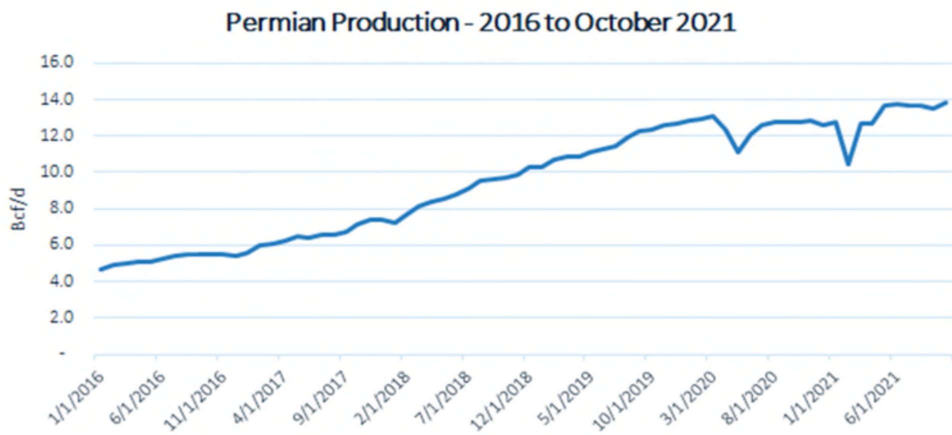
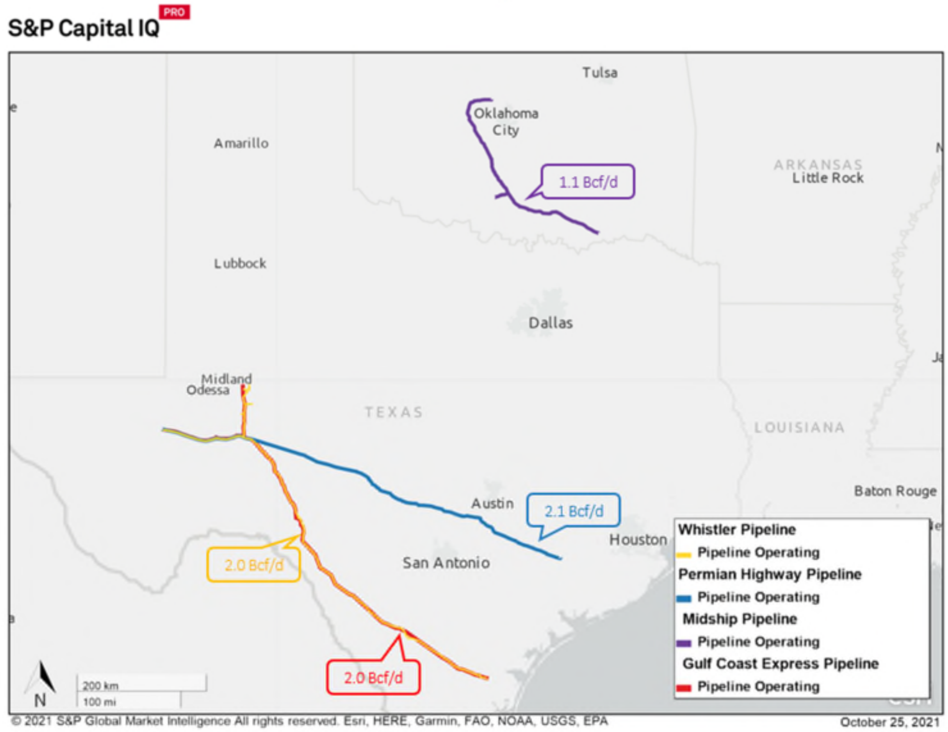


Figure 7



Production growth in these regions resulted in significant physical pipeline capacity congestion out of these three basins, which significantly increased basis spreads between the SW Area and the Northern Market Area and produced extremely strong transportation values. The combination of this capacity congestion and weak localized prices in the Permian and Mid-Continent fueled the development of new and expanded pipeline capacity to export supply from these basins to serve growing LNG demand in the Gulf Coast region in Texas and Louisiana. The most prominent examples of these new expansions are shown below in Figure 8 totaling 7.2 Bcf/d: Midship Pipeline ("Midship") for 1.1 Bcf/d; Permian Highway Pipeline ("Permian Highway") for 2.1 Bcf/d; Gulf Coast Express Pipeline for 2.0 Bcf/d; and Whistler Pipeline for 2.0 Bcf/d. Specifically, Midship increased capacity out of the Mid-Continent basin by 1.1 Bcf/d reducing supply that utilized ANR's SW Area and SW Mainline transport.

Figure 8



Q: What effect did this increasing production have on ANR's SW Area?

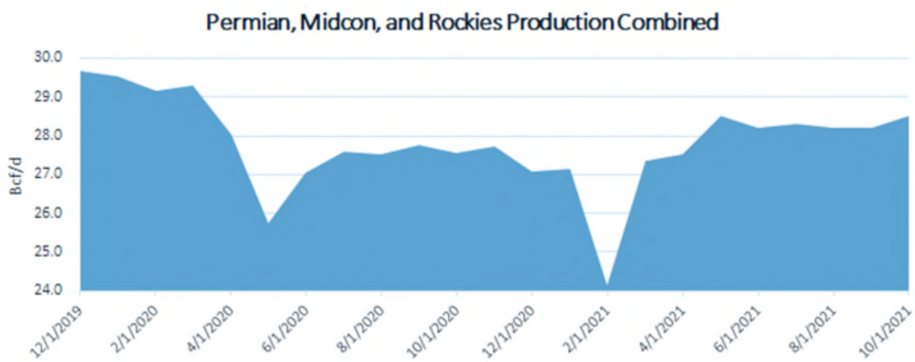
A: As a result of these significant production increases from 2016 to 2019, the SW Area and SW Mainline, which includes the Southwest Gathering system, reached a 100 percent load factor during periods from 2018 to 2019. This resulted in a strong period of contracting on ANR's SW Mainline and SW Gathering system. However, by January 2020, low regional basis prices and low Henry Hub prices began to impact producer decisions and production started to decline in the Rockies and Mid-Continent, while growth in the Permian levelled out.

Q: How did the COVID-19 recession impact supply in these basins?

A: The production declines only accelerated as a result of the COVID-19 commodities price collapse in the summer of 2020 as reflected below in Figure 9, which is derived from S&P Global Platts, 2021 data. In fact, according to S&P Global Platts, 2021, between late 2019 and October 2021, the Mid-Continent basin declined by approximately 1.5 Bcf/d, the

Rockies basin declined by approximately 0.9 Bcf/d, and the Permian basin grew by a historically low 1.0 Bcf/d, all contrary to their previous prolific growth between 2016 and late 2019. The combination of these multiple pipeline expansions and the significant downturn in overall production left the region over built and under supplied.

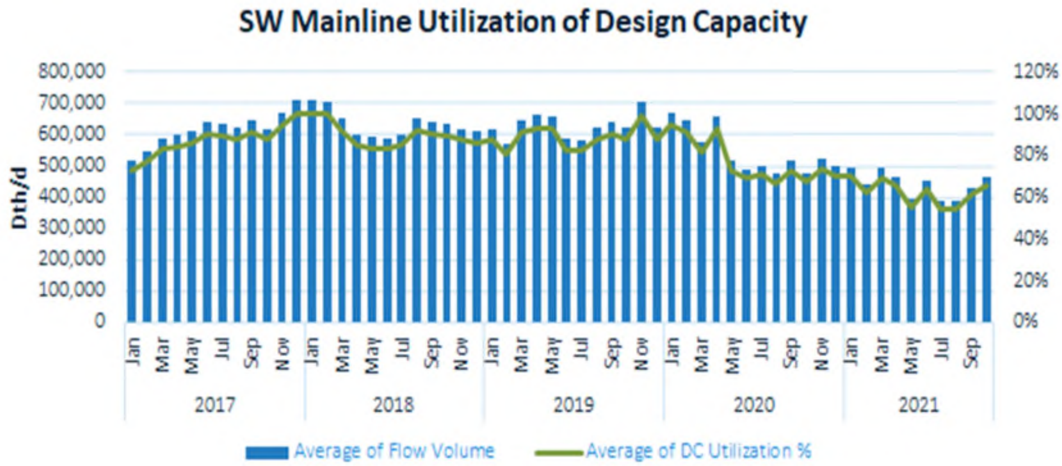
Figure 9



Q: What was the impact to ANR's supply in the SW Area as a result of this significant decline in production and resulting overbuild of capacity?

A: The declining production and excess pipeline capacity in the region has resulted in a significant drop in utilization on ANR's SW Mainline as depicted in Figure 10 below. In fact, utilization on the SW Mainline declined from 89 percent in 2019 to 62 percent for 2021 through October.

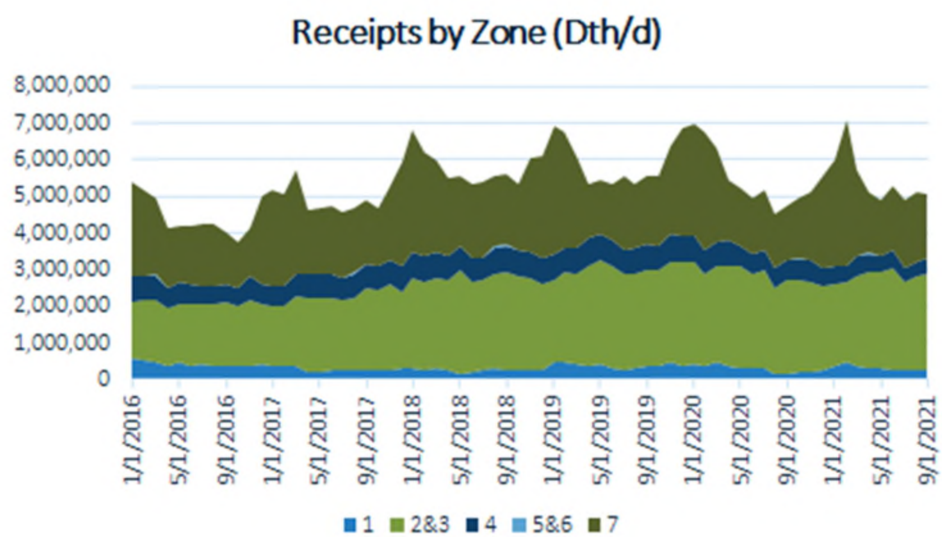
Figure 10



Q. Can you summarize the effect of these changes on ANR's overall supply mix?

A: Yes, the overall supply sources for ANR have shifted since 2016. The Eastern supply has increased 12 percent to make up 43 percent of all ANR receipts in 2021. However, Mid-Continent and Gulf Area receipts have dropped 7 percent and 4 percent respectively. Total receipts on ANR by zone are shown below in Figure 11.

Figure 11



<u>Market Changes</u>

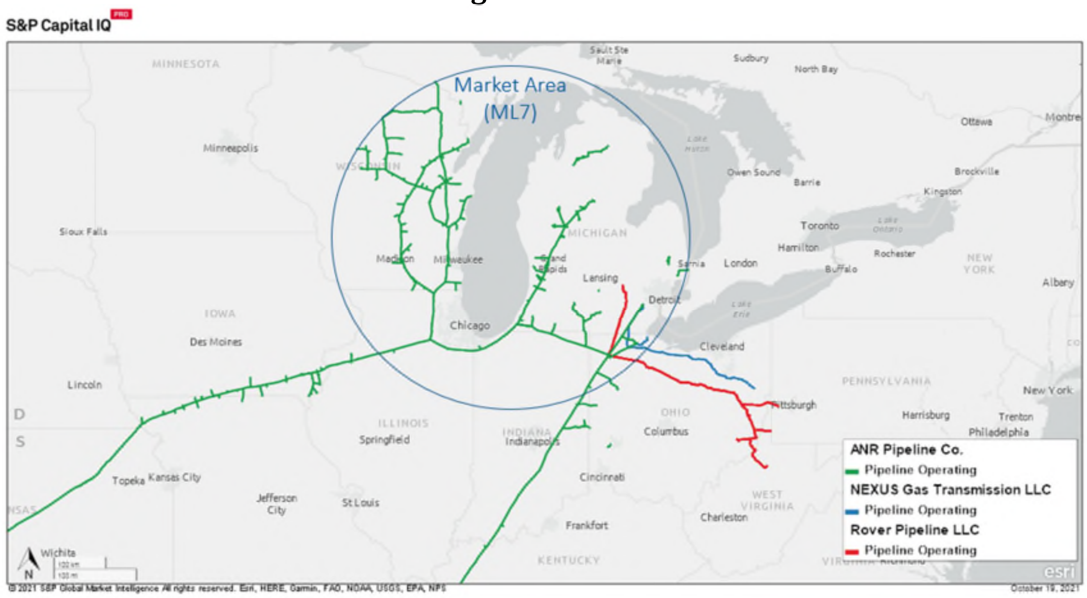
Q: Please summarize the changes that ANR has seen with respect to market areas on its system that have taken place since 2016.

A: ANR has experienced several developments since 2016 that have affected the market areas on its system. These include: (1) increased pipeline competition in ANR's Northern Area markets resulting in significant declines in value and contracting, specifically in the Michigan market; (2) increased demand for deliveries into the Louisiana market area as a result of increased LNG exports; and (3) increasing power generation related deliveries

Q: What changes have occurred in ANR's market areas in Wisconsin and Michigan since 2016?

A: The largest change to ANR's Northern Area markets since 2016 is the increasing competition from new pipeline builds as a result of the continued production in the Utica and Marcellus region. As mentioned previously, Rover and NEXUS pipelines collectively provide an incremental 4.75 Bcf/d of supply capacity into the state of Michigan. The traditional markets that ANR served directly and indirectly in the state including power plants, LDCs, and storage facilities have become far more competitive to serve. The physical intersection of the NEXUS and Rover pipelines with ANR's system can be seen below in Figure 12. In addition to Marcellus and Utica production growth, the WCSB of Alberta has seen strong production growth, which offers access to ANR's traditional markets in Wisconsin and Michigan through secondary pipeline access.

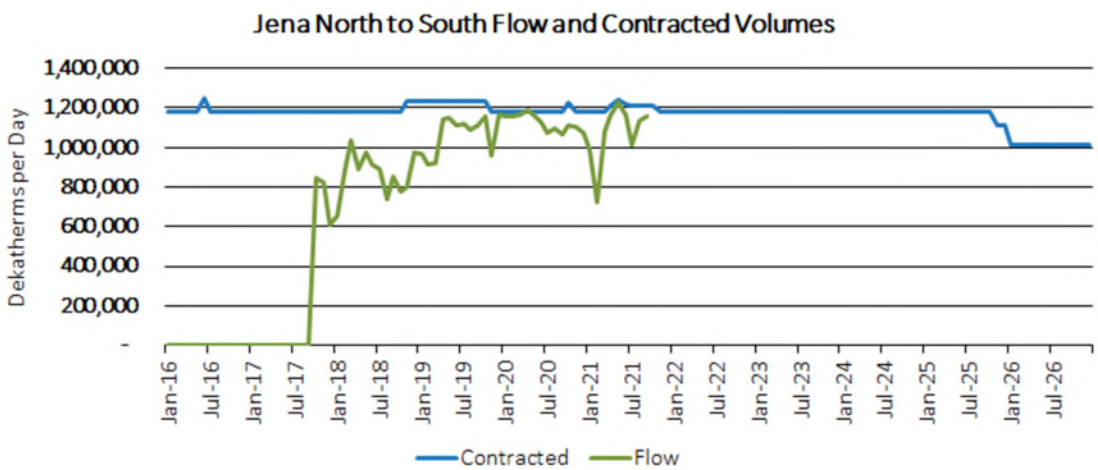
Figure 12



Q: How has increased Utica and Marcellus production affected ANR's market in the SE Area?

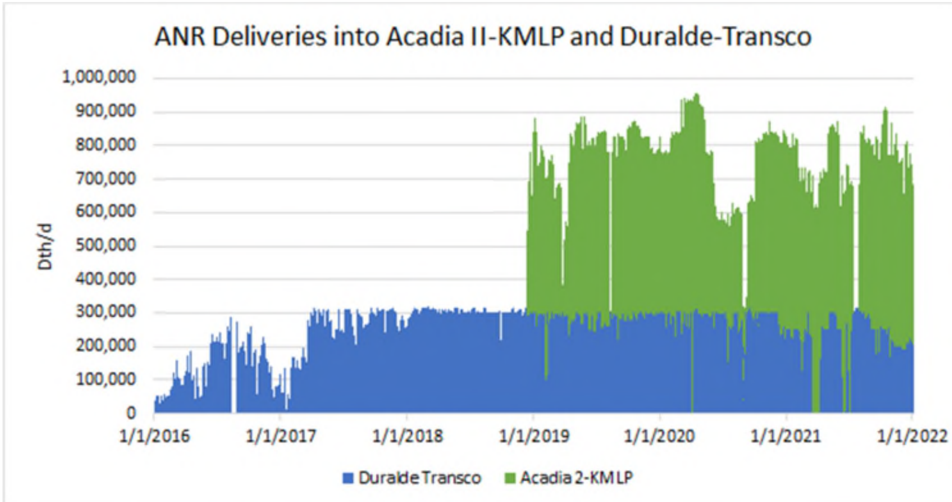
A: As a result of the growing Marcellus and Utica production that I have described previously, ANR's southbound flows on the SE Mainline have continued to increase, fueled by growing demand for LNG exports in Louisiana. As seen below in Figure 13, actual southbound flows through Jena have increased to nearly 1.2-MMDth/d from mid-2017 owing to the continued prolific production in the Marcellus and Utica regions as well as the development of a mature market area along the Gulf Coast, as discussed more below.

Figure 13



With southbound SE Mainline capacity fully contracted, ANR continues to serve the SE Area interstate and intrastate pipelines it interconnects with south of Eunice, but has seen growth in the deliveries to pipelines with direct interconnections to LNG export terminals. At Duralde Evangeline, ANR's interconnect with Williams' Transcontinental Pipeline ("Transco"), ANR averaged deliveries of 293,422 Dth/d in 2020, while in 2016 the number was only 110,573 Dth/d as seen in Figure 14 below. The driving force behind this growth in deliveries is Transco's access to Cheniere's Sabine Pass LNG export facility, which went online in 2016. When Sabine Pass's sixth liquefaction train goes into service in 2022, the facility will be able to process 4.7 Bcf/d of natural gas into LNG. ANR also has access to Sabine Pass LNG via the Acadia II meter where it directly interconnects with Kinder Morgan Louisiana Pipeline ("KMLP"). In 2018, when the Acadia II meter went into service, deliveries into KMLP from ANR averaged 17,894 Dth/d, by 2020 deliveries averaged 435,985 Dth/d as seen below in Figure 14.

Figure 14

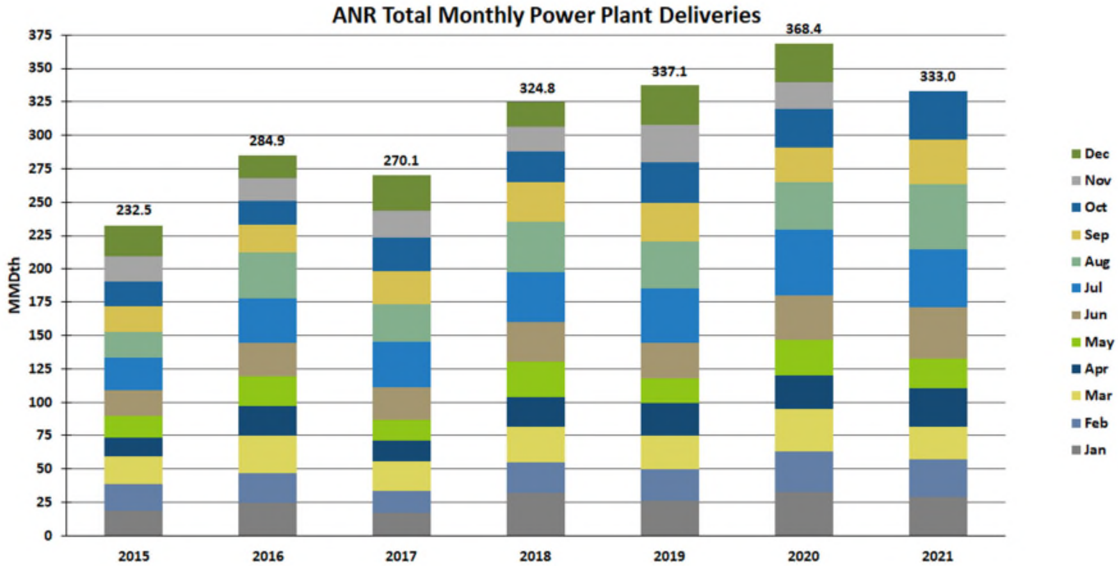


ANR will have its first direct connection with an LNG export facility by way of the TransCameron Pipeline when the Grand Cheniere Xpress Expansion Project goes into service in 2022. As expanded below, the Project will provide 1.1-MMDth/d of incremental capacity from ANR's Southeast Headstation to the Mermentau River GCX Meter Station. ANR has executed a binding precedent agreement with the Project shipper, Venture Global Calcasieu Pass, LLC, for the full 1.1-MMDth/d of long-term firm transportation capacity commencing January 1, 2022.

Q: Has ANR experienced any changes with respect to demand from power generators?

A: With nearly 50 power plants now directly connected to the pipeline system, ANR has seen an increase in power generation deliveries over the years. For example, total power plant deliveries in 2015 were 232.5 Bcf compared to 2020 total deliveries of 368.4 Bcf, a 58 percent increase in only five years. The majority of this increase has come in ANR's Northern Area which includes Illinois, Indiana, Michigan, Ohio, and Wisconsin. Figure 15 below demonstrates the increased growth in annual power plant deliveries on ANR since 2015.

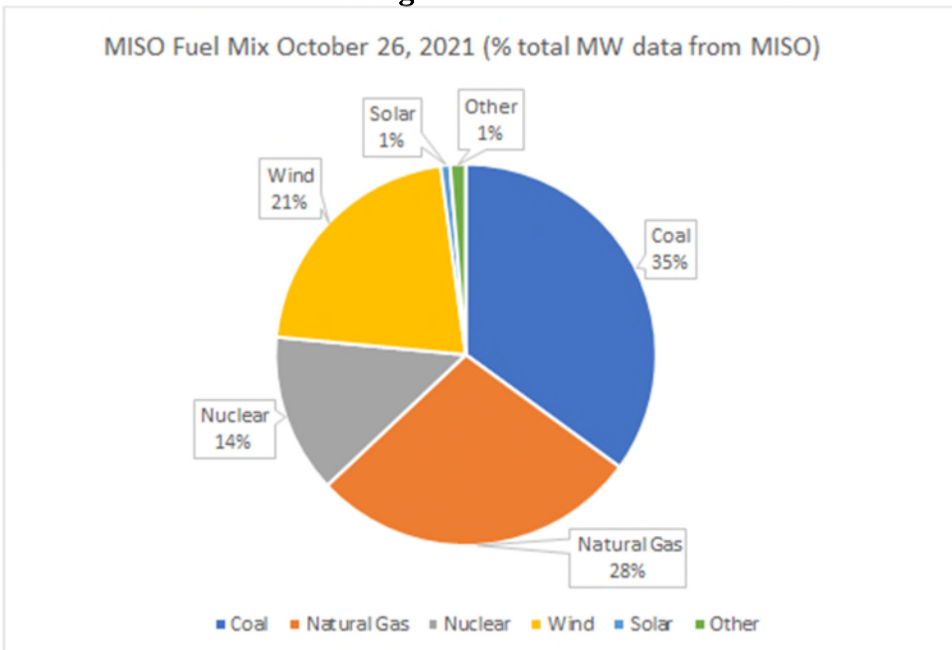
Figure 15



Q: **Does ANR expect this trend to continue?**

A: The trend of year-over-year growth in power plant deliveries on ANR will be under pressure into the future as coal-fired unit retirements plateau and more renewable generation comes online. ANR expects that increasing reliance on renewable generation coupled with state and federal net-zero carbon emission goals will begin to significantly erode ANR's market for natural gas transportation and storage services. In fact, ANR is already beginning to see larger contributions of wind and solar energy into the generation mix in areas it currently serves. For example, as demonstrated in Figure 16 below, per data directly from the Midcontinent Independent System Operator ("MISO"), the October 26, 2021 MISO fuel mix included 21 percent wind generation, nearly as much as natural gas.

Figure 16



Additionally, as detailed in Figure 17 and 18 below, the two major Regional Transmission Operators ("RTO") that generate power for customers across ANR's footprint (PJM and MISO) are expected to expand their reliance on renewables into the future.

By 2030, renewables are projected to become nearly equivalent to natural gas as the primary fuel source for power generation in MISO. In PJM, renewable generation is expected to increase 250 percent by 2030, and will be the third leading generation resource for the RTO.

Figure 17

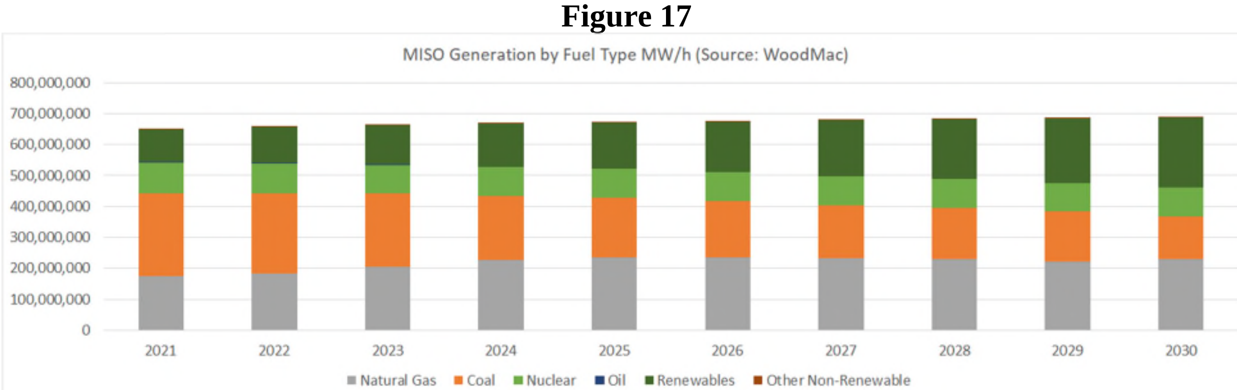


Figure 18

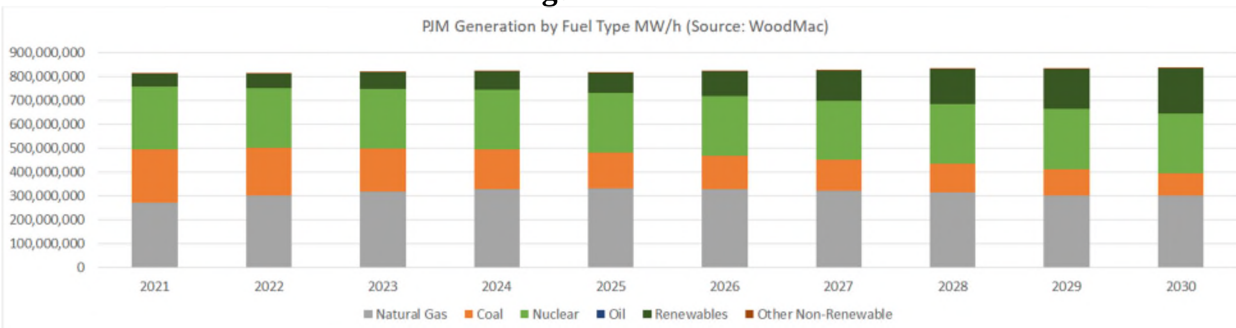
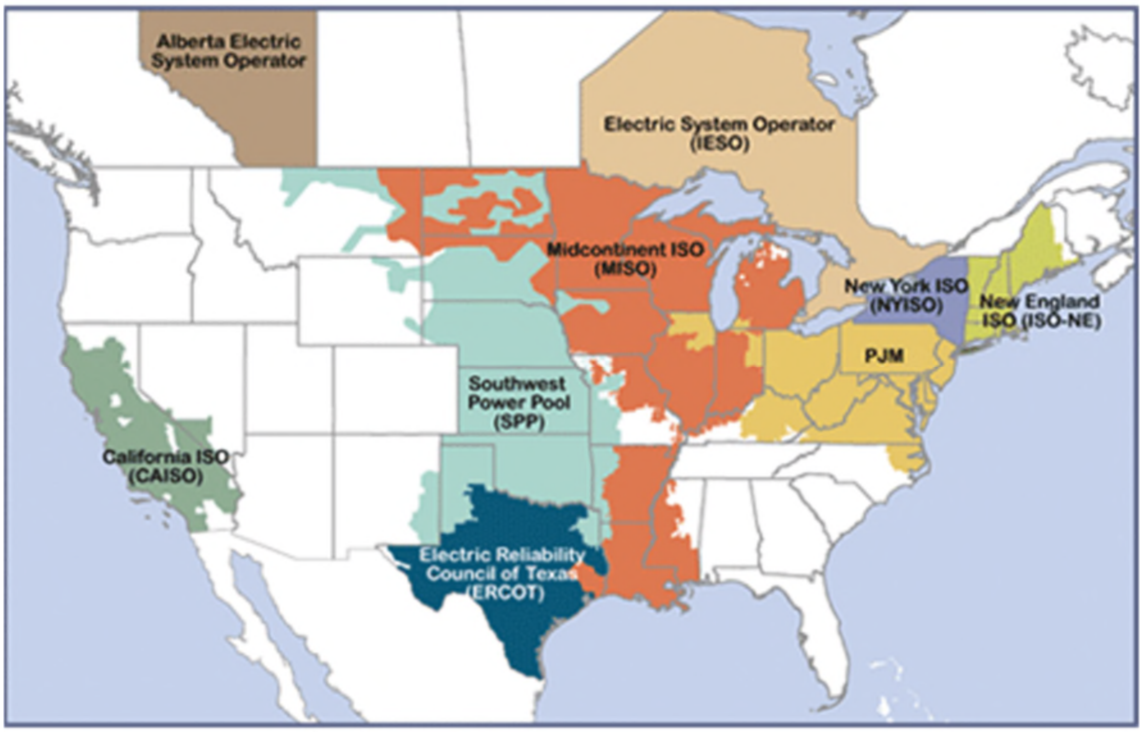


Figure 19 below shows MISO and PJM's breadth of operation, which overlays the geographic footprint of ANR's system.

Figure 19



Q: Are state level initiatives likely to continue to push for even more renewable generation in ANR's footprint?

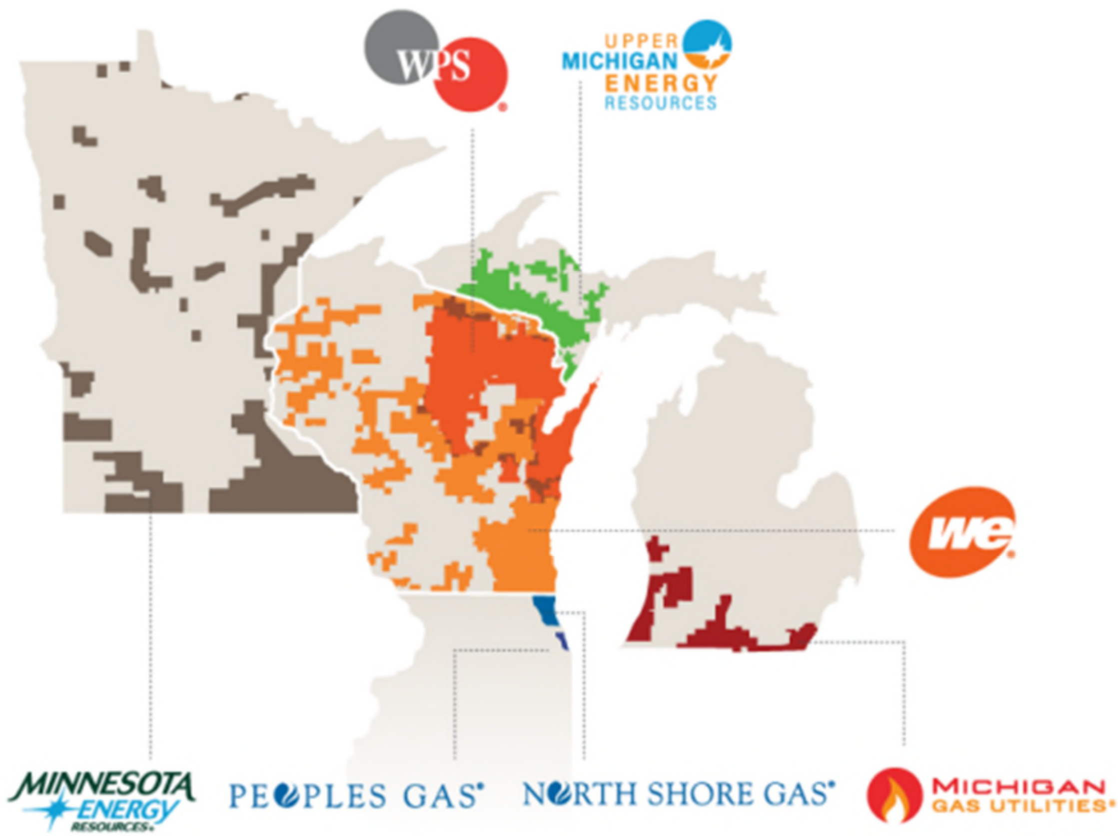
A: Yes, they likely will. On September 15, 2021, Illinois passed the Climate and Equitable Jobs Act (SB2408), which will set the State's path for energy policy through 2050 by replacing fossil fuels with renewable energy including solar and wind power. The legislation aims to achieve 40 percent renewable energy by 2030, 50 percent renewable energy by 2040, and 100 percent clean energy by 2050. Per SB2408, clean energy is defined as energy generation that is 90 percent or greater free of carbon dioxide emissions. As a result, natural gas generation will not qualify as a clean energy source.

To achieve the emissions goals, SB2408 will phase out all coal-fired and natural gas-fired power plants by 2045. Notwithstanding this total phaseout, even the 40 percent renewable energy target by 2030 presents significant risk to ANR given the volume of natural gas that is delivered to the State. The November 1, 2021 contracted level of firm delivery within the state of Illinois is 1.19 Bcf/d, which includes deliveries to power plants, LDCs, and other interstate pipelines that supply natural gas to power generators within the State. These renewable energy targets will likely mean that power generators that rely on gas supply from ANR may de-contract and choose other generation outlets to meet the State-mandated targets leaving large amounts of unsubscribed capacity on ANR.

Q: Do LDCs that take service on ANR have similar greenhouse gas (“GHG”) proposals that could adversely impact ANR?

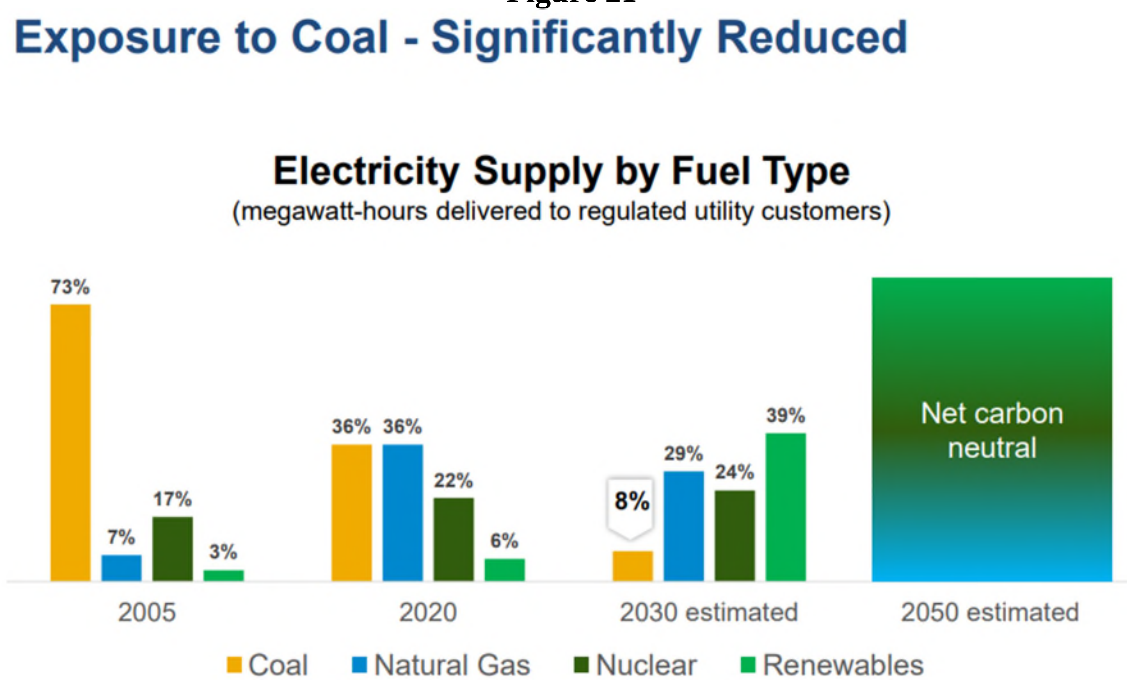
A: Yes, one of the largest customers by revenue on ANR is the WEC Energy Group (“WEC”), which owns LDCs in Illinois, Michigan, and Wisconsin. See Figure 20 below. Effective November 1, 2021, ANR will provide approximately 1.56 Bcf/d of firm natural gas transportation contracting to WEC via the FTS-1, FTS-3, ETS, and NNS services. In terms of total storage Maximum Storage Quantity, the WEC Energy group has contracted for 43.2 Bcf of FSS service across its eight entities’ contracts on ANR.

Figure 20



In WEC's September 2021 Investor Update, WEC introduced new carbon reduction goals associated with electric generation. WEC's carbon reduction goals are 60 percent below 2005 levels by 2025, 80 percent below 2005 levels by the end of 2030, and net carbon neutral by 2050. In order to accomplish these goals, WEC must reduce their electric generation exposure to coal and natural gas. As seen in Figure 21 below, WEC intends to reduce its natural gas-powered electric generation from 36 percent in 2020 to 29 percent by 2030 and increase its renewable powered generation from 6 percent in 2020 to 39 percent in 2030.

Figure 21



WEC's planned reduction to natural gas-fired generation is likely to negatively impact ANR as WEC will need to transport less natural gas on ANR thereby likely reducing its contracted capacity on the system.

Additionally, WEC is not the only significant shipper on ANR to recently announce updated GHG targets. DTE Energy, the largest LDC in Michigan with a broad portfolio of services on ANR, including 735,000 Dth/d of firm transportation services, published their Sustainability Summary in 2020. Per the report, DTE Energy is calling on its subsidiary, DTE Electric, to reduce carbon emissions by 50 percent relative to 2005 levels by 2030 and 80 percent by 2040. DTE Gas has similar initiatives, targeting an 80 percent reduction in carbon emissions relative to 2005 by 2040. These goals are likely to have a significant impact on ANR's ability to contract for new services or extend existing firm contracts.

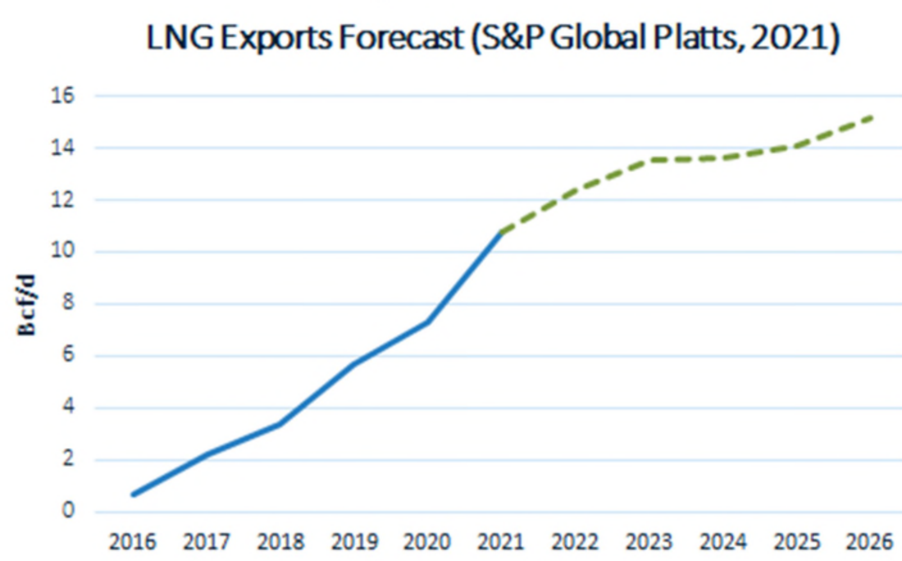
Q: What has been the overall impact on ANR's system of the supply and market changes you have described?

A: The changes I described have continued to transform the flow patterns and supply and market dynamics on ANR's system from those of just six years ago. ANR has seen continued new supply flood the Northern Area, which enabled new interstate pipelines to deliver into portions of ANR's Northern Area markets, namely Michigan, resulting in significant declines in ANR's market share in these areas.

The significant expansion of unconventional supply in the Rockies, Mid-Continent, and Permian basins, followed by a severe contraction, has significantly decreased ANR's supply on the SW Mainline as previously mentioned above.

The continued rapid production growth from unconventional sources in the Marcellus and Utica shale formations continues to flood into competing pipelines, and as a result, shippers are acquiring the available existing and expanded pipeline capacity on major interstate pipelines to transport to the Gulf Coast. As illustrated in Figure 22 below, natural gas required for LNG liquefication will continue to grow as more facilities come online in the U.S. With demand in 2021 at roughly 11 Bcf/d, the potential supply required in just five years could be as high as 15 Bcf/d.

Figure 22



III. ANR'S BUSINESS RISK

Q: Does ANR face significant business risk in its operations?

A: Yes, ANR faces a variety of business risks including (1) competitive risks in its Southwest Area, SW Mainline, and SE Mainline; (2) counterparty risk along its SE Mainline; (3) operational risk; and (4) regulatory risk.

SW Area Business Risks

Q: Please describe the SW Area.

A: As discussed above, the SW Area is composed of a triangle-like set of facilities as shown in Figure 1 and is primarily a supply region with limited local delivery markets that operates as a market center receiving local supply and supply shipped from the Permian, Rockies, and Mid-Continent supply basins.

Q: What is ANR's current contracting level in the SW Area?

A: ANR currently has 211,833 Dth/d contracted for in 2022 with declining contracted capacity each year through 2024.

Q: What rate schedule do shippers primarily use to transport gas in the SW Area?

A: There are two services available to transport receipt gas to the Southwest Headstation in the SW Area. These are Rate Schedule PTS-1 and PTS-2. The PTS-1 service has no demand, commodity, or fuel charge and is considered a lower priority than PTS-2. PTS-2 has the same demand and commodity charges as FTS-1 for the SW Area and is considered firm. Similar to PTS-1, PTS-2 does not require a fuel charge. During high production periods when the SW Area is congested and there is more receipt gas than capacity, shippers will purchase the PTS-2 service to avoid interruption. However, during undersupplied periods, when utilization of the SW Area is low and the risk of interruption is minimal, shippers will largely elect to utilize the PTS-1 service.

Q: How are transportation values for the SW Area determined?

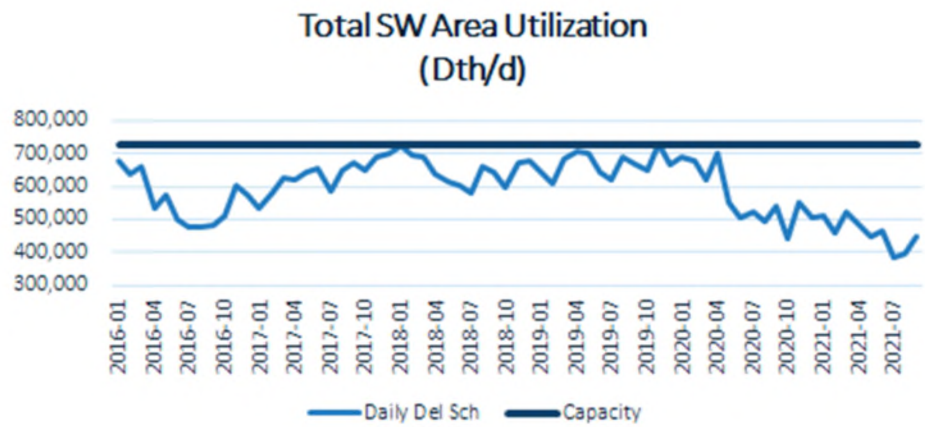
A: Transportation values in the SW Area are driven by the production levels of the source regions serving it and the resulting congestion levels of pipelines in the region. When production surpasses pipeline capacity out of the region as it did from late 2017 to early 2020, then the transportation value of the SW Area is very high. However, when production is not sufficient to fill pipeline infrastructure out of the region, as began in summer 2020 with production declines, the transportation value of the SW Area will be depressed.

Q: Please describe how the boom-bust production cycle in the SW Area you described above has affected ANR's competitive position?

A: During the boom period of production growth from 2017 to 2019, the SW Area was flowing near a 100 percent utilization through several of its constraint points at times. This led to a substantial increase in contracting revenue for the PTS-2 service, peaking in 2020 with over 400-MMDth/d contracted and approximately $12 million in revenue. Several of these contracts extend through 2024, although at a declining rate.

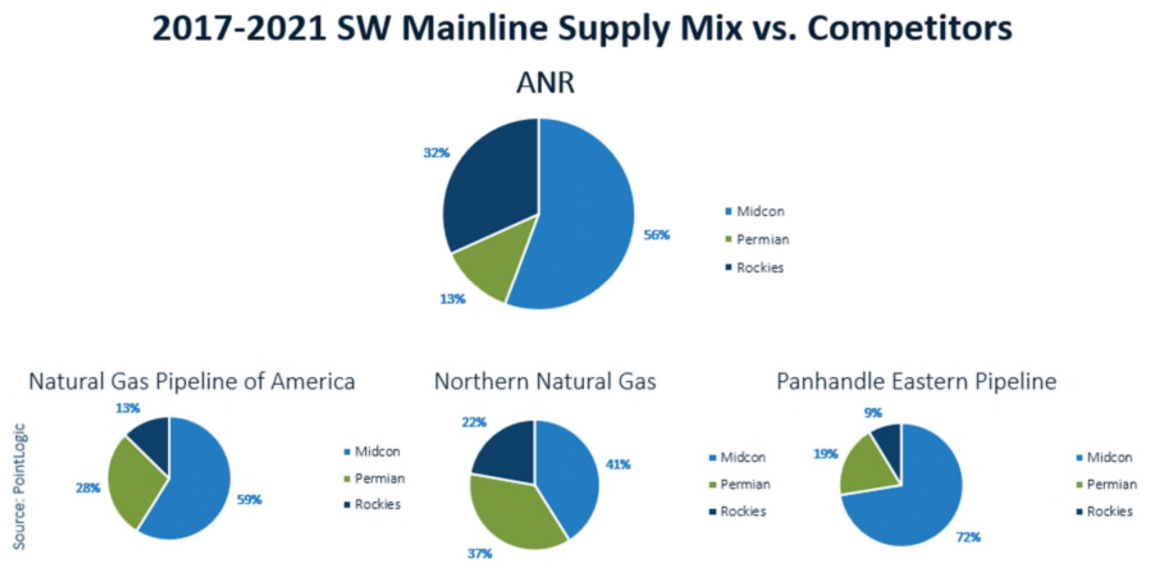
Beginning in the summer of 2020, as production began to decline, the utilization in the SW Area began to drop, reaching as low as 60 percent in the summer of 2021. These utilization patterns can be seen below in Figure 23. As I discuss more below, this expected low utilization is adversely affecting future contracting in the SW Area.

Figure 23



In addition, the declining production in the Mid-Continent and Rockies basins puts ANR at a competitive disadvantage to similarly situated competing pipelines in the region, specifically Natural Gas Pipeline Company of American ("NGPL"), Northern Natural Gas Company ("NNG"), and Panhandle Eastern Pipe Line Company, LP ("PEPL"). ANR derives a much smaller portion of its supply mix via direct interconnections from the Permian Basin than these other competing pipelines in the region. ANR's only firm receipt that is supplied from Permian production is from Oneok Westex pipeline at Red River. This interconnect can only supply 125-MMDth/d of receipts, or roughly only 17 percent of the SW Area capacity. This means that ANR is much more reliant on the Rockies and Mid-Continent declining production basins as show in Figure 24 below, which is derived from flow data provided by PointLogic. However, ANR's competitors will benefit from a future boom cycle of production in the Permian as forecasted by Platts S&P and as discussed below.

Figure 24



Q: What business risks does ANR's SW Area face in the future?

A: The largest business risk confronting the SW Area is the level of capacity expirations occurring over the next few years. As mentioned above, production and utilization drive the value of the SW Area and the vast majority of ANR's supply in the SW Area comes from declining production basins in the Mid-Continent and Rockies basins. As a result, ANR expects that utilization should continue to stay low or even decline in the future resulting in transportation values near zero. With such low expected transportation values, shippers will invariably revert to using the PTS-1 service for free. Consequently, ANR has significant re-contracting and revenue risk over the next several years as well as supply issues that its competitors do not face. Figures 25 and 26 below demonstrate ANR's PTS-2 contracting and revenue cliff through 2025. ANR's 2022 contracted revenue of $6.83 million is expected to decline to $3.93 million in 2023, $2.02 million in 2024, and zero in 2025 and beyond. In addition to the declining contracts, approximately 70 percent of the shippers holding these expiring contracts in 2022 are marketers. This means there is a much higher likelihood of contracts not renewing as the transportation value drops due to declining production.

Figure 25

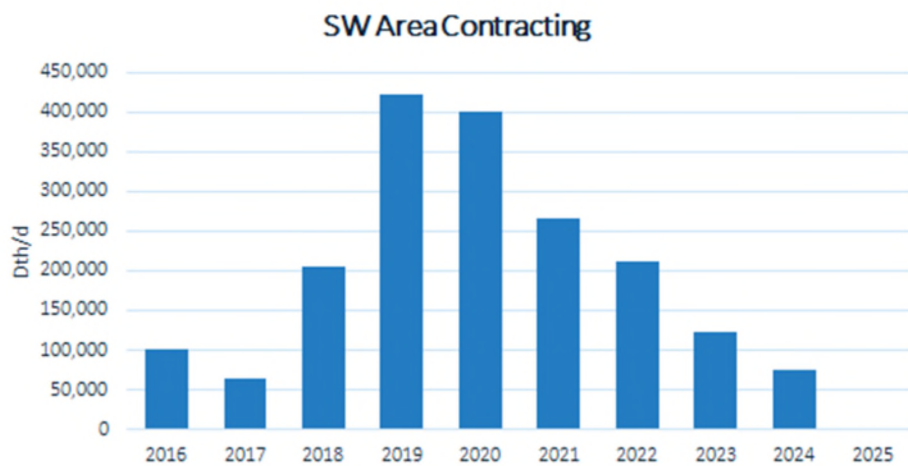
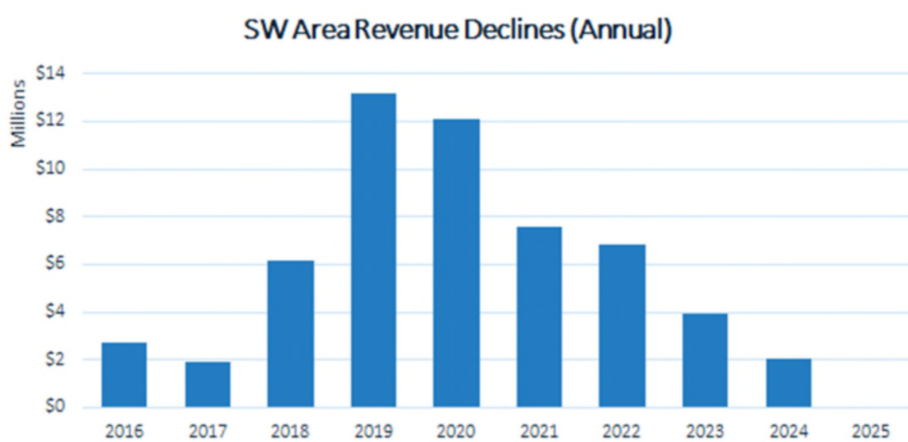


Figure 26



<u>SW Mainline Business Risks</u>

Q: Please describe the SW Mainline.

A: As I described in more detail above, the SW Mainline extends from the Southwest Headstation at Greensburg, Kansas, to the Sandwich compressor station near Sandwich, Illinois. The SW Mainline sources all of its supply from the SW Area system, and thus shares many of the same business risks identified for the SW Area immediately above.

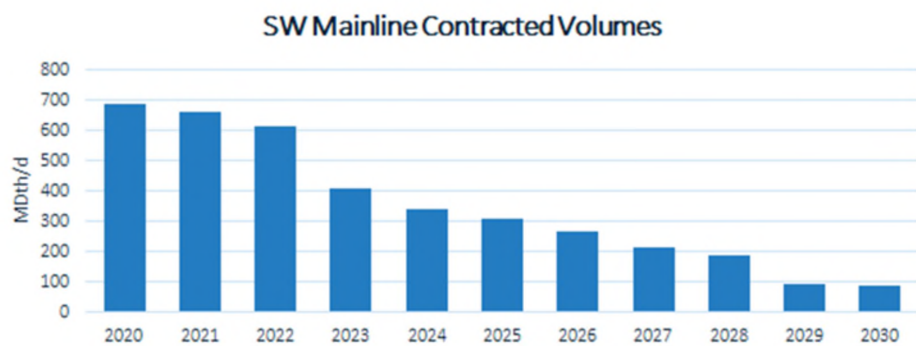
Q: What is ANR's current contracting level on the SW Mainline?

A: As shown in Figure 27 below, ANR has 684,117 Dth/d contracted at different periods throughout 2022, or 614,000 Dth/d contracted for 2022 as an annual average with significant declines in contracting each year thereafter, as shown in Figure 28 below.

Figure 27

Customer Name	Customer Type	Daily Capacity	% of Capacity
NICOR GAS CO.	LDC/ END USER	110,000	16%
ELWOOD ENERGY LLC	LDC/ END USER	110,000	16%
IOWA FERTILIZER	LDC/ END USER	81,000	12%
WISCON PUBLIC SERV	LDC/ END USER	67,542	10%
SEMCO ENERGY INC DBA SEG	LDC/ END USER	42,500	6%
WISCONSIN GAS LLC	LDC/ END USER	40,282	6%
DTE GAS COMPANY	LDC/ END USER	25,000	4%
CONOCOPHILLIPS CO	MARKETER	24,554	4%
WISCONSIN PWR & LGHT	LDC/ END USER	20,000	3%
WISCONSIN ELECTRIC POWER	LDC/ END USER	19,068	3%
Other 24 Customers		144,171	21%

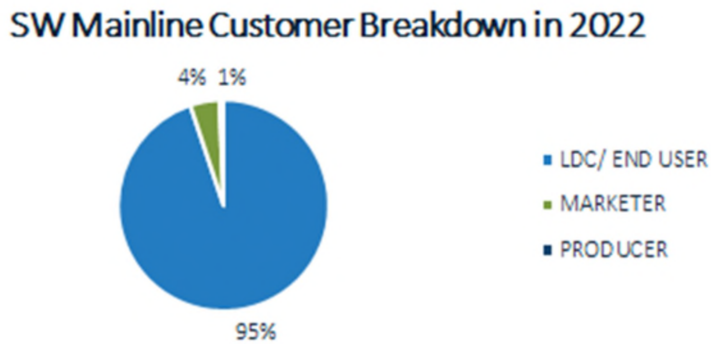
Figure 28



Q: What is the current customer makeup and contract profile for the SW Mainline?

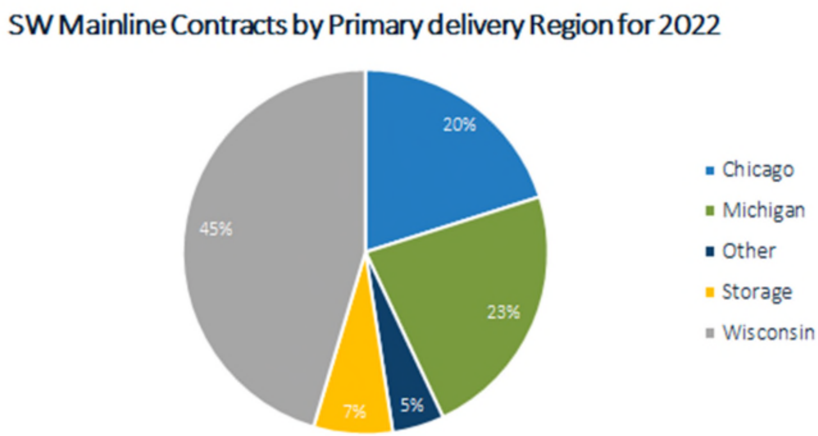
A: Currently, on an annual basis capacity holders consist of approximately 95 percent LDCs and end users and 4 percent marketers as shown below in Figure 29.

Figure 29



ANR's total deliveries from the SW Mainline are to the following market areas in 2022: approximately 23 percent are contracted into Michigan, 7 percent to ANR Storage, 20 percent to Chicago, 45 percent to Wisconsin, and the remaining 5 percent to other markets. See Figure 30 below.

Figure 30

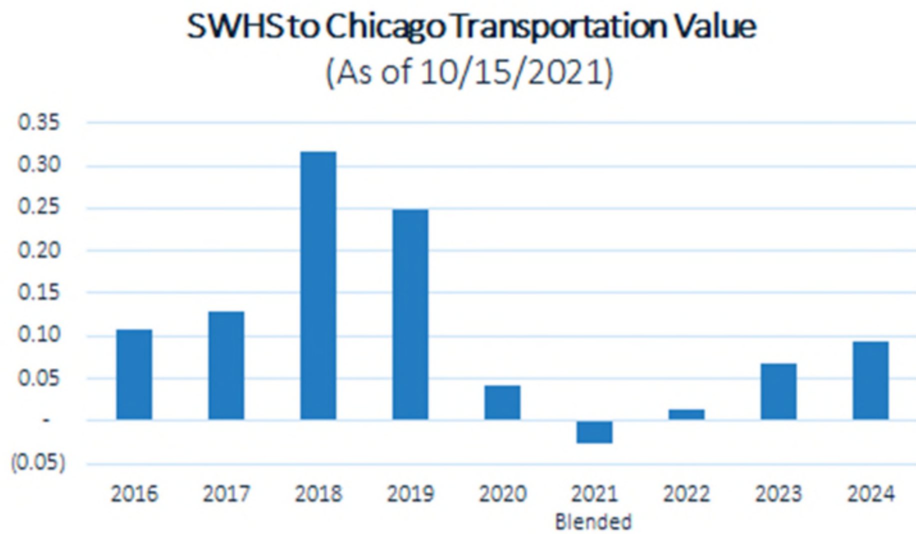


Q: How are transportation values for the SW Mainline determined?

A: Transportation values on the SW Mainline are driven by the difference between the gas price basis at ANR's Southwest Headstation and the gas price basis in ANR's Northern Area, typically Chicago city gates. ANR serves significant LDC and electric generation load across its Northern Area zone, ML-7. In summary, a weak Southwest basis combined with a strong Chicago basis provides the most value. If we take current forward values as reported by S&P Global Platts, 2021, as our expected renewal value, the annual value from

2022 to 2024 averages only about $0.06 per Dth. The decline in value from 2017 to today, and projections based on the current forward curve, is shown below in Figure 31.

Figure 31



Q: What competitive challenges does ANR's SW Mainline face today?

A: As discussed above, there was a significant increase followed by a significant decrease in production in the Rockies and Mid-Continent basins, as well as prolific growth followed by a flattening of Permian basin production growth. The initial increase resulted in several new greenfield pipeline projects resulting in a 7.2 Bcf/d increase in capacity out of the region. This new capacity, and in particular the 1.1 Bcf/d Midship Pipeline capacity, competed with ANR's SW Mainline. Following the COVID-19 recession in summer of 2020, production cratered in the Rockies and Mid-Continent basins resulting in significant excess pipeline capacity, which is directly competing with ANR.

Q: Is production expected to increase again in these basins?

A: As shown in Figures 32-34 below from S&P Global Platts, 2021 forecasts, production declines are expected to continue for the foreseeable future in both the Rockies and Mid-Continent basins, while the Permian basin is expected to see significant growth once again.

Figure 32

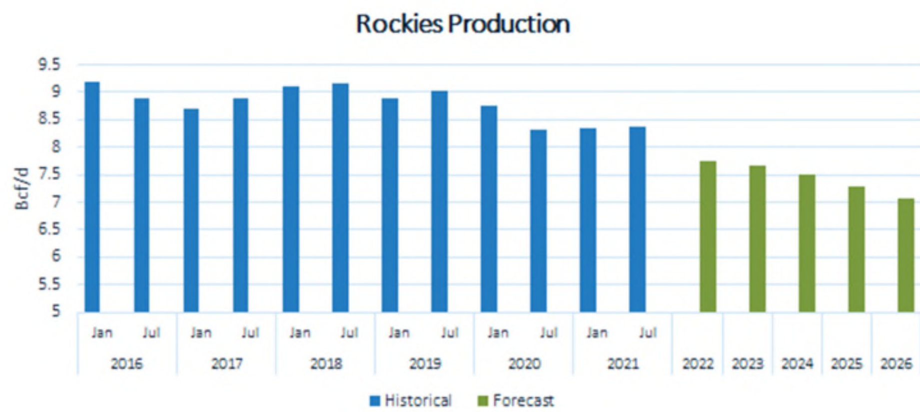


Figure 33

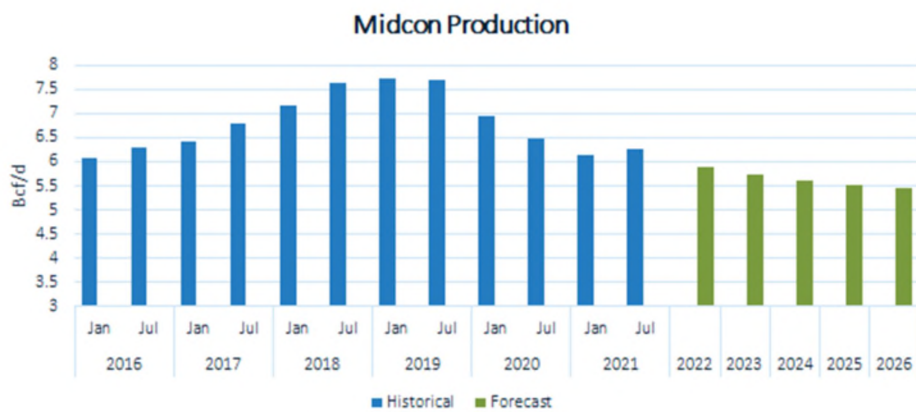
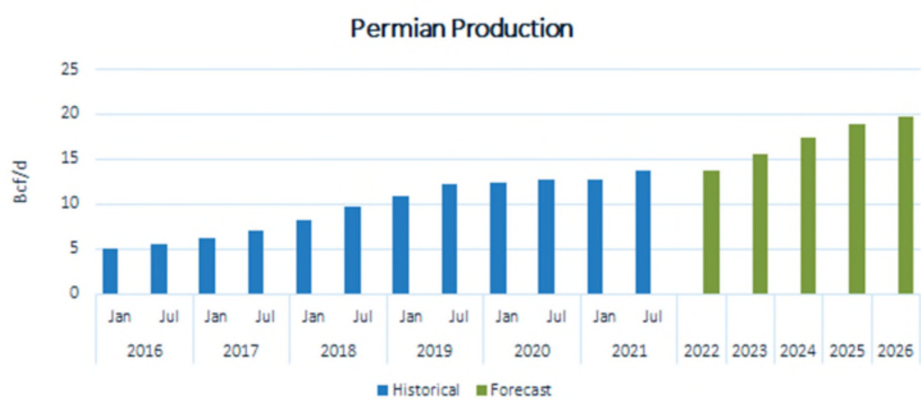


Figure 34



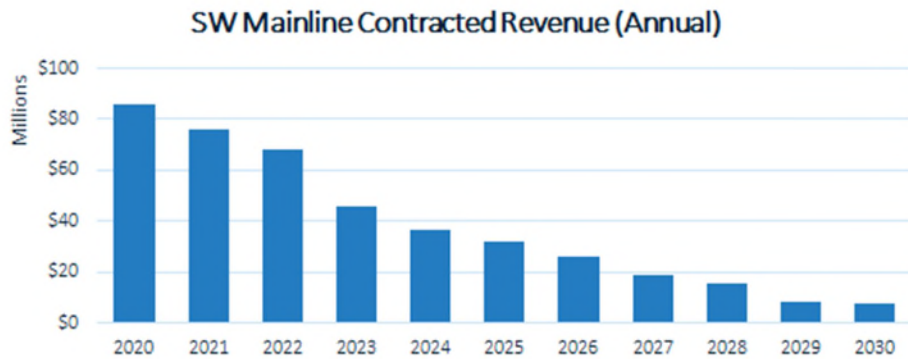
Q: Please describe how these production forecasts impact ANR's business risk on the SW Mainline.

A: As described above in the SW Area business risk section, ANR is at a competitive disadvantage to its direct competitors in the region, namely NGPL, NNG, and PEPL. This is due to the fact that ANR's SW Area, which supplies its SW Mainline, is much more dependent on Rockies and Mid-Continent supply as a whole, while having the smallest direct connection to the Permian basin of the three competing pipelines. Therefore, the decline in the Rockies and Mid-Continent basins will continue to pressure the value of the SW Mainline transport spreads, while the forecasted increase in Permian production will have limited benefits to ANR's SW Mainline.

Q: What other business risks does ANR's SW Mainline face in the future?

A: One of the most significant risks on the SW Mainline in the immediate future is the level of capacity expirations occurring over the next few years. The current projected value of the Southwest Mainline as reflected in the forward curve is minimal as mentioned previously. This indicates that the revenue at risk in contract renewals is substantial. In 2022, the SW Mainline accounts for roughly $68 million of revenue. Using the average forward market value for 2023 and 2024 of $0.08 per Dth, as shown previously in Figure 31, as a renewal rate for SW Mainline capacity expirations suggests that ANR's SW Mainline annualized revenue for 2023 and 2024 will be reduced by approximately $16.4 million in 2023 and $23.6 million in 2024 compared to 2022. While the forward curve for pricing in later years is less likely to be as accurate, we can still expect a similar loss of revenue beyond 2024 as production declines continue in ANR's main production basins for the SW Mainline. Figure 35 below shows expiring contract revenue per year.

Figure 35



Q: Why does this expiring capacity present additional business risk to ANR?

A: The current and future declining supply projections in ANR's primary production basins means that utilities are likely to pivot much of their supply to shorter haul contracts from receipts in zone ML-7 or to competing pipelines. As a result, ANR is likely to face significant re-contracting issues as production continues to decline and utilities that today are not utilizing their significant firm contract entitlements look for cheaper alternatives as their contracts expire. Therefore, ANR may be forced to re-contract this expiring capacity at much lower rates as transport values should remain depressed as a result of both declining production and an over-supply of pipeline capacity.

<u>SE Mainline Business Risks</u>

Q: Please describe the SE Mainline.

A: As described in more detail above, the SE Mainline extends from Eunice, Louisiana, known as the SE Headstation, to Defiance, Ohio. Additionally, ANR is also a partial owner of the Lebanon Lateral, which extends from ANR's SE Mainline at Sulphur Springs, Indiana, to the lateral's terminus near Lebanon, Ohio. The SE Mainline flows and contract in both a forward haul and back haul direction.

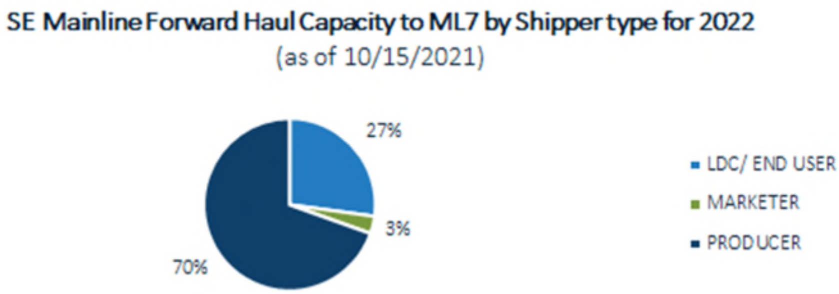
Q: What is ANR's current contracting level on the SE Mainline for forward hauls?

A: ANR currently has approximately 1.0-MMDth/d contracted in 2022 for a term of 12 months or longer. This includes both long hauls as well as short hauls with deliveries into market zone ML-7.

Q: What is the current customer makeup and contract profile for the SE Mainline for forward hauls?

A: Currently for 2022, SE Mainline forward haul capacity holders are made up of approximately 27 percent LDC and end users, three percent marketers, and 70 percent producers on an annual basis. See Figure 36 below.

Figure 36



Contractually on an annual basis for 2022, approximately 50 percent of receipts into the SE Mainline for forward haul transportation enters at the Southeast Headstation, and 50 percent into the ML-2 and ML-3 rate zone. The current contract mix consists of approximately 86 percent at maximum tariff rates and 14 percent at discounted rates as of October 2021.

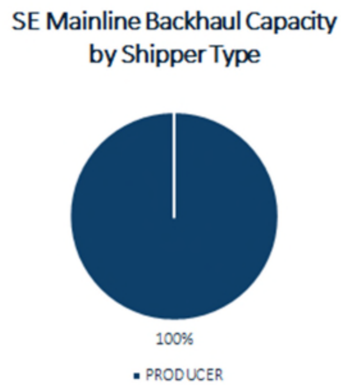
Q. What is ANR's current contracting level on the SE Mainline for backhauls?

A: ANR currently has 1.179-MMDth/d contracted for on a long-term basis with an average term of 20.2 years from 2022.

Q. What is the current customer makeup and contract profile for the SE Mainline for backhauls?

A: Currently, backhaul capacity holders are made up of 100 percent producers. See Figure 37 below. Approximately 91 percent of receipts into the SE Mainline for backhaul transportation enter the ML-3 rate zone and nine percent enter the ML-2 rate zone. The current contract mix consists of approximately 82 percent at maximum tariff rates and 18 percent at discounted rates.

Figure 37



Q: What commercial challenges does ANR face on its SE Mainline today?

A: ANR has seen a degradation in its transport value on the SE Mainline over the last few years. Based on future spreads, these values do not improve substantially. This value decline is true of both forward haul and southbound backhaul values. The forward haul values have declined as a direct result of incremental supply being delivered into Michigan via the NEXUS and Rover pipelines. In addition to the loss of the Michigan market, after the Mid-Continent and Rockies production declined starting in 2020, it lowered the utilization of many pipelines that transport supply out of the Mid-Continent region. The secondary effect of this is that those pipelines now act as additional outlets for gas being transported from the Eastern Utica/Marcellus region to the Mid-Continent via Rockies Express. This has resulted in ANR losing dedicated supply to its SE Mainline from competing pipelines that interconnect with Rockies Express. Consequently, the diversified markets for this supply have added to the reduction in the value of the SE Mainline forward haul and backhaul.

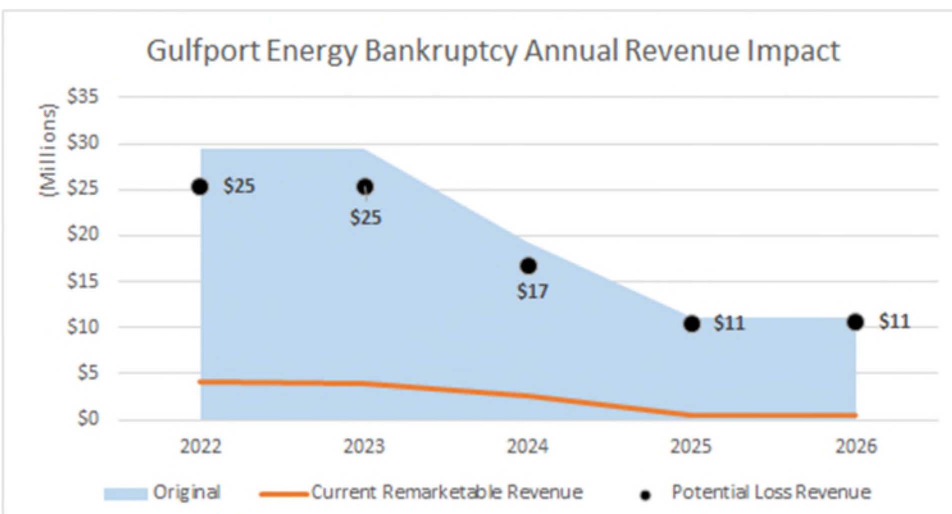
Q: What business risks do you anticipate that ANR's SE Mainline will face in the future?

A: Given that a limited number of producers hold the vast majority of forward haul capacity and all of the backhaul capacity on the SE Mainline, ANR is at significant risk that one or more of its producer shippers will default on its firm transportation contracts as a result of the volatile oil and gas price environment. A clear example of this risk is the recent Gulfport Energy bankruptcy that I discuss below. While underlying commodity prices have improved in 2021, the risk of a return to oversupply in the future has not gone away. This is particularly true for the two largest producers on ANR, Antero Resources and Ascent Resources, as they focus almost entirely on production in the Utica and Marcellus basin in the East. The concentration of these producers into one basin increases the risk of default due to pipeline constraints on exporting gas out of the region. The region is now producing at a level that almost all pipelines out of the region are flowing near full utilization. The regulatory environment makes the prospect of new greenfield pipeline projects extremely challenging as exemplified by the cancelation of the Atlantic Coast Pipeline project. As production rises in this basin, the risk of an extremely weak basis discount grows significantly and adds to the default risk. Additionally, the expansion of new pipeline capacity into ANR's traditional Michigan market has significantly eroded the value of that market to ANR such that ANR would have a very difficult time re-marketing any expiring or defaulted contracted capacity.

Q: Can you elaborate on the default risk of producers?

A: With ANR's contracting profile highly exposed to producers on its SE Mainline, the risk of default and re-contracting at minimal values is considerable. In 2021, ANR realized such risk with Gulfport Energy's bankruptcy due to low natural gas prices. As a result of its bankruptcy, Gulfport Energy turned back approximately 283,700 Dth/d of maximum tariff rate capacity. As mentioned previously, the value of these transport paths are now substantially lower than when a shipper like Gulfport contracted for them. Additionally, in accordance with ANR's tariff and Commission policy, shippers are required to post only three months' worth of collateral on their contracts. The net effect of this loss assuming ANR can remarket the capacity at current forward values is $89 million from 2022 to 2026, or $17.8 million per year on average. As seen in Figure 38 below, the potential lost revenue per year as represented in the black dots, is the difference between what was originally contracted in blue and what we can re-market the turned back capacity for in the orange line using current forward values from Platts.

Figure 38



In addition to Gulfport Energy, the credit profile on ANR's other four SE Mainline producers is shown below in Figure 39. Each of these shipper's credit ratings are speculative to extremely speculative.

Figure 39

Shipper Name	Moody's Credit Rating	Rating Scale
Ascent Resources - Utica, LLC	Caa1	Extremely Speculative
Antero Resources Corporation	Ba3	Speculative
Chesapeake Energy Marketing, L.L.C.	B1	Speculative
EQT Energy, LLC	Ba2	Speculative

Q: Can you elaborate on the contract expiration risk?

A: Yes, as seen in Figure 40 below, the customer base for the SE Mainline northbound is heavily contracted by producers. Additionally, Figures 41 and 42 below show that both contracting levels, as well as revenue on ANR's SE Mainline northbound, will see a significant decline over the next several years. From 2022 to 2026, ANR will see a contracting decline from approximately 1.0-MMDth/d to 650,000 Dth/d. Similarly, revenue is expected to decline from approximately $125 million to $86 million.

Figure 40

Customer Name	Customer Type	Daily Capacity	% of Capacity
ASCENT RESOURCES - UTICA	PRODUCER	323,000	35%
ANTERO RESOURCES	PRODUCER	200,000	22%
NICOR GAS CO.	LDC/ END USER	100,000	11%
DTE GAS COMPANY	LDC/ END USER	60,000	7%
NIPSCO LLC	LDC/ END USER	33,000	4%
CNX GAS COMPANY	PRODUCER	27,143	3%
MIDLAND COGEN VENTURE LP	LDC/ END USER	21,000	2%
DTE ENERGY TRADING INC	MARKETER	20,000	2%
EXELON GENERATION CO	LDC/ END USER	19,400	2%
INDIANA GAS COMPANY	MARKETER	15,548	2%
Other 14 Customers		100,437	11%

Figure 41

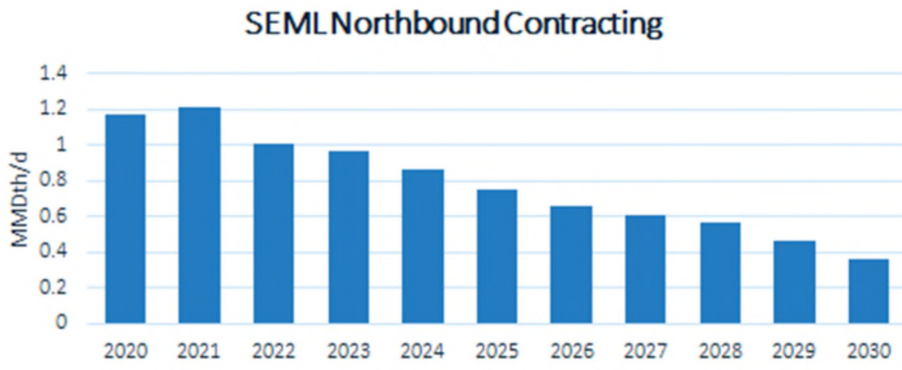
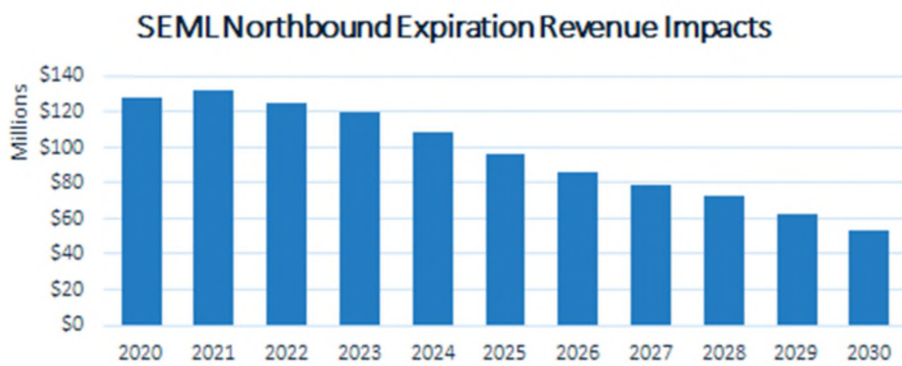


Figure 42



Q: What marketing obstacles would ANR face in remarketing this capacity?

A: As production has continued in the Marcellus/Utica basins, this incremental production has required new transportation capacity away from these production basins and ANR's competitors, NEXUS and Rover, have captured much of this incremental supply. As seen in Figures 43 and 44 below from Point Logic data, NEXUS's and Rover's utilization is mostly at or above 80 percent since inception. This competition has eroded any value to ANR in the Michigan market as I discuss below, and as a result, ANR will likely be unable to remarket much of the SE Mainline Northbound capacity.

Figure 43

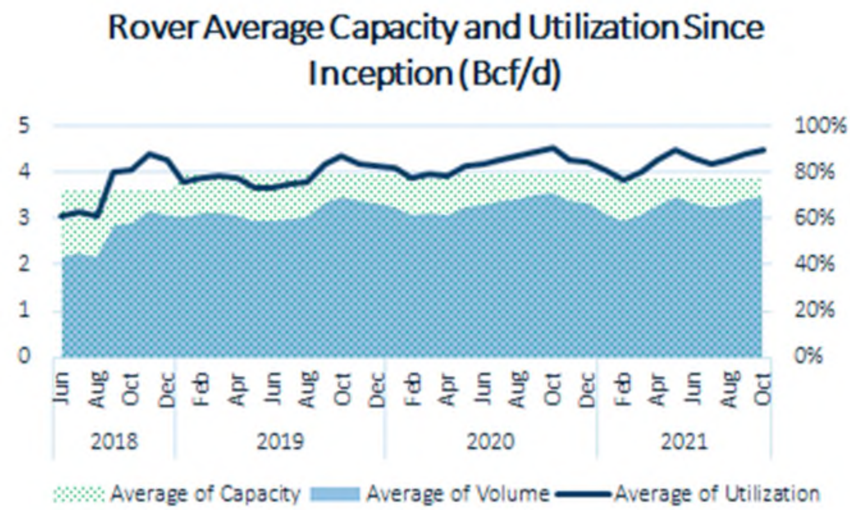
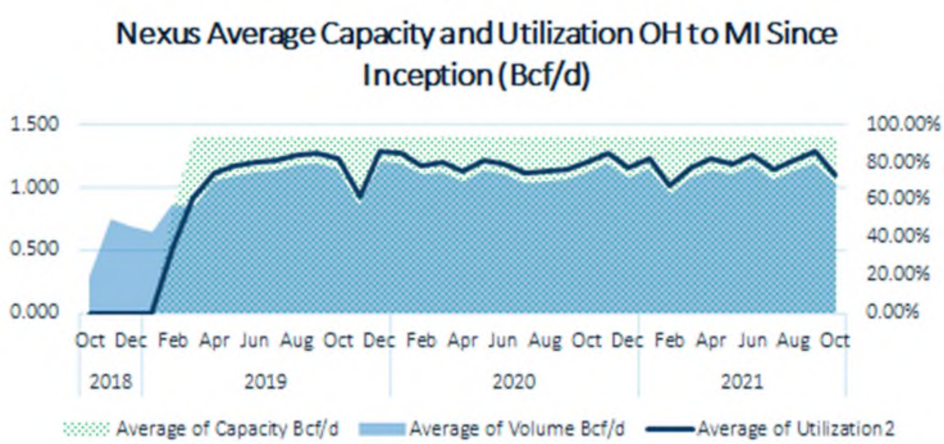


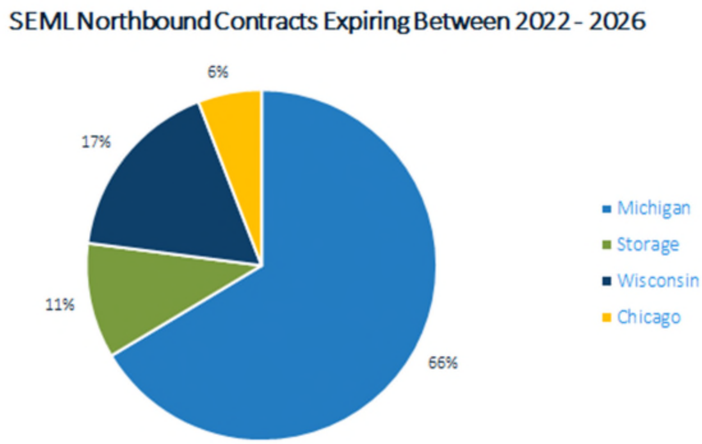
Figure 44



Q: Given this increased competition in the Northern Area, what percentage of ANR's contracts that expire prior to the end of 2026 on the SE Mainline have delivery points in the Northern Area?

A: As shown on Figure 45 below, approximately 66 percent of the SE Mainline Northbound contract volumes have delivery points in Michigan, 11 percent deliver to ANR Storage, six percent deliver to Chicago deliveries, and 17 percent land in Wisconsin.

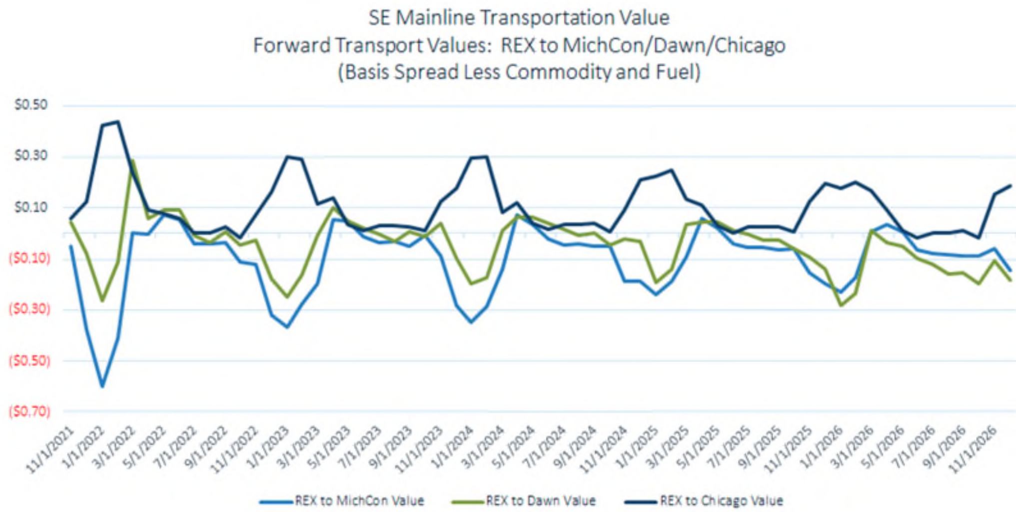
Figure 45



Q: **Do the forward pricing curves reflect this reduction in value?**

A: Yes, Figure 46 below from S&P Global Platts, 2021 data depicts forecasted values showing ANR's SE Mainline to Willow Run value as reflected in the Rex Zone 3 to MichCon value, as well as values from Rex Zone 3 to Dawn and Chicago, as representative of the value of transport from ANR's SE Mainline to deliveries further west of Michigan. As the figure shows, the value to transport to MichCon and Dawn are less than zero into the future. The value to Chicago is positive in the winter and close to zero in the summer, averaging only $0.10 of value for the period from 2022 through 2026 on an annual basis. These forward values are significantly lower than the current maximum tariff rates of $0.266 per Dth daily from ML-3 to ML-7 and $0.432 per Dth daily from the SE Headstation to ML-7. As a result, ANR will be unable to remarket and sell the anticipated available capacity or be forced into selling it at steep discount.

Figure 46



Q: Can you summarize ANR's business risk on its SE Mainline?

A: ANR's business risks can be summarized as a severe compression of transport spreads across its system driven by increased competition for its markets being served by the SE Mainline. These realities substantially increase the risk of being unable to re-contract expiring capacity over the next several years that becomes unsubscribed from either contract expirations or from further default by its shippers that are producers similar to Gulfport Energy.

<u>Operational Risk</u>

Q: Does ANR face heightened risk associated with operating its pipeline system?

A: Yes. ANR faces increased operational risk due to its significant and ongoing need to modernize its pipeline and storage infrastructure to ensure continued safe and reliable operation of the pipeline as well as compliance with existing and newly-promulgated regulations by the U.S. Department of Transportation ("DOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA"). ANR witnesses Linder and Parks discuss the reliability and safety issues driving ANR's modernization program, while ANR witness

Currier discusses the costs associated with ANR's compliance with PHMSA's Mega Rule and ANR witness Word discusses the costs associated with ANR's compliance with PHMSA's recent storage-related rules.

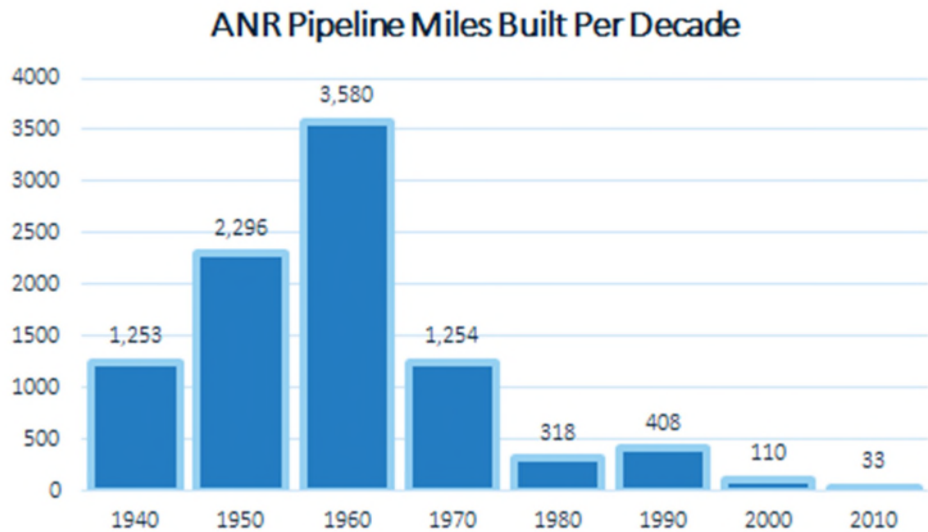
Q: Does the age of ANR's pipeline system and its associated modernization program create operational risk for ANR?

A: Yes. As described by ANR witnesses Parks and Linder, ANR is embarking upon a second highly capital-intensive modernization program to ensure the continued reliability and safety of its system. As described by ANR witness Linder, the RP16-440 Settlement was successful in its stated goals of increasing integrity, reliability, and safety; however, additional infrastructure investment is still required. This filing proposes a new modernization program to be implemented over the next five years to continue this modernization effort to ensure the continued reliability and safety of the system as well as compliance with newly-issued safety and other regulations imposed upon the pipeline industry.

Q: How does the age of the ANR system compare to other pipelines?

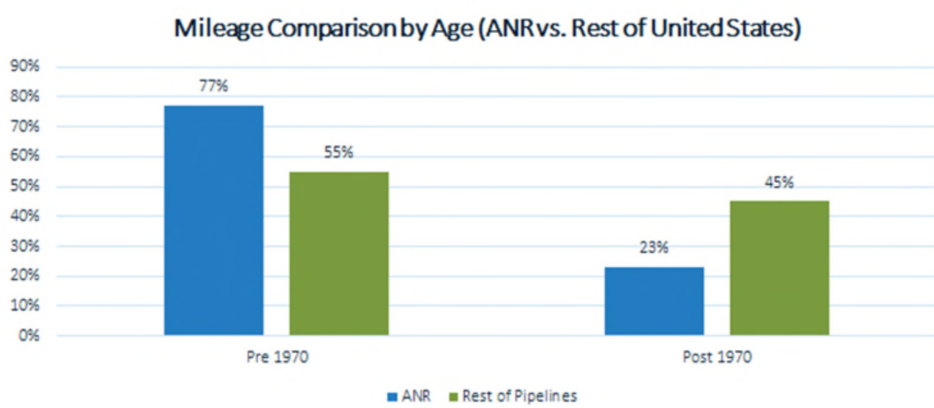
A: On average ANR's assets are older than other FERC-regulated interstate natural gas pipelines and the data provided by PHMSA demonstrates this. Figure 47 below shows the mileage of ANR's PHMSA-regulated transmission lines built by decade.

Figure 47



Over 77 percent of ANR's current mileage was installed before 1970. As demonstrated in Figure 48 below, this is significantly greater than the rest of the PHMSA-regulated pipeline grid, of which only 55 percent was installed prior to 1970.

Figure 48



Q: Does the relative age of the ANR system put it at a higher operational risk?

A: Yes. As ANR witnesses Linder and Parks testify, because of the age of the ANR system, it anticipates having to undertake numerous modernization projects to ensure the continued reliability and safety of the system. Many of these future modernization projects will require approval by FERC of NGA section 7(c) certificate applications filed by ANR. As a result of the higher number of projects ANR must undertake as compared to its competitor pipelines, it is disproportionately exposed to the numerous obstacles and overall challenges to obtaining the necessary permits to develop and construct pipeline infrastructure in the current environment, including coordinated public opposition (which I discuss below) and the delay and uncertainty associated with regulatory proceedings. This further amplifies the operational and regulatory risks related to ANR's modernization program and adds additional uncertainty to its ability to recover these costs and complete this necessary work.

Q: Has ANR been afforded the opportunity to recover all of the capital costs it has expended over the past several years?

A: No. Since 2016, ANR has incurred capital expenditures in excess of the $837 million required to be spent by the RP16-440 Settlement that have yet to be recovered, which has outpaced its depreciation expense over the same period. The inability to recover these capital costs during the period in which they were incurred and placed in service has now resulted in proposed rates in this filing that are higher than they otherwise would have been. As outlined in my earlier testimony, ANR sees large amounts of competition across its system and also increased business risk due to expiring contracts and low re-contracting values. The increase in rates can lead to both increased default risk from shippers and to shippers looking at more competitive alternatives.

Q: Is the operational risk that ANR faces from its modernization work exacerbated by delays in the regulatory process and associated costs?

A. Yes, it is. As I discuss below, the duration of the approval process before the Commission and state permitting agencies and associated costs of obtaining regulatory approvals have increased substantially. This is true even for projects that are not designed to serve additional load but solely to repair and replace aging portions of ANR's system. In part this is due to public opposition to any proposed natural gas infrastructure, no matter the purpose, and in part to increasing delays in the regulatory process. As ANR witness Linder explains, regulatory delays can have significant impacts on project timing and execution which in turn adds additional costs and time to projects.

Q: Does the current high inflationary environment further compound ANR's operational risk?

A: Yes. The current high inflationary environment as described by ANR witness Villadsen creates additional operational risk for ANR as it is executing a capital-intensive modernization program as described by ANR witness Linder. This program requires ANR to purchase large amounts of material and labor that in a continuously increasing price environment exposes ANR to additional operational risk as the total costs of necessary modernization projects continues to increase.

<u>Regulatory Risk</u>

Q: Please explain how regulatory risk has increased for ANR over time.

FERC-regulated pipelines have faced significantly increased regulatory risk in recent years and ANR is no exception. ANR faces regulatory risks as a result of continued and growing opposition to pipeline development at all stages, including permitting at FERC as well as in federal district and appellate courts, which only further complicates the regulatory process and increases the risk associated with developing new critical infrastructure projects. For example, recent legal challenges to pipeline development have been mounted in the following areas: (1) pipelines' right to exercise eminent domain as set forth in the NGA with respect to private and public land; (2) the need to assess any impacts of new pipeline development on upstream and downstream GHG emissions; (3) environmental and public lands permitting, including assessing environmental justice considerations; and (4) FERC's procedural rules, including the rehearing process and notices to proceed, as part of its certification of new pipeline projects. Moreover, recent legislative and state initiatives also reflect an increasingly hostile environment towards natural gas infrastructure development. ANR thus faces increased uncertainty and costs associated with seeking authorizations from the Commission and other permitting agencies for new projects, whether for modernization of existing facilities or expansions. Additionally, and as discussed at length by ANR witness Kirk, the Biden administration is undertaking various initiatives to promote the replacement of natural gas with non-gas sources of energy. Taken together, these combined factors create substantial business risks for ANR.

Q: Can you provide a specific example of how FERC's recent approach to assessing environmental impacts, including GHG impacts, in certificate applications is increasing regulatory risk to ANR?

A: Yes. Recently the Commission has begun to examine GHG impacts of nearly every project that involves any amount of incremental capacity regardless of whether the project requires greenfield construction. For example, ANR's Wisconsin Access Project is designed to increase ANR's firm capacity by approximately 50,707 Dth/d into Wisconsin, effectuated through modifications to the original design assumptions and software within ANR's engineering models and minor modifications to the existing meter stations. Even though the project involves no new greenfield construction, very limited facility modifications, and was not protested by a single party, the Commission on August 26, 2021 issued a notice of Intent to Prepare an Environmental Impact Statement ("EIS"), which will in part explore the project's GHG impacts. The Commission's decision to require an EIS for this type of project presents significant regulatory risk to ANR as it will considerably delay the issuance of a certificate and potentially the in-service date of the project.

Q: What is the overall impact from these increased regulatory risks for the development of new natural gas infrastructure in the United States?

A: The result of this increased regulatory risk is that successfully developing new natural gas infrastructure projects has become far from certain and pipelines risk expending significant capital on new projects that may never actually be built or go into service. The uncertainty created by these regulatory risks has already resulted in losses of hundreds of millions of dollars by project proponents in the form of significant delays in project execution caused by such opposition and, in some cases as described above, in project termination.

Q: Does this conclude your testimony?

A: Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-____-000

State of Texas)
) ss.
County of Harris)

AFFIDAVIT OF ADAM LAKHANI

Adam Lakhani, being first duly sworn, on oath states that he is the witness whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of Adam Lakhani"; that, if asked the questions which appear in the text of said testimony, he would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as Adam Lakhani's sworn testimony in this proceeding.

DocuSigned by:
Adam Lakhani
62332F1E8D8E47B...

Adam Lakhani

SWORN TO AND SUBSCRIBED BEFORE ME THIS 19th DAY OF January, 2022. This notarial act was an online notarization.

Notary Seal

NOTARY PUBLIC STATE OF TEXAS
SHELIA O. COPUS
Notary ID
976876
My Commission Expires
2/22/2023

Digital Certificate

DocuSigned by:
Shelia Copus
6B60C3597ADE4AD...

Exhibit No. ANR-0006

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR PIPELINE COMPANY) DOCKET NO. RP22-___-000

PREPARED DIRECT TESTIMONY
OF
BENTE VILLADSEN

January 28, 2022

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**SUMMARY OF PREPARED DIRECT TESTIMONY
OF
BENTE VILLADSEN**

Dr. Bente Villadsen provides direct testimony before the Federal Energy Regulatory Commission ("FERC" or "the Commission") on behalf of ANR Pipeline Company, ("ANR") regarding the appropriate return on equ0ity ("ROE") for ANR. Dr. Villadsen recommends an ROE of 15.70 percent, which results from the application of the Commission's discounted cash flow ("DCF") and the capital asset pricing model ("CAPM") estimation methods, as specified in the Commission's "*Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines*" ("*Pipeline Policy Statement*").[1] The recommended ROE of 15.70 percent represents the average of medians of the upper 1/3 of the Zone of Reasonableness. Dr. Villadsen computed the overall composite zone of reasonableness as well as the upper and lower 1/3 according to the Commission's Opinion No. 569-A.

In her testimony, Dr. Villadsen first defines the cost of capital, its relation to risk, and Commission precedent as it pertains to natural gas pipelines.

Second, Dr. Villadsen discusses the selection of a Proxy Group Sample of pipeline companies used in the cost of equity analyses and identifies the Proxy Group Sample as appropriate for assessing ANR's cost of equity. The Proxy Group Sample consists of publicly-traded companies that own FERC-regulated pipelines and have substantial natural gas pipeline activity in the form of assets or income. Dr. Villadsen broadens the group of pipeline companies by looking to a lower, yet still meaningful, proportion of natural gas pipeline activity in order to achieve at least five companies in the expanded sample. She does so to meet the Commission's

[1] 171 FERC ¶ 61,155, Docket No. PL19-4-000, "Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines," issued May 21, 2020.

preference for "at least five members" of the proxy group as indicated in the *Pipeline Policy Statement*.[2]

Third, Dr. Villadsen outlines the estimation procedures she used in this proceeding to calculate the required return on equity for ANR. She discusses the Commission's traditional DCF methodology and its CAPM methodology, and explains the data sources she used to implement these two models.

Fourth, applying the Commission's DCF and CAPM methodologies, Dr. Villadsen finds that the Proxy Group Sample results in a median ROE for the sample of 12.94 percent as of October 31, 2021, while the midpoint of the upper 1/3 of the Proxy Group is 15.70 percent. Figure 1 in Dr. Villadsen's testimony summarizes the full results of Dr. Villadsen's analysis. The Expanded Sample includes one additional company and confirms the results from the Core Sample.

Based on the estimation results (shown in Figure 1) and ANR witness Thapa's finding that ANR's business risk is above that of the average / median of the pipelines in the Core Sample, Dr. Villadsen finds that it is reasonable to allow ANR an opportunity to earn a ROE at the midpoint of the upper 1/3 of the zone of reasonableness; *i.e.*, 15.70 percent. Dr. Villadsen notes that the Expanded Sample confirms the Core Sample's results.

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[2] 171 FERC ¶61,155 Inquiry Regarding the Commission's Policy for Determining Return on Equity, Docket No. PL19-4-000 ("*Pipeline Policy Statement*"), ¶ 59. I acknowledge that the Commission also states the proxy group "should consist of at least four" members.

GLOSSARY

Bps	Basis Points
CAPM	Capital Asset Pricing Model
DCF	Discounted Cash Flow
ENB	Enbridge Inc.
ENBL	Enable Midstream Partners
EPD	Enterprise Products
EPS	Earnings Per Share
ET	Energy Transfer LP
IBES	Institutional Brokers' Estimate System
KMI	Kinder Morgan Inc.
MLP	Master Limited Partnership
MRP	Market Risk Premium
NEB	Canadian National Energy Board
NYSE	New York Stock Exchange
ROE	Return on Equity
TRP	TransCanada Corporation
TRSL	Thomson Reuters Spreadsheet Link
TSE	Toronto Stock Exchange
WMB	Williams Companies, Inc.

PREPARED DIRECT TESTIMONY OF BENTE VILLADSEN

I. INTRODUCTION AND SUMMARY

Q1: Please state your name, title, and business address.

A1: My name is Bente Villadsen. I am a Principal at The Brattle Group's ("Brattle") Boston office located at One Beacon St., Suite 2600, Boston, MA 02108, USA.

Q2: On whose behalf are you submitting testimony?

A2: I am submitting testimony on behalf of ANR Pipeline Company ("ANR").

Q3: Please briefly summarize your professional qualifications and educational background.

A3: I am a Principal of The Brattle Group, an economic, environmental, and management consulting firm with offices in Boston, Washington D.C., Chicago, London, San Francisco, Madrid, Rome, New York, Toronto, Sydney, and Brussels with specialties including financial economics, regulatory economics, and the gas, water, electric, and pipeline industries. My work concentrates on regulatory finance and accounting. As a Principal, I work in the areas of cost of capital, risk, regulatory accounting, regulatory precedent and related matters for regulated entities, regulators, or investors.

I am the co-author of the text, "Risk and Return for Regulated Industries" and I have testified or filed expert reports on cost of capital before the Federal Energy Regulatory Commission ("FERC" or Commission), the Bonneville Power administration, and the Surface Transportation Board as well as before state regulators in Alaska, Arizona, California, Hawaii, Illinois, Iowa, New Mexico, New York, Ohio, Oregon, and Washington. I have also provided expert reports or testimony before the Alberta Utilities Commission, Ontario Energy Board, *Régie de l'énergie du Québec*, Barbados' Fair Trading Commission and Mexico's *Reguladora de Energía*. I have provided white papers on cost of capital to the British Columbia Utilities Commission, the Canadian Transportation Agency as well as to Australian, and European regulators on cost of capital. I have testified or filed testimony on regulatory accounting issues before the FERC, the Regulatory Commission of Alaska, the Michigan Public Service Commission, and Texas Public Utility Commission as well as in international and U.S. arbitrations. In addition, I regularly provide advice to utilities on regulatory matters.

I hold a Ph.D. from Yale University's School of Management with a concentration in accounting. I also hold a Master of Science as well as a Bachelor of Science joint degree in mathematics and economics from University of Aarhus in Denmark.

Additional details regarding my professional experience and qualifications are contained in my résumé, which is attached as Exhibit No. ANR-0007.

Q4: Have you previously testified before or submitted testimony to this Commission?

A4: Yes. I have submitted testimony on cost of capital in Docket Nos. ER19-1553, RP19-59, RP19-1353, RP19-1291, and RP21-778 and testimony on regulatory accounting matters before the Commission in Docket Nos. PA10-13-000 and EL11-13-000.

Q5: What is the purpose of your testimony in this proceeding?

A5: The purpose of my testimony is to determine the appropriate return on equity ("ROE") for ANR. I do so by determining the zone of reasonableness from a proxy group of pipeline companies by (1) using the Discounted Cash Flow ("DCF") methodology that the FERC traditionally has applied to natural gas pipeline companies and (2) using the Capital Asset Pricing Model ("CAPM") methodology approved in the Commission's "*Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines*" ("*Pipeline Policy Statement*").[3] Having determined the zone of reasonableness indicated by these financial analyses, I discuss how the results are best applied in determining a reasonable ROE for ANR and consider the directions in the *Pipeline Policy Statement*.

Q6: How did you approach the task of determining ANR's cost of equity?

A6: First, I selected a proxy group of comparable companies that reflect the business risk characteristics of a natural gas pipeline at this time. In order to achieve a large enough sample for statistical robustness, given current data limitations, I relaxed the Commission's proxy group selection criteria.

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[3] 171 FERC ¶ 61,155, Docket No. PL19-4-000, "Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines," issued May 21, 2020.

Doing so allows me to rely on a sample of five companies, which is consistent with the Commission's preference[4] and which, all else equal, provide a more robust estimate. For each company I include in my "Proxy Group Sample", I apply the Commission's DCF, as articulated in the *Pipeline Policy Statement.* In addition to the DCF methodology, I also calculate ROE under the CAPM methodology based on both Value Line and IBES growth rates based market risk premium. Again, the use and implementation of the CAPM is based on the Commission's *Pipeline Policy Statement*.

The results of my analysis are summarized in Figure 1 below. Figure 1 shows the overall composite range of reasonableness—which is computed using the DCF and CAPM zones of reasonableness, as specified in the *Pipeline Policy Statement*. I focus on the average of the medians determined using the DCF and CAPM models implemented as indicated in the Commission's *Pipeline Policy Statement*.

Q7: Please summarize the results of your ROE analysis.

A7: Implementation of the DCF model and the CAPM according to the methodology specified in the *Pipeline Policy Statement* provides a composite zone of reasonableness of 10.98 percent to 17.28 percent as shown in Figure 1 below.

Figure 1: Summary of Results

		Core Sample		Expanded Sample	
		DCF/IBES CAPM	DCF/VL CAPM	DCF/IBES CAPM	DCF/VL CAPM
		[1]	[2]	[3]	[4]
Composite Risk Range					
Zone Of Reasonableness	[a]	10.98% - 17.28%	10.18% - 16.17%	10.98% - 17.28%	10.18% - 16.17%
Average of Median Estimations	[b]	13.43%	12.45%	13.99%	13.01%
Median ROE Estimation	[c]	**12.94%**		**13.50%**	
Upper Risk Range					
Zone Of Reasonableness	[d]	15.18% - 17.28%	14.17% - 16.17%	15.18% - 17.28%	14.17% - 16.17%
Average of Median Estimations	[e]	16.23%	15.17%	16.23%	15.17%
Median ROE Estimation	[f]	**15.70%**		**15.70%**	

As explained in the Prepared Direct Testimony of Mr. Anul Thapa ("Thapa Testimony"), ANR's business risk is above that of the average or median of the pipelines owned by the

[4] *Pipeline Policy Statement* at P 59 ("The Commission has explained that proxy groups 'should consist of at least four, and preferably at least five members'….").

Proxy Group Sample companies. Consequently, a just and reasonable ROE is for ANR to be placed at the average of the average medians obtained using the Commission's preferred DCF and CAPM implementations. Specifically, if I look to the Commission's Order 569-A, a placement at the median / midpoint of the upper 1/3 of the zone of reasonableness is recommended. This results in an estimated median ROE from the Proxy Group Sample of 15.70 percent as shown Figure 2. This final estimation is calculated by averaging the median ROE estimations using the two models specified by the Commission's *Pipeline Policy Statement*. The average of median estimations is calculated by determining for the Proxy Group Sample, the median estimate of the DCF approach and the median estimate of the CAPM approach and averaging the two. The CAPM method is further distinguished by whether Value Line or IBES growth rates are used to calculate the Market Risk Premium ("MRP"). The DCF does not change. This results in an average estimate of 12.45 percent for the medians, when Value Line data is used for the CAPM MRP (DCF/VL CAPM). The average of the midpoints of the upper 1/3 is 15.17 percent in this case. If IBES growth rates are used for both the DCF and CAPM MRP, the average of the medians is 13.43 percent and the average of the midpoints of the upper 1/3 is 16.23 percent (DCF/IBES CAPM).

Figure 2: Results

		DCF	CAPM	
			IBES	*Value Line*
		[1]	[2]	[3]
Core Sample				
Enbridge Inc.	[a]	17.5%	12.8%	11.2%
Kinder Morgan Inc.	[b]	12.7%	15.9%	13.8%
TC Energy Corp.	[c]	10.5%	14.7%	12.8%
Williams Cos.	[d]	9.1%	17.1%	14.9%
Expanded Sample				
Enterprise Products	[e]	15.7%	15.3%	13.3%
Core Sample				
Minimum	[h]	9.1%	12.8%	11.2%
Maximum	[i]	17.5%	17.1%	14.9%
Median	[j]	11.6%	15.3%	13.3%
Average of Median Estimations (equal weight on IBES and Value Line CAPM)	[k]		**12.94%**	
Expanded Sample				
Minimum	[l]	9.1%	12.8%	11.2%
Maximum	[m]	17.5%	17.1%	14.9%
Median	[n]	12.7%	15.3%	13.3%
Average of Median Estimations (equal weight on IBES and Value Line CAPM)	[o]		**13.50%**	
Upper 1/3 of Range, Core Sample				
Minimum	[p]	14.69%	15.68%	13.65%
Maximum	[r]	17.5%	17.1%	14.9%
Midpoint	[s]	16.1%	16.4%	14.3%
Average of Midpoints (equal weight on IBES and Value Line CAPM)	[t]		**15.70%**	

[4],[5]: Simple average of DCF and respective CAPM estimate.
[k] Average of DCF and Average from CAPM models
[o] Average of DCF and Average from CAPM models

Source: Exhibit No. ANR-0008, Tables BV1.3 (a) – (c).

As shown in Figure 1, the ROE estimation method produces a zone of reasonableness of 10.98 percent to 17.28 if I rely on IBES for the MRP in the CAPM and a range of 10.18 percent to 16.17 percent if I rely on Value Line for the MRP in the CAPM. Looking to the average of the minimums and maximums a range of 10.58 percent to 16.72 percent becomes the zone of reasonableness. The median using IBES growth rates for the CAPM MRP is 13.43 percent, whereas the median using Value Line growth rates for the CAPM is 12.45 percent. Finally, using the average of the CAPM results from IBES and Value Line growth rates in the MRP along with the DCF results in a median of 12.94 percent.

However, as the Thapa Testimony finds that ANR has higher than average business risk, it is reasonable to place ANR at the midpoint of the upper 1/3 of the zone of reasonableness, which range from 15.18 percent to 17.28 percent if IBES growth rates are used for the MRP and from 14.17 percent to 16.17 percent if Value Line growth rates are used for the MRP. The midpoint of the two zones of reasonableness is 16.23 percent and 15.17 percent, respectively, It is reasonable to average the two results for the CAPM and then averaging that average with the DCF result for a recommended ROE of 15.70 percent.

I note that the expanded sample, which includes a fifth company, also result in a recommended ROE of 15.70 percent and thus confirms the recommendation.

Q8: How is the remainder of your testimony organized?

A8: Section II formally defines the cost of capital and explains the principles relating to the estimation of the cost of capital for a business as well as the theory underlying the DCF and CAPM models. Section III first describes the process used to develop the Proxy Group Sample of proxy comparable companies that I use to calculate the cost of equity using market data. Second, it describes the Commission's DCF and CAPM estimation methodologies as specified in the *Pipeline Policy Statement*. Section IV presents the results of my implementation of these two models for the Proxy Group Sample, and summarizes my interpretation of these results as it relates to the overall composite zone of reasonableness that I determine for ANR.

Q9: What exhibits are you sponsoring?

A9: I am sponsoring this Prepared Direct Testimony, Exhibit No. ANR-0006, as well as Exhibit No. ANR-0007, which contains my résumé, and Exhibit No. ANR-0008, which contains the tables supporting the results summarized in this testimony.

Q10: Were your testimony and exhibits prepared by you or under your direct supervision?

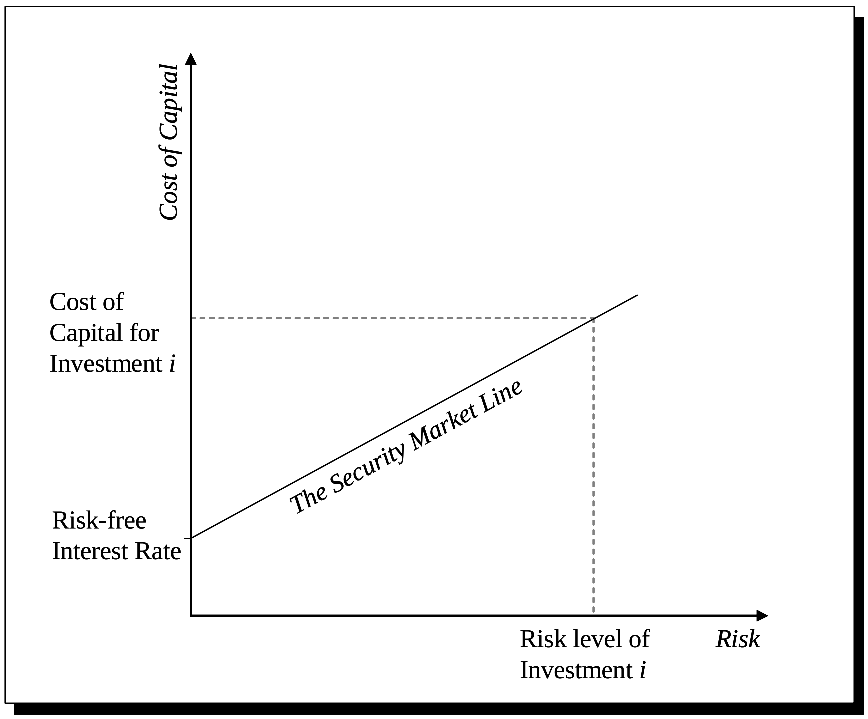
A10: Yes.

II. THE COST OF CAPITAL AND RISK

Q11: Please formally define the term "Cost of Capital."

A11: The cost of capital can be defined as *the expected rate of return in capital markets on alternative investments of equivalent risk*. In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. The definition of the cost of capital recognizes a tradeoff between risk and return that is known as the "security market risk-return line," or "security market line" for short. This line is depicted in Figure 3. The higher the risk, the higher the cost of capital. Variations of Figure 3 apply for all investments.

Figure 3: The Security Market Line



Q12: Please explain why the cost of capital is relevant in rate regulation.

A12: It has become routine in U.S. rate regulation to accept the "cost of capital" as the appropriate expected rate of return on utility investment. That practice is normally viewed as consistent with the U.S. Supreme Court's opinions in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), and *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

A return that determines the ROE (absent incentive or other adders) is the expected rate of return investors will require to maintain the Company's ability to attract capital and preserve its financial integrity.

Importantly, an inadequate return raises serious issues not only for the regulated utility but also for its customers. Specifically, it may adversely affect the utility's ability to provide stable and favorable rates (because the company may need to potentially postpone desirable projects that are not immediately required for reliable service in the near term) or it may require the company to file more frequent rate cases. Long-term, inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. The costs of an undercapitalized industry can be far greater than any short-run gains from shortfalls in the allowed rate of return. Moreover, in capital-intensive industries (such as the pipeline industry), systems with long expected service lives cannot be fixed overnight, so it becomes crucial to allow a return that ensures sufficient investments in the system.

Of note, some recent developments may have impacted the pipeline industry's expected cost of equity even if the full impact has yet to show up in the cost of equity estimates. Specifically, the CAPM relies on five years of data to determine the systematic risk of the sample companies' stock, so recent developments in inflation and pipeline policy decisions may not have been fully incorporated in the estimates.

First, over the past five years, inflation has been between 1.2 percent and 2.4 percent[5] – well below that of recent months[6] and well below the forecast for 2022-2023.[7] The CPI increased by 7.0 percent in December, which is the highest inflation rate since the early eighties. While it is too early to determine the impact on the cost of equity, the directional impact is clear – all else equal, the cost of capital increases.

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[5] Historical Inflation Rates: 1914-2021 | US Inflation Calculator

[6] According to the Bureau of Labor Statistics, the annualized inflation as measured by the CPI index was 5.4, 6.2, 6.8, and 7.0 percent for September, October, November, and December 2021, respectively.

[7] Blue Chip Economic Indicators, January 2022 forecast the CPI inflation for 2022 at 4.6 percent, while Consensus Forecasts as of January 2022 forecast the inflation for 2022 at 4.8 percent.

Second, over the past year several pipelines have been cancelled. For example, the permit for the Keystone Pipeline XL was revoked on January 20, 2021,[8] Spire's STL pipeline is currently operating with a temporary certificate and faces an uncertain future,[9] and in late 2020, the Atlantic Coast Pipeline was cancelled following legal challenges.[10] More recently, there have been discussions surrounding permitting / not permitting Enbridge's Line 5 expansion.[11] Again, it is too early to quantify the impact of these policies on the risks of the pipeline industry, but all else equal, it will increase the industry's business risk and hence the cost of equity.

As the CAPM-based cost of equity was calculated using betas estimated over the past five years and a risk-free rate derived over the past six months, the developments discussed above are not fully incorporated in the data. As these new phenomena, all else equal, increases the cost of equity, the CAPM-based results are more likely to be too low than too high.

III. THE COMMISSION'S COST OF CAPITAL METHODOLOGY SPECIFIED IN THE *PIPELINE POLICY STATEMENT*

Q13: How is this section of your testimony organized?

A13: This section first presents the sample companies used in the determination of the estimated ROE for ANR. It then describes the Commission's ROE methodology as laid out in the *Pipeline Policy Statement*, which provides the specifics of the implementation of the DCF

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8 Executive Order 13990 of January 20, 2021 Section 6.

Federal Register :: Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis

9 Spire's STL pipeline was completed in 2019, but currently operates with a temporary certificate from the FERC. The pipeline was originally approved by FERC in 2018, but subsequently a federal court vacated the certificate.

A pipeline shutdown? Midwest war heats up over FERC permit - E&E News (eenews.net)

10 North American Energy Pipelines, "Finding the Way Forward After a Series of Setbacks," October 16, 2020.

A New Era of Pipeline Development Overcoming Challenges (napipelines.com)

11 S&P Global, "US Army Corps to require new Enbridge Line 5 review but defends Line 3 permit," Jun 24, 2021.

CIQ Pro: US Army Corps to require new Enbridge Line 5 review but defends Line 3 permit (spglobal.com) model and CAPM. Finally, this section discusses the results of the ROE calculations based on the methodology specified in the *Pipeline Policy Statement*.

A. Sample Selection

1. Criteria for Selecting the Proxy Group

Q14: Please describe the Commission's precedent for selecting a sample that best reflects the business risk of natural gas transmission.

A14: The Commission's *Proxy Group Policy Statement* regarding sample composition provides the most important guidance in this regard.[12] Specifically, the *Proxy Group Policy Statement* addresses criteria for assuring a sample that is both representative and robust. A key decision in the *Proxy Group Policy Statement* was that it explicitly permitted the inclusion of Master Limited Partnerships ("MLPs") in proxy groups for estimating the ROE of Commission-regulated pipeline companies and the notion that proxy groups "should consist of at least four and preferably at least five."[13]

Q15: What was the genesis of the *Proxy Group Policy Statement*?

A15: Because of shrinking availability of suitable proxy group candidates, the Commission has had to revise its criteria for sample selection. In *El Paso Natural Gas Co.*, 145 FERC ¶ 61,040 at P 595 (2013) ("*El Paso*"), the Commission announced that it preferred to have at least five proxy group companies in order to ensure statistical accuracy.[14] The Commission's preference prior to *El Paso* in *Williston Basin Interstate Pipeline Co.*, 104 FERC ¶ 61,036 (2003) ("*Williston Basin*"), was to select companies that satisfied the following criteria:

- The selected company had to be publicly-owned with publicly-traded stock;
- The selected company had to be recognized by investors as reflective of the risks of natural gas pipelines, own one or more FERC-regulated

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[12] *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048 (2008) ("*Proxy Group Policy Statement*").

[13] *Id*. at P 42, 49-51 and *Pipeline Policy Statement*, ¶59.

[14] This view was qualified in *Kern River*, Opinion No. 486-B, 126 FERC ¶ 61,034 at P 104: "[W]hile the Commission agrees that adding more members to the proxy group results in greater statistical accuracy, this is true only if the additional members are appropriately included in the proxy group as representative firms."

interstate natural gas pipelines, and have stock tracked by an investment information service (such as Value Line); and

- Natural gas pipeline operations had to constitute a high proportion of the company's business, where "high" means that pipeline operations have accounted for at least 50 percent of the company's assets or 50 percent of their operating income, or both, on average over the most recent three-year period.

Application of these criteria, however, resulted in ever-smaller proxy groups to the point that any resulting proxy group would be of questionable reliability. At the time, MLPs were not included in the proxy group based on concerns about the applicability of the DCF model to the MLP organizational structure and cash distribution patterns. Thus, the Commission ultimately accepted the proposal to expand the sample to nine companies based on the Diversified Natural Gas industry group generated by Value Line Investment Survey, all of which owned FERC-regulated natural gas pipelines.

Although the requirement to have at least 50 percent of operations concentrated in the natural gas pipeline industry was relaxed in *Williston Basin*, and thereby provided a temporary solution to the shrinking sample problem, it proved insufficient in subsequent proceedings. Mergers and acquisitions in the industry and the growing trend of forming MLPs to invest in pipeline assets continued to result in smaller samples even under the revised selection criteria. Subsequent decisions in *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043 at PP 117-18 (2005) ("*HIOS*"),[15] and *Kern River Gas Transmission Co.*, 117 FERC ¶ 61,077 at PP 139-40, 161 (2006) ("*Kern River*"), left the Commission with a four-company proxy group even under the revised criteria.

Following a technical conference in 2007, the Commission issued the *Proxy Group Policy Statement*, which determined that the DCF method could be applied to MLPs as well as to corporations, but specified that the long-term growth rate used in the two-step DCF calculation for MLP proxy group members would be one half the expected long-term future

[15] *Id*. at P 124.

rate of the U.S. Gross Domestic Product ("GDP") growth, rather that the full GDP growth rate.[16]

Q16: How has the situation changed since the *Proxy Group Policy Statement* was issued?

A16: At the time the *Proxy Group Policy Statement* was issued in 2008, the ability to include MLPs in the proxy group generally made it possible to select a reasonably large sample of companies meeting the Commission's other criteria for inclusion in a natural gas pipeline sample (*i.e.*, publicly-traded companies with investment-grade bond ratings and the majority of their business activities consisting of FERC-regulated natural gas pipeline operations). However, since that time, the midstream natural gas industry has developed in such a way that there are very few companies whose majority focus is on regulated interstate natural gas pipeline transportation.

Through organic growth and especially merger and acquisition, the publicly-traded holding companies that own interstate natural gas pipelines and storage systems have generally become diversified to include—among other business activities—(i) interstate pipeline transportation of natural gas liquids ("NGLs"), crude oil, and petroleum products (*i.e.*, "liquids pipelines"), (ii) intrastate natural gas and liquids pipelines, (iii) natural gas gathering systems, (iv) natural gas and NGL processing facilities, and (v) the provision of terminaling, marketing, and assorted other midstream natural gas and petroleum services.

Additionally, in recent years, several pipeline-owning MLP entities were acquired by corporate entities, including several that were "rolled up" by the corporations that served as their general partners. Examples include the July 2018 acquisition of Boardwalk Pipeline Partners ("BWP") by diversified conglomerate Loews, which had controlled its general partner,[17] the August 2018 roll-up of Williams Partners ("WPZ") into Williams Companies, Inc. ("WMB"),[18] the late 2018 acquisitions of U.S. MLPs Spectra Energy Partners ("SEP")

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16 *Proxy Group Policy Statement*, at P 42.

17 *See* Loews to Buy Out Investors in Boardwalk Pipeline MLP, July 13, 2018. Accessible at https://www.barrons.com/articles/loews-to-buy-out-investors-in-boardwalk-pipeline-mlp-1531511536.

18 *See* Williams Completes Acquisition of Williams Partners, August 10, 2018. Accessible at https://investor.williams.com/press-release/williams/williams-completes-acquisition-williams-partners.

and Enbridge Energy Partners ("EEP") by the Canadian corporation Enbridge, Inc,[19] and the March 2021 roll up of TC Pipelines LP ("TCP") into TC Energy Corporation ("TC Energy").[20]

Q17: Is it necessary again to revise or relax certain of the Commission's traditional sample selection criteria to assemble a sample group for the current case?

A17: Yes. For the reasons stated above it is not possible to identify at least four and preferably five proxy companies for which FERC-regulated interstate natural gas pipelines operations constitute a majority of their business activities (as measured by assets or operating income). In the *Pipeline Policy Statement*, the Commission has indicated its preference that proxy groups consist of at least four members and preferably five.[21] Therefore, to obtain a sample size of five companies, I relaxed this criterion by looking to include an additional company with a substantial proportion of its assets, property, plant and equipment ("PP&E"), or operating income from business activities in pipeline business (including liquids pipelines, crude oil pipelines as well as natural gas pipelines) and which has a large proportion of its assets subject to rate regulation.[22] Using this approach, I was able to select a Proxy Group Sample of four companies that are substantially devoted to rate-regulated natural gas transportation operations—including rate-regulated natural gas gathering and distribution of natural gas, operation of rate-regulated liquids pipelines, and provision of fee-based natural gas and NGL gathering and processing services— and an additional fifth company that operates substantial amount of FERC-regulated pipeline assets (including liquids pipelines as

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[19] *See* Enbridge Inc. and Spectra Energy Partners, LP Complete Merger, December 17, 2018; and Enbridge Inc. Completes Mergers with Enbridge Energy Partners, L.P. and Enbridge Energy Management, L.L.C., December 20, 2018. Accessible at https://www.enbridge.com/media-center/news.

[20] *See* "TC Energy and TC PipeLines, LP complete merger", March 03, 2021. Accessible at https://www.tcenergy.com/announcements/2021-03-03-tc-energy-and-tc-pipelines-lp-complete-merger/.

[21] *See* 171 FERC ¶61,155 Inquiry Regarding the Commission's Policy for Determining Return on Equity, Docket No. PL19-4-000 ("*Pipeline Policy Statement*"), ¶ 59.

[22] Different companies report different disaggregated financial metrics for their various business segments. Depending on the company, a percentage of "assets" may refer to gross original cost of total assets on the balance sheet or to gross or net balances of long-lived property, plant, and equipment ("PP&E") assets. Similarly, my analysis of income and cash flows is in certain cases expanded to include reported data on EBITDA ("Earnings Before Interest, Taxes, Depreciation and Amortization") and gross operating margin, as well as operating income (often defined to be synonymous with EBIT – Earnings Before Interest and Taxes).

well as natural gas pipelines). Below, I demonstrate that the broader business profiles of these five companies make them generally risk appropriate for evaluating ANR's cost of capital.

Q18: In considering regulated pipeline operations other than FERC-regulated natural gas transmission, are you assuming that all categories of regulated pipelines have identical risk for cost of capital purposes?

A18: No. It is not even the case that all natural gas pipeline companies have identical risk. However, I do believe that the inclusion of companies with a substantial percentage of pipeline assets under rate regulation is the best possible indicator of the risk of a natural gas pipeline such as ANR. For clarity, I am not arguing that the risks of different classes of FERC-regulated pipelines are identical. Rather it is my opinion that, relative to other types of business activities that potential sample companies may engage in, rate-regulated gas or liquids transportation activities, be they under FERC, state, or Canadian Energy Regulator jurisdiction, are likely to be the most risk comparable for purposes of assessing ANR's cost of capital with a reasonably sized sample.

2. Sample Selection Process

Q19: Please explain how you select a sample that is consistent with the Commission's precedent for estimating a gas pipeline's cost of capital.

A19: Consistent with the *Proxy Group Policy Statement*, I consider both C-Corporations and MLPs for inclusion in my sample. I began with the lists of all companies categorized by Value Line as (i) "Gas or Oil Distribution," or (ii) "Pipeline MLPs in the U.S." This group was narrowed to only include companies that meet the following criteria:

1. The company's stock is publicly traded and has been for the most recent six-month period;
2. The company pays dividends and has done so during the last six months without any cuts to its dividends;[23]
3. The company has a majority of its credit ratings at an investment-grade level;
4. The company has had no significant amount of completed merger and acquisition ("M&A") activity over the last six months;

[23] The Commission's traditional DCF methodology requires only six months of historical data to compute the cost of equity for each comparable company.

5. If a company has less than $300 million in Market Capitalization (i.e., is micro cap), then I examine the daily trading volume to ensure the company's stock price reflect active trading;[24] and

6. The company must have FERC-regulated pipeline assets, and meet the business activity segmentation criteria described in the preceding subsection (1) for final selection into the Proxy Group Sample.

Criteria 1 and 2 are necessary for the implementation of the DCF model. Criteria 3 and 4 ensure that there are no recent impacts from either potential financial distress situations or M&A activities. Criterion 5 eliminates companies that are too small to provide meaningful comparable data.[25]

As discussed above, Criterion 6 intends to capture the risk of the natural gas pipeline industry. This criterion requires me to investigate the companies' business descriptions and financial statement disclosure to assess whether sufficient assets, revenue or income is devoted to natural gas transportation or at least regulated activities. Specifically, if a company has operations outside the natural gas transportation business, I examine the nature of such business and favor regulated activities over non-regulated activities. For example, to expand the sample, I give preference to regulated liquids pipeline activities over oil and gas exploration and production activities because the former is subject to rate of return regulation while the latter is not.

Q20: Please describe specifically how you applied the criteria outlined above to select your sample companies.

A20: I began with 46 companies listed in the two relevant Value Line categories. First, I eliminated 3 companies that either do not regularly pay dividends or had a dividend cut during the six months leading up to the study date, leaving 43 companies as the subject of further screening. Next, I eliminated 32 companies that have non-investment grade credit ratings, leaving 11

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[24] This is not currently relevant for any of the companies in the pipeline sample as they all are larger than micro caps.

[25] Companies with a market cap below $300 million are considered microcaps and often have limited analysts' following or trading. In this case, no company was eliminated due to Criterion 5.

potential sample companies after this step of the sample selection process.[26] One remaining company was eliminated due to M&A activity.[27] None of the remaining companies were eliminated because of their market capitalization, Criterion 5. That left 10 companies for a review of asset and earnings composition.

For the 10 remaining companies, I reviewed their business descriptions and segmented financial data from their 2020 Annual Reports and selected companies meeting the business segmentation discussed above. Companies that did not engage substantially in rate-regulated natural gas and/or liquids transportation activities, as well as companies that engaged predominantly in businesses with very different risk profiles (such as oil and gas exploration and production, petroleum refining, fuels distribution, electric utility service, or non-energy-related businesses) were excluded. Five companies were excluded due to asset composition. Specifically, I excluded: Magellan Midstream Partners L.P. for not having natural gas pipelines assets (but 54% oil and liquids pipelines); MPLX LP for having 29% midstream services and 20% oil and liquids pipelines; ONEOK, Inc. for having only 8% natural gas pipeline assets (33% oil and liquids pipelines); Pembina Pipeline Corporation for not having natural gas pipelines assets; and Phillips 66 Partners LP for not having natural gas pipeline assets. Furthermore, Natural Fuel Gas, which has been included by some parties in the past, was not considered in the initial 47 group Value Line Company Universe as (i) Value line lists the company as "GASDIVERS" (gas diversified) and (ii) because it generates the majority of its revenues from Utility and Energy Marketing (47% of fiscal 2020 sales) and Exploration/Production and other (40%), whereas Pipeline, Storage & Gathering only accounted for 13% of 2020 revenues.[28]

The selection is depicted in Figure 4.

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[26] At this stage, I also eliminate companies for which I cannot procure credit ratings through any of the major ratings agencies: Standard and Poor's ("S&P"), Moody's Analytics ("Moody's") and Fitch Ratings ("Fitch").

[27] I elected to remove Enable Midstream from my sample due to the announced acquisition by Energy Transfer on February 17th 2021, https://www.businesswire.com/news/home/20210217005332/en/Energy-Transfer-to-Acquire-Enable-Midstream-in-7-Billion-All-Equity-Transaction.

[28] Additionally, I note that National Fuel Gas has a systematic risk, as measured by beta, that is below that of other sample companies and recently engaged in the acquisition of Shell's upstream and midstream assets in Pennsylvania.

Figure 4: Sample Selection Elimination Summary

Value Line Company Universe	[a]	46
Eliminated due to Dividend Cuts	[b]	3
Elimiminated due to Bond Ratings	[c]	32
Eliminated due to M&A	[d]	1
Eliminated due to Market Cap	[e]	0
Eliminated due to Asset Composition	[f]	5
Prospective Sample Companies	[g]	5

In the end, the sample selection process resulted in five sample companies: Four Core Sample companies (Enbridge, Kinder Morgan, TC Energy, and Williams) and one additional company I add to the Expanded Sample (Enterprise Products Partners). Figure 5, below, summarizes the percentages of the remaining five companies' assets and earnings (e.g., EBITDA) that I estimated are dedicated to (i) regulated natural gas pipeline operations and (ii) rate-regulated activities more broadly.

Figure 5: Sample Regulated Assets and EBITDA Summary

	Assets		EBITDA	
Company	Regulated Natural Gas Pipeline Operations	Total Regulated Business Activities	Regulated Natural Gas Pipeline Operations	Total Regulated Business Activities
	[1]	[2]	[3]	[4]
Enbridge Inc.	27%	96%	10%	97%
Kinder Morgan Inc.	71%	84%	67%	86%
TC Energy Co.	77%	95%	75%	93%
Williams Cos.	45%	51%	33%	33%
Enterprise Products	9%	46%	6%	49%
Sample Average	46%	74%	38%	71%

Sources and Notes: See Thapa Testimony, Exhibit No. ANR-0009, Workpaper #1, Tables AT-1 to AT-5 (a) and (b) for Assets and EBITDA, respectively. Total Regulated Business Activities calculated as sum of Gas Pipelines & Storage, Oil and Liquids Pipelines, Gas Distribution columns.

Reviewing Figure 5, it is clear that Enbridge, Kinder Morgan, TC Energy and Williams each belong in the proxy group with an average of 55 percent natural gas pipeline assets and over 80 percent regulated activities. Enterprise Products is the fifth best company to include, so

I include that in an Expanded Sample. While Enterprise Products has a lower percentage of natural gas pipeline assets or EBITDA than other companies in the sample, it has almost half of its assets or EBITDA subject to regulation, which makes it comparable to the other four companies and higher than Williams Cos. Enterprise Products comprises 46 percent of assets dedicated to regulated business activities. Similarly, 49 percent of its EBITDA comes from its regulated business operations. Additionally, Enterprise Products generated 87 percent of its 2020 operating income from its Pipelines & Services segment, even though the majority of those are from natural gas liquid and crude oil Pipelines and Services segments.[29] But importantly, only about 13 percent of the Company's 2020 operating income was generated by non-pipeline related Petrochemical & Refined Products Services segment.[30] Therefore, a substantial proportion of the company's operating income is generated from business activities in the Pipelines & Services business (including liquids pipelines, crude oil pipelines as well as natural gas pipelines). Further, Enterprise Products' systematic risk, as measured by Value Line's beta, reinforces that it is of comparable systematic risk to the other four companies.[31] Lastly, Enterprise Products' S&P credit rating of BBB falls squarely in between the BBB+ and BBB- credit ratings of the other four companies.[32] Accordingly, for the reasons I delineated above, I find it appropriate to include Enterprise Products in an Expanded Sample as a check on the results from the four company sample.

Based on the foregoing analysis, I selected the four companies to the Core Sample and one additional company for the Expanded Sample, which consists of the four Core Sample companies plus Enterprise Product Partners. Characteristics of all five companies are presented in Figure 5.

Q21: How does the Proxy Group Sample compare to ANR?

A21: Like ANR, the Proxy Group Sample has substantial gas pipeline transportation assets that are regulated by FERC. As discussed above, regulated natural gas pipeline operations comprise

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[29] Enterprise Products Partners L.P. 2020 Form 10-K, p. F-47.

[30] *Id.*

[31] *See* Figure 7.

[32] *See* Figure 6.

an average of 55 percent of the Core Proxy Group Sample's assets and an average of 46 percent of their EBITDA. The Proxy Group Sample similarly includes companies with a substantial percentage of pipeline assets under rate regulation, providing a comparable indicator of the risk for natural gas pipeline such as ANR. Moreover, as discussed in the Thapa Testimony, the main business activities of the majority of the proxy group is natural gas pipelines and storage, with a lesser amount of non-regulated business activities (such as midstream services).[33]

B. The Commission's DCF Methodology and Input Parameters for DCF Calculation

a. The Commission's Revised DCF Calculation

Q22: Please describe the Commission's estimation methodology.

A22: In the *Pipeline Policy Statement*, the Commission maintained its traditional DCF model, which places 2/3 weight on company-specific growth rates and 1/3 weight on the economy-wide growth rate. Previously, the *Proxy Group Policy Statement* essentially re-affirmed the Commission's DCF methodology as articulated in prior decisions such as *Williston Basin*, *Kern River*, and *HIOS*, but outlined a modification in the case of MLPs, which were now permitted to be included in the sample. The one modification indicated for MLPs was to reduce the estimated long-term growth rate to one-half of the long-term GDP growth forecast instead of the full amount of the GDP growth rate forecast used for the C-corporations in the sample.[34]

Q23: Please describe the details of the DCF model used by the Commission to establish the "range of reasonableness".

A23: As noted earlier, the Commission's DCF model is a modification of the standard, constant-growth DCF model, where the dividend growth rate is a weighted-average of the company's 5-year analyst growth rate estimates (⅔ weight), such as those provided by IBES or Bloomberg, plus a common long-term growth rate estimate of the GDP (⅓ weight). Details

[33] *See* Thapa Testimony, Exhibit No. ANR-0009.

[34] *Proxy Group Policy Statement* at P 96.

of the approach are articulated in *Kern River*, as well as in *Williston Basin* and *Enbridge Pipelines (KPC)* ("*Enbridge*"). As the Commission stated in *Enbridge*:

> The Commission uses the Discounted Cash-Flow (DCF) methodology when calculating a range of reasonable rates of return on equity for natural gas pipelines. Under that methodology, the rate of return equals the dividend yield (stock price divided by dividends), plus the projected growth in dividends.
>
> For natural gas pipelines, the Commission uses a two-step procedure to determine the projected growth in dividends of the proxy group companies, averaging short-term and long-term growth estimates. The Commission uses five-year Institutional Broker's Estimate System (I/B/E/S) growth projections for each proxy group company for the short-term growth projection. The Commission uses the growth rate of the Gross Domestic Product (GDP) as its long-term growth rate, since the Commission has found that pipeline specific projections of long-term growth cannot reasonably be developed based on available data sources. The Commission averages these growth projections, giving two-thirds weight to the short-term growth projection and one-third weight to the long-term growth projection.[35]

In formulating the DCF model, the Commission further adds an adjustment to the dividend yield term resulting in the Commission's DCF cost of capital equation. As explained by Commission Staff, the formula is:[36]

$$k = \frac{D_0 \times \left(1 + \frac{1}{2}g\right)}{P} + g$$

Where k is the return on equity, D_0 is the current dividend, P is the share price variable, and g is the growth rate. The growth rate was assumed to be a composite long-term and short-term growth rate.

Q24: Has the Commission made any adjustments to the DCF model?

A24: Yes, Opinion No. 569 made a distinction between the growth rate applied to the first dividend and that applied to later dividends in the DCF formula. According to Opinion No. 569:

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35 *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at PP 214-215 (2002) ("*Enbridge*").

36 *Seaway Crude Pipeline Co.*, 154 FERC ¶ 61,070 at P 198 (2016) ("*Seaway*").

> Because the first dividend is necessarily paid within the time-period covered by the IBES short-term growth projection, that rate is the more appropriate growth rate for calculating the (1+.5g) adjustment to the dividend yield.[37]

This determination from Opinion No. 569 was adopted in the *Pipeline Policy Statement*. Therefore, I adjust the formula so that the first growth rate (*i.e.*, the *g* in (1+½g)) reflects the short-term growth rates. The amended DCF formula is as follows:

$$k = \frac{D_0 \times \left(1 + \frac{1}{2} g_1\right)}{P} + g_2$$

Where g_1 is the short-term (company-specific, IBES) growth rate and g_2 is the composite growth rate.[38] In keeping with the *Pipeline Policy Statement*, the composite long-term growth rate (g_2) is weighted two-thirds on the short-term IBES growth rate estimates and one-third on long-term nominal GDP growth forecasts.[39] For MLPs, the *Proxy Group Policy Statement* prescribes the use of ½ of the GDP growth rate forecast instead of the full amount as the long-term growth rate.

Q25: How is the dividend yield determined?

A25: The Commission has established a very specific procedure for calculating the dividend yield to use in the DCF formula. Specifically, the "current" dividend yield is to be computed using the prior six months of dividend and price data. One first records the highest and lowest trading price during the month for each of the prior six months. The current dividend for each quarter is annualized (*i.e.*, multiplied by 4) and then divided by the average of these two prices (the highest and lowest trading price during each month) to produce six monthly dividend yields. Averaging these six dividend yields produces an unadjusted dividend yield for each company as of today. To obtain the dividend yield for the next period, which is what is used in the FERC's DCF model, today's dividend yield (D_0/P) is multiplied by:

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[37] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 at P 98 (2019).

[38] For MLPs, the *Pipeline Policy Statement* prescribes the use of ½ of the GDP growth rate forecast instead of the full amount as the long-term growth rate.

[39] Per the *Pipeline Policy Statement*, P 6 n.7, the GDP forecast is based on the long-term GDP forecast produced by the Social Security Administration, the Energy Information Administration, and Global Insight.

$$\left(1 + \frac{1}{2}g\right)$$

Where *g* is the company's IBES growth rate. Thus, the adjusted dividend yield is obtained by growing the dividend by ½ of the IBES growth rate.

Q26: Why is only one-half of the growth rate used to determine the dividend yield in the Commission's traditional DCF methodology?

A26: The Commission has chosen this implementation as an adjustment for the timing in how dividends are paid and the fact that they are paid quarterly. I disagree with the use of the 0.5 multiplier for the IBES growth rate as a matter of economic principle because it violates the basic assumptions of the DCF model. The DCF model is derived under the assumption that dividends grow at the full growth rate for the period. However, because it is the Commission's traditional approach to calculating the DCF model, my calculations follow the Commission's precedent and use this version of the dividend yield in the DCF model.

1. IBES Growth Rate Inputs

Q27: How do you obtain the IBES growth rates?

A27: I downloaded them from Eikon (previously Thomson ONE)—a third-party data platform provided by Thomson Reuters—using the Thomson Reuters Spreadsheet Link ("TRSL") plug-in for Microsoft Excel.

Q28: How does Thomson Reuters update IBES growth rates over time?

A28: Thomson Reuters tracks 3- to 5-year earnings growth rate estimates submitted by equity analysts who cover a specific company, and calculates the consensus earnings per share ("EPS") growth rate estimate as the average of the growth rates reported by the individual analysts. IBES communicates with the analysts and assembles their submissions to maintain as up-to-date a value for the consensus growth rate as possible at any point in time.

Q29: Is there sometimes a difference between IBES growth rates reported by *Yahoo! Finance* and Thomson Reuters?

A29: Yes. Although I do not know the exact reasons, estimates reported by *Yahoo! Finance* may be "stale" in that, if there are no currently available valid estimates, *Yahoo! Finance* could continue to report an estimate that has been removed by Thomson Reuters as out of date.

Q30: How have growth rates for the Proxy Group Sample changed over time?

A30: The IBES 5-year growth rates forecasts for the companies in Proxy Group Sample have been highly volatile. There are two primary drivers of the observed volatility. First, there are only a few analysts—often no more than one or two—tracking each sample company. Second, individual analysts' forecasts can be updated as infrequently as every six months. When only a few analysts (fewer than three in most cases for the selected Proxy Group Sample) forecast a company's growth rate, even a change in a single analyst's forecast can alter the consensus growth rate estimate substantially.

Q31: In your opinion, are the IBES growth rate forecasts reliable?

A31: Generally, yes. The brokers and equity analysts who contribute estimates to IBES are in general knowledgeable about the companies they cover, and their views are visible to and frequently cited by the investment community. Furthermore, IBES has a long history of gathering the contributed estimates and a reputation for doing so according to consistent standards. I therefore believe that the EPS growth rate estimates aggregated and reported by IBES provide useful information about the market expectation regarding the growth prospects of the sample companies.

However, the IBES consensus growth rate forecasts for the companies in the Proxy Group Sample are determined by averaging estimates from a small and variable group of contributing analysts, so increasing the number of analysts providing forecasts by including estimates from Value Line would reduce some of the volatility, as explained below.

Q32: How did your DCF-based cost of equity incorporate IBES growth rates?

A32: As specified in the *Pipeline Policy Statement*, I implemented the traditional FERC DCF model using IBES growth rates. I have in the past relied upon Value Line growth rates when there were no IBES growth rates available and continue to find that Value Line's growth rates provide valuable insight. However, because all sample companies currently have IBES growth rates available, here, I rely exclusively on IBES-provided growth rates in the DCF model in adherence with the Commission's preference.[40]

Of note, Value Line analysts update their reports on a strict 13-week schedule so the forecast will never be older than 13 weeks. The reliability of Value Line's quarterly review schedule is a key benefit of using Value Line EPS growth forecasts alongside the IBES estimates, given that (as mentioned above) the Thomson Reuters IBES consensus growth rates can include estimates that may not have been updated for 6 months or more.

C. The Capital Asset Pricing Model

Q33: Can you explain the CAPM?

A33: Yes. The CAPM is a long-standing and widely used version of modern finance models. The model requires the specification of the values of the benchmarks that determine the Security Market Line (see Figure 3 above). The CAPM specifies the relationship as being determined by the risk-free rate, the market risk premium and the relative risk of a security or investment (*i.e.*, beta). More precisely, the CAPM calculates the cost of capital for an investment, (*e.g.*, a particular common stock) as follows:

$$r_s = r_f + \beta_s \times MRP$$

Where r_s is the cost of capital for investment S;

r_f is the risk-free interest rate;

β_s is the beta risk measure for the investment S; and

MRP is the market risk premium.

The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities. The higher the systematic risk, the greater is the expected return.[41] Thus, the CAPM states that the Security Market Line starts at the risk-free interest rate (that is the return on a zero-risk security, the y-axis intercept in Figure 3,

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[40] *Pipeline Policy Statement* at P 15 ([The Commission] "will consider, based on evidence provided in future proceedings, use of *Value Line* data, instead of IBES data, as the source of the short-term growth projection in the DCF component of the CAPM.").

[41] *See* Section II above.

equals the risk-free interest rate). Further, the risk premium of a security over the risk-free rate equals the product of the beta of that security and the risk premium on a value-weighted portfolio of all investments, which by definition has average risk.

1. The Risk-free Interest Rate

Q34: What interest rates do your calculations require?

A34: Modern capital market theories of risk and return (*e.g.*, the theoretical version of the CAPM as originally developed) use the short-term risk-free rate of return as the starting benchmark, but the FERC methodology relies upon the version of the model that is based upon the long-term risk-free rate. Using a long-term estimate of the risk-free interest rate mitigates the volatility of short-term interest rates. In addition, long-term rates are less amenable to monetary policy driven changes by the Federal Reserve in its efforts to manage economic growth and expected inflation than short-term interest rates.

Q35: What interest rate do you use in your implementation of the CAPM?

A35: I have implemented CAPM consistent with the methodology and inputs specified in the *Pipeline Policy Statement*. Therefore, the interest rate used in my analysis is the average yield on a 30-year Treasury bond over the six months preceding the date of analysis of October 31, 2021.

2. The Market Risk Premium

Q36: How should the MRP be estimated per the Commission's *Pipeline Policy Statement* and Opinion No. 569-A?

A36: Per the *Pipeline Policy Statement*, the MRP is calculated by implementing a single-stage DCF model for the dividend paying S&P 500 companies with analyst growth rate forecasts for earnings per share between zero and 20 percent (inclusive).[42] For growth rate forecasts, I have relied on (i) Value Line projected EPS growth rates and (ii) IBES growth rates. The use of Value Line growth rates is consistent with the Commission's statements that it will consider

[42] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 at p.15 (2020).

Value Line growth rate estimates to diversify data sources.[43] I agree with the Commission's rationales for using Value Line growth rates in the CAPM. Specifically, the following:

> (1) "Value Line estimates . . . are vetted through internal processes . . . and thus incorporate the input of multiple analysts;"[44]
>
> (2) "there is…value in including Value Line projections because they are updated on a more predictable basis;"[45]
>
> (3) "diversifying data sources may better reflect the data sources that investors consider in making investment decisions and mitigate the effect of any unusual or incorrect data in a given source;"[46] and
>
> (4) "there is substantial evidence that *Value Line* is used by numerous investors."[47]

I present the results of the CAPM using both the Value Line and the IBES growth rates to calculate the MRP.

In keeping with the Commission's specification, any companies with Value Line growth rates (or IBES growth forecasts in the IBES scenario) that are negative or greater than 20 percent are excluded. I then calculate the expected market return by taking the sum of the market-value weighted-average of the next twelve-month Value Line reported dividend yield for the dividend paying S&P 500 companies with zero to 20 percent Value Line (or IBES) growth rate forecasts, and the market-value weighted-average of the Value Line growth rate forecasts (or IBES growth rates) for the same subset of S&P 500 companies. Finally, to derive the MRP, I subtract the 6-month historical average interest rate on 30-year Treasury bonds.

Q37: What MRP did you estimate?

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43 *Id.* at p.40.

44 *Id.* at 39-40.

45 *Id.*

46 *Id.*

47 *Id.*

A37: Using the method in the *Pipeline Policy Statement*, I estimated the MRP to be 10.43 percent (based on Value Line growth rate projections) and 12.21 percent (based on IBES growth rate projections). See Exhibit No. ANR-0008, Table BV-1.8.

3. Beta

Q38: What is the source of your beta estimates?

A38: The *Pipeline Policy Statement* specifies that the beta estimates for the sample companies should be accessed from Value Line. As such, I use Value Line as the source of my beta estimates.

Q39: Can you more fully explain beta?

A39: The basic idea behind beta is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification. Beta is a measure of the risks that cannot be eliminated by diversification. That is, it measures the "systematic" risk of a stock---the extent to which a stock's value fluctuates more or less than average when the market fluctuates.

Diversification is a vital concept in the study of risk and return. (Harry Markowitz won a Nobel Prize for work showing just how important it was.[48]) Over the long run, the rate of return on the stock market has a very high standard deviation, around 20 percent per year. Many individual stocks have much higher standard deviations than this. The stock market's standard deviation is "only" about 15-20 percent over the long term because when stocks are combined into portfolios, some of the risk of individual stocks is eliminated by diversification. Some stocks go up when others go down, and the average portfolio return—whether positive or negative—is usually less extreme than that of many individual stocks within it.[49] The part of the risk that an investor cannot eliminate through diversification is called systematic risk (or non-diversifiable risk) and in practice the return on stocks is positively correlated. The reason is that many factors that make a particular stock go up or

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[48] Professor Markowitz won the Nobel Prize in 1990 for developing "the theory of portfolio choice." *See* Press Release from Royal Swedish Academy of Science, October 16, 1990.

[49] In any given year, the stock market volatility may be smaller or larger. For example, stock market volatility (VIX Index) during 2020 was approximately 29.20 compared to the long-term average of 19.5 (1990-2020 daily average). It has recently reduced substantially.

down also affect other stocks. Examples include the state of the economy, the balance of trade, and inflation.

Single-factor equity risk premium models (such as the CAPM) are based upon the assumption that all of the systematic factors that affect stock returns can be considered simultaneously, through their impact on one factor: the market portfolio. Other models derive somewhat less restrictive conditions under which several factors might be individually relevant.

Q40: What does a particular value of beta signify?

A40: By definition, a stock with a beta equal to 1.0 has an average non-diversifiable risk: it goes up or down by 10 percent on average when the market goes up or down by 10 percent. Stocks with betas above 1.0 exaggerate the swings in the market: stocks with betas of 2.0 tend to fall 20 percent when the market falls 10 percent, for example. Stocks with betas below 1.0 are less volatile than the market and stocks with a beta above 1.0 are more volatile than the market. For example, a stock with a beta of 0.5 will tend to rise 5 percent when the market rises 10 percent.

4. Size Adjustment

Q41: What is the size adjustment?

A41: The size adjustment is a modification to the CAPM estimates based upon empirical evidence from academic studies documenting a difference between a company's theoretical return as estimated by the CAPM and its realized return. The difference is a function of the size of the entity, where size is measured by its market value capitalization. The size adjustment applied to the CAPM estimates is reported by Duff & Phelps and varies with decile. The smallest decile of companies requires the largest addition to the expected return estimated to depend solely on beta, while stocks in the largest decile have actually shown an empirical tendency to return less than the rate of return predicted by applying the CAPM equation to its beta; hence, companies with very large market capitalizations actually receive a downward adjustment. I employed the size adjustment data reported by Duff & Phelps' Cost of Capital Navigator for December 31, 2020, which I understand to be the most recent estimate as of October 2021.

5. Zone of Reasonableness

Q42: Explain the zone of reasonableness.

A42: The first step in setting a new just and reasonable ROE is to calculate the overall composite zone of reasonableness. Note that the DCF and CAPM models produce estimates of the ROE for individual sample companies. The range of maximum and minimum estimates from each model is the starting point for ultimately evaluating the overall composite zone of reasonableness,[50] and subsequently, the just and reasonable ROE for ANR. According to the *Pipeline Policy Statement*, "[t]he range of the proxy group's returns produces the zone of reasonableness in which the pipeline's ROE may be set based on specific risks."[51]

I calculated the overall composite zone of reasonableness based on the individual zones of reasonableness of the CAPM and DCF models. The overall composite zone of reasonableness is calculated by averaging the zone of reasonableness results from the CAPM and DCF models.

Q43: How do you determine the precise ROE within this overall composite zone of reasonableness?

A43: The *Pipeline Policy Statement* affirms that the Commission's policy is to rely upon median ROE results other than in unusual circumstances where a pipeline faces anomalously high or low risks.[52] ANR witness Thapa provides an analysis of the key business risks of ANR relative to the sample companies. This includes an analysis of contract risk, supply risk, demand risk, competitive risk, and operating risk. The Thapa Testimony demonstrates that the Company faces above average business risk compared to the pipelines owned by the Proxy Group Sample.[53]

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[50] According to the *Pipeline Policy Statement*, any outliers will be addressed "on a case-by-case basis in accordance with our policy to remove 'anomalous' or 'illogical' cost-of-equity estimates that do not provide meaningful indicia of the returns that the pipeline needs to attract capital from the market." *Pipeline Policy Statement* at P 87.

[51] *Pipeline Policy Statement* at P 6.

[52] *Pipeline Policy Statement* at P 6.

[53] Thapa Testimony, Exhibit No. ANR-0009.

As ANR witness Thapa concludes that ANR has elevated business risk as compared to the Proxy Group, I base my recommendation on the upper 1/3 of the Zone of Reasonableness.

IV. RESULTS FROM ROE ESTIMATION MODELS

A. DCF Results

Q44: What are your results from your implementation of the Commission's DCF model?

A44: The results of my implementation of the Commission's DCF model for my Proxy Group Sample using the IBES short-term growth rate estimates are shown in Figure 6 below. The zone of reasonable estimates for the DCF range from 9.1 percent to 17.5 percent with a median of 11.6 percent and a midpoint of the upper 1/3 of 16.1% (see Figure 1).

Figure 6: Results from the DCF Method

Company	S&P Credit Rating	Dividend Yield	Adjusted Dividend Yield	GDP Growth Forecast	Growth Estimate	Combined Growth Rate	Implied Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Core Sample							
Enbridge Inc.	BBB+	8.46%	8.92%	4.20%	10.71%	8.54%	17.46%
Kinder Morgan Inc.	BBB	6.20%	6.43%	4.20%	7.33%	6.28%	12.7%
TC Energy Corp.	BBB+	7.06%	7.16%	4.20%	2.89%	3.33%	10.5%
Williams Cos.	BBB	6.34%	6.40%	4.20%	2.00%	2.73%	9.1%
Expanded Sample							
Enterprise Products	BBB+	7.80%	8.20%	2.10%	10.20%	7.50%	15.7%
Core Sample						*Minimum*	*9.1%*
						Maximum	*17.5%*
						Median	*11.6%*
Expanded Sample						*Minimum*	*9.1%*
						Maximum	*17.5%*
						Median	*12.7%*

Source: Exhibit No. ANR-0008, Table BV-1.3 (a), BV-1.4 to BV-1.7

B. CAPM Results

Q45: Please summarize the return on equity results based on the CAPM model.

A45: The results of implementing the CAPM are displayed in Figure 7 and Figure 8 below. As shown in Figure 7 and Figure 8, the zone of reasonable ROE estimates for ANR based on the CAPM model ranges from 12.8 percent to 17.1 percent (for IBES growth rate projections), and from 11.2 percent to 14.9 percent (for Value Line growth rate projections), for the Proxy Group Sample. The median for the Core Proxy Group is 15.3 and 13.3 percent using IBES and Value Line growth rates respectively, to determine the MRP. The midpoints of the upper 1/3 are 16.4 and 14.3 percent, respectively (see Figure 1). The average of the two CAPM implementations is 15.4 percent.

Figure 7: Results from the CAPM (*Based on IBES Growth Rates)*

	Unadjusted Cost of Equity Estimate				**Size Premium Adjustment**		
Company	Risk Free Rate	Market Risk Premium	Value Line Beta	Unadjusted Cost of Equity	Market Cap ($ millions)	Size Adjustment	**Size Adjusted Cost of Equity**
	[1]	[2]	[3]	[4] = [1] + [2] x [3]	[5]	[6]	[7] = [4] + [6]
Core Sample							
Enbridge Inc.	2.06%	12.21%	0.9	13.0%	$105,615	-0.2%	12.8%
Kinder Morgan Inc.	2.06%	12.21%	1.15	16.1%	$39,178	-0.2%	15.9%
TC Energy Corp.	2.06%	12.21%	1.05	14.9%	$51,196	-0.2%	14.7%
Williams Cos.	2.06%	12.21%	1.3	17.3%	$34,356	-0.2%	17.1%
Expanded Sample							
Enterprise Products	2.06%	12.21%	1.1	15.5%	$52,165	-0.2%	15.3%
						Min	*12.8%*
		Core Sample				Max	*17.1%*
						Median	*15.3%*
						Min	*12.8%*
		Expanded Sample				Max	*17.1%*
						Median	*15.3%*

Sources and Notes:
[1]: 6-month average of 30-year U.S. Treasury Constant Maturity Rate series up to 10/29/2021, St. Louis Federal Reserve Economic Data.
[2]: MRP calculations consistent with FERC guidelines.
[3],[5]: Value Line Investment Analyzer as of 10/27/2021.
[6]: Duff &Phelps Cost of Capital Navigator as of 10/29/2021.

Source: Exhibit No. ANR-0008, Table BV-1.3 (b) and BV-1.8

Figure 8: Results from the CAPM (*Based on Value Line Growth Rates)*

	Unadjusted Cost of Equity Estimate				Size Premium Adjustment		
Company	Risk Free Rate	Market Risk Premium	Value Line Beta	Unadjusted Cost of Equity	Market Cap ($ millions)	Size Adjustment	**Size Adjusted Cost of Equity**
	[1]	[2]	[3]	[4] = [1] + [2] x [3]	[5]	[6]	[7] = [4] + [6]
Core Sample							
Enbridge Inc.	2.06%	10.43%	0.9	11.4%	$105,615	-0.2%	11.2%
Kinder Morgan Inc.	2.06%	10.43%	1.15	14.0%	$39,178	-0.2%	13.8%
TC Energy Corp.	2.06%	10.43%	1.05	13.0%	$51,196	-0.2%	12.8%
Williams Cos.	2.06%	10.43%	1.25	15.1%	$34,356	-0.2%	14.9%
Expanded Sample							
Enterprise Products	2.06%	10.43%	1.1	13.5%	$52,165	-0.2%	13.3%
		Core Sample				Min	*11.2%*
						Max	*14.9%*
						Median	*13.3%*
		Expanded Sample				Min	*11.2%*
						Max	*14.9%*
						Median	*13.3%*

Sources and Notes:
[1]: 6-month average of 30-year U.S. Treasury Constant Maturity Rate series up to 10/29/2021, St. Louis Federal Reserve Economic Data.
[2]: MRP calculations consistent with FERC guidelines.
[3],[5]: Value Line Investment Analyzer as of 10/27/2021.
[6]: Duff &Phelps Cost of Capital Navigator as of 10/29/2021.

Source: Exhibit No. ANR-0008, Table BV-1.3 (c) and BV-1.8

C. Low-End Outlier Test

Q46: Does the *Pipeline Policy Statement* specify the application of an outlier test to CAPM and DCF results for the sample companies?

A46: Yes. For low-end outliers, the Commission requires the removal of DCF and CAPM estimates that are less than the Baa utility bond yield plus 20 percent of the estimated CAPM MRP. As detailed below, the low-end outlier test has support in basic financial theory: bonds are less risky than equity, and investors cannot be expected to purchase common stock if less risky bonds yield essentially the same or similar returns.

Q47: Were the DCF or CAPM results impacted by the Commission's low-end threshold test?

A47: No. No DCF or CAPM estimates were eliminated due to the low-end screen of 5.40 percent (using Value Line growth projections) or 5.76 percent (using IBES growth projections), which were calculated as 20 percent of the IBES or Value Line based-MRP, plus the 6-month daily average yield of the Baa Utility bond.

D. The Composite Zone of Reasonableness Results

Q48: How did you use the DCF and CAPM cost of equity results to derive an estimate of the appropriate ROE for ANR?

A48: Figure 9 (recreation of Figure 2) below summarizes the overall composite zone of reasonableness for ANR based on CAPM and DCF methodology results presented in the preceding sections of this testimony. As noted previously, the overall composite zone of reasonableness is calculated by averaging the zone of reasonableness results from the CAPM, and the DCF. Figure 9 shows the composite zone of reasonableness and median estimates based on both the Value Line and IBES growth rate CAPM scenarios. As shown, the composite zone of reasonableness for the Proxy Group Sample ranges from 10.98 percent to 17.28 percent with an upper 1/3 midpoint of 16.23 percent using IBES growth rates in both the DCF and CAPM model. The midpoint of the upper 1/3 is 15.17 percent using Value Line projections for the MRP used in the CAPM (and IBES for the DCF). I recommend using an average of these two measures for an estimate of 15.70 percent. The use of the upper 1/3 of the reasonable range is based on Mr. Thapa's finding that ANR has above average business risk.

Figure 9: Zone of Reasonableness and Medians

		Core Sample		Expanded Sample	
		DCF/IBES CAPM	**DCF/VL CAPM**	**DCF/IBES CAPM**	**DCF/VL CAPM**
		[1]	[2]	[3]	[4]
Composite Risk Range					
Zone Of Reasonableness	[a]	10.98% - 17.28%	10.18% - 16.17%	10.98% - 17.28%	10.18% - 16.17%
Average of Median Estimations	[b]	13.43%	12.45%	13.99%	13.01%
Median ROE Estimation	[c]	**12.94%**		**13.50%**	
Upper Risk Range					
Zone Of Reasonableness	[d]	15.18% - 17.28%	14.17% - 16.17%	15.18% - 17.28%	14.17% - 16.17%
Average of Median Estimations	[e]	16.23%	15.17%	16.23%	15.17%
Median ROE Estimation	[f]	**15.70%**		**15.70%**	

Q49: What conclusions do you draw from these results?

A49: First, based on the analysis, I find that an ROE of 15.70 percent is consistent with the Commission's ROE methodology in Order 569-A, which considers the upper 1/3 for companies with above average risk.[54]

In the table above, 16.23 percent reflects the reliance on IBES growth rates for the MRP in the CAPM, while 15.17 percent reflects the use of Value Line growth rates for the MRP in the CAPM. I find the average of these results appropriately reflects the median result for the proxy group. Further, given Mr. Thapa's conclusion that ANR faces above average business risk, I find that the appropriate ROE for ANR is 15.70 percent. Therefore, I recommend that ANR be allowed the opportunity to earn a ROE of 15.70 percent on its equity-financed portion of its Commission-regulated gas pipeline assets.

Q50: Does this conclude your direct testimony?

A50: Yes.

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[54] The median result for an average pipeline is 12.94 percent for the Core Sample and higher at 13.50 for the Expanded Sample.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22-____-000

State of Texas	)
	) ss.
County of Harris	)

AFFIDAVIT OF DR. BENTE VILLADSEN

Bente Villadsen, being first duly sworn, on oath states that she is the witness whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of Dr. Bente Villadsen" (Exhibits ANR-0006, ANR-0007, and ANR-0008); that, if asked the questions which appear in the text of said testimony, she would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as Bente Villadsen's sworn testimony in this proceeding.

Bente Villadsen
Bente Villadsen

SWORN TO AND SUBSCRIBED BEFORE ME THIS 21 DAY OF January, 2022. This notarial act was an online notarization.

Notary Seal **Digital Certificate**

see attached certificate

JURAT

State/Commonwealth of ______TEXAS______)

☐ City ☑ County of ______collin______)

)

On ____01/21/2022____, before me, ______Turkessa Roundtree______ ,

Date *Notary Name*

the foregoing instrument was subscribed and sworn (or affirmed) before me by:

______Bente Villadsen______.

Name of Affiant(s)

❑ Personally known to me **-- OR --**

❑ Proved to me on the basis of the oath of ________________ **-- OR --**

Name of Credible Witness

☑ Proved to me on the basis of satisfactory evidence: ______driver_license______

Type of ID Presented

NOTARY PUBLIC · STATE OF TEXAS

Turkessa Roundtree

ID NUMBER
131532233
COMMISSION EXPIRES
April 16, 2022

Notarized online using audio-video communication

WITNESS my hand and official seal.

Notary Public Signature: ______________ Notary Public, State of Texas

Notary Name: ______Turkessa Roundtree______

Notary Commission Number: ______131532233______

Notary Commission Expires: ______04/16/2022______

Notarized online using audio-video communication

DESCRIPTION OF ATTACHED DOCUMENT

Title or Type of Document: ______Federal Energy Regulatory Commission______

Document Date: ______01/21/2022______

Number of Pages (including notarial certificate): ______2______

Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent advisory work is assisting entities in the acquisition of regulated utilities regarding issues such the return on equity, capital structure, recovery of costs and capital expenditures, growth opportunities, and regulatory environments as well as the precedence for regulatory approval in mergers or acquisitions. Dr. Villadsen's accounting work has pertained to disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. Dr. Villadsen has estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. She has filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions on accounting issues, damages, discount rates and cost of capital for regulated entities.

Dr. Villadsen holds a Ph.D. from Yale University's School of Management with a concentration in accounting. She has a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, Dr. Villadsen was a faculty member at Washington University in St. Louis, University of Michigan, and University of Iowa.

She has taught financial and managerial accounting as well as econometrics, quantitative methods, and economics of information to undergraduate or graduate students. Dr. Villadsen served as the president of the Society of Utility Regulatory Financial Analysts for 2016-2018.

AREAS OF EXPERTISE

- Regulatory Finance
  - Cost of Capital
  - Cost of Service (including prudence)
  - Energy Efficiency, De-coupling and the Impact on Utilities Financials
  - Relationship between regulation and credit worthiness
  - Risk Management
  - Regulatory Advisory in Mergers & Acquisitions
- Accounting and Corporate Finance
  - Application of Accounting Standards
  - Disclosure Issues
  - Forensics
  - Credit Issues in the Utility Industry
- Damages and Valuation (incl. international arbitration)
  - Utility valuation

- Lost Profit for construction, oil&gas, utilities
- Valuation of construction contract
- Damages from the choice of inaccurate accounting methdology

EXPERIENCE

Regulatory Finance

- Dr. Villadsen has testified on cost of capital and capital structure for many regulated entities including electric and gas utilities, pipelines, railroads, water utilities and barges in many jurisdictions including at the FERC, the Surface Transportation Board, the states of Alaska, Arizona, California, Hawaii, Illinois, Iowa, Michigan, New Mexico, New York, Oregon, and Washington as well as in the provinces of Alberta, Ontario, and Quebec.
- On behalf of the Association of American Railroads, Dr. Villadsen appeared as an expert before the Surface Transportation Board (STB) and submitted expert reports on the determination of the cost of equity for U.S. freight railroads. The STB agreed to continue to use two estimation methods with the parameters suggested.
- On behalf of two taxpayers, Dr. Villadsen has testified on the methodology used to estimate the discount rate for the income approach to property valuation in Utah district court.
- For several electric, gas and transmission utilities as well as pipelines in Alberta, Canada, Dr. Villadsen filed evidence and appeared as an expert on the cost of equity and appropriate capital structure for 2015-17. Her evidence was heard by the Alberta Utilities Commission.
- For potential acquirers of electric, natural gas, and water utilities, Dr. Villadsen has conducted regulatory due diligence in the form of an assessment of the regulatory environment in the jurisdictions at issue including the ability to earn the allowed return and recover costs associated with operations or capital expenditures. Her evaluations also involved an assessment of needed capital expenditures and the recovery of such expenditure through rates or specific adjustment clauses. Her prior work includes more than 15 US states, the FERC, and several Canadian provinces.
- Dr. Villadsen has estimated the cost of capital and recommended an appropriate capital structure for natural gas and liquids pipelines in Canada, Mexico, and the US. using the jurisdictions' preferred estimation technique as well as other standard techniques. This work has been used in negotiations with shippers as well as before regulators.

- For the Ontario Energy Board Staff, Dr. Villadsen submitted evidence on the appropriate capital structure for a power generator that is engaged in a nuclear refurbishment program.
- Dr. Villadsen has advised many acquirers and potential acquirers of regulated utilities regarding the return on equity, capital structure, recovery of costs and capital expenditures, growth opportunities, and regulatory environments as well as the precedence for regulatory approval in mergers or acquisitions. Her work has pertained to many jurisdiction in the U.S. and Canada including more than 20 states and three provinces as well as the Federal Energy Regulatory Commission. She has worked on electric, natural gas, pipeline, transmission, and water utility acquisitions.
- She has estimated the cost of equity on behalf of entities such as Anchorage Municipal Light and Power, Arizona Public Service, Portland General Electric, Anchorage Water and Wastewater, NW Natural, Nicor, Consolidated Edison, Southern California Edison, American Water, California Water, and EPCOR in state regulatory proceedings. She has also submitted testimony before the FERC on behalf of electric transmission and natural gas pipelines as well as Bonneville Power Authority. Much of her testimony involves not only cost of capital estimation but also capital structure, the impact on credit metrics and various regulatory mechanisms such as revenue stabilization, riders and trackers.
- In Australia, she has submitted led and co-authored a report on cost of equity and debt estimation methods for the Australian Pipeline Industry Association. The equity report was filed with the Australian Energy Regulator as part of the APIA's response to the Australian Energy Regulator's development of rate of return guidelines and both reports were filed with the Economic Regulation Authority by the Dampier Bunbury Pipeline. She has also submitted a report on aspects of the WACC calculation for Aurizon Network to the Queensland Competition Authority.
- In Canada, Dr. Villadsen has co-authored reports for the British Columbia Utilities Commission and the Canadian Transportation Agency regarding cost of capital methodologies. Her work consisted partly of summarizing and evaluating the pros and cons of methods and partly of surveying Canadian and world-wide practices regarding cost of capital estimation.
- Dr. Villadsen worked with utilities to estimate the magnitude of the financial risk inherent in long-term gas contracts. In doing so, she relied on the rating agency of Standard & Poor's published methodology for determining the risk when measuring credit ratios.

- She has worked on behalf of infrastructure funds, pension funds, utilities and others on understanding and evaluating the regulatory environment in which electric, natural gas, or water utilities operate for the purpose of enhancing investors ability to understand potential investments. She has also provided advise and testimony in the approval phase of acquisitions.
- On behalf of utilities that are providers of last resort, she has provided estimates of the proper compensation for providing the state-mandated services to wholesale generators.
- In connection with the AWC Companies application to construct a backbone electric transmission project off the Mid-Atlantic Coast, Dr. Villadsen submitted testimony before the Federal Energy Regulatory Commission on the treatment the accounting and regulatory treatment of regulatory assets, pre-construction costs, construction work in progress, and capitalization issues.
- On behalf of ITC Holdings, she filed testimony with the Federal Energy Regulatory Commission regarding capital structure issues.
- For a FERC-regulated entity, Dr. Villadsen undertook an assessment of the company's classification of specific long-term commitments, leases, regulatory assets, asset retirement obligations, and contributions / distributions to owners in the company's FERC Form 1.
- Testimony on the impact of transaction specific changes to pension plans and other rate base issues on behalf of Balfour Beatty Infrastructure Partners before the Michigan Public Service Commission.
- On behalf of financial institutions, Dr. Villadsen has led several teams that provided regulatory guidance regarding state, provincial or federal regulatory issues for integrated electric utilities, transmission assets and generation facilities. The work was requested in connection with the institutions evaluation of potential investments.
- For a natural gas utility facing concerns over mark to market losses on long term gas hedges, Dr. Villadsen helped develop a program for basing a portion of hedge targets on trends in market volatility rather than on just price movements and volume goals. The approach was refined and approved in a series of workshops involving the utility, the state regulatory staff, and active intervener groups. These workshops evolved into a forum for quarterly updates on market trends and hedging positions.
- She has advised the private equity arm of three large financial institutions as well as two infrastructure companies, a sovereign fund and pension fund in connection with their acquisition of regulated transmission, distribution or integrated electric assets in the U.S. and Canada. For these clients, Dr. Villadsen evaluated the regulatory climate and the treatment of

acquisition specific changes affecting the regulated entity, capital expenditures, specific cost items and the impact of regulatory initiatives such as the FERC's incentive return or specific states' approaches to the recovery of capital expenditures riders and trackers. She has also reviewed the assumptions or worked directly with the acquirer's financial model.

- On behalf of a provider of electric power to a larger industrial company, Dr. Villadsen assisted in the evaluation of the credit terms and regulatory provisions for the long-term power contract.
- For several large electric utility, Dr. Villadsen reviewed the hedging strategies for electricity and gas and modeled the risk mitigation of hedges entered into. She also studies the prevalence and merits of using swaps to hedge gas costs. This work was used in connection with prudence reviews of hedging costs in Colorado, Oregon, Utah, West Virginia, and Wyoming.
- She estimated the cost of capital for major U.S. and Canadian utilities, pipelines, and railroads. The work has been used in connection with the companies' rate hearings before the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Surface Transportation Board, and state and provincial regulatory bodies. The work has been performed for pipelines, integrated electric utilities, non-integrated electric utilities, gas distribution companies, water utilities, railroads and other parties. For the owner of Heathrow and Gatwick Airport facilities, she has assisted in estimating the cost of capital of U.K. based airports. The resulting report was filed with the U.K. Competition Commission.
- For a Canadian pipeline, Dr. Villadsen co-authored an expert report regarding the cost of equity capital and the magnitude of asset retirement obligations. This work was used in arbitration between the pipeline owner and its shippers.
- In a matter pertaining to regulatory cost allocation, Dr. Villadsen assisted counsel in collecting necessary internal documents, reviewing internal accounting records and using this information to assess the reasonableness of the cost allocation.
- She has been engaged to estimate the cost of capital or appropriate discount rate to apply to segments of operations such as the power production segment for utilities.
- In connection with rate hearings for electric utilities, Dr. Villadsen has estimated the impact of power purchase agreements on the company's credit ratings and calculated appropriate compensation for utilities that sign such agreements to fulfill, for example, renewable energy requirements.
- Dr. Villadsen has been part of a team assessing the impact of conservation initiatives, energy efficiency, and decoupling of volumes and revenues on electric utilities financial performance.

Specifically, she has estimated the impact of specific regulatory proposals on the affected utilities earnings and cash flow.

- On behalf of Progress Energy, she evaluated the impact of a depreciation proposal on an electric utility's financial metric and also investigated the accounting and regulatory precedent for the proposal.
- For a large integrated utility in the U.S., Dr. Villadsen has for several years participated in a large range of issues regarding the company's rate filing, including the company's cost of capital, incentive based rates, fuel adjustment clauses, and regulatory accounting issues pertaining to depreciation, pensions, and compensation.
- Dr. Villadsen has been involved in several projects evaluating the impact of credit ratings on electric utilities. She was part of a team evaluating the impact of accounting fraud on an energy company's credit rating and assessing the company's credit rating but-for the accounting fraud.
- For a large electric utility, Dr. Villadsen modeled cash flows and analyzed its financing decisions to determine the degree to which the company was in financial distress as a consequence of long-term energy contracts.
- For a large electric utility without generation assets, Dr. Villadsen assisted in the assessment of the risk added from offering its customers a price protection plan and being the provider of last resort (POLR).
- For several infrastructure companies, Dr. Villadsen has provided advice regarding the regulatory issues such as the allowed return on equity, capital structure, the determination of rate base and revenue requirement, the recovery of pension, capital expenditure, fuel, and other costs as well as the ability to earn the allowed return on equity. Her work has spanned 14 U.S. states as well as Canada, Europe, and South America. She has been involved in the electric, natural gas, water, and toll road industry.
- For an electric utility, Dr. Villadsen provided guidance regarding the regulatory accounts needed as the utility was separated into separate generation, transmission, and distribution entities with each their accounting records.

Accounting and Corporate Finance

- For an electric utility subject to international arbitration, Dr. Villadsen submitted expert testimony on the application of IFRS as it pertains to receivables, the classification of liabilities and contingencies.

- In international arbitration, she submitted an expert report on IFRS' requirements regarding carve out financials, impairment, the allocation of costs to segments, and disclosure issues.
- On behalf of a construction company in arbitration with a sovereign, Dr. Villadsen filed an expert report report quantifying damages in the form of lost profit and consequential damages.
- In arbitration before the International Chamber of Commerce Dr. Villadsen testified regarding the true-up clauses in a sales and purchase agreement, she testified on the distinction between accruals and cash flow measures as well as on the measurement of specific expenses and cash flows.
- On behalf of a taxpayer, Dr. Villadsen recently testified in federal court on the impact of discount rates on the economic value of alternative scenarios in a lease transaction.
- On behalf of a taxpayer, Dr. Villaden has provided an expert report on the nature of the cost of equity used in regulatory proceedings as well as the interest rate regine in 2014.
- In an arbitration matter before the International Centre for Settlement of Investment Disputes, she provided expert reports and oral testimony on the allocation of corporate overhead costs and damages in the form of lost profit. Dr. Villadsen also reviewed internal book keeping records to assess how various inter-company transactions were handled.
- Dr. Villadsen provided expert reports and testimony in an international arbitration under the International Chamber of Commerce on the proper application of US GAAP in determining shareholders' equity. Among other accounting issues, she testified on impairment of long-lived assets, lease accounting, the equity method of accounting, and the measurement of investing activities.
- In a proceeding before the International Chamber of Commerce, she provided expert testimony on the interpretation of certain accounting terms related to the distinction of accruals and cash flow.
- In an arbitration before the American Arbitration Association, she provided expert reports on the equity method of accounting, the classification of debt versus equity and the distinction between categories of liabilities in a contract dispute between two major oil companies. For the purpose of determining whether the classification was appropriate, Dr. Villadsen had to review the company's internal book keeping records.

- In U.S. District Court, Dr. Villadsen filed testimony regarding the information required to determine accounting income losses associated with a breach of contract and cash flow modeling.
- Dr. Villadsen recently assisted counsel in a litigation matter regarding the determination of fair values of financial assets, where there was a limited market for comparable assets. She researched how the designation of these assets to levels under the FASB guidelines affect the value investors assign to these assets.
- She has worked extensively on litigation matters involving the proper application of mark-to-market and derivative accounting in the energy industry. The work relates to the proper valuation of energy contracts, the application of accounting principles, and disclosure requirements regarding derivatives.
- Dr. Villadsen evaluated the accounting practices of a mortgage lender and the mortgage industry to assess the information available to the market and ESOP plan administrators prior to the company's filing for bankruptcy. A large part of the work consisted of comparing the company's and the industry's implementation of gain-of-sale accounting.
- In a confidential retention matter, Dr. Villadsen assisted attorneys for the FDIC evaluate the books for a financial investment institution that had acquired substantial Mortgage Backed Securities. The dispute evolved around the degree to which the financial institution had impaired the assets due to possible put backs and the magnitude and estimation of the financial institution's contingencies at the time of it acquired the securities.
- In connection with a securities litigation matter she provided expert consulting support and litigation consulting on forensic accounting. Specifically, she reviewed internal documents, financial disclosure and audit workpapers to determine (1) how the balance's sheets trading assets had been valued, (2) whether the valuation was following GAAP, (3) was properly documented, (4) was recorded consistently internally and externally, and (5) whether the auditor had looked at and documented the valuation was in accordance with GAAP.
- In a securities fraud matter, Dr. Villadsen evaluated a company's revenue recognition methods and other accounting issues related to allegations of improper treatment of non-cash trades and round trip trades.
- For a multi-national corporation with divisions in several countries and industries, Dr. Villadsen estimated the appropriate discount rate to value the divisions. She also assisted the

company in determining the proper manner in which to allocate capital to the various divisions, when the company faced capital constraints.

- Dr. Villadsen evaluated the performance of segments of regulated entities. She also reviewed and evaluated the methods used for overhead allocation.
- She has worked on accounting issues in connection with several tax matters. The focus of her work has been the application of accounting principles to evaluate intra-company transactions, the accounting treatment of security sales, and the classification of debt and equity instruments.
- For a large integrated oil company, Dr. Villadsen estimated the company's cost of capital and assisted in the analysis of the company's accounting and market performance.
- In connection with a bankruptcy proceeding, Dr. Villadsen provided litigation support for attorneys and an expert regarding corporate governance.

Damages and Valuation

- For the Alaska Industrial Development and Export Authority, Dr. Villadsen co-authored a report that estimated the range of recent acquisition and trading multiples for natural gas utilities.
- On behalf of a taxpayer, Dr. Villadsen testified on the economic value of alternative scenarios in a lease transaction regarding infrastructure assets.
- For a foreign construction company involved in an international arbitration, she estimated the damages in the form of lost profit on the breach of a contract between a sovereign state and a construction company. As part of her analysis, Dr. Villadsen relied on statistical analyses of cost structures and assessed the impact of delays.
- In an international arbitration, Dr. Villadsen estimated the damages to a telecommunication equipment company from misrepresentation regarding the product quality and accounting performance of an acquired company. She also evaluated the IPO market during the period to assess the possibility of the merged company to undertake a successful IPO.

- On behalf of pension plan participants, Dr. Villadsen used an event study estimated the stock price drop of a company that had engaged in accounting fraud. Her testimony conducted an event study to assess the impact of news regarding the accounting misstatements.

- In connection with a FINRA arbitration matter, Dr. Villadsen estimated the value of a portfolio of warrants and options in the energy sector and provided support to counsel on finance and accounting issues.

- She assisted in the estimation of net worth of individual segments for firms in the consumer product industry. Further, she built a model to analyze the segment's vulnerability to additional fixed costs and its risk of bankruptcy.

- Dr. Villadsen was part of a team estimating the damages that may have been caused by a flawed assumption in the determination of the fair value of mortgage related instruments. She provided litigation support to the testifying expert and attorneys.

- For an electric utility, Dr. Villadsen estimated the loss in firm value from the breach of a power purchase contract during the height of the Western electric power crisis. As part of the assignment, Dr. Villadsen evaluated the creditworthiness of the utility before and after the breach of contract.

- Dr. Villadsen modeled the cash flows of several companies with and without specific power contract to estimate the impact on cash flow and ultimately the creditworthiness and value of the utilities in question.

BOOKS

"*Risk and Return for Regulated Industries*," (with Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe) Elsevier, May 2017.

PUBLICATIONS AND REPORTS

"A Review of International Approaches to Regulated Rates of Return," (with J. Anthony, T. Brown, L. Figurelli, D. Harris, and N. Nguyen) published by the *Australian Energy Regulator*, September 2020.

"Global Impacts and Implications of COVID-19 on Utility Finance," (with R. Mudge, F. Graves, J. Figueroa, T. Counts, L. Mwalenga, and S. Pant), *The Brattle Group*, July 2020.

"Impact of New Tax Law on Utilities' Deferred Taxes," (with Mike Tolleth and Elliott Metzler), *CRRI 37'th Annual Eastern Conference*, June, 2018.

"Implications of the New Tax Law for Regulated Utilities," The Brattle Group, January 2018.

"Using Electric and Gas Forwards to Manage Market Risks: When a power purchase agreement with a utility is not possible, standard forward contracts can act as viable hedging instruments*," North American Windpower*, May 2017, pp. 34-37.

"*Managing Price Risk for Merchant Renewable Investments: Role of Market Interactions and Dynamics on Effective Hedging Strategies*," (with Onur Aydin and Frank Graves), Brattle Whitepaper, January 2017.

"Aurizon Network 2016 Access Undertaking: Aspects of the WACC," (with Mike Tolleth), filed with the *Queensland Competition Authority*, Australia, November 2016.

"Report on Gas LDC multiples," with Michael J. Vilbert, *Alaska Industrial Development and Export Authority*, May 2015.

"Aurizon Network 2014 Draft Access Undertaking: Comments on Aspects of the WACC," prepared for Aurizon Network and submitted to the *Queensland Competition Authority*, December 2014

"Brattle Review of AE Planning Methods and Austin Task Force Report." (with Frank C. Graves) September 24, 2014.

Report on "Cost of Capital for Telecom Italia's Regulated Business" with Stewart C. Myers and Francesco Lo Passo before the *Communications Regulatory Authority of Italy* ("AGCOM"), March 2014. *Submitted in Italian.*

"Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of the 21st Century," (with J. Wharton and H. Bishop), prepared for the *National Association of Water Companies*, October 2013.

"Estimating the Cost of Debt," (with T. Brown), prepared for the Dampier Bunbury Pipeline and filed with the *Economic Regulation Authority*, Western Australia, March 2013.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, M.J. Vilbert, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the *Australian Energy Regulator* and the *Economic Regulation Authority*, Western Australia, February 2013.

"Calculating the Equity Risk Premium and the Risk Free Rate," (with Dan Harris and Francesco LoPasso), prepared for *NMa and Opta, the Netherlands*, November 2012.

"Shale Gas and Pipeline Risk: Earnings Erosion in a More Competitive World," (with Paul R. Carpenter, A. Lawrence Kolbe, and Steven H. Levine), *Public Utilities Fortnightly*, April 2012.

"Survey of Cost of Capital Practices in Canada," (with Michael J. Vilbert and Toby Brown), prepared for *British Columbia Utilities Commission*, May 2012.

"Public Sector Discount Rates" (with rank Graves, Bin Zhou), *Brattle* white paper, September 2011

"FASB Accounting Rules and Implications for Natural Gas Purchase Agreements," (with Fiona Wang), *American Clean Skies Foundation*, February 2011.

"IFRS and You: How the New Standards Affect Utility Balance Sheets," (with Amit Koshal and Wyatt Toolson), *Public Utilities Fortnightly*, December 2010.

"Corporate Pension Plans: New Developments and Litigation," (with George Oldfield and Urvashi Malhotra), Finance Newsletter, Issue 01, *The Brattle Group*, November 2010.

"Review of Regulatory Cost of Capital Methodologies," (with Michael J. Vilbert and Matthew Aharonian), *Canadian Transportation Agency*, September 2010.

"Building Sustainable Efficiency Businesses: Evaluating Business Models," (with Joe Wharton and Peter Fox-Penner), *Edison Electric Institute*, August 2008.

"Understanding Debt Imputation Issues," (with Michael J. Vilbert and Joe Wharton and *The Brattle Group* listed as an author), *Edison Electric Institute*, June 2008.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," *Public Utilities Fortnightly*, August 2005 (with A. Lawrence Kolbe and Michael J. Vilbert).

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," (with A. Lawrence Kolbe and Michael J. Vilbert, and with "*The Brattle Group*" listed as author), *Edison Electric Institute,* April 2005.

"Communication and Delegation in Collusive Agencies," *Journal of Accounting and Economics*, Vol. 19, 1995.

"Beta Distributed Market Shares in a Spatial Model with an Application to the Market for Audit Services" (with M. Hviid), *Review of Industrial Organization*, Vol. 10, 1995.

SELECTED PRESENTATIONS

"Current Issues in Cost of Capital" presented to *EEI Members*, July, 2018-19, 2021.

"The Future of Gas: Options and Regulatory Strategies in a Carbon-Constrained Future," (with Ahmad Faruqui, Josh Figueroa, Long Lam), Presented to Executive Team at Gas Utility, June 2021.

"FERC's new ROE methodology for pipelines and electric transmission," (with Michael J. Vilbert) *UBS Fireside Chat*, June 24, 2020.

"Managing Price Risk for Merchant Renewable Investments," (with Onur Aydin) *EIA Electricity Pricing Workgroup* (webinar), April 30, 2019.

"Decoupling and its Impact on Cost of Capital" presented to *SURFA Members and Friends*, February 27, 2019.

"Introduction to Capital Structure & Liability Management", *the American Gas Association/Edison Electric Institute "Introduction and Advanced Public Utility Accounting Courses",* August 2018-2019.

"Lessons from the U.S. and Australia" presented at *Seminar on the Cost of Capital in Regulated Industries: Time for a Fresh Perspective?* Brussels, October 2017.

"Should Regulated Utilities Hedge Fuel Cost and if so, How?" presented at *SURFA's 49 Financial Forum*, April 20-21, 2017.

"Transmission: The Interplay Between FERC Rate Setting at the Wholesale Level and Allocation to Retail Customers," (with Mariko Geronimo Aydin) presented at *Law Seminars International: Electric Utility Rate Cases*, March 16-17, 2017.

"Capital Structure and Liability Management," *American Gas Association and Edison Electric Institute Public Utility Accounting Course*, August 2015-2017.

"Current Issues in Cost of Capital," *Edison Electric Institute Advanced Rate School*, July 2013-2017.

"Alternative Regulation and Rate Making Approaches for Water Companies," *Society of Depreciation Professionals Annual Conference*, September 2014.

"Capital Investments and Alternative Regulation," *National Association of Water Companies Annual Policy Forum*, December 2013.

"Accounting for Power Plant," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

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"International Innovations in Rate of Return Determination," *Society of Utility Financial and Regulatory Analysts' Financial Forum*, April 2012.

"Utility Accounting and Financial Analysis: The Impact of Regulatory Initiatives on Accounting and Credit Metrics," 1.5 day seminar, EUCI, Atlanta, May 2012.

"Cost of Capital Working Group Eforum," *Edison Electric Institute webinar*, April 2012.

"Issues Facing the Global Water Utility Industry" Presented to Sensus' Executive Retreat, Raleigh, NC, July 2010.

"Regulatory Issues from GAAP to IFRS," NASUCA *2009 Annual Meeting*, Chicago, November 2009.

"Subprime Mortgage-Related Litigation: What to Look for and Where to Look," *Law Seminars International: Damages in Securities Litigation*, Boston, May 2008.

"Evaluating Alternative Business / Inventive Models," (with Joe Wharton). *EEI Workshop, Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, Washington DC, December 2007.

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TESTIMONY

Direct Testimony on the Cost of Equity and Capital Structure on behalf of Anchorage Water and Wastewater Utility before the *Regulatory Commission of Alaska*, TA-172-122 and TA-172-126, December 2021.

Direct Testimony on Cost of Equity and Capital Structure on behalf of Énergir, Gazifère, and Intragaz before *Régie de l'énergie du Québec*, R-4156-2021, November 2021.

Direct Testimony on Cost of Equity for Advanced Ratemaking on behalf of Interstate Power and Light Company, *Iowa Utilities Board*, RPU-2021-0003, November 2021.

Expert Report on Cost of Equity and the Weighted Average Cost of Capital on behalf of Barbados Light and Power Company, *Barbados Fair Trading Commission*, September 2021.

Direct Testimony on California's Cost of Capital Mechanism and Cost of Equity on behalf of Southern California Edison, *California Public Utilities Commission*, Application A.21-08-013, August 2021.

Expert Report on Contingent Liabilities and Materiality under IFRS on behalf of of Norilsk Nickel Mauritius, *LCIA Arbitration* No. 163506, August 2021.

Deposition Testimony re. rate of return and bypass rates on behalf on Southwest Gas Corporation, *Superior Court for the state of Arizona, County of Maricopa*, CV2012-050939, August 2021.

Direct Testimony on Cost of Equity on behalf of Portand General Electric, *Oregon Public Utility Commission*, UE-324, July 2021.

Direct Testimony on Cost of Capital on behalf of California-American Water Company, *California Public Utilities Commission*, Application No. 21-05-, May 2021.

Prefiled Direct Testimony on cost of equity on behalf of Southern Star Central Gas Pipeline, *Federal Energy Regulatory Commission*, Docket RP21-778-000, April 2021.

Direct Testimony re. the prospective excessive earnings test on behalf of Cleveland Electric Illuminating Company and the Toledo Edison Company, *Public Utilities Commission of Ohio*, Case Nos. 20-1034-EL UNC and 20-1476-EL-UNC, March 2021.

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Direct Testimony and Rebuttal Testimony on cost of equity on behalf of DTE Gas submitted to the *Michigan Public Service Commission*, U-20940, February and June 2020.

Direct Testimony on the cost of equity on behalf of Orange & Rockland Utilities submitted to the *New York Department of Public Service*, Case No. 21-E-0074, January 2021.

Direct Testimony, Rebuttal Testimony, and Surrebuttal Testimony on the cost of equity on behalf of Nicor Gas submitted to the *Illinois Commerce Commission*, Docket No. 21-0098, January 2021, June 2021, July 2021.

Direct Testimony on the cost of equity and capital structure on behalf of Anchorage Water and Wastewater Utility submitted to the *Regulatory Commission of Alaska*, Matters TA168-122 and 168-126, December 2020.

Direct Testimony on the cost of equity on behalf of NW Natural submitted to the *Washington Transportation and Utilities Commission*, Docket No. UG-200994, December 2020.

Written Evidence in Review and Variance of Decision 22570-D01-2018 Stage 2 (AltaGas' capital structure) (joint with Paul R. Carpenter) on behalf of AltaGas Utilities Inc. Filed with the *Alberta Utilities Commission*, Proceeding 25031, January 2020.

Written Evidence on Cost of Equity and Capital Structure on behalf of ATCO, AltaGas and FortisAlberta in 2021-2022 Generic Cost of Capital Proceeding. Filed with the *Alberta Utilities Commission*, Proceeding No. 24110, January 2020.

Report on the Return Margin for the Alberta Bottle Depots on behalf of the Alberta Beverage Container Recycling Corporation, February 2020.

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Affidavit regarding the creation of a regulatory asset for earthquake related costs on behalf of Anchorage Water and Wastewater submitted to the *Regulatory Commission of Alaska*, December 2019.

Expert Report and Hearing Appearance on Going Concern and Impairment, *American Arbitration Association*: International Engineering & Construction S.A., Greenville Oil & Gas Co. Ltd and GE Oil & Gas, Inc., November, December 2019.

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Expert Report on IFRS Issues and Forensics. *SIAC Arbitration* No. 44 of 2018, October 2019.

Expert Report, Reply Report and Hearing Appearance on IFRS issues. *ICC Arbitration* No. 23896/GSS, September 2019, September and November 2020.

Direct Testimony on the cost of debt and equity capital as well as capital structure on behalf of Young Brothers, LLC. submitted to the *Public Utilities Commission of the State of Hawaii*, Docket No. 2019-0117, September 2019.

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Expert Report on discount rates in property tax matter for Union Pacific Company in *Union Pacific Railroad Co. v. Utah State Tax Comm'n, et. al.*, Case No. 2:18-cv-00630-DAK-DBP, Utah August 2019.

Answering Testimony on the Cost of Equity on behalf of Northern Natural Gas Company submitted to the *Federal Energy Regulatory Commission*, Docket No. RP19-59-000, August 2019.

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on Cost of Equity on behalf of DTE Electric Company submitted to the *Michigan Public Service Commission*, Docket No. U-20561, July, November, December 2019.

Prepared Direct Testimony on Cost of Capital for Northern Natural Gas Company submitted to the *Federal Energy Regulatory Commission*, Docket No. RP19-1353-000, July 2019.

Prepared Direct Testimony on Cost of Capital and Term Differentiated Rates for Paiute Pipeline Company submitted to the *Federal Energy Regulatory Commission*, Docket No. RP19-1291-000, May 2019.

Expert report, deposition, and oral trial testimony on behalf of PacifiCorp in the Matter of *PacifiCorp, Inc. v. Utah State Tax Comm'n*, Case No. 180903986 TX, *Utah District Court* April, May, September 2019.

Direct Testimony, Rebuttal Testimony, and hearing appearance on the cost of capital for Southern California Edison submitted to the *California Public Utilities Commission*, Docket No. A.19-04-014, April 2019, August 2019.

Prepared Direct Testimony on the cost of equity for Southern California Edison's transmission assets submitted to the *Federal Energy Regulatory Commission*, Docket No. ER19-1553, April 2019.

Direct and Rebuttal Testimony on cost of equity for Consolidated Edison of New York submitted to the *New York Public Service Commission*, Matter No. 19-00317, January, June 2019.

Direct Testimony on cost of capital and capital structure for Northwest Natural Gas Company submitted to the *Washington Utilities and Transportation Commission*, Docket No. 181053, December 2018.

Pre-filed Direct Testimony and Reply Testimony on cost of capital and capital structure for Anchorage Water Utility and Anchorage Wastewater Utility submitted to the *Regulatory Commission of Alaska*, TA163-122 and TA164-126, December 2018, October 2019.

Expert Report on the Cost of Capital for Sur De Texas-Tuxpan Pipeline provided to *Comisión Reguladora de Energía*, Mexico (with Paul Carpenter and Augustin J. Ros), May 2018.

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Direct Testimony, Rebuttal Testimony, deposition, and hearing appearance on wholesale water rates for Petitioner Cities, *Texas Public Utility Commission*, PUC Docket 46662, SOAH Docket 473-17-4964.WS, November 2017, January, June, July, October 2018.

Affidavit on Lifting the Dividend Restriction for Anchorage Water Utility for AWWU, *Regulatory Commission of Alaska*, U-17-095, November 2017.

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Direct and Rebuttal Testimony, Hearing Appearance on Cost of Capital for California-American Water Company for California-American Water submitted to the *California Public Utilities Commission*, Application 17-04-003, April, August, September 2017.

Direct, Rebuttal, Surrebuttal, Supplemental, Supplemental Rebuttal Testimony and Hearing Appearance on the Cost of Capital for Northern Illinois Gas Company submitted to the *Illinois Commerce Commission*, GRM #17-055, March, July, August, September, and November 2017.

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Pre-filed Direct and Reply Testimony and Hearing Appearance on Cost of Equity and Capital Structure for Anchorage Municipal Light and Power, *Regulatory Commission of Alaska*, Docket No. TA357-121, December 2016, August and December 2017.

Expert report and Hearing Appearance regarding the Common Equity Ratio for OPG's Regulated Generation for OEB Staff, *Ontario Energy Board*, EB-2016-0152, November 2016, April 2017.

Pre-filed Direct Testimony on Cost of Equity and Capital Structure for Anchorage Municipal Wastewater Utility, *Regulatory Commission of Alaska*, Docket No. 158-126, November 2016.

Expert Report, Reply Expert Report and Hearing on damages (quantum) in exit arbitration (with Dan Harris), *International Center for the Settlement of Investment Disputes*, October 2016, October 2018, July 2019.

Direct Testimony on capital structure, embedded cost of debt, and income taxes for Detroit Thermal, Michigan Public Service Commission, Docket No. UE-18131, July 2016.

Direct Testimony on return on equity for Arizona Public Service Company, Arizona Corporation Commission, Docket E-01345A-16-0036, June 2016.

Written evidence, rebuttal evidence and hearing appearance regarding the cost of equity and capital structure for Alberta-based utilities, the *Alberta Utilities Commission*, Proceeding No. 20622 on behalf of AltaGas Utilities Inc., ENMAX Power Corporation, FortisAlberta Inc., and The ATCO Utilities, February, May and June 2016.

Verified Statement, Verified Reply Statement, and Hearing Appearance regarding the cost of capital methodology to be applied to freight railroads, the *Surface Transportation Board* on behalf of the Association of American Railroads, Docket No. EP 664 (Sub-No. 2), July 2015, September and November 2015.

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Supplemental Direct Testimony and Reply Testimony on cost of capital submitted to the *Regulatory Commission of Alaska* on behalf of Anchorage Water and Wastewater utilities, Docket U-13-202, September 2014, March 2015.

Expert Report and hearing appearance on specific accrual and cash flow items in a Sales and Purchase Agreement in international arbitration before the *International Chamber of Commerce*. Case No. 19651/TO, July and November 2014. (*Confidential*)

Rebuttal Testimony regarding Cost of Capital before the *Oregon Public Utility Commission* on behalf of Portland General Electric, Docket No. UE 283, July 2014.

Direct Testimony on the rate impact of the pension re-allocation and other items for Upper Peninsula Power Company in connection with the acquisition by BBIP before the *Michigan Public Service Commission* in Docket No. U-17564, March 2014.

Expert Report on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of oil pipeline in arbitration, April 2013. (with A. Lawrence Kolbe, Michael J. Vilbert, *Confidential*)

Direct Testimony on the treatment of goodwill before the *Federal Energy Regulatory Commission* on behalf of ITC Holdings Corp and ITC Midwest, LLC in Docket No. PA10-13-000, February 2012.

Direct and Rebuttal Testimony on cost of capital before the *Public Utilities Commission of the State of California* on behalf of California-American Water in Application No. 11-05, May 2011.

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Case No. 11-00196-UT, May 2011, November 2011, and December 2011.

Direct Testimony on regulatory assets and FERC accounting before the *Federal Energy Regulatory Commission* on behalf of AWC Companies, EL11-13-000, December 2010.

Expert Report and deposition in Civil Action No. 02-618 (GK/JMF) in the *United States District Court for the District of Columbia*, November 2010, January 2011. (*Confidential*)

Direct Testimony, Rebuttal Testimony, and Rejoinder Testimony on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-10-0448, November 2010, July 2011, and August 2011.

Direct Testimony on the cost of capital before *the New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Docket No. 09-00156-UT, August 2009.

Direct and Rebuttal Testimony and Hearing Appearance on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-09-0343, July 2009, March 2010 and April 2010.

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Direct Testimony, Rebuttal Testimony and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Docket No. 08-00134-UT, June 2008 and January 2009.

Direct Testimony on cost of capital and carrying charge on damages, U.S. Department of Energy, *Bonneville Power Administration*, BPA Docket No. WP-07, March 2008.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-08-0227, April 2008, February 2009, March 2009.

Expert Report, Supplemental Expert Report, and Hearing Appearance on the allocation of corporate overhead and damages from lost profit. *The International Centre for the Settlement of Investment Disputes*, Case No. ARB/03/29, February, April, and June 2008 (*Confidential*).

Expert Report on accounting information needed to assess income. *United States District Court* for the District of Maryland (Baltimore Division), Civil No. 1:06cv02046-JFM, June 2007 (*Confidential*)

Expert Report, Rebuttal Expert Report, and Hearing Appearance regarding investing activities, impairment of assets, leases, shareholder' equity under U.S. GAAP and valuation. *International Chamber of Commerce* (ICC), Case No. 14144/CCO, May 2007, August 2007, September 2007. (Joint with Carlos Lapuerta, *Confidential*)

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0491, July 2006, July 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, Supplemental Rejoinder Testimony and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0403, June 2006, April 2007, May 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, and Hearing Appearance on cost of capital before *the Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0014, January 2006, October 2006, November 2006.

Expert report, rebuttal expert report, and deposition on behalf of a major oil company regarding the equity method of accounting and classification of debt and equity, *American Arbitration Association*, August 2004 and November 2004. (*Confidential*).

Table No. BV-1.1

Pipeline Proxy Group

Index to Tables for the Testimony of Bente Villadsen

Table No. BV-1.2

Pipeline Proxy Group

Current Company Credit Ratings

Company	S&P Credit Rating
Enbridge Inc.	BBB+
Enterprise Products	BBB+
Kinder Morgan Inc.	BBB
TC Energy Corp.	BBB+
Williams Cos.	BBB

Source: Bloomberg as of 10/29/2021.

Table No. BV-1.3 (a)

Pipeline Proxy Group

Summary of DCF Cost of Equity Estimates Forecast as of 10/29/2021

Company	S&P Credit Rating	Dividend Yield	Adjusted Dividend Yield	GDP Growth Forecast	Growth Estimate	Combined Growth Rate	Implied Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Core Sample							
Enbridge Inc.	BBB+	8.46%	8.92%	4.20%	10.71%	8.54%	17.46%
Kinder Morgan Inc.	BBB	6.20%	6.43%	4.20%	7.33%	6.28%	12.7%
TC Energy Corp.	BBB+	7.06%	7.16%	4.20%	2.89%	3.33%	10.5%
Williams Cos.	BBB	6.34%	6.40%	4.20%	2.00%	2.73%	9.1%
Expanded Sample							
Enterprise Products	BBB+	7.80%	8.20%	2.10%	10.20%	7.50%	15.7%
	Core Sample					*Minimum*	*9.1%*
						Maximum	*17.5%*
						Median	*11.6%*
	Expanded Sample					*Minimum*	*9.1%*
						Maximum	*17.5%*
						Median	*12.7%*

Sources and Notes:
[1] - [2]: Bloomberg as of 10/29/2021.
[3] = [2] x (1 + 0.5 x [5])
[4]: GDP halved for MLPs per Commission precedent.
[5]: Thomson Reuters as of 10/29/2021.
[6] = {(1/3) × [4]} + {(2/3) × [5]}
[7] = [3] + [6]

Table No. BV-1.3 (b)

Pipeline Proxy Group

CAPM Cost of Equity Estimates as of 10/29/2021 IBES

	Unadjusted Cost of Equity Estimate				Size Premium Adjustment		
Company	Risk Free Rate	Market Risk Premium	Value Line Beta	Unadjusted Cost of Equity	Market Cap ($ millions)	Size Adjustment	**Size Adjusted Cost of Equity**
	[1]	[2]	[3]	[4] = [1] + [2] x [3]	[5]	[6]	[7] = [4] + [6]
Core Sample							
Enbridge Inc.	2.06%	12.21%	0.9	13.0%	$105,615	-0.2%	12.8%
Kinder Morgan Inc.	2.06%	12.21%	1.15	16.1%	$39,178	-0.2%	15.9%
TC Energy Corp.	2.06%	12.21%	1.05	14.9%	$51,196	-0.2%	14.7%
Williams Cos.	2.06%	12.21%	1.3	17.3%	$34,356	-0.2%	17.1%
Expanded Sample							
Enterprise Products	2.06%	12.21%	1.1	15.5%	$52,165	-0.2%	15.3%
						Min	*12.8%*
		Core Sample				Max	*17.1%*
						Median	*15.3%*
						Min	*12.8%*
		Expanded Sample				Max	*17.1%*
						Median	*15.3%*

Sources and Notes:

[1]: 6-month average of 30-year U.S. Treasury Constant Maturity Rate series up to 10/29/2021, St. Louis Federal Reserve Economic Data.

[2]: MRP calculations consistent with FERC guidelines.

[3],[5]: Value Line Investment Analyzer as of 10/27/2021.

[6]: Duff &Phelps Cost of Capital Navigator as of 10/29/2021.

Table No. BV-1.3 (c)

Pipeline Proxy Group

CAPM Cost of Equity Estimates as of 10/27/2021 Value Line

Company	Unadjusted Cost of Equity Estimate: Risk Free Rate	Market Risk Premium	Value Line Beta	Unadjusted Cost of Equity	Size Premium Adjustment: Market Cap ($ millions)	Size Adjustment	**Size Adjusted Cost of Equity**
	[1]	[2]	[3]	[4] = [1] + [2] x [3]	[5]	[6]	[7] = [4] + [6]
Core Sample							
Enbridge Inc.	2.06%	10.43%	0.9	11.4%	$105,615	-0.2%	11.2%
Kinder Morgan Inc.	2.06%	10.43%	1.15	14.0%	$39,178	-0.2%	13.8%
TC Energy Corp.	2.06%	10.43%	1.05	13.0%	$51,196	-0.2%	12.8%
Williams Cos.	2.06%	10.43%	1.25	15.1%	$34,356	-0.2%	14.9%
Expanded Sample							
Enterprise Products	2.06%	10.43%	1.1	13.5%	$52,165	-0.2%	13.3%
Core Sample						Min	*11.2%*
						Max	*14.9%*
						Median	*13.3%*
Expanded Sample						Min	*11.2%*
						Max	*14.9%*
						Median	*13.3%*

Sources and Notes:

[1]: 6-month average of 30-year U.S. Treasury Constant Maturity Rate series up to 10/29/2021, St. Louis Federal Reserve Economic Data.

[2]: MRP calculations consistent with FERC guidelines.

[3],[5]: Value Line Investment Analyzer as of 10/27/2021.

[6]: Duff &Phelps Cost of Capital Navigator as of 10/29/2021.

Table No. BV-1.4

Pipeline Proxy Group

Calculation of Dividend Yields

	Average Monthly Stock Prices as of						Annualized Monthly Dividend as of						Dividend Yield as of						
Company	May. 2021	Jun. 2021	Jul. 2021	Aug. 2021	Sep. 2021	Oct. 2021	May. 2021	Jun. 2021	Jul. 2021	Aug. 2021	Sep. 2021	Oct. 2021	May 31, 2022	Jun 30, 2022	Jul 31, 2022	Aug 31, 2022	Sep 30, 2022	Oct 31, 2022	**Average Dividend Yield**
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	**[19]**
Enbridge Inc.	$38.38	$39.84	$39.02	$38.69	$39.57	$41.42	$3.34	$3.34	$3.34	$3.34	$3.34	$3.34	8.7%	8.4%	8.6%	8.6%	8.4%	8.1%	**8.5%**
Enterprise Products	$23.17	$24.62	$23.67	$22.01	$22.06	$23.13	$1.80	$1.80	$1.80	$1.80	$1.80	$1.80	7.8%	7.3%	7.6%	8.2%	8.2%	7.8%	**7.8%**
Kinder Morgan Inc.	$17.64	$18.47	$17.80	$16.75	$16.34	$17.64	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	6.1%	5.8%	6.1%	6.4%	6.6%	6.1%	**6.2%**
TC Energy Corp.	$48.78	$51.43	$48.42	$46.98	$49.09	$51.54	$3.48	$3.48	$3.48	$3.48	$3.48	$3.48	7.1%	6.8%	7.2%	7.4%	7.1%	6.8%	**7.1%**
Williams Cos.	$24.97	$27.20	$25.68	$24.53	$25.30	$27.89	$1.64	$1.64	$1.64	$1.64	$1.64	$1.64	6.6%	6.0%	6.4%	6.7%	6.5%	5.9%	**6.3%**

Sources and Notes:

[1] - [6]: Average of Intraday High and Low Prices, Monthly.

[7] - [12]: Most recent quarterly dividend as of each month from Bloomberg, annualized.

[13] - [18]: Dividend yield = Annualized monthly dividends (columns [7] through [12]) divided by corresponding monthly average price (columns [1] through [6]).

[19]: Average of [13] through [18].

Table No. BV-1.5

Pipeline Proxy Group

LT EPS Growth Rate Forecasts

Company	IBES Consensus Mean Estimate	Number of Analysts	VL Growth Rates	Weighted Average	Composite Growth Rate
	[1]		[2]		[3]
Enbridge Inc.	10.7%	2	6.5%	9.3%	10.7%
Enterprise Products	10.2%	1	7.5%	8.9%	10.2%
Kinder Morgan Inc.	7.3%	2	19.0%	11.2%	7.3%
TC Energy Corp.	2.9%	2	4.5%	3.4%	2.9%
Williams Cos.	2.0%	1	10.5%	6.3%	2.0%

Sources and Notes:

[3]: If IBES is negative or does not exist, Value Line growth rate is used as substitute.

Table No. BV-1.6

Pipeline Proxy Group

Bloomberg Bond Yields

Month	Public Utility Bond Rating A Yield	Public Utility Bond Rating BBB+ Yield	Public Utility Bond Rating BBB Yield	Public Utility Bond Rating BBB- Yield
Apr-2021	3.19	3.40	3.51	4.29
May-2021	3.16	3.36	3.44	4.18
Jun-2021	2.96	3.18	3.23	3.89
Jul-2021	2.78	2.99	3.03	3.67
Aug-2021	2.86	3.07	3.11	3.70
Sep-2021	3.03	3.25	3.27	3.81
Oct-2021	2.98	3.20	3.25	3.80
Average	3.00	3.21	3.27	3.92

Source: Bloomberg as of 10/29/2021.

Table No. BV-1.7

Pipeline Proxy Group

Long Term GDP Growth Rate Forecast

[1]	**SSA - 2020**	**2020**	**2040**	**CAGR**	
	GDP in dollars (billions)	$22,341	$50,291	4.1%	[a]
[2]	**SSA - 2020**	**2020**	**2090**		
	GDP in dollars (billions)	$22,341	$369,382	4.1%	[b]
[3]	**EIA (2021 - 2050)**	**2021**	**2050**		
	Real GDP Forecast	$18,739	$34,365		
	GDP Chain-type Price Index (2012=1.000)	1.145	2.213		
		$21,463	$76,054	4.5%	[c]
[4]	**Blue Chip Value Indicators (2028-32)**				
	Nominal GDP Growth Forecast (%)			4.0%	[d]
	UPDATED AVERAGE				
[5]	Average (SSA, EIA, Blue Chip)			**4.2%**	
[6]	Average (SSA, EIA, Blue Chip)			**4.2%**	

Sources and Notes:

[1] - [2]: Social Security Administration: The 2020 OASDI Trustees Report, Table VI.G4 -- OASDI and HI Annual and Summarized Income, Cost, and Balance as a Percentage of GDP, 2020-2095, Intermediate Assumptions.

[3]: Nominal GDP = (Real GDP)*(GDP Chain-Type Price Index).

[4]: Blue Chip Economic Indicators, March 31st, 2021, pg. 14.

[5]: Average ([b], [c], [d]).

[6]: Average ([a], [c], [d]).

Table No. BV-1.8

Market Risk Premium Summary

		IBES	Value Line	Weighted Average
Dividend Yield	[a]	1.83%	1.79%	1.84%
Growth Rate	[b]	12.44%	10.69%	11.91%
Estimated Cost of Equity	[c] = [a] + [b]	14.27%	12.48%	13.76%
Risk Free Rate	[d]	2.06%	2.06%	2.06%
Market Risk Premium	**[e] = [c] - [d]**	**12.21%**	**10.43%**	**11.70%**
Low End Thresholds:				
Baa 6-Month Daily Average	[f]	3.32%	3.32%	3.32%
20% MRP	[g]	2.44%	2.09%	2.34%
Low End Threshold	[h] = [f] + [g]	**5.76%**	**5.40%**	**5.66%**

Sources and Notes:
Workpapers to BV-1.8 .

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-____-000

Summary of the Prepared Direct Testimony of Mr. Anul Thapa

Mr. Thapa is a Principal of The Brattle Group ("Brattle"), an economic and management consulting firm. Mr. Thapa's testimony evaluates the business risk of ANR Pipeline Company ("ANR") relative to the proxy group selected by ANR witness Dr. Bente Villadsen for the purposes of determining the appropriate return on equity ("ROE") for the pipeline.

Mr. Thapa first explains the relevance of business risk in determining the authorized rate of return for a natural gas pipeline. He also explains his framework for analyzing business risk that evaluates pipelines along five dimensions: supply risk, demand (market) risk, competition risk, operating risk, and regulatory risk.

Mr. Thapa then compares the business risk faced by ANR to the proxy group selected by Dr. Villadsen. For this purpose, Mr. Thapa analyzes ANR's level of contract coverage and exposure to higher risk shippers (with lower credit quality) in relation to the 20 largest pipelines owned by the proxy group ("Proxy Group Pipelines"). He also evaluates the operating risks of ANR. Based on his analysis, Mr. Thapa concludes that ANR faces above average business risk compared to the median of the pipelines in the proxy group. ANR has above average risk due to a large share of its capacity being contracted by high-risk (lower credit quality) producer-shippers relative to the Proxy Group Pipeline. ANR also has higher operating risk as evidenced by the fact that it has the second highest historical maintenance and modernization capital expenditures compared to the Proxy Group Pipelines.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company — Docket No. RP22-____-000

DIRECT TESTIMONY AND SUPPORTING EXHIBITS OF
ANUL THAPA
ON BEHALF OF ANR PIPELINE COMPANY

January 28, 2022

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Glossary of Terms

Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Commission	Federal Energy Regulatory Commission
Dth	Dekatherms
EBB	Electronic Bulletin Board
EBITDA	Earnings before interest, tax, depreciation and amortization
ENB	Enbridge, Inc.
EPD	Enterprise Products Partners, LP
FERC	Federal Energy Regulatory Commission
ANR	ANR Pipeline Company
KMI	Kinder Morgan, Inc.
PPE	Plant, Property, and Equipment
ROE	Return on equity
TRP	TC Energy Corp.
WMB	Williams Cos.

I. INTRODUCTION AND QUALIFICATIONS

Q1: Please state your name, address and position.

A1: My name is Anul Thapa. I am a Principal at The Brattle Group, an economic and management consulting firm with offices in the U.S., Canada, Europe, and Australia. My office is located at 1 Beacon Street, Suite 2600, Boston, MA 02108.

Q2: Could you briefly describe your educational background and professional qualifications?

A2: I specialize in the economics of the energy sector. I received a Master of Business Administration (MBA) from the Massachusetts Institute of Technology and a Bachelor of Arts from DePauw University. I have over twelve years of experience working on regulatory and litigation matters involving the natural gas industry. This includes assessing the business risks faced by natural gas pipelines, analyzing the rates charged by natural gas and oil pipelines, evaluating the economics of natural gas pipelines and LNG storage facilities, pipeline access issues, and evaluating competition and market manipulation in natural gas markets. I have previously testified before the Maine Public Utilities Commission and have submitted written testimony before the Federal Energy Regulatory Commission ("FERC" or "Commission"). I am a co-author of "Understanding Natural Gas Markets" prepared for the American Petroleum Institute. My background, publications, and presentations are described in my curriculum vitae, included as Exhibit No. ANR-0010. My workpapers are included as Exhibit No. ANR-0011.

II. PURPOSE OF TESTIMONY AND SUMMARY

Q3: What is the purpose of your testimony?

A3: I have been asked by ANR Pipeline Company ("ANR") to review its business risk and position it on a risk basis relative to the proxy group companies selected by ANR witness Dr. Bente Villadsen.

Q4: Could you summarize your approach?

A4: I start by explaining the primary elements of business risk that an investor may take into account in making investment decisions and the relevance of business risk in determining the authorized rate of return. Then, I compare ANR's business risk to the pipelines owned by the companies in Dr. Villadsen's proxy group to determine the risk positioning of ANR relative to the proxy group pipeline sample.

Q5: Please summarize your conclusions.

A5: ANR's business risk is higher than the median of the pipelines in the proxy group sample. ANR's business risk is primarily driven by a large share of its capacity being contracted by high-risk (lower credit quality) producer-shippers. ANR has the third highest share of contracts held by producer-shippers compared to the largest 20 pipelines owned by the proxy group companies ("Proxy Group Pipelines"). Additionally, ANR also has higher operating risk as it has the second highest historical maintenance and modernization capital expenditures compared to the Proxy Group Pipelines.

Q6: How is the rest of your testimony organized?

A6: Section III explains how business risk is defined and evaluated and its relevance in determining the authorized rate of return on equity ("ROE") for a natural gas pipeline. Section IV discusses my understanding of the ANR system and the key business risks faced by the pipeline. Section V includes my analysis of the business risk of the proxy group pipelines identified by Dr. Villadsen. Section VI presents my conclusions.

III. CONCEPT OF BUSINESS RISK AND ITS RELEVANCE TO AUTHORIZED ROE

Q7: What is business risk in the context of a regulated natural gas pipeline?

A7: In finance theory, risk is the variability of outcome from the expected value. Business risk is a similar concept that refers to the factors that contribute to uncertainty in the future cash flows of a business. Regulated natural gas pipelines, like any other business, face a myriad of business risk factors that could lead to variability in their financial performance and uncertainty in returns to their shareholders. Since natural gas pipelines are capital intensive and cannot be easily redeployed, their ability to sell transportation capacity and generate revenues is largely dependent upon many business risk factors such as the demand and supply conditions in their origin and destination markets, competition with other pipelines, their operational characteristics, and the regulatory framework under which they operate.

Q8: What is the relevance of long-term contracts to a pipeline's business risk?

A8: Natural gas pipelines can mitigate these business risk factors to a large degree through long-term contracts that include fixed monthly capacity reservation payments from shippers. These long-term fixed obligations from the shippers allow for a more stable cash flow for the pipeline and transfer much of the business risk from the pipeline to the shippers. Pipelines without long-term contracts face greater cash flow uncertainty and thus pose a higher risk to their shareholders.

As an example, long-term contracts can mitigate the risk to the pipeline from a decline in the value of its transportation due to a decrease in demand for natural gas in its destination markets. With long-term contracts, the pipeline continues to receive fixed monthly payments from shippers regardless of market conditions. The uncertainty resulting from changes in market conditions is thus borne by the shippers instead of the pipeline during the term of the contract.

The importance of long-term contracting as a mechanism to mitigate risks is also recognized by FERC. In certificate proceedings for new pipeline capacity or expansions, for example, the Commission uses the presence of binding long-term precedent agreements to evaluate the need for and financial viability of the project.

Q9: Does the presence of long-term contracts completely mitigate a pipeline's business risk?

A9: No. Long-term contracts do not completely protect the pipeline from all elements of business risk. Even if fully contracted, the pipeline may continue to face the risk that its shippers may default on their long-term obligations and the pipeline may be unable to remarket this capacity. Furthermore, even if a pipeline currently has contracted all of its capacity, it is not guaranteed that it will be able to remarket its expiring capacity as market conditions could change in the future. The pipeline may also be exposed to certain operational risks or regulatory risks that might have an adverse impact on its financial performance.

Q10: What is your understanding of how the Commission uses evidence of business risk?

A10: The Commission allows natural gas pipelines it regulates to charge rates that will provide them with an opportunity to recover their cost-of-service, which includes a fair rate of return on the equity invested in the pipeline (*i.e.*, the allowed ROE). I understand that the Commission considers the business risks of the pipeline in determining a pipeline's allowed ROE.

The Commission's ROE policy is guided by the U.S. Supreme Court's opinions in *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) and *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), which stated that:

> the return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[1]

In order to set an allowed ROE that follows these principles, the Commission first estimates a zone of reasonableness of returns of publicly-traded comparable companies and then places the pipeline within that zone based on its relative risks compared to the pipelines owned by the proxy group sample. This is explained in a recent FERC policy statement:

> Because most natural gas and oil pipelines are wholly owned subsidiaries and their common stocks are not publicly traded, the Commission must use a proxy group of publicly traded firms with corresponding risks to set a range of reasonable returns. The firms in the proxy group must be comparable to the pipeline whose ROE is being determined, or, in other words, the proxy group must be "risk-appropriate." The range of the proxy group's returns produces the zone of reasonableness in which the pipeline's ROE may be set based on specific risks. Absent unusual circumstances showing that the pipeline faces anomalously high or low risks, the Commission sets

[1] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

> the pipeline's cost-of service nominal ROE at the median of the zone of reasonableness.[2]

As explained above, unless there is evidence that the pipeline's business risks are different from the business risks faced by the pipelines owned by the proxy group companies, the Commission sets the ROE at the median of the zone of reasonableness. However, if the pipeline's business risk is higher than that of the proxy group, the Commission may consider approving an ROE that is higher than the median.

The Commission's approach of setting the ROE within the zone of reasonableness and deviation from the median if warranted based on the pipeline's business risk relative to the proxy group is consistent with the widely understood relationship between risk and return. The Commission recognizes that investors will require higher returns for investing in firms with a higher degree of risk and therefore approves a higher ROE for pipelines that are riskier in comparison to the proxy group.

Q11: How do you analyze business risk for a natural gas pipeline?

A11: I understand that the Commission has not articulated a standard methodology or framework for evaluating business risk and there may be many reasonable ways to structure an analysis of business risk. One such method which I use herein is to consider five different dimensions of business risks, which includes supply risk, demand (market) risk, competition risk, operating risk, and regulatory risk. This framework has also been utilized by the Canadian Energy Regulator (previously National Energy Board) since the early 2000s.[3]

Q12: Please explain supply risk and demand (market) risk in the context of assessing a pipeline's business risk.

A12: Supply risk and demand (market) risk relate to the market conditions in a pipeline's origin and destination markets, respectively. In my opinion, the analysis of a pipeline's business

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[2] Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines, 171 FERC ¶ 61,155 at P 6 (2020).

[3] *See*, for example, Canadian National Energy Board's Reasons for Decision, RH-4-2001, p. 13.

risk should include a review of the pipeline's origin and destination markets because they have a bearing on the value of, and consequently demand for, the pipeline's transportation services.

For example, if there is an abundance of supply of natural gas available at low prices in a pipeline's origin market and high demand for natural gas in its destination market willing to pay high prices, the value of a pipeline's transportation service will be high. Consequently, the pipeline is likely to face a steady source of demand for its transportation services. On the other hand, if there is an insufficient supply of natural gas at low prices in the origin market, and/or there is insufficient or declining demand for natural gas in the destination market, the value of the pipeline's service will be low. As a result, the pipeline is unlikely to be able to market its capacity at full recourse rates as existing contracts expire.

In this sense, market conditions in the pipeline's origin and destination markets influence the pipeline's business risk. In my analysis, I consider supply risk to evaluate the risk that there is declining supply of natural gas in the pipeline's origin market. Market risk, on the other hand, includes the risk that there is declining demand for natural gas in the pipeline's destination market.

Q13: Please explain competitive risk in the context of assessing a pipeline's business risk.

A13: Competitive risk considers the degree of competition a pipeline faces from other pipelines. Notably, even if a pipeline serves a market with low supply and market risk, it may still face competitive risk. For example, if the pipeline's origin and destination markets have favorable conditions resulting in high value of transportation capacity connecting them, these conditions may attract competing pipelines into the market. A higher degree of competition increases the risk the pipeline may be unable to fully contract its capacity and ensure a stable source of revenue. Supply risk, market risk, and competitive risk are all interrelated.

Q14: Please explain operating risk in the context of assessing a pipeline's business risk.

A14: Operating risk examines the risk that a pipeline faces operating issues and will need to incur large expenses to maintain its level of service. If a pipeline is likely to spend more on maintenance and modernization than its peers, it will likely experience higher operating risk. A good proxy for operating risk is whether the pipeline has incurred higher capital maintenance and modernization costs than its peers in the past, or if it is planning to execute a costly maintenance and modernization program in the near future. For example, older pipelines are likely to face higher operating risk than newer pipelines, given the age of their facilities.

Q15: Please explain regulatory risk in the context of assessing a pipeline's business risk.

A15: Regulatory risk considers the risk that the future regulatory decisions or framework will influence a pipeline's ability to recover its costs and generate profits. For example, I would consider a pipeline to have high regulatory risk if it were more likely than its peers to experience regulatory change that could adversely impact its ability to recover its prudently-incurred costs in a timely manner.

IV. ANR'S SYSTEM AND KEY BUSINESS RISK FACTORS

Q16: What is your understanding of the ANR system?

A16: The ANR pipeline system consists of approximately 9,000 miles of pipeline and 203 billion cubic feet ("Bcf") of storage, including storage by others, and delivers more than 1 trillion cubic feet ("Tcf") of natural gas annually. The ANR system is divided into five major areas: the Southwest Area, the Southeast Area, the Northern Area, the Southwest Mainline ("SW Mainline"), and the Southeast Mainline ("SE Mainline").

As discussed by ANR witness Lakhani, the SW Mainline and the SE Mainline are ANR's two main legs and connect two traditional supply areas–Southwest Area and Southeast Area–to the Northern Area, which is ANR's largest market area. The ANR system has access to multiple supply regions including Appalachia, Western Canada, the Rocky Mountains, Midcontinent, and Permian. The SW Mainline transports gas from the Southwest Area supply region (which spans Texas, Oklahoma, and Kansas) through Missouri and Iowa to markets in the Northern Area. The SE Mainline historically connected the Southeast Area to the Northern Area. However, with the rise in shale gas production in the eastern United States, the SE Mainline has evolved into a bidirectional pipeline that also transports gas from Utica and Marcellus shale basins to markets in the Southeast area, including LNG terminals in Louisiana. The SE Mainline spans from Louisiana through Arkansas, Mississippi, Tennessee, Kentucky, Indiana, Ohio, and Michigan. For ratemaking purposes, the SW Mainline and SE Mainline are each split into two rate zones. The SW Mainline is split into the Southwest Southern and Southwest Central zones and the SE Mainline is split into the Southeast Southern and Southeast Central zones. The Southwest Area, Southeast Area, and Northern Area each constitute separate rate zones. Mr. Lakhani describes these zones in more detail in his testimony.

Q17: Could you summarize your understanding of the key elements of ANR's business risk?

A17: ANR is exposed to above average business risks compared to the median of the Proxy Group Pipelines. Specifically, over 40 percent of ANR's contractual commitments are from producer-shippers who have higher exposure to commodity price fluctuations compared to other types of shippers. Relative to the proxy group, ANR has the third highest proportion of contractual commitments from producer-shippers. Additionally, ANR has the second highest historical maintenance and modernization capital expenditures compared to the Proxy Group Pipelines. ANR also faces supply risk on its western leg (*i.e.*, SW Mainline and SW Area) due to production uncertainty and low basis differentials from the Rocky Mountain and Midcontinent which are the major sources of supply for ANR in this region. ANR also faces competitive risks due to the introduction of competing pipelines in both its supply and market areas.

Q18: What is your understanding of the business risks discussed by ANR witness Lakhani?

A18: Mr. Lakhani's testimony describes ANR's exposure to supply and competitive risks. His testimony shows the Rocky Mountain maintained a production volume of approximately 9 Bcf/d between January 2016 and January 2019. During the same period, Midcontinent's production increased by 26 percent to 7.7 Bcf/d from 6.1 Bcf/d and production in the Permian grew by 120 percent to 11 Bcf/d from 5 Bcf/d. This high production period resulted in the Southwest Area and SW Mainline approaching a load factor of almost 100 percent between 2018 and early 2020. The increasing production during this pre-COVID period in the Rocky

Mountain, Midcontinent, and Permian regions led to the development of several competing pipelines, such as Cheniere Energy, Inc.'s 1.1 Bcf/d Midship Pipeline ("Midship"),[4] that increased capacity out of these regions. With subsequent declines in production in the Midcontinent and Rockies, the excess take-away capacity in these regions has resulted in increased competition for ANR and a decline in utilization of its western leg.

Mr. Lakhani's testimony also explains that the growth in production from the Marcellus/Utica region has resulted in the development of other pipeline projects that compete with ANR to serve the Northern Area. The Marcellus/Utica region is considered to be the largest producing supply region in the United States and its growth is expected to continue in the near term before stabilizing in 2023. New pipelines such as Energy Transfer Partners' Rover Pipeline Project ("Rover") as well as DTE Energy and Enbridge's Nexus Gas Transmission ("NEXUS") began service in 2017 and 2018, respectively, to transport growing Marcellus/Utica supplies to demand regions in the Midwest currently served by ANR. Rover and NEXUS are able to transport 3.25 and 1.5 Bcf/d, respectively, from the Marcellus/Utica region to serve the Northern Area. As described in Mr. Lakhani's testimony, the introduction of these competing pipelines connected to the Marcellus/Utica region has eroded ANR's position in the Northern Area which has historically been ANR's primary market area.

Mr. Lakhani also highlights the risks associated with uncertainty in production from the Rocky Mountain and Midcontinent that are key supply sources for the western leg (*i.e.*, SW Mainline and SW Area). As mentioned by Mr. Lakhani, S&P Global Platts projects production to decrease to 7.5 and 5.5 Bcf/d by 2024 in the Rocky Mountain and Midcontinent regions, respectively, creating supply risk exposure. The reduction in supply and low basis differentials from these two production basins to ANR's market areas have already caused

[4] Midship transports gas from Oklahoma's Anadarko Basin to the Gulf Coast and Southeast markets via deliveries to existing pipelines.

reduced utilization on its western leg and may result in ANR's shippers opting away from firm service contracts such as PTS-2 as these contracts expire.[5]

Mr. Lakhani's testimony also describes the elevated credit risk faced by ANR due to producers that hold significant capacity on the SE Mainline.

V. COMPARING ANR'S RISKS WITH THE PROXY GROUP

A. DESCRIPTION OF THE PROXY GROUP

Q19: Which companies are in the proxy group?

A19: Dr. Villadsen has selected a core proxy group containing four companies she considers relevant for her assessment of authorized ROE for a natural gas pipeline. These companies include:

- Enbridge Inc. (ENB)
- Kinder Morgan Inc. (KMI)
- TC Energy Corp. (TRP)
- Williams Cos. (WMB)

Dr. Villadsen has also selected an expanded proxy group sample that includes Enterprise Products Partners (EPD). I understand that Dr. Villadsen explains why each of these companies in the proxy group are relevant for the determination of an interstate natural gas pipeline ROE.

Q20: What are the business activities of the core proxy group companies?

A20: The companies in the core proxy group are involved in various business activities, as described in their Form 10-K and annual reports. These activities include natural gas transmission and storage, liquids pipelines services, natural gas distribution, midstream

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5 PTS-2 is the rate schedule that transports receipt gas to the Southwest Headstation in the SW Area.

services, and terminal services. While each proxy company is not involved in all of these business activities, all own at least one FERC-regulated interstate natural gas pipeline.

A short description of the reported business segments for each core proxy group company is provided below:

Natural Gas Pipelines and Storage: This business segment encompasses the services provided by natural gas pipelines and storage facilities. Natural gas pipelines provide natural gas transportation services both within and across state lines. Storage facilities provide underground storage services as well as pipeline balancing services.

Natural gas transportation and storage services tend to be regulated by governmental authorities; the operations and profitability of these business segments are heavily influenced by the relevant governing authorities. Interstate transportation services are regulated at the federal level by the FERC. Intrastate transportation services, on the other hand, are generally regulated at the state level by state commissions. Lastly, storage services may be subject to FERC regulation. All of the companies in the core proxy group (ENB, KMI, TRP, and WMB) own interstate natural gas pipelines and are consequently regulated by the FERC. In addition, some of the companies in the proxy group operate natural gas storage facilities.

Liquids Pipelines: This business segment consists of transportation services for crude oil, refined products, natural gas liquids, and other liquid petroleum products. Liquid petroleum pipelines can be categorized as interstate if they cross state lines and, otherwise may be categorized as intrastate. The FERC regulates interstate liquids pipelines. All core proxy group companies (ENB, KMI, TRP, and WMB) own and operate interstate and intrastate liquid petroleum pipelines.

Gas Distribution: This business segment consists of the distribution of natural gas by utilities on a low-pressure pipeline network to reach residential, commercial and industrial customers. Of the four core proxy group companies, only ENB owns natural gas utilities, which are located in Ontario and Quebec, and are regulated by the Ontario and Quebec provincial regulatory bodies, respectively.

Midstream Services: This business segment consists of the gathering of petroleum products (such as crude oil, natural gas, and natural gas liquids) from producing fields to processing plants. Additionally, midstream services include the processing of petroleum products so that they meet the quality standards required by mainline pipelines for transportation services. Midstream services are often unregulated. WMB is the only core proxy group company that provides midstream services.

Terminals: This business segment includes business activities required to inject, store and withdraw petroleum liquids into liquids terminals. For example, the storage of petroleum liquids, the loading of petroleum liquids into trucks and railcars, and additive injection services for liquids and dry-bulk materials are included in this business segment. KMI is the only company in the core proxy group that provides terminal services. Rates for terminal services are generally unregulated.

Other: This business segment includes miscellaneous business activities that do not fit into the above categories. In particular, this category includes ENB's Renewable Power Generation and Energy Services operations; KMI's CO_2 operations; TRP's power generation and unregulated natural gas storage; and WMB's previously-owned operations, minor business activities, and corporate operations.

Q21: Can you provide the breakdown of assets and earnings by business segment for the core proxy group companies?

A21: The breakdown of total assets[6] in 2020 for the core proxy group companies based on Form 10-K data and annual reports is shown in Figure 1 below. On average, natural gas pipelines and storage represent 55 percent of business activity by assets for the core proxy group

[6] If the asset information was not reported for a business segment, I used the Property, Plant and Equipment ("PPE") to determine the share of assets.

companies. This is followed by 22 percent associated with oil and liquids pipelines, and 11 percent associated with midstream activities. Gas distribution, terminals, and other each account for 3 to 5 percent of assets for the core proxy group.

Figure 1: Assets by Business Segment

Company		Gas Pipelines & Storage	Oil and Liquids Pipelines	Gas Distribution	Midstream Services	Terminals	Other	Total
Enbridge Inc.	[1]	27%	52%	17%	0%	0%	4%	100%
Kinder Morgan Inc.	[2]	71%	13%	0%	0%	13%	4%	100%
TC Energy Co.	[3]	77%	18%	0%	0%	0%	5%	100%
Williams Cos.	[4]	45%	6%	0%	43%	0%	6%	100%
Enterprise Products	[5]	9%	37%	0%	25%	12%	17%	100%
Core Sample Average	[6]	55%	22%	4%	11%	3%	5%	100%
Expanded Sample Average	[7]	46%	25%	3%	14%	5%	7%	100%

Source: Data from 2020 company annual reports (10-K SEC Filing). See Thapa Workpaper #1.

Similarly, the segment level breakdown for earnings as measured by earnings before interest, taxes, depreciation, and amortization ("EBITDA") is shown in Figure 2 below. On average, natural gas pipelines and storage represent 46 percent of business activity for the core proxy group companies based on earnings. This is followed by 27 percent associated with oil and liquids pipelines, and 17 percent associated with midstream activities. Gas distribution, terminals, and other each account for 1 to 5 percent of EBITDA of the core proxy group.

Figure 2: EBITDA by Business Segment

Company		Gas Pipelines & Storage	Oil and Liquids Pipelines	Gas Distribution	Midstream Services	Terminals	Other	Total
Enbridge Inc.	[1]	10%	71%	16%	0%	0%	3%	100%
Kinder Morgan Inc.	[2]	67%	19%	0%	0%	20%	-6%	100%
TC Energy Co.	[3]	75%	18%	0%	0%	0%	7%	100%
Williams Cos.	[4]	33%	0%	0%	67%	0%	0%	100%
Enterprise Products	[5]	6%	43%	0%	26%	12%	13%	100%
Core Sample Average	[6]	46%	27%	4%	17%	5%	1%	100%
Expanded Sample Average	[7]	38%	30%	3%	19%	6%	3%	100%

Source: Data from 2020 company annual reports (10-K SEC Filing). See Thapa Workpaper #1.

Q22: Do you consider that overall the core proxy group has business risks comparable to those of interstate natural gas pipeline operations?

A22: Yes. Interstate natural gas transmission and storage account for almost half of the business segment of the core proxy group as a whole (55 percent by asset and 46 percent by EBITDA). In addition, regulated oil and liquids pipelines, which are largely FERC-regulated, account for a further 22 percent by asset value and 27 percent by EBITDA. Thus, regulated pipelines by far dominate the core proxy group business activities as a whole. Furthermore, the gas distribution business also accounts for 4 percent by asset and EBITDA. In total, roughly 81 percent by asset and 77 percent by EBITDA of the core proxy group's business activities are regulated. While the remaining quarter of business activities from core proxy group companies are from unregulated activities, which likely have higher business risk compared to regulated natural gas pipelines, they are a minority and I expect the regulated activities of the proxy group to have a higher degree of influence on the business risk of the proxy group as a whole.

Q23: Does the overall expanded proxy group sample have business risks similar to those of interstate natural gas pipeline operations?

A23: Yes. As with the core proxy group, the regulated interstate gas pipelines & storage business segment represents the most important business segment in the expanded proxy group's business activities (46 percent by assets and 38 percent by EBIDTA). In addition, regulated pipelines (including natural gas pipeline & storage and oil & liquids pipeline) represent a significant portion of the group's activities. This is because Enterprise Product Partners, which is the additional company in the expanded proxy group sample, has large intrastate natural gas pipeline systems and oil & liquids pipelines that are regulated either at the state or federal level.

Q24: How would you describe your process for selecting the pipelines that are representative of the proxy group?

A24: While the four companies in the core proxy group own, or have ownership interests, in 58 FERC-regulated interstate natural gas pipelines, the majority of the proxy group's assets and income are generated by a subset of these 58 interstate pipelines. In order to streamline my analysis, I have selected the 20 largest pipelines to represent the proxy group's FERC-regulated natural gas pipelines. The 38 pipelines that I exclude from my analysis are small, and it is unlikely that they would significantly alter my conclusions with respect to the overall business risk of the core proxy group. In particular, the 20 largest pipelines account for 89 percent of the core proxy group's total income, and 87 percent of the core proxy group's assets. As such, they are representative of the business activities with respect to the core proxy group's FERC-regulated interstate natural gas pipelines. Since Enterprise Products Partners is not in the core proxy group, I exclude it from my business risk analysis below.

Q25: Can you describe the 20 pipeline systems in your analysis?

A25: Figure 3 shows the 20 largest pipeline systems in the core proxy group (*i.e.*, the Proxy Group Pipelines) that account for 89 percent of the total income and 87 percent of the total assets of the 58 pipelines.

Figure 3: Proxy Group Pipeline Systems: Selected Sample

Company	Pipeline System	Income ($MM, USD)	Assets ($MM, USD)
Enbridge Inc.	Algonquin Gas Transmission, LLC	$217	$2,878
Enbridge Inc.	East Tennessee Natural Gas, LLC	$70	$811
Enbridge Inc.	Gulfstream Natural Gas System, LLC	$89	$755
Enbridge Inc.	Sabal Trail Transmission, LLC	$111	$1,495
Enbridge Inc.	Texas Eastern Transmission, LP	$632	$8,733
Kinder Morgan Inc.	Colorado Interstate Gas Company, LLC	$125	$1,106
Kinder Morgan Inc.	El Paso Natural Gas Company, LLC	$340	$2,129
Kinder Morgan Inc.	Elba Express Company, LLC	$86	$645
Kinder Morgan Inc.	Florida Gas Transmission Company, LLC	$215	$2,220
Kinder Morgan Inc.	Natural Gas Pipeline Company of America LLC	$139	$993
Kinder Morgan Inc.	Ruby Pipeline, LLC	$75	$1,370
Kinder Morgan Inc.	Southern Natural Gas Company, LLC	$131	$1,204
Kinder Morgan Inc.	Tennessee Gas Pipeline Company, LLC	$725	$5,595
TC Energy	Columbia Gas Transmission, LLC	$820	$13,115
TC Energy	Columbia Gulf Transmission, LLC	$125	$2,003
TC Energy	Gas Transmission Northwest LLC	$129	$878
TC Energy	Great Lakes Gas Transmission Limited Partnership	$137	$707
TC Energy	Northern Border Pipeline Company	$84	$471
Williams Companies, Inc.	Gulfstream Natural Gas System, LLC	$89	$755
Williams Companies, Inc.	Northwest Pipeline LLC	$131	$1,745
Williams Companies, Inc.	Transcontinental Gas Pipe Line Company, LLC	$1,034	$11,389
	Total of Top 20	$5,505	$60,998
	Other 38 Pipeline and Storage Systems	$626	$10,032
	Total 58 Pipelines and Storage Systems	$6,174	$70,078
	Top 20 Pipelines as Percent of Total	89%	87%

Sources and Notes:
Gulfstream Natural Gas System, L.L.C. is jointly owned by Enbridge Inc. and Williams Companies, Inc. Each company has 50 percent ownership. See Thapa Workpaper #2.
Net Utility Operating Income and Net Utility Plant are reported in each pipeline's 2020 FERC Form 2 via S&P Market Intelligence (accessed 12/14/2021). Parent company ownership from 2020 corporate annual reports when available, else from company websites (accessed 04/28/2021).
Income and assets of each pipeline system are weighted by proxy group company ownership. See Thapa Workpaper #2.

B. BUSINESS RISKS OF ANR AND THE PIPELINE SYSTEMS OWNED BY PROXY GROUP COMPANIES

Q26: Please describe the elements of business risk you consider when evaluating a pipeline's relative business risk.

A26: In my opinion, a reasonable approach for assessing a pipeline's relative business risk is to compare the subject pipeline to a group of pipelines owned by the proxy group companies across various dimensions of business risk. In particular, five relevant considerations for assessing a pipeline's business risk are: supply risk, market risk, competitive risk, operating risk, and regulatory risk.

Q27: How have you compared ANR's business risk to the group of proxy group pipelines?

A27: As discussed above, I believe it is reasonable to compare ANR to the 20 largest pipelines owned by the core proxy group (which I refer to as Proxy Group Pipelines) across five different dimensions of business risk. While there are many ways to compare and assess these various elements of business risk, I rely on the following metrics.

I compare the degree to which ANR and the Proxy Group Pipelines have forward contract cover. In particular, pipelines and shippers often enter into long-term contracts that specify the quantity and price at which the pipeline will provide transportation service. All else equal, a pipeline that has contracted more of its capacity, and for a longer duration, will face lower supply risk, market risk, and competitive risk. This is because the long-term contract assures stable revenues for the pipeline's transportation service at an agreed upon price. It is also important to assess the credit risk of the pipeline's shippers. Contract cover and shipper credit risk can significantly impact a pipeline's exposure to supply, market, and competitive risks due to the need to remarket its capacity as contracts expire or terminate as a result of shipper bankruptcies.

To assess ANR's relative operating risk, I compare its historical maintenance and modernization capital expenditures to those of the Proxy Group Pipelines. In my opinion, a pipeline's maintenance and modernization capital expenditures are a good proxy for a pipeline's operating risk. If the pipeline has, or will, spend more on maintenance and modernization than its peers, it will likely experience a higher degree of operating risk.

Lastly, because ANR and the Proxy Group Pipelines are all FERC-regulated interstate pipelines, they are all subject to the same regulatory regime. For this reason, I do not consider ANR to face relatively more regulatory risk than the largest 20 proxy group pipelines. Therefore, I do not consider regulatory risk for the remainder of my analysis.

When I compare the business risk of ANR to the business risk of the Proxy Group Pipelines, I am considering the group as a whole and not comparing ANR to any individual pipeline in the sample. Specifically, I compare the business risk metrics for ANR to the average and median of the Proxy Group Pipelines. This is because the purpose of my analysis is to place ANR's business risk in relation to the proxy group. The averages and medians are properties of the group as a whole and will be impacted if the composition of the group changes.

1. Contract cover

Q28: What is contract cover?

A28: Shippers and pipelines often enter into long-term contracts that specify the amount of capacity on a pipeline, and the corresponding price, that a shipper may use to transport natural gas on the pipeline. Often, these long-term contracts outline a minimum payment that the shipper will pay the pipeline regardless of whether the shipper uses all of its contracted capacity. This has the effect of reducing a pipeline's supply risk, market risk, and competitive risk as the long-term contract guarantees the pipeline a certain level of revenue regardless of market conditions in its origin and destination markets.

Contract cover measures the average duration of a pipeline's long-term contracts for long-term transportation service to its shippers. A pipeline's contract cover increases as the average duration of its long-term contracts increases. For example, a pipeline for which 80 percent of its long-term contracts are contracted out for 10 years or more will have higher contract cover than a pipeline for which 50 percent of its long-term contracts are contracted out for 10 years or more.

Q29: Please explain the alternatives available to a pipeline if a shipper defaults or does not renew its contracted capacity.

A29: If a shipper defaults on or does not renew its contracted capacity, leaving the pipeline with unsubscribed capacity, the pipeline will typically attempt to re-contract the unsubscribed capacity. The FERC requires pipelines to contract out unsubscribed capacity to any shipper willing to pay the recourse rate. The recourse rate is determined by the FERC and is tied to the pipeline's costs of providing transportation service.

If, however, there is no demand for the pipeline's transportation service at the recourse rate, the pipeline may attempt to contract out its capacity at a rate below the recourse rate.

If demand is low enough, or there is competition from other pipelines, a pipeline may not be able to re-contract its unsubscribed capacity at all.

Q30: How did you assess business risk using contract cover?

A30: I consider the length of ANR's and the Proxy Group Pipelines' current contracts in order to assess business risk relating to contracting. To conduct my analysis, I rely on publicly available shipper contract data for each of the Proxy Group Pipelines in addition to ANR. This data is publicly available because FERC requires interstate natural gas pipelines to file a list of all of their shipper contracts on a quarterly basis.

The list, known as the "Index of Customers," includes information on volume, contract length, and receipt/delivery points associated with each shipper contract. I use the Q1 2021 Index of Customers to calculate several measures of contract cover, as I discuss below.[7]

Q31: Please describe your approach for measuring business risk exposure from long-term contracts.

A31: I employ several methods for assessing business risk exposure from long-term contracts. Specifically, I calculate the capacity-weighted average contract life and the age-discounted net present value of the pipeline's remaining contract life. I also evaluate the credit risk for the shippers for each pipeline. A pipeline's risk exposure can be mitigated with long-term contracts with creditworthy shippers. Consequently, longer contract lengths and creditworthy shippers generally result in less risk exposure for the pipeline.

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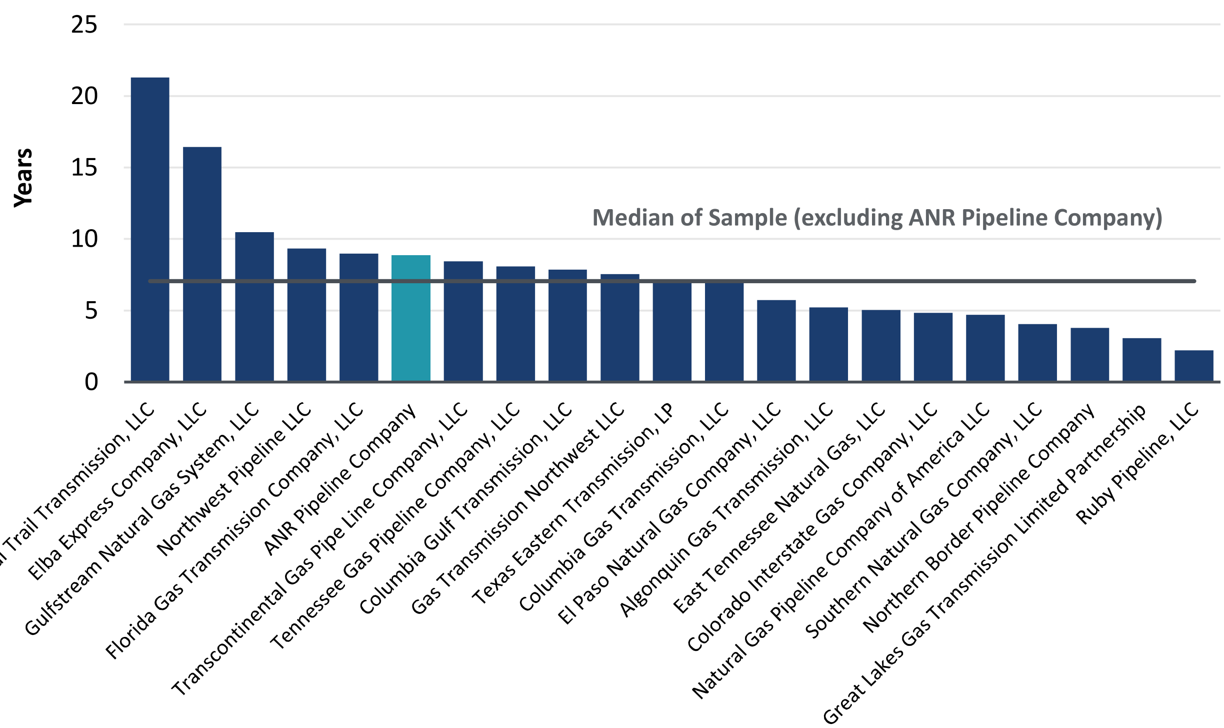
[7] I rely on the database of Q1 2021 index of customers complied by the S&P Market Intelligence (SNL Energy) for my analysis. This database does not designate if contracted quantities are summer or winter capacity. However, I understand that the Q1 2021 index of customers database reflects the contracted capacity as of January 1, 2021. That is, for contracts that have contracted volumes that vary by season, the Q1 2021 report reflects the winter capacities. While SNL Energy also provides a database of Q2, Q3, and Q4 2021 index of customers, the contracted capacities in these reports could reflect a mix of summer, winter, or annual capacities. Therefore, in order to perform a like-for-like comparison, I use the database based on Q1 2021 index of customers reports.

Q32: How does ANR compare to the 20 largest proxy group pipelines in terms of its capacity-weighted average contract life?

A32: I calculate the capacity-weighted average duration of long-term contracts held by ANR and the Proxy Group Pipelines as a measure of the pipelines' exposure to long-term contracting risk. The capacity-weighted average contract life captures the average duration of time for which a pipeline has contracted out its capacity. Figure 4 illustrates the capacity-weighted average contract life for the Proxy Group Pipelines and ANR. As shown in the figure, ANR has a capacity-weighted average contract life of 8.9 years while the median weighted-average contract life for the Proxy Group Pipelines is 7.1 years. As such, ANR has higher contract cover than the median of the pipelines in the core proxy group.

Figure 4: Capacity-Weighted Average Remaining Life



Sources and Notes:
Data from Q1 2021 Index of Customers via S&P Market Intelligence (accessed 12/14/2021). Weighted average life remaining calculated as the average remaining contract life weighted by volume, starting on January 1, 2021. See Thapa Workpaper #3.

Q33: Are there any limitations to solely relying on the capacity-weighted average contract life as a proxy for exposure to long-term contracting risk?

A33: Yes. One limitation to analyzing the capacity-weighted average contract life is that it weighs capacity evenly over time. However, the value of long-term contracting protection is greater in earlier years than in later years. This is consistent with standard valuation theory where companies are assumed to value present earnings more than future earnings, holding all else equal. To account for this imbalance, I calculate an age-discounted net present value measure of contract cover that assigns more weight to the value of contract coverage in earlier years over contracts signed in later years.

Q34: How did you analyze forward contract cover using the age-discounted net present value?

A34: The age-discounted net present value measure of contract cover places greater weight on contract commitments closer to 2021 than in later years. To calculate the age-discounted net present value, I first calculate the quantity of contracted capacity in 2021 and each subsequent year for each pipeline. Then, I calculate the quantity of capacity in each year that would have been contracted if none of the current contracts expired, which represents the maximum capacity subscribed. Finally, I calculate a discounted total for both measures and calculate the ratio of total discounted contracted capacity to the total discounted maximum capacity. Figure 5 shows this metric over 5-, 10-, and 25-year time periods.

Figure 5: Age-Discounted Contract Capacity Cover

Pipeline System	5-Year Contract Cover	10-Year Contract Cover	25-Year Contract Cover
Elba Express Company, LLC	99%	97%	84%
Sabal Trail Transmission, LLC	98%	98%	94%
Gulfstream Natural Gas System, LLC	95%	90%	66%
Florida Gas Transmission Company, LLC	89%	76%	57%
Tennessee Gas Pipeline Company, LLC	83%	69%	52%
Gas Transmission Northwest LLC	82%	65%	49%
Northwest Pipeline LLC	77%	68%	53%
Columbia Gas Transmission, LLC	75%	63%	46%
Colorado Interstate Gas Company, LLC	73%	54%	37%
Transcontinental Gas Pipe Line Company, LLC	73%	65%	50%
Columbia Gulf Transmission, LLC	72%	63%	49%
ANR Pipeline Company	**71%**	**57%**	**46%**
East Tennessee Natural Gas, LLC	69%	49%	36%
El Paso Natural Gas Company, LLC	69%	55%	39%
Natural Gas Pipeline Company of America LLC	64%	47%	34%
Algonquin Gas Transmission, LLC	61%	51%	37%
Texas Eastern Transmission, LP	61%	51%	40%
Northern Border Pipeline Company	60%	43%	30%
Great Lakes Gas Transmission Limited Partnership	53%	37%	25%
Southern Natural Gas Company, LLC	50%	40%	29%
Ruby Pipeline, LLC	38%	26%	18%
Average (excluding ANR Pipeline Company)	72%	60%	46%
Median (excluding ANR Pipeline Company)	72%	59%	43%

Sources and Notes:
Data from Q1 2021 (01/01/2021) Index of Customers via S&P Market Intelligence (accessed 12/14/2021). Ratios calculated as discounted contracted capacity divided by discounted maximum capacity. Maximum annual capacity calculated as the maximum daily contracted capacity on the pipeline multiplied by 365.25. A discount rate of ten percent is used. Pipeline systems are ranked by 5-Year Contract Cover. See Thapa Workpaper #4.

Q35: How does ANR compare to the proxy group on this age-discounted measure?

A35: As seen in Figure 5 above, ANR has similar contract coverage to the median of the core Proxy Group Pipelines when factoring in the time value of contracts. I have analyzed the age-discounted contract cover for these pipelines over three different time horizons. First, I assess the net present value of contract coverage for contracts in effect during the period 2021 through 2025, ignoring all contracts extending beyond 2025. Second, I evaluate the net present value of contracts in effect during the period 2021 through 2030, ignoring all contracts extending beyond 2030. Third, I calculate the net present value of all contracts in effect from

2021 through 2045. I do not extend my analysis beyond these three scenarios because I do not expect investors would place any significance on the existence of contracts further into the future than 2045. Figure 5 shows that for all three measures, ANR is similar to the average of the Proxy Group Pipelines.

Q36: What other factors do you consider for assessing ANR's contract cover relative to the Proxy Group Pipelines?

A36: I consider the contractual commitments by shipper type and a qualitative assessment of shipper's creditworthiness. In order to do this, I classified shippers into various groups of differing credit quality which include natural gas producers, marketers, gas-fired generators, and gas utilities.[8] Of these groups, I would expect natural gas producers to have the highest credit risk, the utilities to have the lowest credit risk, and the marketers and gas-fired generators to have intermediate credit risk.

Natural gas producers have higher exposure to commodity price fluctuations. While the producers may enjoy higher degree of financial stability during periods of high oil and gas prices, there are uncertainties with future prices as commodity prices often fluctuate. During periods where oil and gas prices are low, shippers are more likely to be exposed to financial pressures and may file for bankruptcy protection. As such, shippers who are natural gas producers are more likely to have low credit quality and have a higher likelihood to default on their contractual obligations. In fact, one of ANR's largest shippers, Gulfport Energy Corporation ("Gulfport"), recently filed for bankruptcy in 2020. As a result of the bankruptcy, Gulfport turned back 283,700 Dth/d of maximum tariff rate capacity. As discussed in Mr. Lakhani's testimony, ANR could potentially lose $89 million between 2022 and 2026 on this turned back capacity, assuming ANR is able to remarket the capacity at current forward values which are lower than the maximum tariff rate that Gulfport was previously paying to ANR. Therefore, as highlighted by ANR's recent experience, a higher

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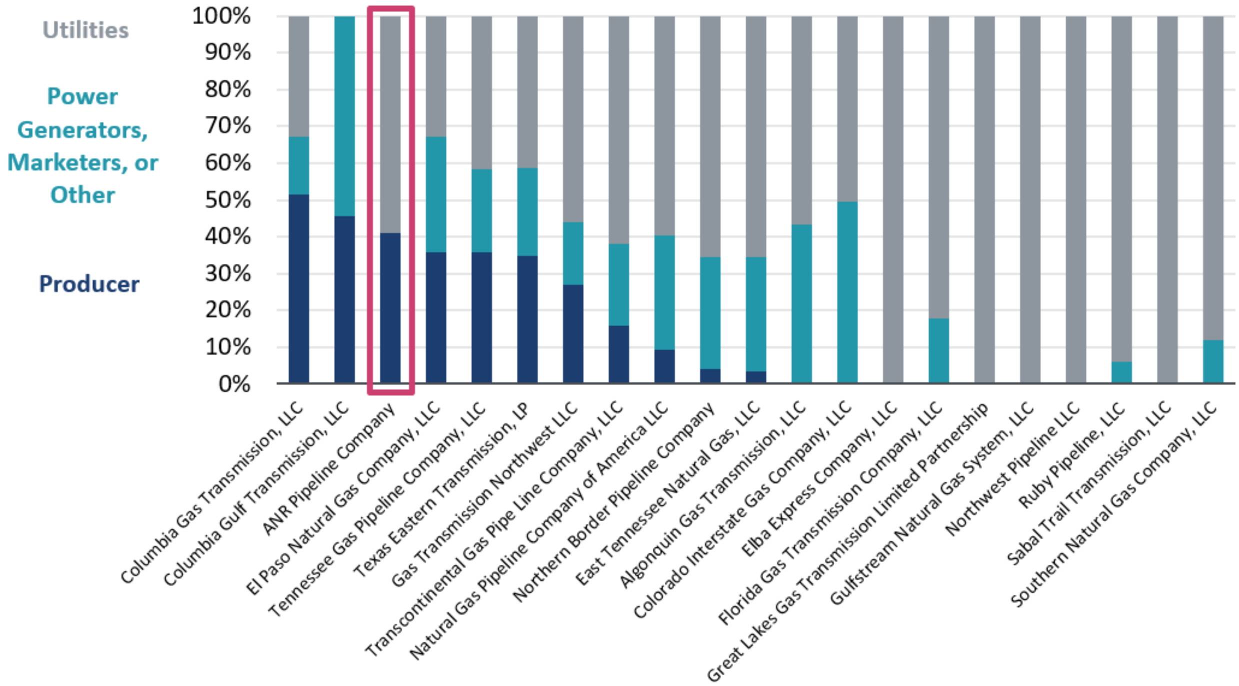
[8] Since there are over a thousand different shippers listed in the index of customers reports for ANR and the 20 Proxy Group Pipelines, I focused my analysis on the largest shippers representing the top 80% of capacity holdings in order to simplify my analysis.

level of contractual commitment by producer-shippers can expose a pipeline to additional business risks such as requiring the pipeline to remarket a large share of its capacity, potentially at lower rates, during a market downturn if contracts are terminated as a result of a bankruptcy. Comparatively, regulated utilities have higher credit quality and pose less credit and re-marketing risk to the pipeline because utilities are less impacted by fluctuations in the commodity market as they can generally pass their natural gas procurement costs on to end-users.

Q37: Please explain the influence a shipper's credit risk and contractual commitments can have on ANR's business risk.

A37: Both the shipper's credit risk and contractual commitments to ANR have a significant impact on ANR's business risk. Figure 6 shows ANR has the third highest contractual commitments from producer-shippers compared to other pipelines. Due to the higher credit risk from producer-shippers and the large share of contractual commitments from producer-shippers, ANR is exposed to significant re-marketing risk.

Figure 6: Split of Discounted Contractual Commitment by Type of Shipper



Sources and Notes:
Data from Q1 2021 Index of Customers via S&P Market Intelligence (accessed 12/14/2021). Percentages calculated using forward contract commitments, discounted on a ten-year basis with a discount rate of 10 percent. See Thapa Workpaper #7.

Q38: Do the results of your age-discounted capacity coverage analysis change if producers are excluded?

A38: I have calculated the age-discounted contract coverage that excludes contracts with natural gas producers. Figure 7 shows that ANR has less contract cover than the median of the Proxy Group Pipelines when excluding contracts with gas producers.

Figure 7: Age-Discounted Contract Cover, Excluding Contracts with Gas Producers

Pipeline System	5-Year Contract Cover	10-Year Contract Cover	25-Year Contract Cover
Elba Express Company, LLC	99%	61%	41%
Sabal Trail Transmission, LLC	98%	60%	41%
Gulfstream Natural Gas System, LLC	95%	59%	40%
Florida Gas Transmission Company, LLC	89%	55%	37%
Northwest Pipeline LLC	77%	47%	32%
Colorado Interstate Gas Company, LLC	73%	45%	31%
Gas Transmission Northwest LLC	67%	41%	28%
East Tennessee Natural Gas, LLC	67%	41%	28%
Transcontinental Gas Pipe Line Company, LLC	64%	40%	27%
Algonquin Gas Transmission, LLC	61%	38%	26%
Tennessee Gas Pipeline Company, LLC	61%	37%	25%
Natural Gas Pipeline Company of America LLC	60%	37%	25%
Northern Border Pipeline Company	59%	36%	24%
Great Lakes Gas Transmission Limited Partnership	53%	33%	22%
ANR Pipeline Company	**51%**	**32%**	**21%**
El Paso Natural Gas Company, LLC	50%	31%	21%
Southern Natural Gas Company, LLC	50%	31%	21%
Columbia Gas Transmission, LLC	47%	29%	20%
Columbia Gulf Transmission, LLC	46%	29%	19%
Texas Eastern Transmission, LP	44%	27%	18%
Ruby Pipeline, LLC	38%	23%	16%
Average (excluding ANR Pipeline Company)	65%	40%	27%
Median (excluding ANR Pipeline Company)	61%	38%	26%

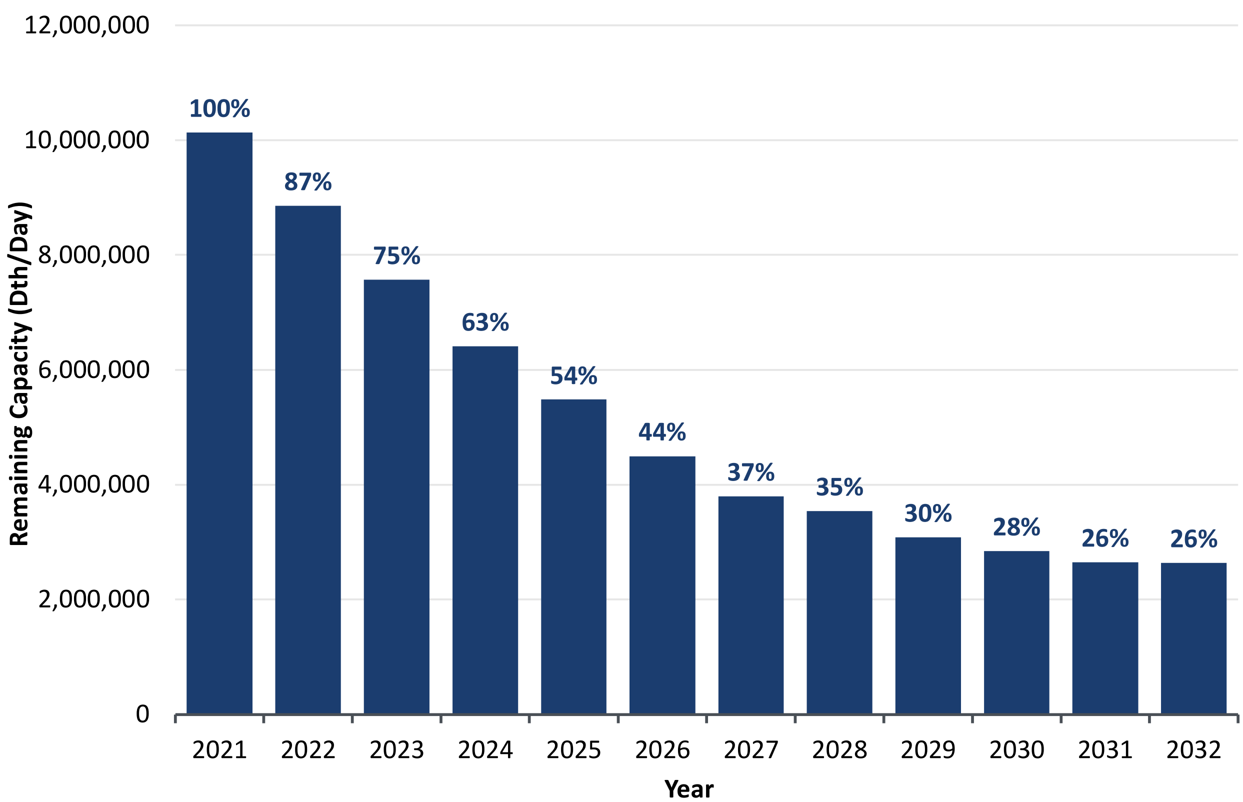
Sources and Notes:
Data from Q1 2021 (1/1/2021) Index of Customers via S&P Market Intelligence (accessed 12/14/2021). Ratios calculated as discounted contracted capacity divided by discounted maximum capacity. Maximum annual capacity calculated as the maximum daily contracted capacity on the pipeline multiplied by 365.25. A discount rate of ten percent is used. Pipeline systems are ranked by 5-Year Contract Cover. See Thapa Workpaper #5.

Q39: Can you describe ANR's contract expiration profile?

A39: Yes. Figure 8 shows the level of contracted capacity on ANR through 2032. As shown in the figure, over half of currently-contracted capacity could expire by 2026 exposing it to re-marketing risk. Mr. Lakhani provides segment level details on ANR's contract expiration profile in his testimony. As described in Mr. Lakhani's testimony, there are significant contract capacity expirations over the next 5 – 10 years. According to Mr. Lakhani, contracting levels for the SW Area decline to zero after 2025. SW Mainline and SE Mainline Northbound contracting levels are expected to decline by 57 percent, and 34 percent from

2022 to 2026, respectively. By 2030, only 14 percent and 36 percent of capacity from the SW Mainline and SE Mainline will remain under contract, respectively. Similar to other pipelines that will experience contract expirations in the near future, these expiring contracts will create challenges for ANR in the near future. As these contracts on ANR expire, the pipeline will have to re-market and re-contract its capacity.

Figure 8: ANR Contracted Capacity (2021 – 2032)



Sources and Notes:
Data from Q1 2021 (1/1/2021) Index of Customers via S&P market intelligence (accessed 12/14/2021). Ratios calculated as discounted contracted capacity divided by discounted maximum capacity. Maximum annual capacity calculated as the maximum daily contracted capacity on the pipeline multiplied by 365.25. A discount rate of ten percent is used. Pipeline systems are ranked by 5-Year Contract Cover. See Thapa Workpaper #8.

Q40: What are your overall conclusions regarding the impact of forward contracting on ANR's business risk?

A40: While ANR has a higher capacity-weighted average remaining contract life compared to the median of the Proxy Group Pipelines, I find that it has above average contract cover risk because it has an relatively high share of contractual commitments from high-risk (low credit quality) producer-shippers. This high exposure to low credit quality producer-shippers exposes ANR to substantial credit risk and re-marketing risk as the recent experience with Gulfport demonstrates.

2. Operating risks

Q41: How would you describe operating risk?

A41: Operating risk relates to the risk that a pipeline may incur higher levels of costs to maintain its service levels. If a pipeline is likely to incur significant expenses related to the maintenance of its pipeline, then the pipeline likely has high operating risk. As I mention above, it is common for older pipelines to spend more on the maintenance of its pipeline than is the case for newer pipelines. Therefore, it is typical for older pipelines to have higher operating risk relative to newer pipelines.

Q42: Can you describe your process for analyzing the operating risk for ANR?

A42: In order to assess the operating risk of ANR, I compare the historical maintenance and modernization capital expenditures across the Proxy Group Pipelines and ANR. Maintenance and modernization capital expenditures are investments made to maintain the service levels on the pipeline or to modernize the pipeline to improve safety and reliability rather than investments to increase the pipeline's capacity (*e.g.*, expansion costs). Thus, maintenance and modernization capital expenditures can be used to measure a pipeline's operating risk.

Q43: Can you describe how you calculate maintenance and modernization capital expenditures for each of the Proxy Group Pipelines?

A43: Yes. Since I do not have access to data on the maintenance and modernization capital expenditures of the Proxy Group Pipelines, I estimate the maintenance and modernization capital expenditures by using data from FERC Form 2 and the EIA's Natural Gas Pipeline Projects database. Specifically, I rely on total transmission plant additions reported on each pipeline's FERC Form 2 and expansion costs reported in EIA's Natural Gas Pipeline Projects database. The total transmission plant additions reported in the FERC Form 2 include both maintenance and modernization capital expenditures and expansion capital expenditures. Therefore, a reasonable proxy for maintenance and modernization capital expenditures can be obtained by subtracting expansion costs (as reported in the EIA data) from the total transmission plant additions reported in the FERC Form 2. I employ this method in my analysis below.

Q44: Can you discuss the operating risk of ANR in relation to the operating risk of the Proxy Group Pipelines?

A44: Yes. Figure 9 shows the average maintenance capital and modernization expenditures from 2016-2019, calculated as described above, in relation to the 2015 net utility plant for each pipeline. I express maintenance expenditures in relation to net utility plant because one would expect maintenance expenditures to increase in proportion to the size of the pipeline. By expressing maintenance expenditures as a percentage of net utility plant, I can standardize the expenditures across the pipelines in the proxy group. As shown in the figure, ANR's historical maintenance and modernization capital expenditures are higher than 19 of the 20 Proxy Group Pipelines.

I understand that ANR plans to continue making large maintenance and modernization capital expenditures in the future. As explained by ANR witness Linder, ANR is planning to invest $900 million over 5 years under the modernization program.[9]

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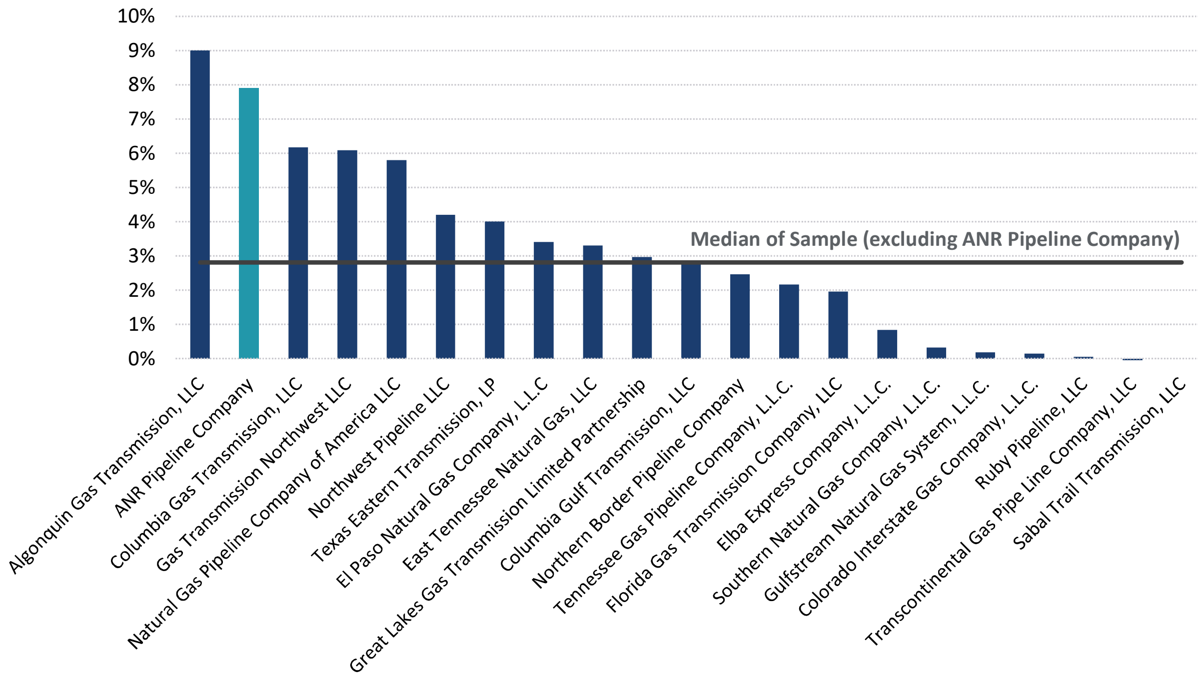
9 *See* the prepared direct testimony of ANR witness Linder.

Figure 9: Average Annual Transmission Plant Additions less Expansion Capex as Percentage of Net Utility Plant



Sources and Notes:

U.S. Natural Gas Pipeline Projects, EIA, release date 04/29/2021. Historical transmission plant additions from 2017-2020 FERC Form 2 via S&P market intelligence (accessed 05/11/21). Net Utility Plant: Gas from 2016 FERC Form 2 via S&P Market Intelligence (accessed 05/11/21). See Thapa Workpaper #9.

VI. CONCLUSIONS

Q45: What is your overall conclusion?

A45: I find that ANR has above average business risk in comparison to the proxy group. ANR has supply risk due to production uncertainty in the key supply basins serving its western leg and has experienced an increase in competition from new pipelines in its supply and market areas. However, the major driver of ANR's business risk is its exposure to shipper credit risk. ANR has a relatively high share of contracts with high-risk (lower credit quality) producer-shippers compared to the Proxy Group Pipelines. This risk was demonstrated by the recent bankruptcy of a large ANR producer-shipper that resulted in significant capacity turn backs, which may lead to substantial revenue loss for the pipeline. Additionally, ANR has the second highest historical maintenance and modernization capital expenditures compared to the Proxy Group Pipelines.

Q46: Do you support Dr. Villadsen's proposal to set the ROE for ANR at the average of the median of the upper 1/3 of the Zone of Reasonableness?

A46: Yes, I do. In my opinion, Dr. Villadsen's proposal is reasonable and justified, given that ANR has a higher level of business risk compared to the median of the Proxy Group Pipelines.

Q47: Does this conclude your direct testimony?

A47: Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-___-000

AFFIDAVIT OF ANUL THAPA

I, Anul Thapa, state that the information contained in my Prepared Direct Testimony is true and correct to the best of my knowledge and if asked the questions that appear in the text of this Prepared Direct Testimony, I would give the answers that are also set forth therein, and I adopt this Prepared Direct Testimony as my sworn testimony in this proceeding.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed this 24 day of January, 2022.

Anul Thapa
____
Anul Thapa

State of Texas
County of Harris
Sworn at and subscribed before me on 01/24/2022 by Anul Thapa.

NOTARY PUBLIC STATE OF TEXAS
Lisa Nicole Viser
ID NUMBER
133045738
COMMISSION EXPIRES
April 16, 2025

Lisa Nicole Viser
____
Notary Public, State of Texas

My Commission Expires: 04/16/2025

My Commission ID: 133045738

Notarized online using audio-video communication

ANUL THAPA

Principal

Boston, MA | +1.617.864.7900 | Anul.Thapa@brattle.com

Mr. Anul Thapa is a Principal in the Boston, MA office of The Brattle Group. He specializes in applying economics and finance principles to estimate damages and value energy assets and contracts in complex litigation, arbitration, and regulatory proceedings. He also has expertise in regulatory economics of the midstream oil and gas sector. Mr. Thapa works closely with testifying experts to develop and present economic and financial testimony and also provides non-testimonial consulting services to counsel.

Mr. Thapa's experience in commercial disputes includes damages estimation, valuation and pricing related to energy assets and contracts. He has experience evaluating pricing of and damages arising from disputes involving natural gas storage facilities, long-term purchase and sale agreements for natural gas and LNG, oil and natural gas pipeline transportation contracts, natural gas gathering and processing contracts, natural gas storage contracts, and power purchase agreements. Mr. Thapa builds complex discounted cash flow models and applies discount rates that are appropriate for the risk profiles of these cash flows to assess the value of these assets and contracts and to estimate damages.

Mr. Thapa's experience in regulatory economics includes analyzing the rates charged by natural gas and oil pipelines, the business risks faced by natural gas pipelines, the economic justification for proposed natural gas pipelines and LNG storage facilities, pipeline access issues, and evaluating competition and market manipulation in natural gas markets. Mr. Thapa has testified before the Maine Public Utilities Commission and submitted written testimony before the Federal Energy Regulatory Commission.

He is an author of "Understanding Natural Gas Markets" prepared for the American Petroleum Institute in 2014.

Mr. Thapa worked as a Research Associate at *Brattle* from 2006-2009 assisting testifying experts in energy-related litigation and regulatory matters. He also has previous experience as a Summer Associate in the Acquisition and Strategic Department at Harvest Power, a renewable waste-to-energy company.

Mr. Thapa received an M.B.A. with a concentration in finance from MIT Sloan School of Management and a B.A. magna cum laude in Mathematics and Computer Science from DePauw University.

AREAS OF EXPERTISE

- *Commercial Damages in Oil and Gas Litigation and Arbitration*
- *Oil & Gas Bankruptcy*
- *Ratemaking and Regulatory Policy*
- *Gas-Electric*

EXPERIENCE

Commercial Damages in Energy-Related Litigation and Arbitration

- **International LNG Arbitration**, consulting expert to the owner of a liquefied natural gas (LNG) import terminal regarding the compensation owed to them by a party from termination of a Terminal Use Agreement (TUA) and counterclaim associated with the party's actions that thwarted the client's ability to develop a liquefaction project.

- **International LNG Price Review Arbitration**, consulting expert to a consortium of sellers regarding the appropriate price for LNG cargoes pursuant to the price review provisions of an LNG sale and purchase agreement. Mr. Thapa led a team to assess whether the existing price formula needed to be changed pursuant to the price review clause in the LNG sale and purchase agreement.

- **International LNG Price Review Arbitration under UNCITRAL rules**, consulting expert to a consortium of sellers regarding the appropriate price for LNG cargoes sold and amounts due to sellers pursuant to the price review provisions of an LNG sale and purchase agreement. Mr. Thapa led a team to create a model to analyze various relevant contracts to assess the appropriate price applicable to the LNG cargoes sold and delivered by the sellers to the buyer during the relevant period and calculate the amounts due.

- **Antero Resources Corporation v. South Jersey Resources Group LLC and South Jersey Gas Company (United States District Court of Colorado Civil Action No. 1:15-cv-00656-REB-MEH)**, consulting expert to Antero Resources Corporation in a dispute involving a Marcellus-area, long-term North American Energy Standards Board (NAESB) natural gas supply contract. Mr. Thapa analyzed the contemporaneous evidence regarding the underlying transaction composition of published natural gas price indices and examined natural gas market conditions in the Marcellus area and the contracting parties' pipeline transportation arrangements to support Antero's claims of damages.

- **BP Products North America Inc. v. Sunoco Pipeline L.P. (FERC Docket No. OR15-25-000)**, consulting expert to BP Products North America Inc. (BP) on the damages to BP's Toledo refinery as a result of the discriminatory conduct of Sunoco Pipeline that reduced BP's allocation of pipeline capacity and required BP to purchase more expensive crude oil on alternative pipeline routes.

- **Rockies Express Pipeline LLC v. Department of the Interior (U.S. Civilian Board of Contract Appeals No. 1821)**, consulting expert to U.S. Department of the Interior Minerals Management Service (MMS) on the damages to Rockies Express Pipeline resulting from the termination of a long-term natural gas pipeline transportation contract by MMS. Mr.

Thapa worked closely with the testifying experts to estimate damages under three different damage theories.

- **United States of America v. 9.345 Acres of Land, more or less, situated in Iberville Parish, State of Louisiana, and Sidney Vincent Arbour, III, et al. (United States District Court Middle District of Louisiana Civil Action No. 3:11-CV-803-JWD-EWD,** consulting expert to the Department of Justice (representing the United States of America) on the factors impacting the value of natural gas storage facility acquired by the government through condemnation.

- **Chevron Pipe Line Company v. Sunoco Pipeline, L.P. (Court of Chancery of the State of Delaware, C.A. No. 8573-VCL),** consulting expert to Chevron Pipe Line Company on the damages that resulted from the majority owner of a crude oil pipeline entering into a pipeline lease with a subsidiary at a below-market lease price. Mr. Thapa analyzed the demand for oil pipeline transportation services in Texas and the prices obtained for oil pipeline transportation service on new oil pipeline projects serving the Gulf Coast market.

- **Estimating Damages Related to Alleged Trespass by Pipeline (United States District Court for the Western District of Oklahoma, Civ. No. 5:15-cv-01262-M),** consulting expert to Enable Midstream Partners, L.P. to evaluate the calculation of damages arising from alleged trespass of plaintiff's property by Enable's pipeline prepared by the opposing expert.

- **Estimating Damages Related to Breach of Power Purchase Agreement,** consulting expert to a large diversified energy company in Canada to estimate damages owed to the energy company due to a breach of a contract (power purchase agreement) by its counterparty. Mr. Thapa created a discounted cash flow model and disaggregated the cash flows related to the power plant into individual components with distinct risk profiles and applied appropriate discount rates to each component order to accurately value the damages.

- **Estimating Damages Related to Breach of Gas Supply Agreement,** consulting expert to a large multi-national energy company with power plant operations in South America, assisted in preparation of expert report estimating the damages owed by a natural gas provider to our clients due to the breach of a long-term natural gas supply agreement. Modeled the deliver-or-pay penalties and damages associated with the breach of contract.

- **Assessment of Factors Affecting Valuation of Natural Gas Storage Facility,** consulting expert to the U.S. Department of Justice to evaluating the economic assumptions underlying valuation of a natural gas storage facility by the opposing witness.

Oil & Gas Bankruptcy

- **Chesapeake Energy Bankruptcy (Southern District of Texas Bankruptcy Court, Case No. 20-33233),** financial advisor to the Second Lien Notes Indentured Trustee and their counsel, representing over $2.4 billion of claims, in the recent Chesapeake bankruptcy. Advised the clients on Chesapeake's valuation and provided economic analysis to assist counsel in consideration of potential confirmation objection based on Best Interest of Creditor's Test.
- **Contract Rejection in Oil & Gas Bankruptcy,** consulting expert to an oil pipeline in a matter before the bankruptcy court related to a proposed midstream contract rejection by a large oil & gas producer. The producer claimed that the rates charged by the oil pipeline under their contract were above market based on proposals it received from other pipelines in the region. Analyzed the market for oil transportation and the alternative proposals available to the producer and concluded that the services offered under the alternative proposals were of lower quality and subject to higher risk of prorationing compared to the firm service under the current contract.

Ratemaking and Regulatory Policy

- **Pipeline Business Risk,** Mr. Thapa has submitted testimony before the Federal Energy Regulatory Commission (Docket No. RP21-778) evaluating the business risk of Southern Star Central Gas Pipeline in relation to the pipelines owned by the proxy group companies. He has also assisted in the preparation of several expert testimonies analyzing the business risk of North American natural gas pipelines where he conducted quantitative analysis and performed comparative risk studies of various North American pipelines and LDCs.

- **Recommendations regarding Maine Physical Energy Storage Contract (Maine Public Utilities Commission, Docket No. 2016-00253),** submitted testimony evaluating the PUC staff consultant's report analyzing proposals for LNG storage in Maine. The testimony highlighted the substantial risk to ratepayers associated with the LNG storage proposals and recommended the Commission to not proceed with the proposals.

- **Oil Pipeline Rates and Rate Design (FERC Docket No. IS12-226-000, FERC Docket No. IS12-203-000, FERC Docket No. OR14-4-000, FERC Docket No. OR17-11),** consulting expert on proceedings evaluating the reasonableness of rates and rate design on major crude oil and products pipelines. This included assessing the appropriateness of cost-of-service and market-based rates for the pipeline.

- **Analyzing Market Manipulation (FERC Docket No. IN06-3-003),** consulting expert for the Enforcement Litigation Staff of the Federal Energy Regulatory Commission in an investigation of the activities of a natural gas trading company over a two-year period.

Determined that the company manipulated the index price of natural gas at a specific location through its trading patterns on the Intercontinental Exchange (ICE) trading platform. The company's fixed-price sales transactions dominated the price index reported by Platts at that location, and its trading patterns were designed to lower the price index in order to benefit the company's trading positions that were established to profit from downward price movements. The results of the investigation were included in a report to the Federal Energy Regulatory Commission.

- **Imputing Expenditures Consistent with Authorized Revenue Requirements,** consulting expert for a large utility evaluating the level of capital and operating expenditures corresponding to the rates that had been authorized in prior rate case proceedings spanning over a decade for two separate lines of businesses. Constructed a cost-of-service model to impute the level of operating expenses and capital expenditures that were consistent with the authorized revenue requirement in each year.

- **Pricing for Long-Term Natural Gas Contracts**, consulting expert to Alaskan natural gas utility. Mr. Thapa assisted in preparation of expert testimony regarding the price terms for long-term contracts between the utility and large natural gas producers.

Gas-Electric

- **Recommendations regarding Maine Energy Cost Reduction Act**. Provided advice and analysis to the Maine Office of Public Advocate regarding the Maine Energy Cost Reduction Act. The Act authorizes the Maine Public Utilities Commission (PUC) to procure up to 200 million cubic feet of natural gas pipeline capacity for a cost not exceeding $75 million annually. The Act addressed concerns that, in the face of rising demand for natural gas, limited investment in natural gas transportation infrastructure in the region could threaten reliability and the economy. Assisted in preparation of written evidence on behalf of the Maine OPA on this matter.

- **Assist Massachusetts Attorney General's Office (AGO) in the Gas Infrastructure Investigation.** Assisted the Massachusetts Attorney General's Office (AGO) draft their initial comments in the Massachusetts Department of Public Utilities' docket investigating the means by which new natural gas delivery capacity may be added to the New England market, including the role of the Massachusetts electric utilities (EDCs) in this matter. Analyzed the drivers of natural gas price spikes in New England and identified the scope of potential solutions to evaluate; and developed a framework for evaluating the candidate solutions, including the key modelling elements required to conduct a proper evaluation.

One of the recommendations was to use total resource cost (TRC) as the primary economic evaluation metric instead of metrics that are based on price suppression. Also provided advice on potential solutions to avoid conflicts of interest and foster competition in the procurement of solutions.

- **Advising Midcontinent ISO on Gas-Electric Reliability Challenges.** Advised the Midwest ISO regarding potential gas-electric challenges the ISO might face as coal retirements and retrofits cause more reliance on natural gas in the region. Assisted the ISO define the problem by building a framework for understanding the gas-electric issue and also catalogued the existing gas-electric challenges and solutions implemented and proposed in other ISOs. Provided valuable inputs on cost of firm gas and cost and operational characteristics of dual-fuel capability for an ongoing MISO study comparing the cost of firm gas and dual-fuel.

- **Connecticut IRP and Assessment of Reliance on Gas in New England.** Worked with the investor-owned utilities in Connecticut to develop statewide 10-year Integrated Resource Plans (IRP) under a legislative mandate. As part of the study, analyzed gas market supply and demand conditions in New England and the effects of reliance on natural gas on the reliability of the New England electricity grid. The analysis showed that although non-gas generation capacity together with gas-fired generation (with either access to firm fuel or dual-fuel capability) is sufficient to meet peak-day demand during the planning horizon, the firmness of fuel supply or dual-fuel capabilities are not currently verified and there is no guarantee that these capabilities will be maintained in the future.

- **Evaluation of Energy Market Prices in ATSI and PJM.** For a major retail energy provider in the region, analyzed the natural gas and electricity price spikes in ATSI and PJM during the winter weather events during 2014 to understand whether the recent price spikes in energy and natural gas markets in PJM are indicative of similar episodes over the next few years. Oversaw the analysis of regional natural gas prices and flows on various pipelines serving the region along with research on the expected changes in natural gas infrastructure in the region in the next few years.

Other

- **Natural Gas Primer.** Co-authored a report for the American Petroleum Institute (API) that provided a comprehensive overview of the natural gas markets. "Understanding Natural Gas Markets," discusses the implications of increased U.S. natural gas production. Technological advancements in natural gas extraction methods have made unconventional shale gas resources more accessible and economic. As of 2013, shale gas production accounted for approximately 40% of U.S. Lower 48 natural gas production, compared to approximately 5% in 2006. The growth in natural gas supply has outpaced demand growth, resulting in lower prices and lower volatility. The report discusses several key trends affecting the industry, and describes some of the key changes that will affect U.S. natural gas markets and prices in the coming years.

- **Market Power in a Gas-Electric Merger.** Evaluated the potential for increased market power from a vertical merger between a natural gas utility and an electric utility. Assisted in the preparation of presentation before the Federal Trade Commission and expert testimony before a state commission addressing the merger's potential competitive effects.

- **Analyzing Competitive Effects of Proposed Merger.** On behalf of a large utility in Alaska, co-authored a report analyzing the competitive effects on the natural gas industry in the region as a result of a proposed acquisition of all the production and pipeline assets of a producer in the region by another producer. The report concluded that serious anti-competitive concerns existed for gas consumers in the market area and recommended that competitively priced long-term contracts be a condition for the approval of the acquisition.

- **Calculations of Damages Related to Manipulation of Reported Index Prices.** Assisted in the preparation of expert testimony regarding false information provided by natural gas traders to major natural gas publications in order to manipulate reported index prices. Also analyzed voice-broker transaction data to calculate damages.

- **Assessment of Pipelines in the U.S. Northeast.** For a diversified energy company operating in Pennsylvania, experts analyzed changes in flows on various pipelines in Pennsylvania, New York and New England and provided strategic advice regarding new infrastructure build-outs in the region designed to transport growing natural gas production from the Marcellus. *Brattle* presented the analysis to senior management of the company.

- **Position Limits for Derivatives.** Assisted an outside expert in preparation of comments to CFTC with relation to its December 2013 notice of proposed rulemaking on position limits for derivatives. Oversaw the research on the use of derivative contracts by various independent natural gas and oil producers.

- **Business Acquisition and Valuation.** Assisted in the successful acquisition of a Canadian recycling company as a Summer Associate at Harvest Power. Built valuation models, assisted in drafting term-sheets, and managed both internal and external resources to facilitate the acquisition.

- **Electric Transmission Network Upgrade Policy.** For a large transmission company in Canada, assisted in preparation of expert testimony evaluating the transmission company's existing and proposed network upgrade policy. The testimony discussed the principles underlying transmission upgrade policy and cost allocation applicable to FERC-regulated transmission companies.

- **Operational and Regulatory Consideration Applicable to "Interruptible" Electricity Sales.** On behalf of a large electric company in Canada, assisted in preparation of expert testimony evaluating whether counterparty to a power purchase agreement with our client had infringed upon the rights of our client by selling power, from capacity committed to our client, to its affiliate on what it claimed to be "interruptible" basis. Since the affiliate of the counterparty exported the "interruptible" power to external markets, Brattle experts considered the applicable industry standards and practices and also reviewed the market rules in these export markets and protocols of transmission providers to conclude that such transactions cannot be interrupted in a timely manner to ensure that rights of our clients under the power purchase agreement are protected.

ACADEMIC HONORS AND FELLOWSHIPS

- MIT Sloan Social Impact Fellowship (2010)

PUBLICATIONS AND PRESENTATIONS

"Demand Response for Natural Gas Distribution: Opportunities and Challenges" (with Jürgen Weiss, Steven H. Levine, Sanem Sergici, and Léa Grausz), June 2018.

"The Global Context for Alaskan Oil and LNG" (with Paul Carpenter and Steve Levine), LSI Energy in Alaska Conference, December 12, 2016.

"LNG and Renewable Power: Risk and Opportunity in a Changing World" (with Jurgen Weiss, Steve Levine and Yingxia Yang), January 15, 2016.

"The Collapse of World Oil Prices and its Effects on Global LNG Trade," (with Paul Carpenter and Steve Levine) Energy Regulatory Commission of Thailand, Bangkok, March 8, 2015.

"Changing Times – New Uncertainties: Assessing Their Effects on Global Energy and LNG Export Markets" (with Paul Carpenter and Steve Levine), LSI Energy Markets and Regulation in Alaska Conference, December 8, 2014.

"Understanding Natural Gas Markets" (with Paul Carpenter and Steve Levine), prepared for the American Petroleum Institute, September 2014.

"Natural Gas Market Update" (with Paul Carpenter and Steve Levine), LSI Electric Utility Rate Cases Seminar, Las Vegas, Nevada, February 27, 2014.

"Outlook for North American Trade in LNG and Oil" (with Paul Carpenter and Steve Levine), LSI Energy Exports in the Northwest Conference, Seattle, Washington, October 24-25, 2013.

"The Uncertain Future of Global LNG Trade" (with Paul Carpenter and Steven Levine), LSI Natural Gas for Transportation and LNG Markets Conference, Washington, DC, July 18, 2013.

"The Uncertain Future for ANS LNG Exports" (with Paul Carpenter and Steven Levine), LSI Energy in Alaska Conference, Anchorage, December 3, 2012.

TESTIMONY AND REGULATORY FILINGS

Before the Federal Energy Regulatory Commission, Docket No. RP21-778-000, Direct Testimony and Supporting Exhibits of Anul Thapa on Behalf of Southern Star Central Gas Pipeline, April 30, 2021.

Before the Maine Public Utilities Commission, Docket No. 2016-00253, *Request for Proposals for Physical Energy Storage Contracts for Liquefied Natural Gas Storage Capacity*, Comments of Steven H. Levine and Anul Thapa on Navigant's December 2016 Report Analyzing Proposals for Liquefied Natural Gas Storage Capacity, January 30, 2017.

Before the Federal Energy Regulatory Commission, Docket No. AD12-12-000, Filed Comments re: Coordination between Natural Gas and Electricity Markets, March 30, 2012 (with Matt O'Loughlin, Frank Graves, Steven Levine and Metin Celebi.

Table of Contents
Anul Thapa Direct Testimony Workpapers

Thapa Workpaper #1: Business Segment Analysis

Table AT-1 (a)

Enbridge Inc.: Segment Data

		($M, CAD)	(%)
Property, Plant and Equipment			
Liquids Pipelines	[1]	$48,799	52%
Gas Transmission and Midstream	[2]	$25,745	27%
Gas Distribution and Storage	[3]	$16,079	17%
Renewable Power Generation	[4]	$3,495	4%
Energy Services	[5]	$24	0%
Eliminations and Other	[6]	$429	0%
Gross PPE	**[7]**	**$94,571**	**100%**
EBITDA			
Liquids Pipelines	[8]	$7,683	71%
Gas Transmission and Midstream	[9]	$1,087	10%
Gas Distribution and Storage	[10]	$1,748	16%
Renewable Power Generation	[11]	$523	5%
Energy Services	[12]	-$236	(2%)
Eliminations and Other	[13]	-$113	
Total EBITDA (Exclude Eliminations and Other)	**[14]**	**$10,805**	**100%**

Sources and Notes:
PPE from Enbridge Inc. 2020 Form 10-K, p. 129.
EBITDA from Enbridge Inc. 2020 Form 10-K, Note , p. 62.

Thapa Workpaper #1: Business Segment Analysis

Table AT-1 (b)

Enbridge Inc.: Gas Transmission and Midstream Revenues and Costs

		($M, CAD)
2020 Gas Transmission and Midstream Revenue		
Transportation Revenue	[1]	$4,523
Storage and other Revenue	[2]	$274
Gas Gathering and Processing Revenue	[3]	$27
Commodity Sales	[4]	$0
Total Revenue from Contracts with Customers	**[5]**	**$4,824**
Transportation and Storage Revenue	[6]	$4,797
Transportation and Storage Revenue as % of Total Revenue	[7]	99%

Sources and Notes:
[1]-[4]: Enbridge Inc. 2020 10-K Form, p.125.
[5]: Sum from[1] to [4].
[6]: [1] + [2]
[7]: [6] / [5]

Thapa Workpaper #1: Business Segment Analysis

Table AT-1 (c)

Enbridge Inc.: Regulated Ratio Summary

		Gas Pipelines & Storage	Oil and Liquids Pipelines	Gas Distribution	Midstream Services	Terminals	Other	Total
Property, Plant and Equipment								
Liquids Pipelines	[1]	0%	52%	0%	0%	0%	0%	52%
Gas Transmission and Midstream	[2]	27%	0%	0%	0%	0%	0%	27%
Gas Distribution and Storage	[3]	0%	0%	17%	0%	0%	0%	17%
Renewable Power Generation	[4]	0%	0%	0%	0%	0%	4%	4%
Energy Services	[5]	0%	0%	0%	0%	0%	0%	0%
Eliminations and Other	[6]	0%	0%	0%	0%	0%	0%	0%
Total	**[7]**	**27%**	**52%**	**17%**	**0%**	**0%**	**4%**	**100%**
EBITDA								
Liquids Pipelines	[8]	0%	71%	0%	0%	0%	0%	71%
Gas Transmission and Midstream	[9]	10%	0%	0%	0%	0%	0%	10%
Gas Distribution and Storage	[10]	0%	0%	16%	0%	0%	0%	16%
Renewable Power Generation	[11]	0%	0%	0%	0%	0%	5%	5%
Energy Services	[12]	0%	0%	0%	0%	0%	-2%	-2%
Total	**[13]**	**10%**	**71%**	**16%**	**0%**	**0%**	**3%**	**100%**

Sources and Notes:
[1]-[6], [8], [10]-[12]: Table AT-1 (a).
[2]: Table AT-1 (a)[2] x Table AT-1 (b)[7].
[9]: Table AT-1 (a)[9] x Table AT-1 (b)[7].

Thapa Workpaper #1: Business Segment Analysis

Table AT-2 (a)

Enterprise Products: Segment Data

		($M, CAD)	(%)
Assets			
NGL Pipelines & Services	[1]	$20,759	40%
Crude Oil Pipelines & Services	[2]	$12,484	24%
Natural Gas Pipelines & Services	[3]	$9,402	18%
Petrochemical & Refined Products Services	[4]	$8,621	17%
Adjustments and Eliminations	[5]	$1,808	
Total Asset (Exlcude adjustment and elimination)	[6]	**$51,265**	**100%**
Operating Income			
NGL Pipelines & Services	[7]	$4,182	51%
Crude Oil Pipelines & Services	[8]	$1,997	24%
Natural Gas Pipelines & Services	[9]	$927	11%
Petrochemical & Refined Products Services	[10]	$1,082	13%
Total Operating Income (Exclude shared activity)	[11]	**$8,188**	**100%**

Sources and Notes:

Assets from Enterprise Product Partners 2020 10-K , p. F-47.

Operating Income from Enterprise Product Partners 2020 10-K, p.F-45.

Thapa Workpaper #1: Business Segment Analysis

Table AT-2 (b)

Enterprise Products: NGL Pipelines and Services

		($M, USD)	(%)
NGL Pipelines and Services			
Natural gas porcessing and related NGL marketing activities	[1]	$1,000	24%
NGL pipelines, storage and terminals	[2]	$2,524	60%
NGL fractionation	[3]	$661	16%
Total	**[4]**	**$4,185**	**100%**

Sources and Notes:
[1]-[3]: Enterprise Products 2020 10-K Form p.78.
[4]: SUM([1]:[3])

Thapa Workpaper #1: Business Segment Analysis

Table AT-2 (c)

Enterprise Products: Regulated Ratio Summary

		Gas Pipelines & Storage	Oil and Liquids Pipelines	Gas Distribution	Midstream Services	Terminals	Other	Total
				Asset - Using total assets				
NGL Pipelines & Services	[1]	0%	24%	0%	16%	0%	0%	40%
Crude Oil Pipelines & Services	[2]	0%	12%	0%	0%	12%	0%	24%
Natural Gas Pipelines & Services	[3]	9%	0%	0%	9%	0%	0%	18%
Petrochemical & Refined Products Services	[4]	0%	0%	0%	0%	0%	17%	17%
Total	**[5]**	**9%**	**37%**	**0%**	**25%**	**12%**	**17%**	**100%**
				Operating Income				
NGL Pipelines & Services	[6]	0%	31%	0%	20%	0%	0%	51%
Crude Oil Pipelines & Services	[7]	0%	12%	0%	0%	12%	0%	24%
Natural Gas Pipelines & Services	[8]	6%	0%	0%	6%	0%	0%	11%
Petrochemical & Refined Products Services	[9]	0%	0%	0%	0%	0%	13%	13%
Total	**[10]**	**6%**	**43%**	**0%**	**26%**	**12%**	**13%**	**100%**

Sources and Notes:
[1]-[10]: See Table AT-2 (a) and Table AT-2 (b).
[1]: Table AT-2 (a)[7] x Table AT-2 (b)[2].
[2]: Table AT-2 (a)[8] x 50%. Assumes that the 'Crude Oil Pipeline & Services' is equally divided between oil pipelines and midstream services
[3]: Table AT-2 (a)[9] x 50%. Assumes that the 'Natural Gas Pipeline & Services' is equally divided between natural gas pipelines and midstream services

Thapa Workpaper #1: Business Segment Analysis

Table AT-3 (a)

Kinder Morgan Inc.: Segment Data

		($M, USD)	(%)
Assets			
Natural Gas Pipelines	[1]	$48,597	71%
Products Pipelines	[2]	$9,182	13%
Terminals	[3]	$8,639	13%
CO2	[4]	$2,478	4%
Corporate Assets		$3,077	
Total Assets (Exclude Corporate Asset)	**[5]**	**$68,896**	**100%**
EBDA			
Natural Gas Pipelines	[6]	$3,483	67%
Product Pipelines	[7]	$977	19%
Terminals	[8]	$1,045	20%
CO2	[9]	-$292	-6%
Kinder Morgan Canada	[10]	$0	0%
Total EBDA	**[11]**	**$5,213**	**100%**

Sources and Notes:
Asset information from 2020 Form 10-K, Note 16, p.128.
EBDA from Kinder Morgan Inc.2020 Form 10-K, Note 16, p. 127.

Thapa Workpaper #1: Business Segment Analysis

Table AT-3 (b)

Kinder Morgan

		Gas Pipelines & Storage	Oil and Liquids Pipelines	Gas Distribution	Midstream Services	Terminals	Other	Total
Asset - Using total asset								
Natural Gas Pipelines	[1]	71%	0%	0%	0%	0%	0%	71%
Products Pipelines	[2]	0%	13%	0%	0%	0%	0%	13%
Terminals	[3]	0%	0%	0%	0%	13%	0%	13%
CO2	[4]	0%	0%	0%	0%	0%	4%	4%
Kinder Morgan Canada	[5]	0%	0%	0%	0%	0%	0%	0%
Total	**[6]**	**71%**	**13%**	**0%**	**0%**	**13%**	**4%**	**100%**
EBITDA								
Natural Gas Pipelines	[7]	67%	0%	0%	0%	0%	0%	67%
Products Pipelines	[8]	0%	19%	0%	0%	0%	0%	19%
Terminals	[9]	0%	0%	0%	0%	20%	0%	20%
CO2	[10]	0%	0%	0%	0%	0%	-6%	-6%
Kinder Morgan Canada	[11]	0%	0%	0%	0%	0%	0%	0%
Total	**[12]**	**67%**	**19%**	**0%**	**0%**	**20%**	**-6%**	**100%**

Sources and Notes:
[1]-[5], [7]-[11]: See Table AT-3 (a).

EBITDA percentages are based on segment-level EBDA values reported by KMI.

Thapa Workpaper #1: Business Segment Analysis

Table AT-4 (a)

TC Energy Co.: Segment Data

		($M, CAD)	(%)
Assets			
Canadian Natural Gas Pipelines	[1]	$22,852	24%
U.S. Natural Gas Pipelines	[2]	$43,217	45%
Mexico Natural Gas Pipelines	[3]	$7,215	8%
Liquids Pipelines	[4]	$16,744	18%
Power and Storage	[5]	$5,062	5%
Corporate	[6]	$5,210	
Total Assets (Exclude Corporate)	**[7]**	**$95,090**	**100%**
EBITDA			
Canadian Natural Gas Pipelines	[8]	$2,566	27%
U.S. Natural Gas Pipelines	[9]	$3,638	39%
Mexico Natural Gas Pipelines	[10]	$786	8%
Liquids Pipelines	[11]	$1,700	18%
Energy	[12]	$677	7%
Corporate	[13]	-$16	
Total EBITDA (Exclude Corporate)	**[14]**	**$9,367**	**100%**

Sources and Notes:
Assets from TC Energy Co. 2020 Annual Report, Note 4, p. 134.
EBITDA from TC Energy Co. 2020 Annual Report, Note 4, p. 25.

Thapa Workpaper #1: Business Segment Analysis

Table AT-4 (b)

TC Energy Co.: Regulated Ratio Summary

		Gas Pipelines & Storage	Oil and Liquids Pipelines	Gas Distribution	Midstream Services	Terminals	Other	Total
				Asset - Using total asset				
Canadian Natural Gas Pipelines	[1]	24%	0%	0%	0%	0%	0%	24%
U.S. Natural Gas Pipelines	[2]	45%	0%	0%	0%	0%	0%	45%
Mexico Natural Gas Pipelines	[3]	8%	0%	0%	0%	0%	0%	8%
Liquids Pipelines	[4]	0%	18%	0%	0%	0%	0%	18%
Power and Storage	[5]	0%	0%	0%	0%	0%	5%	5%
Total	**[6]**	**77%**	**18%**	**0%**	**0%**	**0%**	**5%**	**100%**
				EBITDA				
Canadian Natural Gas Pipelines	[7]	27%	0%	0%	0%	0%	0%	27%
U.S. Natural Gas Pipelines	[8]	39%	0%	0%	0%	0%	0%	39%
Mexico Natural Gas Pipelines	[9]	8%	0%	0%	0%	0%	0%	8%
Liquids Pipelines	[10]	0%	18%	0%	0%	0%	0%	18%
Energy	[11]	0%	0%	0%	0%	0%	7%	7%
Total	**[12]**	**75%**	**18%**	**0%**	**0%**	**0%**	**7%**	**100%**

Sources and Notes:
[1]-[5], [7]-[11]: See Table AT-4 (a).

Thapa Workpaper #1: Business Segment Analysis

Table AT-5 (a)

Williams Cos.: Segment Data

		($M, USD)	(%)
Property, Plant and Equipment			
Nonregulated:			
Natural gas gathering and processing facilities	[1]	$17,813	43%
Other	[2]	$2,658	6%
Regulated			
Natural gas transmission facilities	[3]	$18,688	45%
Other	[4]	$2,659	6%
Gross PPE (Exclude construction in progress)	**[5]**	**$41,818**	**100%**
Assets			
Northeast G&P	[6]	$14,569	33%
Transmission & Gulf of Mexico	[7]	$19,110	43%
West	[8]	$10,558	24%
Other	[9]	$927	
Eliminations	[10]	-$999	
Total Assets (Exclude Other and Eliminations)	**[11]**	**$44,237**	**100%**
Modified EBITDA			
Northeast G&P	[12]	$1,489	31%
Transmission & Gulf of Mexico	[13]	$2,379	49%
West	[14]	$998	21%
Other	[15]	-$15	
Total Modified EBITDA (Exclude Other)	**[16]**	**$4,866**	**100%**

Source and Notes:
The "Other" and "Eliminations" categories are excluded from the calculation of total and percent contribution, since they are related to shared corporate activities.
PPE from Williams Cos. 2020 Annual Report, Note 11, p. 111.
Assets from Williams Cos. 2020 Annual Report, Note 20, p. 136.
EBITDA from Williams Cos. 2020 Annual Report, Note 20, p. 135.

Thapa Workpaper #1: Business Segment Analysis

Table AT-5 (b)

Williams Cos.: Earnings

		Utility EBITDA ($000, USD)	% Ownership	Ownership-Adjusted EBITDA ($000, USD)
		[A]	[B]	[C]
Transmission & Gulf of Mexico Segment				
Transcontinental Gas Pipe Line Company, LLC	[1]	$1,189,011	100%	$1,189,011
Gulfstream Natural Gas System, L.L.C.	[2]	$233,286	50%	$116,643
Northwest Pipeline LLC	[3]	$298,711	100%	$298,711
Discovery Gas Transmission LLC	[4]	-$3,321	60%	-$1,993
FERC Jurisdictional Transportation EBITDA	**[5]**			**$1,602,372**
Total Segment EBITDA	[6]			$2,379,000
% FERC Jurisdictional to Segment Total	**[7]**			**67%**

Sources and Notes:
[A]: 2019 Federal Energy Regulatory Commission Annual Report Form 2 or Form 2-A.
[B], [6]: Williams Cos. 2020 Form 10-K.
[C]: [A] x [B]
[5]: SUM([1]:[4])
[7]: [5] / [6]

Thapa Workpaper #1: Business Segment Analysis

Table AT-5 (c)

Williams Cos.: Assets

		Asset ($000, USD)	% Ownership	Ownership-Adjusted EBITDA ($000, USD)
		[A]	[B]	[C]
Transmission & Gulf of Mexico Segment				
Transcontinental Gas Pipe Line Company, LLC	[1]	$12,350,568	100%	$12,350,568
Gulfstream Natural Gas System, L.L.C.	[2]	$1,672,386	50%	$836,193
Northwest Pipeline LLC	[3]	$2,206,158	100%	$2,206,158
Discovery Gas Transmission LLC	[4]	$263,204	60%	$157,922
FERC Jurisdictional Transportation Asset	**[5]**			**$15,550,841**
Total Segment Asset	[6]			$19,110,000
% FERC Jurisdictional to Segment Total	**[7]**			**81%**

Sources and Notes:
[A]: 2019 Federal Energy Regulatory Commission Annual Report Form 2 or Form 2-A Total Asset and Debits.
[B], [6]: Williams Cos. 2020 Form 10-K.
[C]: [A] x [B]
[5]: SUM([1]:[4])
[7]: [5] / [6]

Thapa Workpaper #1: Business Segment Analysis

Table AT-5 (d)

Williams Cos.: Regulated Ratio Summary

		Gas Pipelines & Storage	Oil and Liquids Pipelines	Gas Distribution	Midstream Services	Terminals	Other	Total
				Asset - Using PPE				
Total	**[1]**	**45%**	**6%**	**0%**	**43%**	**0%**	**6%**	**100%**
				EBITDA				
Northeast G&P	[2]	0%	0%	0%	31%	0%	0%	31%
Transmission & Gulf of Mexico	[3]	33%	0%	0%	16%	0%	0%	49%
West	[4]	0%	0%	0%	21%	0%	0%	21%
Total	**[5]**	**33%**	**0%**	**0%**	**67%**	**0%**	**0%**	**100%**

Sources and Notes:
[1], [2]: See Table AT-5 (a). The Regulated Other is assumed to be Oil and Liquids Pipeline.
[3]: Table AT-5 (a)[13] x Table AT-5 (b)[7]
[4]: Table AT-5 (a)[14]

Thapa Workpaper #2: Pipeline Selection Database

Table AT-6

Company	Pipeline Name	Ownership %	Net Utility Plant $000s	Net Utility Operating Income $000s	Net Utility Plant (Weighted) $000s	Net Utility Operating Income (Weighted) $000s	Total Net Utility Plant (Weighted) $000s	Total Net Utility Operating Income (Weighted) $000s
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Williams Companies, Inc.	Transcontinental Gas Pipe Line Company, LLC	100%	$11,388,604	$1,034,179	$11,388,604	$1,034,179	$11,388,604	$1,034,179
TC Energy	Columbia Gas Transmission, LLC	100%	$13,114,554	$820,195	$13,114,554	$820,195	$13,114,554	$820,195
Kinder Morgan Inc.	Tennessee Gas Pipeline Company, LLC	100%	$5,594,807	$724,897	$5,594,807	$724,897	$5,594,807	$724,897
Enbridge Inc.	Texas Eastern Transmission, LP	100%	$8,733,240	$632,077	$8,733,240	$632,077	$8,733,240	$632,077
Kinder Morgan Inc.	El Paso Natural Gas Company, LLC	100%	$2,129,361	$339,635	$2,129,361	$339,635	$2,129,361	$339,635
TC Energy	ANR Pipeline Company	100%	$3,013,540	$255,670	$3,013,540	$255,670	$3,013,540	$255,670
Enbridge Inc.	Algonquin Gas Transmission, LLC	92%	$3,128,694	$235,463	$2,878,398	$216,626	$2,878,398	$216,626
Kinder Morgan Inc.	Florida Gas Transmission Company, LLC	50%	$4,440,795	$429,771	$2,220,398	$214,886	$2,220,398	$214,886
Enbridge Inc.	Gulfstream Natural Gas System, LLC	50%	$1,510,540	$178,537	$755,270	$89,269	$1,510,540	$178,537
Williams Companies, Inc.	Gulfstream Natural Gas System, LLC	50%	$1,510,540	$178,537	$755,270	$89,269	$1,510,540	$178,537
Kinder Morgan Inc.	Southern LNG Company, LLC	100%	$879,015	$150,230	$879,015	$150,230	$879,015	$150,230
Kinder Morgan Inc.	Natural Gas Pipeline Company of America LLC	50%	$1,985,443	$278,150	$992,722	$139,075	$992,722	$139,075
TC Energy	Great Lakes Gas Transmission Limited Partnership	100%	$707,377	$136,680	$707,377	$136,680	$707,377	$136,680
Williams Companies, Inc.	Northwest Pipeline LLC	100%	$1,744,812	$131,190	$1,744,812	$131,190	$1,744,812	$131,190
Kinder Morgan Inc.	Southern Natural Gas Company, LLC	50%	$2,407,945	$261,979	$1,203,973	$130,990	$1,203,973	$130,990
TC Energy	Gas Transmission Northwest LLC	100%	$878,295	$129,211	$878,295	$129,211	$878,295	$129,211
TC Energy	Columbia Gulf Transmission, LLC	100%	$2,003,223	$125,499	$2,003,223	$125,499	$2,003,223	$125,499
Kinder Morgan Inc.	Colorado Interstate Gas Company, LLC	100%	$1,105,799	$125,351	$1,105,799	$125,351	$1,105,799	$125,351
Enbridge Inc.	Sabal Trail Transmission, LLC	50%	$2,989,588	$221,365	$1,494,794	$110,683	$1,494,794	$110,683
Kinder Morgan Inc.	Elba Express Company, LLC	100%	$644,654	$85,773	$644,654	$85,773	$644,654	$85,773
TC Energy	Northern Border Pipeline Company	50%	$942,046	$168,418	$471,023	$84,209	$471,023	$84,209
Kinder Morgan Inc.	Ruby Pipeline, LLC	50%	$2,740,767	$149,655	$1,370,384	$74,828	$1,370,384	$74,828
Enbridge Inc.	East Tennessee Natural Gas, LLC	100%	$811,402	$70,426	$811,402	$70,426	$811,402	$70,426

Thapa Workpaper #2: Pipeline Selection Database

Table AT-6

Company	Pipeline Name	Ownership %	Net Utility Plant $000s	Net Utility Operating Income $000s	Net Utility Plant (Weighted) $000s	Net Utility Operating Income (Weighted) $000s	Total Net Utility Plant (Weighted) $000s	Total Net Utility Operating Income (Weighted) $000s
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Williams Companies, Inc.	Transcontinental Gas Pipe Line Company, LLC	100%	$11,388,604	$1,034,179	$11,388,604	$1,034,179	$11,388,604	$1,034,179
TC Energy	Millennium Pipeline Company, LLC	48%	$1,173,434	$129,961	$557,381	$61,731	$557,381	$61,731
Enbridge Inc.	Alliance Pipeline LP	50%	$704,767	$119,657	$352,384	$59,829	$352,384	$59,829
Kinder Morgan Inc.	Wyoming Interstate Company LLC	100%	$381,043	$46,526	$381,043	$46,526	$381,043	$46,526
TC Energy	Iroquois Gas Transmission System, LP	49%	$505,530	$94,229	$249,429	$46,493	$249,429	$46,493
Kinder Morgan Inc.	Fayetteville Express Pipeline LLC	50%	$681,846	$92,087	$340,923	$46,044	$340,923	$46,044
Enbridge Inc.	Maritimes & Northeast Pipeline, LLC	78%	$639,303	$58,504	$498,656	$45,633	$498,656	$45,633
Enbridge Inc.	Vector Pipeline LP	60%	$470,111	$49,750	$282,067	$29,850	$282,067	$29,850
TC Energy	North Baja Pipeline, LLC	100%	$109,528	$24,768	$109,528	$24,768	$109,528	$24,768
TC Energy	Portland Natural Gas Transmission System, LP	62%	$373,026	$37,627	$230,194	$23,220	$230,194	$23,220
Enbridge Inc.	NEXUS Gas Transmission, LLC	50%	$2,507,284	$45,832	$1,253,642	$22,916	$1,253,642	$22,916
Enbridge Inc.	Southeast Supply Header, LLC	50%	$1,051,379	$36,703	$525,690	$18,352	$525,690	$18,352
Enbridge Inc.	Big Sandy Pipeline, LLC	100%	$173,272	$16,221	$173,272	$16,221	$173,272	$16,221
Kinder Morgan Inc.	Cheyenne Plains Gas Pipeline Company, LLC	100%	$243,536	$12,240	$243,536	$12,240	$243,536	$12,240
TC Energy	Hardy Storage Company, LLC	100%	$125,758	$11,216	$125,758	$11,216	$125,758	$11,216
TC Energy	Tuscarora Gas Transmission Company	100%	$91,895	$11,070	$91,895	$11,070	$91,895	$11,070
Enbridge Inc.	Destin Pipeline Company, LLC	33%	$6,600	$23,521	$2,178	$7,762	$2,178	$7,762
Kinder Morgan Inc.	Sierrita Gas Pipeline LLC	35%	$176,727	$20,246	$61,854	$7,086	$61,854	$7,086
TC Energy	Bison Pipeline LLC	100%	$486,929	$5,813	$486,929	$5,813	$486,929	$5,813
Enbridge Inc.	Mississippi Canyon Gas Pipeline, LLC	100%	$2,166	$5,262	$2,166	$5,262	$2,166	$5,262
Enbridge Inc.	Saltville Gas Storage Company LLC	100%	$111,093	$4,691	$111,093	$4,691	$111,093	$4,691
Kinder Morgan Inc.	Mojave Pipeline Company, LLC	100%	$55,837	$4,101	$55,837	$4,101	$55,837	$4,101
Kinder Morgan Inc.	Horizon Pipeline Company, LLC	75%	$49,419	$4,995	$37,064	$3,746	$37,064	$3,746
TC Energy	Blue Lake Gas Storage Company	75%	$15,270	$3,788	$11,453	$2,841	$11,453	$2,841
Kinder Morgan Inc.	TransColorado Gas Transmission Company, LLC	100%	$112,593	$2,772	$112,593	$2,772	$112,593	$2,772
Enbridge Inc.	Nautilus Pipeline Company, LLC	74%	$4,240	$3,440	$3,152	$2,557	$3,152	$2,557
Enbridge Inc.	Garden Banks Gas Pipeline, LLC	100%	$1,210	$2,410	$1,210	$2,410	$1,210	$2,410
Kinder Morgan Inc.	Young Gas Storage Company, Ltd	48%	$14,430	$2,614	$6,854	$1,242	$6,854	$1,242
Williams Companies, Inc.	Pine Needle LNG Company, LLC	35%	$64,003	$2,937	$22,401	$1,028	$22,401	$1,028
Kinder Morgan Inc.	Kinder Morgan Louisiana Pipeline LLC	100%	$876,558	$876	$876,558	$876	$876,558	$876
TC Energy	Crossroads Pipeline Company	100%	$17,567	$145	$17,567	$145	$17,567	$145
TC Energy	ANR Storage Company	100%	NA	NA	NA	NA	$0	$0
Kinder Morgan Inc.	Kinder Morgan Illinois Pipeline LLC	50%	$7,040	-$23	$3,520	-$12	$3,520	-$12
Enbridge Inc.	Discovery Gas Transmission LLC	20%	$185,920	-$793	$37,184	-$159	$148,736	-$634
Williams Companies, Inc.	Discovery Gas Transmission LLC	60%	$185,920	-$793	$111,552	-$476	$148,736	-$634
Enbridge Inc.	Cimarron River Pipeline, LLC	50%	$56,743	-$5,045	$28,372	-$2,523	$28,372	-$2,523
Enbridge Inc.	Dauphin Island Gathering Company, LP	50%	$35,229	-$5,052	$17,615	-$2,526	$17,615	-$2,526
Kinder Morgan Inc.	Midcontinent Express Pipeline LLC	50%	$1,555,178	-$7,435	$777,589	-$3,718	$777,589	-$3,718

Sources and Notes:

Net Utility Operating Income and Net Utility Plant as reported in each pipeline's 2020 FERC Form 2 via S&P Market Intelligence (accessed 05/13/2021).

Parent company ownership from 2020 corporate annual reports when available, else from company websites (accessed 02/27/2021).

Thapa Workpaper #3: Weighted Average Remaining Life of Contracts

Table AT-7

Pipeline System	Years
Sabal Trail Transmission, LLC	21.3
Elba Express Company, LLC	16.4
Gulfstream Natural Gas System, LLC	10.5
Northwest Pipeline LLC	9.3
Florida Gas Transmission Company, LLC	9.0
ANR Pipeline Company	8.9
Transcontinental Gas Pipe Line Company, LLC	8.4
Tennessee Gas Pipeline Company, LLC	8.1
Columbia Gulf Transmission, LLC	7.9
Gas Transmission Northwest LLC	7.5
Texas Eastern Transmission, LP	7.1
Columbia Gas Transmission, LLC	7.0
El Paso Natural Gas Company, LLC	5.7
Algonquin Gas Transmission, LLC	5.2
East Tennessee Natural Gas, LLC	5.0
Colorado Interstate Gas Company, LLC	4.8
Natural Gas Pipeline Company of America LLC	4.7
Southern Natural Gas Company, LLC	4.1
Northern Border Pipeline Company	3.8
Great Lakes Gas Transmission Limited Partnership	3.1
Ruby Pipeline, LLC	2.2
Average of Sample (excluding ANR Pipeline Company)	7.6
Median of Sample (excluding ANR Pipeline Company)	7.1

Sources and Notes:
Data from Q1 2021 Index of Customers via S&P Market Intelligence (accessed 12/14/2021). Calculated as the average remaining contract life weighted by contracted volume starting on January 1, 2021.

Thapa Workpaper #4: NPV Contract Capacity Cover

Table AT-8

	Contracted Capacity (Dth)			Maximum Capacity (Dth)			Contracted Share of Maximum Capacity		
Pipeline System	5 Years	10 Years	25 Years	5 Years	10 Years	25 Years	5 Years	10 Years	25 Years
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Algonquin Gas Transmission, LLC	4,736,032,139	6,363,635,832	6,740,603,462	7,701,818,540	12,484,041,897	18,442,006,726	61%	51%	37%
ANR Pipeline Company	10,990,613,621	14,178,990,051	16,966,187,550	15,434,026,363	25,017,342,433	36,956,780,601	71%	57%	46%
Colorado Interstate Gas Company, LLC	6,341,983,843	7,651,010,253	7,767,309,972	8,662,613,686	14,041,415,237	20,742,630,983	73%	54%	37%
Columbia Gas Transmission, LLC	18,582,130,647	25,240,576,758	27,474,844,264	24,870,297,336	40,312,795,263	59,551,934,180	75%	63%	46%
Columbia Gulf Transmission, LLC	6,108,541,789	8,639,917,762	9,894,825,340	8,448,312,348	13,694,049,629	20,229,486,366	72%	63%	49%
East Tennessee Natural Gas, LLC	2,105,257,046	2,408,929,707	2,610,913,277	3,056,038,274	4,953,597,602	7,317,684,533	69%	49%	36%
El Paso Natural Gas Company, LLC	8,662,960,734	11,169,048,844	11,851,194,653	12,626,553,334	20,466,649,536	30,234,285,618	69%	55%	39%
Elba Express Company, LLC	3,119,490,732	4,969,432,181	6,366,507,752	3,152,999,783	5,110,764,580	7,549,858,894	99%	97%	84%
Florida Gas Transmission Company, LLC	5,723,729,115	7,931,336,788	8,747,541,824	6,446,613,020	10,449,452,506	15,436,416,746	89%	76%	57%
Gas Transmission Northwest LLC	3,857,560,534	5,007,415,039	5,523,222,404	4,732,133,778	7,670,416,544	11,331,095,703	82%	65%	49%
Great Lakes Gas Transmission Limited Partnership	3,142,235,799	3,622,738,587	3,622,862,399	5,962,344,632	9,664,491,550	14,276,835,951	53%	37%	25%
Gulfstream Natural Gas System, LLC	1,870,127,665	2,868,546,480	3,130,350,104	1,967,772,014	3,189,603,616	4,711,830,657	95%	90%	66%
Natural Gas Pipeline Company of America LLC	10,229,424,273	12,143,397,761	12,823,387,464	15,960,225,658	25,870,270,089	38,216,764,964	64%	47%	34%
Northern Border Pipeline Company	4,025,698,630	4,629,769,395	4,717,017,241	6,667,171,021	10,806,959,672	15,964,542,942	60%	43%	30%
Northwest Pipeline LLC	6,029,343,551	8,612,924,038	9,990,408,823	7,834,577,660	12,699,233,986	18,759,898,477	77%	68%	53%
Ruby Pipeline, LLC	770,163,159	855,131,529	868,347,883	2,039,659,660	3,306,127,835	4,883,965,647	38%	26%	18%
Sabal Trail Transmission, LLC	1,373,496,982	2,224,497,349	3,163,088,557	1,401,199,886	2,271,234,773	3,355,173,533	98%	98%	94%
Southern Natural Gas Company, LLC	3,534,750,768	4,588,672,278	4,871,360,044	7,045,566,573	11,420,309,091	16,870,611,201	50%	40%	29%
Tennessee Gas Pipeline Company, LLC	16,771,589,269	22,668,490,914	25,117,016,839	20,213,182,582	32,763,978,653	48,400,471,551	83%	69%	52%
Texas Eastern Transmission, LP	13,088,925,161	17,645,813,458	20,470,642,362	21,288,905,057	34,507,640,151	50,976,289,329	61%	51%	40%
Transcontinental Gas Pipe Line Company, LLC	19,450,242,333	28,339,863,744	32,317,944,414	26,806,846,961	43,451,789,843	64,189,002,819	73%	65%	50%

Sources and Notes:

Data from Q1 2021 Index of Customers via S&P Market Intelligence (accessed 12/14/2021). Ratios calculated as discounted contracted capacity divided by discounted maximum capacity, which is calculated as the maximum daily contracted capacity on the pipeline between 2021 and 2045, multiplied by 365.25 days per year. A discount rate of ten percent is used.

Thapa Workpaper #5: NPV Contract Capacity Cover (Excluding Producers)

Table AT-9

	Contracted Capacity (Dth)			Maximum Capacity (Dth)			Contracted Share of Maximum Capacity		
Pipeline System	5 Years	10 Years	25 Years	5 Years	10 Years	25 Years	5 Years	10 Years	25 Years
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Algonquin Gas Transmission, LLC	4,736,032,139	4,736,032,139	4,736,032,139	7,701,818,540	12,484,041,897	18,442,006,726	61%	38%	26%
ANR Pipeline Company	7,927,501,821	7,927,501,821	7,927,501,821	15,434,026,363	25,017,342,433	36,956,780,601	51%	32%	21%
Colorado Interstate Gas Company, LLC	6,341,983,843	6,341,983,843	6,341,983,843	8,662,613,686	14,041,415,237	20,742,630,983	73%	45%	31%
Columbia Gas Transmission, LLC	11,757,339,055	11,757,339,055	11,757,339,055	24,870,297,336	40,312,795,263	59,551,934,180	47%	29%	20%
Columbia Gulf Transmission, LLC	3,914,142,543	3,914,142,543	3,914,142,543	8,448,312,348	13,694,049,629	20,229,486,366	46%	29%	19%
East Tennessee Natural Gas, LLC	2,041,918,141	2,041,918,141	2,041,918,141	3,056,038,274	4,953,597,602	7,317,684,533	67%	41%	28%
El Paso Natural Gas Company, LLC	6,371,684,649	6,371,684,649	6,371,684,649	12,626,553,334	20,466,649,536	30,234,285,618	50%	31%	21%
Elba Express Company, LLC	3,119,490,732	3,119,490,732	3,119,490,732	3,152,999,783	5,110,764,580	7,549,858,894	99%	61%	41%
Florida Gas Transmission Company, LLC	5,723,729,115	5,723,729,115	5,723,729,115	6,446,613,020	10,449,452,506	15,436,416,746	89%	55%	37%
Gas Transmission Northwest LLC	3,166,846,009	3,166,846,009	3,166,846,009	4,732,133,778	7,670,416,544	11,331,095,703	67%	41%	28%
Great Lakes Gas Transmission Limited Partnership	3,142,235,799	3,142,235,799	3,142,235,799	5,962,344,632	9,664,491,550	14,276,835,951	53%	33%	22%
Gulfstream Natural Gas System, LLC	1,870,127,665	1,870,127,665	1,870,127,665	1,967,772,014	3,189,603,616	4,711,830,657	95%	59%	40%
Natural Gas Pipeline Company of America LLC	9,599,072,491	9,599,072,491	9,599,072,491	15,960,225,658	25,870,270,089	38,216,764,964	60%	37%	25%
Northern Border Pipeline Company	3,905,006,813	3,905,006,813	3,905,006,813	6,667,171,021	10,806,959,672	15,964,542,942	59%	36%	24%
Northwest Pipeline LLC	6,029,343,551	6,029,343,551	6,029,343,551	7,834,577,660	12,699,233,986	18,759,898,477	77%	47%	32%
Ruby Pipeline, LLC	770,163,159	770,163,159	770,163,159	2,039,659,660	3,306,127,835	4,883,965,647	38%	23%	16%
Sabal Trail Transmission, LLC	1,373,496,982	1,373,496,982	1,373,496,982	1,401,199,886	2,271,234,773	3,355,173,533	98%	60%	41%
Southern Natural Gas Company, LLC	3,534,750,768	3,534,750,768	3,534,750,768	7,045,566,573	11,420,309,091	16,870,611,201	50%	31%	21%
Tennessee Gas Pipeline Company, LLC	12,278,980,245	12,278,980,245	12,278,980,245	20,213,182,582	32,763,978,653	48,400,471,551	61%	37%	25%
Texas Eastern Transmission, LP	9,361,334,492	9,361,334,492	9,361,334,492	21,288,905,057	34,507,640,151	50,976,289,329	44%	27%	18%
Transcontinental Gas Pipe Line Company, LLC	17,220,488,219	17,220,488,219	17,220,488,219	26,806,846,961	43,451,789,843	64,189,002,819	64%	40%	27%

Sources and Notes:

Data from Q1 2021 Index of Customers via S&P Market Intelligence (accessed 12/14/2021). Ratios calculated as discounted contracted capacity divided by discounted maximum capacity, which is calculated as the maximum daily contracted capacity on the pipeline between 2021 and 2045, multiplied by 365.25 days per year. A discount rate of ten percent is used.

Thapa Workpaper #6: Top Shippers by Volume (80% Threshold)

Table AT-10

Pipeline Name	Shipper Name (ranked)	Utility	Producer	Powergen	Marketer or Other
Algonquin Gas Transmission, LLC	Kaiser Neg Lateral LLC				x
Algonquin Gas Transmission, LLC	Boston Gas Company	x			
Algonquin Gas Transmission, LLC	NSTAR Gas Company	x			
Algonquin Gas Transmission, LLC	Narragansett Electric Company	x			
Algonquin Gas Transmission, LLC	Kleen Energy Systems, LLC	x			
Algonquin Gas Transmission, LLC	Yankee Gas Services Company	x			
Algonquin Gas Transmission, LLC	Footprint Power LLC			x	
Algonquin Gas Transmission, LLC	The Southern Connecticut Gas Company	x			
Algonquin Gas Transmission, LLC	Connecticut Natural Gas Corporation	x			
Algonquin Gas Transmission, LLC	KeySpan Gas East Corporation	x			
Algonquin Gas Transmission, LLC	Eversource Gas Company Of Massachusetts	x			
ANR Pipeline Company	Antero Resources Corporation		x		
ANR Pipeline Company	Ascent Resources - Utica, LLC		x		
ANR Pipeline Company	DTE Gas Company	x			
ANR Pipeline Company	Northern Illinois Gas Company	x			
ANR Pipeline Company	ExxonMobil Gas & Power Marketing		x		
ANR Pipeline Company	Tennessee Valley Authority	x			
ANR Pipeline Company	Northern Indiana Public Service Company	x			
ANR Pipeline Company	Centra Gas Manitoba Inc.	x			
ANR Pipeline Company	Wisconsin Power and Light Company	x			
ANR Pipeline Company	Gulfport Energy Corporation		x		
ANR Pipeline Company	Wisconsin Electric Power Company	x			
ANR Pipeline Company	Wisconsin Gas LLC	x			
ANR Pipeline Company	Madison Gas and Electric Company	x			
ANR Pipeline Company	Wisconsin Public Service Corporation	x			
ANR Pipeline Company	SEMCO Energy, Inc.	x			
ANR Pipeline Company	Equitable Energy, L.L.C.	x			
ANR Pipeline Company	Interstate Power and Light Company	x			
ANR Pipeline Company	North Shore Gas Company	x			
Colorado Interstate Gas Company, LLC	Public Service Company of Colorado	x			
Colorado Interstate Gas Company, LLC	Anadarko Energy Services Company				x
Colorado Interstate Gas Company, LLC	Rocky Mountain Midstream Holdings LLC				x
Colorado Interstate Gas Company, LLC	DCP Midstream, LLC				x
Colorado Interstate Gas Company, LLC	Black Hills Service Company LLC	x			
Columbia Gas Transmission, LLC	Antero Resources Corporation		x		
Columbia Gas Transmission, LLC	Southwestern Energy Services Co		x		
Columbia Gas Transmission, LLC	Washington Gas Light Company	x			
Columbia Gas Transmission, LLC	Kaiser Marketing Northeast, LLC				x
Columbia Gas Transmission, LLC	Columbia Gas of Ohio, Inc.	x			
Columbia Gas Transmission, LLC	CNX Gas Corporation		x		
Columbia Gas Transmission, LLC	Range Resources – Appalachia, LLC		x		
Columbia Gas Transmission, LLC	Ascent Resources - Utica, LLC		x		
Columbia Gas Transmission, LLC	Baltimore Gas and Electric Company	x			

Thapa Workpaper #6: Top Shippers by Volume (80% Threshold)

Table AT-10

Pipeline Name	Shipper Name (ranked)	Utility	Producer	Powergen	Marketer or Other
Columbia Gas Transmission, LLC	Virginia Power Services Energy Corp., Inc.	x			
Columbia Gas Transmission, LLC	THQ Marketing LLC				x
Columbia Gas Transmission, LLC	EP Rock Springs, LLC			x	
Columbia Gas Transmission, LLC	Columbia Gas of Virginia, Incorporated	x			
Columbia Gas Transmission, LLC	UGI Utilities, Inc.	x			
Columbia Gas Transmission, LLC	Equitable Energy, L.L.C.	x			
Columbia Gas Transmission, LLC	Columbia Gas of Kentucky, Incorporated	x			
Columbia Gas Transmission, LLC	Columbia Gas of Pennsylvania, Inc.	x			
Columbia Gas Transmission, LLC	Equinor Natural Gas LLC				x
Columbia Gulf Transmission, LLC	Kaiser Marketing Northeast, LLC				x
Columbia Gulf Transmission, LLC	Range Resources – Appalachia, LLC		x		
Columbia Gulf Transmission, LLC	Antero Resources Corporation		x		
Columbia Gulf Transmission, LLC	Total Gas & Power North America, Incorporated				x
Columbia Gulf Transmission, LLC	Southwestern Energy Services Co		x		
Columbia Gulf Transmission, LLC	Mitsui & Co Cameron Lng Sales, Inc				x
Columbia Gulf Transmission, LLC	Sabine Pass Liquefaction, LLC				x
Columbia Gulf Transmission, LLC	Gulfport Energy Corporation		x		
East Tennessee Natural Gas, LLC	Tennessee Valley Authority	x			
East Tennessee Natural Gas, LLC	Eastman Chemical Company				x
East Tennessee Natural Gas, LLC	Knoxville Utilities Board	x			
East Tennessee Natural Gas, LLC	Atmos Energy Corporation	x			
East Tennessee Natural Gas, LLC	Washington Gas Light Company	x			
East Tennessee Natural Gas, LLC	EnerVest Energy Institutional Fund XIV LP				x
East Tennessee Natural Gas, LLC	Oglethorpe Power Corporation			x	
East Tennessee Natural Gas, LLC	Sequent Energy Management, L.P.	x			
East Tennessee Natural Gas, LLC	A E Staley Manufacturing Company				x
East Tennessee Natural Gas, LLC	Duke Energy Progress, LLC	x			
East Tennessee Natural Gas, LLC	CNX Gas Corporation		x		
East Tennessee Natural Gas, LLC	Middle Tennessee Nat Gas Util Dist	x			
East Tennessee Natural Gas, LLC	Public Service Company of North Carolina, Incorporated	x			
East Tennessee Natural Gas, LLC	Elk River Public Utility District	x			
East Tennessee Natural Gas, LLC	Chattanooga Gas Company	x			
El Paso Natural Gas Company, LLC	CFE International LLC				x
El Paso Natural Gas Company, LLC	APA Corporation		x		
El Paso Natural Gas Company, LLC	XTO Energy Inc.		x		
El Paso Natural Gas Company, LLC	Sempra Gas & Power Marketing, Llc			x	
El Paso Natural Gas Company, LLC	El Paso Electric Company	x			
El Paso Natural Gas Company, LLC	New Mexico Gas Company, Inc.	x			
El Paso Natural Gas Company, LLC	Mexicana De Cobre, S. A. De C. V.				x
El Paso Natural Gas Company, LLC	MRC Permian Company		x		
El Paso Natural Gas Company, LLC	Southwest Gas Corporation	x			
El Paso Natural Gas Company, LLC	Pioneer Natural Resources Company		x		
El Paso Natural Gas Company, LLC	ConocoPhillips Company		x		

Thapa Workpaper #6: Top Shippers by Volume (80% Threshold)

Table AT-10

Pipeline Name	Shipper Name (ranked)	Utility	Producer	Powergen	Marketer or Other
El Paso Natural Gas Company, LLC	El Paso Marketing Company, L.L.C.	x			
El Paso Natural Gas Company, LLC	Texas Gas Service Company, Inc.	x			
El Paso Natural Gas Company, LLC	Salt River Project Agricultural Improvement and Power District, Arizona	x			
El Paso Natural Gas Company, LLC	Southern California Gas Company	x			
El Paso Natural Gas Company, LLC	WTG Gas Marketing, Inc.	x			
El Paso Natural Gas Company, LLC	Saavi Energy Solutions, LLC				x
El Paso Natural Gas Company, LLC	Luminant Energy Company LLC	x			
Elba Express Company, LLC	Shell NA LNG LLC	x			
Elba Express Company, LLC	Southern Natural Gas Company, L.L.C.	x			
Elba Express Company, LLC	Southern Company Services, Inc.	x			
Florida Gas Transmission Company, LLC	Florida Power & Light Company	x			
Florida Gas Transmission Company, LLC	Peoples Gas System	x			
Florida Gas Transmission Company, LLC	Angola LNG Supply Services LLC	x			
Florida Gas Transmission Company, LLC	Florida Gas Utility	x			
Florida Gas Transmission Company, LLC	Duke Energy Florida, LLC	x			
Florida Gas Transmission Company, LLC	Shell Energy North America (US), L.P.				x
Florida Gas Transmission Company, LLC	Seminole Electric Cooperative Inc.			x	
Florida Gas Transmission Company, LLC	Tampa Electric Company	x			
Florida Gas Transmission Company, LLC	Jera Energy America LLC				x
Florida Gas Transmission Company, LLC	PowerSouth Energy Cooperative			x	
Gas Transmission Northwest LLC	Tourmaline Oil Corp.		x		
Gas Transmission Northwest LLC	Pacific Gas and Electric Company	x			
Gas Transmission Northwest LLC	Portland General Electric Company	x			
Gas Transmission Northwest LLC	Avista Corporation	x			
Gas Transmission Northwest LLC	Sierra Pacific Power Company	x			
Gas Transmission Northwest LLC	Avangrid Renewables LLC			x	
Gas Transmission Northwest LLC	Seven Generations Energy Ltd.		x		
Gas Transmission Northwest LLC	Shell Energy North America (US), L.P.				x
Gas Transmission Northwest LLC	Cannat Energy Inc.				x
Gas Transmission Northwest LLC	ARC Resources Ltd.		x		
Gas Transmission Northwest LLC	Cascade Natural Gas Corporation	x			
Gas Transmission Northwest LLC	Mercuria Commodities Canada Corp				x
Great Lakes Gas Transmission Limited Partnership	TransCanada PipeLines Limited	x			
Great Lakes Gas Transmission Limited Partnership	ANR Pipeline Company	x			
Great Lakes Gas Transmission Limited Partnership	Centra Gas Manitoba Inc.	x			
Gulfstream Natural Gas System, LLC	Florida Power & Light Company	x			
Gulfstream Natural Gas System, LLC	Duke Energy Florida, LLC	x			
Natural Gas Pipeline Company of America LLC	Northern Illinois Gas Company	x			
Natural Gas Pipeline Company of America LLC	Sabine Pass Liquefaction, LLC				x
Natural Gas Pipeline Company of America LLC	Corpus Christi Liquefaction, LLC	x			
Natural Gas Pipeline Company of America LLC	Lucid Energy Delaware LLC				x
Natural Gas Pipeline Company of America LLC	CenterPoint Energy Resources Corp.	x			
Natural Gas Pipeline Company of America LLC	Northern Indiana Public Service Company	x			

Thapa Workpaper #6: Top Shippers by Volume (80% Threshold)

Table AT-10

Pipeline Name	Shipper Name (ranked)	Utility	Producer	Powergen	Marketer or Other
Natural Gas Pipeline Company of America LLC	The Peoples Gas Light and Coke Company	x			
Natural Gas Pipeline Company of America LLC	Seven Generations Energy Ltd.		x		
Natural Gas Pipeline Company of America LLC	Antero Resources Corporation		x		
Natural Gas Pipeline Company of America LLC	Ascent Resources - Utica, LLC		x		
Natural Gas Pipeline Company of America LLC	Rockford Generation, Llc			x	
Natural Gas Pipeline Company of America LLC	La Frontera Holdings, LLC		x		
Natural Gas Pipeline Company of America LLC	Madill Gas Processing Co LLC				x
Natural Gas Pipeline Company of America LLC	Tenaska Marketing Ventures, Inc.		x		
Natural Gas Pipeline Company of America LLC	North Shore Gas Company		x		
Northern Border Pipeline Company	Tenaska Marketing Ventures, Inc.		x		
Northern Border Pipeline Company	ONEOK Rockies Midstream, L.L.C.				x
Northern Border Pipeline Company	Northern Illinois Gas Company	x			
Northern Border Pipeline Company	Twin Eagle Resource Management, LLC	x			
Northern Border Pipeline Company	Interstate Power and Light Company	x			
Northern Border Pipeline Company	Husky Marketing & Supply Company				x
Northern Border Pipeline Company	Bp Canada Energy Marketing Corp.	x			
Northern Border Pipeline Company	Northern States Power Company	x			
Northern Border Pipeline Company	Ameren Illinois Company	x			
Northern Border Pipeline Company	EDF Trading North America, LLC	x			
Northern Border Pipeline Company	Dakota Gasification Company Inc.		x		
Northern Border Pipeline Company	Hartree Partners LP, Asset Management Arm				x
Northern Border Pipeline Company	Citadel Energy Marketing LLC				x
Northern Border Pipeline Company	TC Energy Marketing Inc.				x
Northwest Pipeline LLC	Puget Sound Energy, Inc.	x			
Northwest Pipeline LLC	Intermountain Gas Company	x			
Northwest Pipeline LLC	Northwest Natural Gas Company	x			
Northwest Pipeline LLC	Cascade Natural Gas Corporation	x			
Northwest Pipeline LLC	Avista Corporation	x			
Northwest Pipeline LLC	FortisBC Energy Inc.	x			
Ruby Pipeline, LLC	Pacific Gas and Electric Company	x			
Ruby Pipeline, LLC	Anadarko Energy Services Company				x
Ruby Pipeline, LLC	Cascade Natural Gas Corporation	x			
Sabal Trail Transmission, LLC	Florida Power & Light Company	x			
Sabal Trail Transmission, LLC	Duke Energy Florida, LLC	x			
Southern Natural Gas Company, LLC	Southern Company Services, Inc.	x			
Southern Natural Gas Company, LLC	Atlanta Gas Light Company	x			
Southern Natural Gas Company, LLC	Shell Energy North America (US), L.P.				x
Southern Natural Gas Company, LLC	Peoples Gas System	x			
Southern Natural Gas Company, LLC	JEA	x			
Southern Natural Gas Company, LLC	Spire Alabama Inc.	x			
Southern Natural Gas Company, LLC	Huntsville Utilities	x			
Tennessee Gas Pipeline Company, LLC	Antero Resources Corporation		x		
Tennessee Gas Pipeline Company, LLC	Mex Gas Supply, S.L.				x

Thapa Workpaper #6: Top Shippers by Volume (80% Threshold)

Table AT-10

Pipeline Name	Shipper Name (ranked)	Utility	Producer	Powergen	Marketer or Other
Tennessee Gas Pipeline Company, LLC	MC Global Gas Corporation	x			
Tennessee Gas Pipeline Company, LLC	Chesapeake Energy Corporation		x		
Tennessee Gas Pipeline Company, LLC	Equinor Natural Gas LLC				x
Tennessee Gas Pipeline Company, LLC	Tennessee Valley Authority	x			
Tennessee Gas Pipeline Company, LLC	Equitable Energy, L.L.C.	x			
Tennessee Gas Pipeline Company, LLC	Corpus Christi Liquefaction, LLC	x			
Tennessee Gas Pipeline Company, LLC	Mitsui & Co Cameron Lng Sales, Inc				x
Tennessee Gas Pipeline Company, LLC	Boston Gas Company	x			
Tennessee Gas Pipeline Company, LLC	Talisman (U.S.) Inc		x		
Tennessee Gas Pipeline Company, LLC	Southwestern Energy Services Co		x		
Tennessee Gas Pipeline Company, LLC	Gulfport Energy Corporation		x		
Tennessee Gas Pipeline Company, LLC	Seneca Resources Corporation		x		
Tennessee Gas Pipeline Company, LLC	Eap Ohio, LLC		x		
Tennessee Gas Pipeline Company, LLC	Lackawanna Energy Center LLC	x			
Tennessee Gas Pipeline Company, LLC	Range Resources – Appalachia, LLC		x		
Tennessee Gas Pipeline Company, LLC	Eversource Gas Company Of Massachusetts	x			
Tennessee Gas Pipeline Company, LLC	Cabot Oil & Gas Corporation		x		
Tennessee Gas Pipeline Company, LLC	Connecticut Natural Gas Corporation	x			
Tennessee Gas Pipeline Company, LLC	Total Gas & Power North America, Incorporated				x
Tennessee Gas Pipeline Company, LLC	Yankee Gas Services Company	x			
Tennessee Gas Pipeline Company, LLC	Central Valle Hermoso S.A. De C.V.			x	
Tennessee Gas Pipeline Company, LLC	Entergy Louisiana, LLC	x			
Tennessee Gas Pipeline Company, LLC	NSTAR Gas Company	x			
Tennessee Gas Pipeline Company, LLC	Central Lomas del Real, S.A. de C.V.	x			
Tennessee Gas Pipeline Company, LLC	Narragansett Electric Company	x			
Tennessee Gas Pipeline Company, LLC	National Fuel Gas Distribution Corporation	x			
Tennessee Gas Pipeline Company, LLC	South Jersey Gas Company	x			
Tennessee Gas Pipeline Company, LLC	Liberty Utilities (EnergyNorth Natural Gas) Corp.	x			
Texas Eastern Transmission, LP	Equitable Energy, L.L.C.	x			
Texas Eastern Transmission, LP	Range Resources – Appalachia, LLC		x		
Texas Eastern Transmission, LP	Total Gas & Power North America, Incorporated				x
Texas Eastern Transmission, LP	Chesapeake Energy Corporation	x			
Texas Eastern Transmission, LP	CFE International LLC				x
Texas Eastern Transmission, LP	Eap Ohio, LLC		x		
Texas Eastern Transmission, LP	NextEra Energy Power Marketing, LLC	x			
Texas Eastern Transmission, LP	Duke Energy Hanging Rock, LLC	x			
Texas Eastern Transmission, LP	New Jersey Natural Gas Company	x			
Texas Eastern Transmission, LP	ConocoPhillips Company		x		
Texas Eastern Transmission, LP	Cogen Technologies Linden Venture, LP	x			
Texas Eastern Transmission, LP	Entergy Arkansas, LLC	x			
Texas Eastern Transmission, LP	Consolidated Edison Company of New York, Inc.	x			
Texas Eastern Transmission, LP	Equinor Natural Gas LLC				x
Texas Eastern Transmission, LP	Chevron USA Prod Inc		x		

Thapa Workpaper #6: Top Shippers by Volume (80% Threshold)
Table AT-10

Pipeline Name	Shipper Name (ranked)	Utility	Producer	Powergen	Marketer or Other
Texas Eastern Transmission, LP	Dynegy Inc.			x	
Texas Eastern Transmission, LP	CNX Gas Corporation		x		
Texas Eastern Transmission, LP	Gulfport Energy Corporation		x		
Texas Eastern Transmission, LP	MC Global Gas Corporation	x			
Texas Eastern Transmission, LP	Mitsui & Co Cameron Lng Sales, Inc				x
Texas Eastern Transmission, LP	PSEG Energy Resources & Trade LLC	x			
Transcontinental Gas Pipe Line Company, LLC	Sabine Pass Liquefaction, LLC				x
Transcontinental Gas Pipe Line Company, LLC	Cabot Oil & Gas Corporation		x		
Transcontinental Gas Pipe Line Company, LLC	Virginia Power Services Energy Corp., Inc.	x			
Transcontinental Gas Pipe Line Company, LLC	Brooklyn Union Gas Company	x			
Transcontinental Gas Pipe Line Company, LLC	Southern Company Services, Inc.	x			
Transcontinental Gas Pipe Line Company, LLC	Angola LNG Supply Services LLC	x			
Transcontinental Gas Pipe Line Company, LLC	KeySpan Gas East Corporation	x			
Transcontinental Gas Pipe Line Company, LLC	Atlanta Gas Light Company	x			
Transcontinental Gas Pipe Line Company, LLC	Corpus Christi Liquefaction, LLC	x			
Transcontinental Gas Pipe Line Company, LLC	Chief Oil & Gas LLC		x		
Transcontinental Gas Pipe Line Company, LLC	Oglethorpe Power Corporation			x	
Transcontinental Gas Pipe Line Company, LLC	Dominion Energy South Carolina, Inc.	x			
Transcontinental Gas Pipe Line Company, LLC	Washington Gas Light Company	x			
Transcontinental Gas Pipe Line Company, LLC	Shore CPV Holdings, LLC	x			
Transcontinental Gas Pipe Line Company, LLC	Piedmont Natural Gas Company, Inc.	x			
Transcontinental Gas Pipe Line Company, LLC	Duke Energy Progress, LLC	x			
Transcontinental Gas Pipe Line Company, LLC	Calpine Energy Services, L.P.			x	
Transcontinental Gas Pipe Line Company, LLC	Direct Energy Business Marketing LLC	x			
Transcontinental Gas Pipe Line Company, LLC	PSEG Energy Resources & Trade LLC	x			
Transcontinental Gas Pipe Line Company, LLC	Seneca Resources Corporation		x		
Transcontinental Gas Pipe Line Company, LLC	Old Dominion Electric Cooperative			x	
Transcontinental Gas Pipe Line Company, LLC	New Jersey Natural Gas Company	x			
Transcontinental Gas Pipe Line Company, LLC	Public Service Company of North Carolina, Incorporated	x			
Transcontinental Gas Pipe Line Company, LLC	St. James Enterprises LLC				x
Transcontinental Gas Pipe Line Company, LLC	Duke Energy Florida, LLC	x			
Transcontinental Gas Pipe Line Company, LLC	Consolidated Edison Company of New York, Inc.	x			

Sources and Notes:
Data from Q1 2021 Index of Customers via S&P Market Intelligence (accessed 12/14/2021). Shippers selected as the shippers for each pipeline that account for the top 80% of total forward contracted capacity discounted on a ten-year basis. A discount rate of 10 percent is used.

Thapa Workpaper #7: Share of Types of Shippers

Table AT-11

Pipeline System	Utilities	Producer	Power Generators	Marketers or Other
Algonquin Gas Transmission, LLC	57%	0%	5%	38%
ANR Pipeline Company	59%	41%	0%	0%
Colorado Interstate Gas Company, LLC	51%	0%	0%	49%
Columbia Gas Transmission, LLC	33%	51%	2%	13%
Columbia Gulf Transmission, LLC	0%	46%	0%	54%
East Tennessee Natural Gas, LLC	65%	3%	6%	25%
El Paso Natural Gas Company, LLC	33%	36%	6%	26%
Elba Express Company, LLC	100%	0%	0%	0%
Florida Gas Transmission Company, LLC	82%	0%	8%	10%
Gas Transmission Northwest LLC	56%	27%	6%	12%
Great Lakes Gas Transmission Limited Partnership	100%	0%	0%	0%
Gulfstream Natural Gas System, LLC	100%	0%	0%	0%
Natural Gas Pipeline Company of America LLC	60%	9%	3%	29%
Northern Border Pipeline Company	65%	4%	0%	30%
Northwest Pipeline LLC	100%	0%	0%	0%
Ruby Pipeline, LLC	94%	0%	0%	6%
Sabal Trail Transmission, LLC	100%	0%	0%	0%
Southern Natural Gas Company, LLC	88%	0%	0%	12%
Tennessee Gas Pipeline Company, LLC	42%	36%	1%	22%
Texas Eastern Transmission, LP	41%	35%	2%	22%
Transcontinental Gas Pipe Line Company, LLC	62%	16%	8%	15%

Sources and Notes:

Data from Q1 2021 Index of Customers via S&P Market Intelligence (accessed 12/14/2021). Calculated using forward contract commitments, discounted on a ten-year basis with a discount rate of 10 percent.

Thapa Workpaper #8: ANR Pipeline Company's Contracted Capacity

Table AT-12

	Remaining Capacity (Dth/day)	% of Capacity as of Jan 1, 2021
2021	10,133,675	100%
2022	8,858,093	87%
2023	7,570,076	75%
2024	6,409,469	63%
2025	5,482,888	54%
2026	4,497,103	44%
2027	3,795,833	37%
2028	3,540,282	35%
2029	3,084,032	30%
2030	2,846,539	28%
2031	2,649,996	26%
2032	2,637,196	26%

Sources and Notes:
Data from Q1 2021 Index of Customers via S&P Market Intelligence (accessed 12/14/2021). Remaining capacity shown as of the beginning of each year.

Thapa Workpaper # 9: Maintenance and Modernization Capital Expenditures
Table AT-13

Historical System Additions	2017-2020 Expansion Costs ($m)	2017-2020 Additions ($m)	2016 Net Utility Plant ($m)	Average Maintenance Capital and Modernization Expenses Relative to Net Utility Plant
	[1]	[2]	[3]	[4]
Algonquin Gas Transmission, LLC	0	967	2,684	9.0%
ANR Pipeline Company	**94**	**822**	**2,300**	**7.9%**
Colorado Interstate Gas Company, L.L.C.	41	48	1,188	0.2%
Columbia Gas Transmission, LLC	6,687	8,003	5,332	6.2%
Columbia Gulf Transmission, LLC	1,300	1,394	836	2.8%
East Tennessee Natural Gas, LLC	0	106	804	3.3%
El Paso Natural Gas Company, L.L.C	155	429	2,007	3.4%
Elba Express Company, L.L.C.	114	136	665	0.8%
Florida Gas Transmission Company, LLC	135	482	4,414	2.0%
Gas Transmission Northwest LLC	0	182	746	6.1%
Great Lakes Gas Transmission Limited Partnership	0	85	714	3.0%
Gulfstream Natural Gas System, L.L.C.	0	12	1,627	0.2%
Natural Gas Pipeline Company of America LLC	314	662	1,501	5.8%
Northern Border Pipeline Company	0	105	1,064	2.5%
Northwest Pipeline LLC	47	345	1,772	4.2%
Ruby Pipeline, LLC	0	8	3,161	0.1%
Sabal Trail Transmission, LLC	0	3,137	0	NA
Southern Natural Gas Company, L.L.C.	240	270	2,335	0.3%
Tennessee Gas Pipeline Company, L.L.C.	1,181	1,609	4,943	2.2%
Texas Eastern Transmission, LP	972	2,081	6,909	4.0%
Transcontinental Gas Pipe Line Company, LLC	7,698	5,980	6,952	-6.2%

Sources and Notes:
[1]: U.S. Natural Gas Pipeline Projects, EIA. Release date 04/29/2021. The EIA data did not provide capital expenditures for Columbia Gulf's Gulf Xpress project and Columbia Gas's Central Virginia Connector project. According to public sources, the cost of the Gulf Xpress project was $600 million and the cost of the Central Virginia Connector project was $12.5 million. Additionally, EIA data lists the cost of Southern Natural Gas's Zone 3 expansion to be $300 million, but the FERC order approving the project reports costs of only $93.5 million. I rely on the Zone 3 Expansion project cost reported in the FERC order.
[2]: Historical transmission plant additions from 2017-2020 FERC Form 2 via S&P market intelligence (accessed 04/16/21).
[3]: Net Utility Plant: Gas from 2015 FERC Form 2 via S&P Market Intelligence (accessed 04/16/21).
[4]: (([2] - [1])/4)/[3].
Sabal Trail Transmission Pipeline came into service on July 3, 2017.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22 -___-000

Summary of the Prepared Direct Testimony of Scott Currier

Mr. Currier is the Director of Integrity for the U.S. Natural Gas Business Unit for TransCanada USA Services Inc. Mr. Currier's testimony is divided into three sections. The first section provides an overview of the recent safety regulations and proposed regulations promulgated by PHMSA, including the Mega Rule, which consists of three parts and makes numerous revisions to PHMSA's regulations that will have significant impacts on ANR Pipeline Company ("ANR").

The second section details the three parts of the Mega Rule and the modernization projects that ANR intends to undertake to comply with Parts 1 and 2. Specifically, Mr. Currier describes that Part 1 of the Mega Rule generally includes, among other things, requirements for MAOP reconfirmation, material verification, and expanded assessments of integrity threats. Mr. Currier supports the currently anticipated projects ANR will need to undertake to meet these requirements as well as an estimate of the anticipated costs.

Next, Mr. Currier discusses Part 2 of the Mega Rule and that it is expected to include various new requirements, such as increased requirements for cathodic protection surveys after backfilling; greater monitoring for internal corrosion; and repair and response criteria for pipelines in certain defined areas, among others. Mr. Currier describes the anticipated costs ANR expects to incur as a result of these new requirements.

In section 4 of his testimony, Mr. Currier explains the recently issued Pipeline Rupture Detection and Mitigation Rule as well as the PIPES Act of 2020 and how both of these emerging regulations may impact ANR.

Docket No. RP22-___-000
Exhibit No. ANR-0012

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-___-000

PREPARED DIRECT TESTIMONY
OF SCOTT CURRIER ON BEHALF OF
ANR PIPELINE COMPANY

January 28, 2022

Glossary of Terms

ANR	ANR Pipeline Company
Commission	Federal Energy Regulatory Commission
DOT	Department of Transportation
EFP	Eligible Facilities Plan
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information System
GPAC	Gas Pipeline Advisory Committee
HCA	High Consequence Area
MAOP	Maximum Allowable Operating Pressure
MCA	Moderate Consequence Area
Mega Rule	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines
NDE	Non-Destruct Examination
NPRM	Notice of Proposed Rulemaking
O&M	Operation and Maintenance (expense)
PHMSA	Pipeline and Hazardous Materials Safety Administration
Rupture Detection and Mitigation Rule	Pipeline Rupture Detection and Mitigation for Onshore Populated & High Consequence Areas
SCC	Stress Corrosion Cracking
SIMM	System Improvement Modernization Mechanism
SMYS	Specific Minimum Yield Strength

TC Energy	TC Energy Corporation
TVC	Traceable Verifiable and Complete Test Pressure Records

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22-___-000

Prepared Direct Testimony of Scott Currier

Q: Please state your name and business address.

A: My name is Scott Currier. My business address is TC Energy Corporation ("TC Energy"), 700 Louisiana Street, Houston, Texas, 77002.

Q: What is your occupation?

A: I am employed by TransCanada USA Services Inc., an indirect subsidiary of TC Energy, as the Director of Integrity for the U.S. Natural Gas Business Unit. TransCanada USA Services Inc. employs all personnel in the United States who are involved in the operation and maintenance of TC Energy's U.S. energy systems and facilities, including ANR Pipeline Company ("ANR"). I am filing testimony on behalf of ANR.

Q: Please describe your educational background and experience as they are related to your testimony in this proceeding.

A: I have a Bachelor of Sciences Degree in Mechanical Engineering and a Minor in Technology and Management. I joined the natural gas pipeline industry approximately eleven years ago and since that time have worked in various positions that address pipeline integrity. From 2010 to 2012, I was employed as an Integrity Field Engineer for TC Energy (formerly TransCanada Corporation). From 2012 to 2014, I was seconded to the Interstate Natural Gas Association of America as the Director of Operations, Safety, and Integrity. From 2014 to 2017, I was lead for TC Energy's MAOP confirmation efforts. From 2016 to 2018, I was the Manager for Pipeline Integrity Data Quality and Strategy. From 2018 to 2019, I was the Manager of USGO Threat Management West, and for several months in 2019, I was the Director of Reliability.

Q: Have you ever testified before the Federal Energy Regulatory Commission ("FERC" or "Commission") or any other energy regulatory commission?

A: Yes. I have filed testimony with the Commission in *Columbia Gas Transmission, LLC*, Docket No. RP20-1060-000.

Q: What is the purpose of your testimony in this proceeding?

A: The general purpose of my testimony is to support certain aspects of the modernization projects related to pipeline safety and integrity as well as regulatory compliance that ANR proposes to include in the Eligible Facilities Plan ("EFP"), Exhibit No. ANR-0016, sponsored by ANR witness Parks. More specifically, my testimony: (1) provides an overview of the recent safety regulations and proposed regulations promulgated by the U.S. Department of Transportation ("DOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA"); and (2) describes some of the modernization projects that ANR intends to undertake to comply with Parts 1 and 2 of the Mega Rule.

Q: Are you sponsoring any exhibits in addition to your testimony?

A: No.

I. OVERVIEW OF RECENT PHMSA REGULATIONS

Q: Please describe the safety regulation of ANR's pipeline system.

A: The ANR system is regulated as PHMSA-jurisdictional interstate transmission pipeline under the supervision of the Office of Pipeline Safety, which is part of PHMSA. The PHMSA-jurisdictional mileage of the ANR system is subject to requirements published under 49 C.F.R. Part 192. These are considered the minimum safety standards that a pipeline operator must comply with when operating a natural gas pipeline.

Q: How many miles of PHMSA-regulated pipeline are part of the ANR system?

A: The ANR system is comprised of approximately 9,000 miles of PHMSA-regulated interstate gas transmission pipeline. ANR's PHMSA-regulated mileage spans Arkansas, Iowa, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Missouri, Mississippi, Nebraska, Ohio, Oklahoma, Tennessee, Texas, and Wisconsin.

Q: Please describe recent regulatory actions by PHMSA affecting ANR.

A: As a result of several high profile gas pipeline infrastructure failures over the last decade, including a large intrastate gas pipeline explosion in San Bruno, California in 2010, PHMSA has been actively working on various rulemakings to ensure natural gas pipeline safety and integrity. These efforts have spawned PHMSA's Mega Rule, which I discuss at length in my testimony, as well as other regulatory initiatives relating to storage facilities that are discussed by ANR witness Word.

Q: Please summarize how ANR is complying with PHMSA's latest regulatory initiatives.

A: ANR's parent company, TC Energy, has formed a dedicated team responsible for revising existing integrity and safety procedures, developing new integrity and safety procedures where needed, defining required work, and identifying synergies across the existing maintenance program. This team is currently focusing on developing and implementing these procedures and will continue to refine them as new information becomes available or new regulations are promulgated.

Q: Please briefly describe the Mega Rule.

A: As described in more detail below, the Mega Rule is in direct response to Congressional mandates in the 2011 Pipeline Reauthorization Act, H.R.2845, Public Law 112-90, and the National Transportation Safety Board's recommendations. The rulemaking includes numerous revisions to PHMSA's regulations that will impact ANR's pipeline operations.

The Mega Rule consists of three parts, referred to as Part 1, Part 2, and Part 3. As discussed more fully below, the largest impacts of Part 1 are associated with: (1) maximum allowable operating pressure ("MAOP") reconfirmation for pipeline segments without traceable, verifiable, and complete ("TVC") pressure test records; (2) a newly-defined area referred to as a Moderate Consequence Area ("MCA") that expands the scope of integrity management programs to certain pipeline segments located in such area; (3) new gas integrity management rules related to crack assessments and spike hydrotesting; (4) expanded integrity management requirements for pipeline segments located outside of high consequence areas ("HCA"); and (5) new prescriptive requirements for operators to perform opportunistic material properties testing.

With respect to Part 2, which has not been issued as a final rule yet, the largest impacts to ANR are expected to result from expanded requirements related to external and internal corrosion and expanded gas integrity management requirements related to the response and repair of dents with metal loss and defects identified within non-HCA areas.

Finally, with respect to Part 3, there is no expected impact to ANR associated with changes to the definition of regulated jurisdictional gathering lines.

II. MODERNIZATION WORK REQUIRED BY PHMSA MEGA RULE

Q: Please provide a broad overview of Part 1 of the Mega Rule.

A: Part 1 of the Mega Rule generally includes requirements for MAOP reconfirmation for Class 3, Class 4, and HCAs when a TVC pressure test does not exist for those areas. As background, transmission pipelines are often constructed across areas that vary in population density from rural to urban centers. PHMSA's pipeline regulations address the risk or consequence associated with these different populations by assigning a Class number, between one and four, to each pipeline segment. The Class number is directly tied to the number of structures that lie within a defined one-mile long, 660 foot parallel corridor on either side of the pipeline. The more structures within the corridor, the higher the Class location. Class 1 is defined as a corridor containing ten or fewer buildings; Class 2 has ten to 46 buildings; Class 3 has 46 or more structures (or a small, well-defined outside area meeting specific occupancy criteria within 100 yards of the pipeline); and Class 4 areas are the most populated, with four or more story buildings prevalent. Furthermore, PHMSA's pipeline regulations also account for consequence by identifying HCAs. The HCA method that ANR uses identifies HCAs as a potential impact radius that contains 20 or more buildings intended for human occupancy, or an identified site. An identified site can be buildings or outside areas that meet specific occupancy requirements or facilities such as hospitals or schools.

Mega Rule Part 1 also includes requirements to perform a pressure test on grandfathered pipelines greater than or equal to 30% specified minimum yield strength ("SMYS") in Class 3, 4, HCAs, or an MCA when the MCA is piggable. The requirements for MAOP reconfirmation must be completed by July 2035. Part 1 also provides requirements for material verification, assessments in non-HCAs, engineering critical assessments, and calculating predictive failure pressures. Finally, Part 1 includes new requirements for records retention, spike hydrotesting, launcher receiver safety, and changes to subpart O, which covers integrity management of covered pipelines. Assessments and reconfirmations must be conducted on a ten-year recurring cycle with all baseline assessments completed by 2034.

Q: Please provide a broad overview of Part 2 of the Mega Rule.

A: Part 2 is anticipated to be issued in February of 2022 and is expected to include: (1) increased requirements for cathodic protection surveys after backfilling; (2) actions to take when low potentials are detected or stray currents are detected; (3) greater monitoring for internal corrosion; (4) repair and response criteria for pipelines in non-HCAs operating at or above 40% SMYS as well as more prescriptive criteria within HCAs; (5) actions following severe weather events; and (6) defined methodology of engineering critical assessments for dents.

Q: What are the timelines for compliance with the Mega Rule?

A: Part 1 of the Mega Rule became effective July 1, 2020. Specific sections within Part 1 of the Mega Rule have prescribed timelines for when certain requirements must be met. ANR established procedures for MAOP reconfirmation for affected pipelines ahead of the required July 1, 2021 deadline. For MAOP reconfirmation, 50% of the eligible mileage must be completed prior to July 3, 2028, and 100% by July 2, 2035. Baseline assessments for pipelines operating at or above 30% SMYS and in either a Class 3, Class 4, or a piggable MCA must be completed by July 3, 2034, with re-assessments required on a repeating ten-year cycle from the date of the baseline assessment. Reporting on the mileages and progress of these baseline assessments will initially take place with ANR's first annual report that includes MCA mileages in March 2022.

Q: Are the costs associated with the Mega Rule compliance projects the types of costs that can be included in ANR's proposed System Improvement Modernization Mechanism ("SIMM")?

A: Yes. As discussed by ANR witnesses Linder and Parks, the Mega Rule compliance projects are required for regulatory compliance and are related to the safety and integrity of ANR's systems. Witnesses Linder and Parks explain that certain of these costs are appropriately recoverable via the proposed SIMM.

B. Modernization Work Required by PHMSA Mega Rule Part 1

1. Mega Rule non-HCA assessments, response criteria in HCAs and outside of HCAs, and additional external corrosion requirements

Q: Please describe the Mega Rule's new definition of MCA.

A: An MCA is defined under section 192.3 as an onshore area within a potential impact radius containing either five or more buildings intended for human occupancy or any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with four or more lanes;[1] and that does not meet the definition of an HCA. The locations of MCAs are important as they are used to identify where MAOP re-confirmation and non-HCA assessments will be required under Mega Rule Part 1.

Q: How many miles of MCA-designated pipeline are on ANR?

A: ANR has performed an analysis of MCAs on the system to identify both MCAs driven by structure count and where the potential impact radius intersects paved surfaces of designated roadways as defined under section 192.3. Table 1 below breaks out the mileage of ANR MCAs by either structure (density driven), highway (defined by roadway intersect), or both.

Table 1: Moderate Consequence Area Mileage Estimate

Mileage of Moderate Consequence Areas on ANR				
Pipeline System	**Structure**	**Structure / Highway**	**Highway**	**Grand Total**
ANR	521.1	89.8	125.7	736.6

[1] As defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures*, Section 3.1.

Q: Please describe what pipeline segments are subject to MAOP reconfirmation under Part 1.

A: Section 192.624(a)(1) requires that pipeline operators have TVC pressure test records that are fully commensurate with a pipeline's MAOP and class location if the MAOP was originally established under section 192.619(a) and is located in either a Class 3, Class 4, or HCA. If the pressure test records are not TVC, then those segments are subject to MAOP reconfirmation. In addition, section 192.624(a)(2) requires that pipeline segments with an MAOP established under section 192.619(c), referred to as grandfathered pipelines, will now be subject to MAOP reconfirmation. So-called grandfathered pipelines have installation dates that precede the introduction of the gas pipeline safety regulations in the Code of Federal Regulations. After these regulations were introduced, the "grandfathered" lines were permitted to operate at an MAOP established at the maximum pressure recorded over a five-year operating period preceding 1970. The Mega Rule removes this exemption and provides that MAOP reconfirmation must be performed for grandfathered pipelines that operate at or above 30% SMYS and are located in either an HCA, Class 3, Class 4, or piggable[2] MCA. Table 2 below provides a preliminary breakdown in estimated mileage by code section of ANR's system that is subject to MAOP reconfirmation under Part 1's new requirement.

[2] Piggable segment is a pipeline that can accommodate an instrumented free-swimming tool without the need for major physical or operational modification, other than the normal operational work required by the process of performing the inline inspection.

Table 2: Mileages associated with MAOP Reconfirmation

Breakdown in estimated ANR pipeline mileage subject to MAOP reconfirmation by code section		
Code Section	**Description**	**ANR Mileage**
192.624(a)(1)(i)	Pipe segment with MAOP established under section 192.619(a) and no TVC Pressure test; located in HCAs	8.87
192.624(a)(1)(ii)	Pipe segment with MAOP established under section 192.619(a) and no TVC Pressure test; located in Class 3 and Class 4 areas	6.88
192.624(a)(2)(i)	Pipe segment with MAOP established under section 192.619(c) (grandfathered) operating at greater than or equal to 30% SMYS and located in an HCA.	0.00
192.624(a)(2)(ii)	Pipe segment with MAOP established under section 192.619(c) (grandfathered) operating at greater than or equal to 30% SMYS and located in Class 3 and Class 4 areas.	0.00
192.624(a)(2)(iii)	Pipe segment with MAOP established under section 192.619(c) (grandfathered) operating at greater than or equal to 30% SMYS and located in a piggable Moderate Consequence Area.	14.75
Pending Records Review HCAs	Pipeline meeting sections 192.624(a)(1) or 192.624(a)(2) requirements that have not been reviewed for TVC	1.09
Pending Records Review Class 3, 4	Pipeline meeting sections 192.624(a)(1) or 192.624(a)(2) requirements that have not been reviewed for TVC	0.81
Pending Records Review MCAs	Pipeline meeting sections 192.624(a)(1) or 192.624(a)(2) requirements that have not been reviewed for TVC	1.36
	Total Mileage	**33.76**

Q: How was the mileage in Table 2 determined?

A: The applicable mileage was derived by overlaying the requirements under section 192.624 with ANR pipeline routes in ANR's Geographic Information System ("GIS"). The GIS is an industry-standard database engine and mapping tool that integrates and aligns spatial information and pipeline attributes as the system of record for all pipelines. GIS enables users to visualize the pipe centerline, facilities, and components against satellite, street maps, or topographic imagery to carry out operations and technical assessments. Roadway classifications and centerline information was pulled from the National Highway System shapefiles, the edge of pavement digitized, and overlaid on the pipeline centerlines. For the purposes of this analysis, the mileages identified by sections 192.624(a)(1) and 192.624(a)(2) have been estimated under the conservative assumption that pipeline segments will likely require either hydrotest or full replacement; however, all methods provided under 192.624 will be evaluated ahead of project scoping.

Q: What methodologies does Part 1 prescribe to reconfirm MAOP for non-TVC pipeline?

A: For segments requiring MAOP reconfirmation, pipelines must apply one of six methodologies to comply with Part 1's reconfirmation requirement. These methodologies include: (1) hydrostatic pressure testing and materials verification; (2) pressure reduction; (3) engineering critical assessments; (4) pipeline replacement; (5) pressure reduction for pipeline segments with small potential impact radius; and (6) alternative technology.

Q: Which of these methodologies does ANR intend to use for MAOP reconfirmation?

A: ANR's current estimate is based on hydrostatic pressure tests or pipeline replacements to complete MAOP reconfirmation for the pipeline segments. ANR conservatively assumes that the affected mileage will largely be reconfirmed through hydrostatic pressure tests or pipeline replacements. Both of these approaches offer the highest likelihood of a successful MAOP reconfirmation and are consistent with similar successful historical efforts by ANR. As projects are further refined through the forecasting process, they are identified as candidates for engineering critical assessments or small potential impact radius pressure reduction opportunities.

Q: Will ANR consider using any of the other identified methodologies for MAOP reconfirmation?

Yes. ANR plans to consider all methodologies as it continues to develop and refine the scope of its MAOP reconfirmation work. The selection of the most appropriate MAOP reconfirmation methodology for each subject pipeline segment will require considerable analysis by a variety of subject matter experts that is anticipated to take substantial time and resources. This additional analysis will examine a variety of factors to determine the best methodology to employ for each pipeline segment, including: (1) the prevailing threats to the pipeline; (2) the location of the particular pipeline segment; (3) pipeline vintage; (4) potential impacts from other requirements contained in the Mega Rule; (5) commercial operations; (6) proximity to HCAs; and (7) past inspection results. These additional factors will influence and assist ANR in determining whether other reconfirmation options, such as an engineering critical assessment, pressure de-rate, or other technology may be better suited for that particular pipeline segment.

Q: What is the estimated total cost for ANR to comply with Part 1's MAOP reconfirmation requirement?

A: Based on currently available data that is subject to change based on the analysis described above, ANR estimates that the total cost to comply with Part 1's MAOP reconfirmation requirement will be approximately $162 million, over a 14-year period, as detailed in Table 3 and Table 4 below. The total cost represents the estimate of completing all of the associated MAOP reconfirmation mileage ahead of the July 2035 compliance deadline.

Table 3: Detailed Cost Estimate Breakdown by 192.624 Code Section

Mileages with Records Reviewed and Actionable under 192.624		
Part 192.624 Code Section	**Mileage**	**Estimated Costs[3] ($)**
192.624(a)(1)(i)	8.87	$46,365,000
192.624(a)(1)(ii)	6.88	$35,964,000
192.624(a)(2)(i)	0.00	$0
192.624(a)(2)(ii)	0.00	$0
192.624(a)(2)(iii)	14.75	$77,113,000
Totals	**30.50**	$159,442,000

Table 4: Estimated costs associated with pending or unreviewed mileages

Pending Mileages	Starting (miles)	Estimated remaining miles after Record search[4]	Estimated Costs[4] ($)
Pending Records Review - HCAs	1.09	0.16	$809,000
Pending Records Review Class 3, 4	0.81	0.12	$597,000
Pending Records Review MCAs	1.36	0.20	$1,005,000
Totals	3.26	0.49	$2,411,000

Q: Please explain whether the estimated costs above will change if ANR utilizes other permitted methodologies for MAOP reconfirmation.

A: The cost estimates above do not include the use of engineering critical assessments or pressure reductions, both of which are acceptable methods of reconfirmation under section 192.624. Each of these methods will be evaluated as possible options, along with others,

[3] Project estimates of hydrotest and replacement based on project length through 2031 escalation of two percent annually.
[4] Pending mileages calculated under assumption that 15% of records reviews results in actionable work.

when projects are identified under the MAOP reconfirmation program. An engineering critical assessment will be a valid approach to utilize for pipelines that can pass an in-line inspection tool in which actual defect information can be assessed to validate a pipeline's MAOP. This approach, however, may not represent the most cost-effective approach compared to a hydrotest or replacement. In addition, the options for accepting a permanent MAOP reduction will be evaluated based on service obligations on an eligible segment. The decision-making process is multi-tiered and requires that ANR not only consider the MAOP reconfirmation work, but also take into account: (1) existing work within the valve segment, such as HCA assessments; (2) future requirements, including the propensity for the MAOP reconfirmation segment length to increase based on population growth; and (3) the cost-benefit analysis of work execution which may favor one project over another due to permitting, outages, or schedule constraints. As a result, the cost estimate provided is subject to further refinement and adjustment as new and better information becomes available to ANR as it further develops its MAOP reconfirmation program.

2. Verification of Pipeline Material Properties

Q: What does Part 1 of the Mega Rule require regarding pipeline material verification?

A: Section 192.607 of Part 1 of the Mega Rule requires that pipeline operators develop a program for opportunistically verifying component pressure ratings and pipeline material properties for those pipeline segments where TVC material records do not exist. Operators must define populations of similar non-TVC pipeline segments based on attributes such as wall thickness, grade, in-service date, and manufacturing process that will be evaluated under section 192.607. These populations will then make up the mileage that is subject to the opportunistic material verification outlined in the code.

Q: Are these verification requirements required to be completed by a certain time?

A: There is no specific timeline associated with meeting the requirements of opportunistic material verification other than that populations must be tested at a frequency of one test per mile or until a 95% confidence interval has been established for that population. Rather than establish a specific timeline, the rule requires that wall thickness, grade, seam type, and toughness be captured as part of an opportunistic dig program that records these values anytime a pipeline segment within one of these populations is exposed for otherwise scheduled activities, such as anomaly evaluations, repairs, remediations, maintenance and replacement, or relocation activities.

Q: Please explain how ANR intends to comply with these material verification requirements.

A: ANR has developed the populations of similar pipeline segments that will become the basis of the mileage required for material testing. Even as the regulator has issued further guidance, ANR anticipates this process will evolve and change considerably as new information is processed and incorporated. Nevertheless, ANR has identified populations of pipelines that meet the material verification requirements or require compilation of materials data to support MAOP reconfirmation efforts. Furthermore, ANR anticipates that the material gathering requirements will represent incremental additional work during opportunistic digs associated with: (1) direct examination or direct assessment; (2) growth, investigation, urgent, or immediate digs related to corrosion, dents, or mechanical damage; (3) hydrostatic pressure tests; and (4) above ground facilities inspections.

The number of digs or opportunities to gather this material information is anticipated to increase based on other mandates in the Mega Rule including expanded assessment requirements outside of HCAs (section 192.710). Additionally, section 192.607 is referenced within the Mega Rule in sections 192.632 (Engineering Critical

Assessment), 192.712 (predicted failure pressure), 192.624 (MAOP Reconfirmation), and 192.619(a)(4) (MAOP of steel and plastic lines). Each of these sections within the Mega Rule identifies material verification options to assist in quantifying pipeline properties when documentation is not available so that these properties may be incorporated in a fitness for service analysis. The fitness for service analysis uses accepted engineering calculations to define a safe pipeline operating pressure by examining the actual or worst-case remaining defects in the pipeline.

Q: What are the estimated costs for complying with the material verification requirements?

A: Historically, ANR has been successful in producing TVC pressure test records that would largely exempt ANR from materials verification; however, there are some mileages that remain unvalidated or pending review. Actionable mileage are segments of pipeline that are currently in-scope for materials verification, while applicable miles are those that are either outside the scope of the Mega Rule or have not had a records review performed (pending) to know if material property documentation is missing. The actionable mileage associated with Mega Rule-eligible segments that require materials verification is minimal as shown in Table 5 below; however, the pending mileages and mileage associated with applicable segments that may be subject to materials verification through expanded assessments is much greater. Table 6 below provides a high-level estimate of the costs to ANR for compliance with section 192.607 based on the historical number of opportunities presented to gather materials properties.

Table 5: Actionable and Applicable Mileages Associated with Materials Verification on ANR

Category	Description	Miles
Actionable	Materials Verification of properties required as part of MAOP Reconfirmation	11.8
Applicable	Material properties documentation is either not TVC or is pending a documentation review and could become Actionable	415

Table 6: Estimated Costs Associated with Material Verification on ANR

Frequency	Dig Type	Estimated Avg Annual Opportunities	Percentage requiring Materials Verification	Opportunities requiring NDE	Estimated incremental annual cost
Annual	Growth, direct assessment, Immediate, urgent, hydrotest or investigatory	120	15%	18	$180,000
Annual	Above ground Facilities, atmospheric corrosion	5	100%	5	$50,000
Annual	Non-HCA Assessments	96	20%	20	$200,000
Total 7-year Cost with 2% Inflation					**$3,196,742**
Annual Average Estimated Cost (with inflation 7-yrs)					**$456,677**

The code allows for Non-Destruct Examination ("NDE") and destructive examination of pipeline materials in complying with the materials verification requirements. NDE tools can provide the mechanical, chemical, and physical properties needed to verify material strength, while destructive examination can provide the material strength and toughness values. There are instances where some or all of these properties will be required. The requirement to perform NDE and destructive testing is mandated as opportunistic for populations of pipes defined by similar attributes (wall thickness, in-service year, seam type, grade), anytime that a representative pipeline segment from a defined population is exposed for almost any reason. Opportunistic digs have no prescribed deadline other than the expectation that there be a minimum of one test per mile of population. Based on these requirements, a portion of ANR's integrity-based work will require the NDE testing under material verification in order to confirm one or all of the properties described under section 192.607.

These figures have been adjusted to a net number of anticipated excavations after applying assumptions around what percentage of the exposed segments may be missing material properties. The net number of excavations includes the anticipated number of integrity-based digs performed under the current program, additional digs associated with expanded assessment requirements, and the expectation that materials properties be obtained when pressure testing for MAOP reconfirmation. The incremental costs associated with the NDE material verification includes the mobilization, equipment costs, and onsite technicians. It is assumed that the NDE materials sampling will be completed at the same time as wall thickness and mag particle evaluations, while the pipe is fully excavated, and coating removed.

Q: Is this estimate subject to change?

A: Yes. As discussed above, ANR is in the very early stages of formulating its compliance plan and assembling the necessary data. As a result, as more data becomes available, the plan is likely to change and evolve, resulting in revised estimates that are different from what is reflected here.

3. Assessment of Integrity Threats Outside of HCAs

Q: What does Part 1 of the Mega Rule require regarding assessment of integrity threats outside of HCAs?

A: Section 192.710 expands the mileage of pipelines that are required to be assessed for integrity threats outside of HCAs. These non-HCA assessment segments are made up of pipeline segments that are not currently in an HCA (1) operating at greater than or equal to 30% SMYS and are located in Class 3 or Class 4 or (2) operating at greater than or equal to 30% SMYS in an MCA capable of accommodating an in-line inspection tool. The assessment methodology of non-HCA segments must be consistent with the threats associated with the pipeline segment and includes in-line inspection, pressure testing, spike testing, direct examinations, direct assessment, and guided wave ultrasonic testing.

Q: Please explain Part 1's compliance timeline for completing baseline assessments and reassessments of these expanded assessments.

A: Pipeline segments are expected to be prioritized using a risk-based approach. Baseline assessments for already identified pipeline mileage are required by July 3, 2034. Any newly identified segments must be completed as soon as practicable but are not to exceed ten years from the date they were identified as non-HCA assessment segments. All periodic re-assessments of non-HCA assessment segments are required on a ten-year recurring cycle.

Q: What are the estimated costs for complying with section 192.710?

A: A summary of mileages associated with section 192.710 and expanded assessments is provided in Table 7 below, while estimated costs for compliance with section 192.710 are detailed in Table 8 below. In generating this cost estimate, the segments are broken out by those segments capable of in-line inspection vs. those segments incapable of in-line inspection. A significant portion of the ANR system is capable of in-line inspection. Where in-line inspection paths already contain HCAs that have been inspected previously, the additional costs are driven by additional assessments for stress corrosion cracking

("SCC"). Based on the ASME B31.8S[5] standard for managing pipeline integrity, SCC is typically limited to pipelines operating at 60% SMYS or more without a high-performance coating (*e.g.*, fusion bonded epoxy). While these lines have likely had an in-line inspection for corrosion-based threats, they may not have been assessed for SCC.

The primary method used for SCC remediation, and the basis for this cost estimate, is direct assessment, which involves conducting an indirect above-ground electrical survey followed by excavations in areas that are prioritized based on data analysis and focusing on areas showing coating deficiencies. These incremental costs are largely associated with remediation of the SCC threat and therefore are appropriately included as part of this assessment. As an initial approach, key ASME B31.8S SCC risk factors were applied to the datasets to arrive at eligible mileages for SCC direct assessment. Using the ASME criteria, piggable lines with segments operating at a SMYS less than 60% or with newer coating types (*e.g.*, fusion bonded epoxy) were excluded because these lines are likely not susceptible to SCC. Where lines are piggable but do not have an identified HCA on the assessment path, it has been assumed that an initial in-line assessment will need to be performed. The estimate includes both SCCDA and a baseline or initial in-line inspection tool run with an assumed number of scheduled or investigative digs. For those segments that are not capable of in-line inspection, additional costs were included that are associated with either external corrosion direct examination, for short segments, or running tethered tools to address corrosion related threats. External corrosion direct assessment is

[5] ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," 2004. Appendix A3.3: SCC Susceptibility criteria (a) operating stress > 60% SMYS; (b) operating temperature > 100 F; (c) distance from compressor station <= 20 miles; (d) age >= 10 years; (e) all corrosion coating systems other than fusion bonded epoxy.

conducted very similarly to SCC direct assessment, consisting of an above ground electrical survey to determine coating performance, followed by risk ranking and an engineering analysis to determine areas for excavation.

Additionally, ANR expects to have a limited number of pipelines that would require additional assessments to address Manufacturing and Construction and Weather and Outside Forces threats. A review has not yet been completed to determine specific line segments or costs.

Table 7: Summary of mileages associated with 192.710 and expanded assessments

ANR Mileage by Expanded Assessment Category	Miles
Piggable Class 3 and 4 Pipelines operating at or above 30% SMYS	110.7
Piggable Class 1 and 2 Moderate Consequence Area operating at or above 30% SMYS	636.2
Unpiggable Pipelines (all Class locations)	8
Total Mileage	**754.9**

Table 8: Cost Estimates Associated with Expanded Assessment Criteria

Expanded Assessment Costs	Qty	Units	$ Millions[6]
Piggable Pipelines located on Assessment Paths with existing HCAs	**664.7**	**miles**	$282,692,000
Stress Corrosion Cracking Direct Assessment Surveys plus validation digs (>=60% SMYS and non-Fusion Bonded Epoxy Coating)	387	miles	--
Direct Examinations contiguous sections <= 120 ft	381	ea	--

[6] These costs have been escalated with a 2% inflation rate over the 14 years for baseline assessment.

Expanded Assessment Costs	Qty	Units	$ Millions[6]
Piggable Pipelines located on Assessment Paths without existing HCAs (no prior assessments)	**82.2**	**miles**	$112,543,000
Inline inspections (MFL Combo Tools)	59	ea	--
Defect Digs	154	ea	--
Stress Corrosion Cracking Direct Assessment Surveys plus validation digs (>=60% SMYS and non-Fusion Bonded Epoxy Coating)	55.7	miles	--
Unpiggable Pipelines:	**8**	**miles**	$23,004,000
Tethered ILI runs (MFL Combo Tools) contiguous sections >120 ft	21	ea	--
Defect Digs	37	ea	--
Direct Examination contiguous sections <= 120 ft	5	ea	--
Grand Total ($ Millions) at 2% inflation			**$418,239,000**

Q: Are these costs subject to change?

A: Yes. This estimate does not account for any additional work associated with changes to the repair and response criteria contemplated for Part 2 of the Mega Rule, as discussed below, or additional repairs resulting from expanded assessment mileage. The estimates only reflect currently contemplated costs associated with the baseline assessment and do not account for reassessment costs that become effective ten years into the program.

4. Pig Launchers and Receivers

Q: What does Part 1 of the Mega Rule require regarding pig launchers and receivers?

A: Section 192.750 requires that pig launchers and receivers have safety features installed that either ensure that barrel pressure is relieved or that prevents opening the closure door with an interlock mechanism when pressure has not been relieved from the launcher/receiver. The Mega Rule requires that launcher/receiver barrels incorporate equipment capable of safely relieving pressure in the barrel and provide confirmation that pressure is relieved on both ends of the in-line inspection tool or include a device that prevents the opening of the launcher receiver when pressure has not been vented from the launcher or receiver barrel closure.

Q: What are the estimated costs for complying with Part 1's launcher/receiver modification requirements over the next seven years beginning January 2021?

A: All launcher and receiver barrels that are in use after July 2021 must be outfitted with the mandated safety measures in advance of being used to conduct in-line inspections. Currently, the launcher and receivers are inspected in advance of the scheduled in-line inspections, and repair work orders generated for retrofit, where required, prior to use. Table 9 breaks out the estimated costs to comply with launcher/receiver safety based on a count of assessment paths and assumed number of launcher and receiver retrofits. The $3,345,427 is the estimated cost of implementation.

Table 9: Estimated Costs Associated with Launcher and Receiver Safety

ANR Launcher and Receivers	Count / Cost
Piggable assessment paths (tethered runs excluded)	238 ea
Estimated launcher and receivers (L/R)	476 ea
Estimated (L/R) total corrections required (~25%)	119 ea
Estimated number of annual L/R repairs (36 ILI's per year)	18
Average cost to bring Launcher and Receiver into compliance	$25,000
Total Estimated Cost (7-years @ 2% inflation)	**$3,345,427**
Average annual cost with inflation over 7-years	**$477,918**

C. PHMSA Mega Rule Part 2

Q. Please describe Part 2 of the Mega Rule.

A. As I explained previously, Part 2 of the Mega Rule has yet to be issued as a final rule, but it is anticipated to be published in February 2022. Based on the Notice of Proposed Rule Making ("NPRM") and language proposed by the Gas Pipeline Advisory Committee ("GPAC"), a board of advisors to PHMSA that evaluates the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposals, Part 2 is expected to include regulations addressing the following issues: (1) increased requirements for cathodic protection surveys after backfilling; (2) required actions to take when low potentials are detected or stray currents are detected; (3) additional monitoring requirements for internal corrosion; (4) repair and response criteria for pipelines in non-HCAs operating at or above 40% SMYS as well as more prescriptive criteria within HCAs; (5) required actions to be undertaken following severe weather events; and (6) required defined methodology of engineering critical assessments for dents.

Q. If Part 2 of the Mega Rule has not been issued as a final rule, how can ANR accurately identify the costs that it may incur in order to comply?

A. ANR cannot estimate with certainty the costs that it will incur in order to comply with the regulatory requirements that will be established by Part 2 once it is issued as a final rule. However, it is reasonable to anticipate that the Part 2 final rule will require ANR to take certain actions to comply with PHMSA's directives, and that compliance will require ANR to incur costs that it will be entitled to recover. ANR therefore has developed initial estimates of the costs that it anticipates it will incur in complying with the Part 2 final rule.

Q. What is the basis for ANR's estimates?

A. ANR has based these estimates on the regulatory requirements that PHMSA proposed in the NPRM with respect to the matters covered by Part 2 of the Mega Rule. Specifically, ANR has reviewed its current PHMSA compliance program, and the condition of its system, and has identified the steps it anticipates it will need to take in order to comply with the Part 2 final rule.

Q. Is it possible that the requirements established in the Part 2 final rule will be substantially different from the NPRM?

A. It is possible that there may be significant changes, but I do not anticipate that this will be the case. ANR has been closely monitoring the PHMSA rulemaking process and expects that the Part 2 final rule will impose requirements that are substantially similar to those reflected in the NPRM.

Q. Can you provide an overview of the costs that ANR anticipates that it will incur in order to comply with the Part 2 final rule?

A. Yes. I estimate that ANR will incur one-time costs and annual costs to comply with the requirements anticipated to be imposed by PHMSA in the Part 2 final rule. The estimated costs, broken out by individual regulatory requirements, are discussed in the sections that follow.

Q: Are these estimates subject to change?

A: Yes. While ANR does not anticipate that the final rule will make significant changes from the proposed rule when it is ultimately released, ANR does anticipate that these cost estimates could change as more data becomes available and ANR refines these estimates.

Q: Can you provide a further breakdown of ANR's estimated costs of complying with Part 2 of the Mega Rule?

A: Yes, I provide further detail below, by Mega Rule section, for ANR's estimated increased annual costs associated with complying with Part 2 of the Mega Rule.

1. Internal Corrosion Management

Q. Can you provide an overview of the costs that ANR anticipates that it will incur in order to comply with Part 2 of the Mega Rule with respect to internal corrosion management?

A: Part 2 of the Mega Rule adds requirements for monitoring via certain methods corrosive contaminants entering onshore gas transmission pipelines. The monitoring program is evaluated once per calendar year and is adjusted based on the findings. The GPAC language includes the word "methods" for implementing the program, but PHMSA had originally proposed "equipment." The cost estimate for this work, set forth in Table 10 below, assumes that monitoring and equipment will be required both to detect and mitigate areas of concern. Methods such as spot sampling will be employed for detecting areas of concern and equipment such as inhibitor injections or separators will be deployed for mitigation.

Table 10: Internal Corrosion management - Gas Quality Monitoring

Internal Corrosion Management – Gas Quality Monitoring			
Criteria	**Estimated annual incremental increase**	**ANR anticipated 7-year cost at 2% inflationary rate**	**Relevant Code Section**
Internal Corrosion Mgmt. - Gas Quality Monitoring	$250,000	$1,859,000	192.478(b)
Install Gas Quality Monitoring Equipment	$250,000	$1,859,000	192.478()
Incremental Program Management Effort	$250,000	$1,859,000	192.478(b)
Total	$750,000	$5,577,000	---

2. HCA Response Criteria

Q. Can you provide an overview of the costs that ANR anticipates that it will incur in order to comply with the Part 2 of the Mega Rule with respect to HCA response criteria?

A. Yes. Proposed sections 192.933(d) of PHMSA's regulations impose new requirements concerning HCA responses to defect remediations related to cracks, corrosion, and dents that are classified as immediate or one-year conditions. In the case where materials values are not TVC, then the operator must use assumed values for the analysis and then add the segment to the materials verification program for testing of the actual material properties.

In many cases ANR procedures already address the criteria associated with the immediate and one-year criteria under 192.933. However, the more stringent requirement of mitigating cracks at higher safety factors (1.39 predicted failure pressure requirement for cracks) in Class 1 locations, the requirement to address metal loss of greater than 50 percent wall loss in specific areas as one-year responses, and the expectation that non-TVC material properties be included into the materials verification program would be new requirements not currently captured in ANR's procedures. These conditions are examined against historical dig information to arrive at an estimated incremental increase to the program. ANR's anticipated costs of complying with these requirements through additional anomaly digs, over a typical ten year cycle, are shown in Table 11 below:

Table 11: HCA Response Criteria Cost Summary

High Consequence Area Response Criteria			
Criteria	**ANR Annual Increase**	**ANR 10-year aggregated Total Cost (2% inflation)**	**Description**
Response criteria (HCA, SCC 1 yr)	$108,000	$1,180,000	192.933(d)(2)(vi)
Response Criteria (HCA, 1 yr, ECOR > 50 %)	$216,000	$2,359,000	192.933(d)(2)(viii)
Total Cost	**$324,000**	**$3,539,000**	----

3. Non-HCA Response Criteria

Q. Can you provide an overview of the costs that ANR anticipates that it will incur in order to comply with Part 2 of the Mega Rule with respect to non-HCA response criteria?

A. Yes. Part 2 of the Mega Rule has introduced amended language to section 192.713(d)(1)(iii), as well as (d)(3)(iii), (v) and (viii), which imposes new requirements associated with the timing and repair required outside of HCAs when corrosion, dents, or crack defects are identified. These new requirements will impact approximately 756.3 miles of expanded assessment segments (637.7 miles of Class 1 and 2 piggable MCAs and 118.6 miles of Class 3, 4 >= 30% SMYS) that meet the applicability under 192.710 and are located outside HCAs. Response criteria are established under this section as either immediate, two-year, or monitored conditions depending on the class location and severity of the defects identified.

Some of the requirements introduced under the Mega Rule are already addressed in the existing ANR response procedures for non-HCAs. For those areas of the code that are anticipated to have a cost impact, ANR's estimated cost to comply with these requirements by completing additional anomaly digs are shown in Table 12 below:

Table 12: Non-HCA Response Criteria Cost Summary

Areas Outside of High Consequence Areas (Non-HCA) Response Criteria			
Criteria	**Annual Cost**	**ANR 10-year aggregated Total Cost (2% inflation)**	**Description**
Response Criteria (pipeline, immediate, dents)	$290,000	$3,167,000	192.713(d)(1)(iii)
Response Criteria (pipeline, 2 yr, dents)	$370,000	$4,043,000	192.713(d)(3)(iii)
Response Criteria (pipeline, 2 yr, ECORR RPR)	$216,000	$2,359,000	192.713(d)(3)(iv)
Response criteria (HCA, SCC 2 yr)	$216,000	$2,359,000	192.713(d)(3)(v)
Response Criteria (pipeline, 2 yr, > 50 % corrosion)	$539,000	$5,896,000	192.713(d)(3)(viii)
Total	**$1,631,000**	**$17,824,000**	**----**

Q: Please describe the anticipated costs associated with monitoring the effectiveness of external corrosion control associated with section 192.465(f)(g).

A: This section requires ANR to document additional readings in both directions when low cathodic protection levels are identified in order to determine the location where those levels have increased to required minimums. In addition, this section requires the cathodic protection current be interrupted when performing these tests.

ANR conducts interrupted annual surveys. ANR has approximately 537 rectifiers with remote interruption capability and 42 rectifiers without it. Since this section will require interruption of all ANR rectifiers, remote interrupters will be installed at all remaining rectifiers. Historical trends show an average of 37 test station deficiencies that require correction on ANR every year.

The labor cost associated with remote interruption capability is estimated at $18,720 annually for Corrosion Engineering and Operations support, along with upfront costs for remote interruptible rectifiers at $176,000, and recurring annual equipment costs of $10,000.

Table 13: 192.465 Cost estimates associated with corrosion monitoring

Corrosion Part II Section	Annual Recurring Costs	One-time Cost
ongoing equipment costs to perform CIS (192.465 (f) & (g)) (capital)	$10,000	
labor to perform CIS survey (192.465 (f) & (g)) (expense)	$18,720	
one-time equipment costs to perform CIS (192.465 (f) & (g)) (capital)	----	$176,000
Total	**$28,720**	**$176,000**

Q: Please describe the anticipated costs associated with responding to the timeline connected with identified deficiencies under section 192.465(d).

A: With respect to the remediation requirements under 192.465(d), direct costs are difficult to quantify but are estimated as follows and shown below in Table 14: shortening the remediation deadline from 15 months to 12 months would have a minimal impact on the project execution cost; however, imposing a shorter remediation deadline would result in the need for additional ANR personnel to manage the work and permitting requirements in order to achieve the compliance date. It is estimated that an average of 33 test station deficiencies will be subjected to the increased survey requirements on an annual basis. For the ANR footprint, primary responsibilities for corrosion control, from initial documentation to final remediation, includes Operations corrosion personnel, corrosion specialists, and corrosion engineers. Cutting remediation deadlines from 15 months to 12 months will increase the workload in any 12-month period by 20% as well as accelerate the permitting needed to meet the six-month window and will require a 25% increase in personnel processing these deficiencies for Engineering, Operations, and Project Teams.

Table 14: Anticipated recurring Corrosion Expense costs associated with Part II of the rulemaking

Corrosion Part II Section	Annual Recurring Costs
Acceleration of remediation timelines for CP deficiencies (192.465(d)) (expense)	$2,000,000
Total	**$2,000,000**

Q: Please describe the cost impacts associated with the section 192.473 Interference current program (co-located pipelines, structures, and High Voltage Alternating Current power lines) including remediation.

A: Part 2 of the Mega Rule proposes to require that each operator whose pipeline system is subjected to stray currents have a continuing program to minimize the detrimental effects of such currents. This section strengthens the requirements for interference testing and remediation and will have a major impact on ANR. Each impressed current type cathodic protection system or galvanic anode system must be designed and installed to minimize any adverse effects on existing adjacent underground metallic structures. This section will require that: (1) interference surveys be conducted on a periodic basis to detect the presence of stray current; (2) an analysis of the survey results be conducted to determine the cause of interference; and (3) remediation activities be implemented to address the interference within six months of the survey.

ANR's current process for new AC mitigation systems is to establish coupon test stations along the co-located HVAC power line corridors for AC interference monitoring, instead of relying solely on computer modeling. Coupons in conjunction with AC pipe-to-soil measurements at all test locations provides a more thorough understanding of the interference on ANR piping. For existing facilities where coupon locations have not been established, the average cost of retrofitting these facilities is estimated at approximately $8,750 for each location. It is estimated that roughly 750 coupon test locations will be needed to comply with section 192.473's requirements, at a total cost of $6,562,500. An alternative monitoring program that involves computer modeling may offer a more economical solution and will be evaluated alongside the installation of coupons once Part 2 is issued as final rule.

With respect to HVAC power lines, ANR operates 886 miles of pipeline co-located with HVAC power lines, with about 820 miles needing to be modeled and mitigated under this requirement. This mileage is subject to monitoring through additional surveys estimated at a total of $2,218,000 during the initial period and $1,363,200 in subsequent years.

With respect to remediation projects, historic observation suggests that in any given year out of 90 areas monitored for AC interference mitigation is required for about two, or about a two percent occurrence. These projects are often driven by changes that occurred between surveys resulting in increased interference levels that have triggered the need for mitigation. An estimated two percent mitigation rate applied over 90 monitored areas yields 1.8 projects per year based on HVAC circuit changes. A typical AC mitigation remediation project estimate comes in at $1,200,000 (including adding coupons to these locations). Therefore, the mitigation costs associated with this requirement are estimated at $2,160,000 per year. A summary of these various estimated costs is shown below in Table 15.

Table 15: Summary of anticipated cost impacts: High Voltage AC (HVAC) interference

Corrosion Part II Section	Annual Recurring Costs	One-time Cost
Installation of AC Interference Coupons in existing locations (192.473)		$6,562,500
Installation AC interference coupons on new projects (192.473)	$317,000	
Monitoring of AC interference coupons (192.473)	$17,760	
AC Mitigation upgrades (192.473)	$1,363,200	$2,218,000
Survey and modeling AC interference (192.473)	$220,000	
Total	**$2,714,760**	**$6,562,500**

Q: What is the anticipated cost associated with external corrosion control and protective coating related to section §192.461.

A: Part 2 of the Mega Rule requires that each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must be: (1) applied on a properly prepared surface; (2) have sufficient adhesion to the metal surface to effectively resist under film migration of moisture; (3) be sufficiently ductile to resist cracking; (4) have sufficient strength to resist damage due to handling and soil stress; and (5) have properties compatible with any supplemental cathodic protection. Furthermore, coating must be protected from damage resulting from conditions in the trench and any damage detrimental to effective corrosion control must be repaired.

In order to check for coating damage, operators must now conduct an indirect survey (Alternating Current Voltage Gradient or Direct Current Voltage Gradient) no later than six months after backfill of 1,000 contiguous feet or more of transmission line. If coating damage is identified through a survey, the operator must remediate all indications classified as "moderate" or "severe", under the referenced industry standard (National Association of Corrosion Engineers), within six months of the assessment or date that the permits are issued.

Based on historical information, it is anticipated that ANR would perform 0.01 remediation digs per 1,000 feet, for "severe" indications, and approximately 0.75 indications per mile or 0.15 remediation digs per 1,000 feet for "moderate" indications of new, repaired, or relocated pipe on an annual basis. A summary of these estimated costs is identified below in Table 16 below.

Table 16: Survey work for replacement projects of 1,000 contiguous feet or more

Corrosion Part II Section	Annual Recurring Costs
Coating surveys of integrity projects of 1,000 contiguous feet or more (192.461)	$60,000
Total	**$60,000**

III. PIPLINE RUPTURE DETECTION RULE & PIPES ACT

Q: What is the Pipeline Rupture Detection and Mitigation for Onshore Populated & High Consequence Areas proposed rule and how will it affect ANR in the foreseeable future?

A: In February 2020, PHMSA issued an NPRM, "Pipeline Rupture Detection and Mitigation for Onshore Populated & High Consequence Areas" ("Rupture Detection and Mitigation Rule"), which will establish new requirements to Part 192, specific to emergency response and consequence mitigation. The proposed language addresses mandates in the 2011 Pipeline Safety Act, as well as NTSB safety recommendations that followed the San Bruno incident, to improve the timeliness associated with the isolation of a gas release in the event of a catastrophic rupture. It is currently expected to be issued as a final rule on February

17, 2022. The Rupture Detection and Mitigation Rule establishes when the installation of automatic shutoff valves (ASV), remote controlled valves (RCV), or manual valves is required on newly constructed pipelines or replacements with two or more contiguous miles of pipe, and six-inches or larger in diameter. The requirements of the rule and valve installation focus primarily on Class 3, Class 4, and HCAs, but also include more stringent mandates on response timeliness and the ability for the SCADA system to detect and alert controllers of a potential large scale leak with a 40-minute requirement to have a release fully isolated. Specifically, rupture mitigation valves are required when class change locations occur and within 24 months from the date that the class change occurred. The operator must have a procedure in place allowing it to identify a rupture event within ten minutes of the initial notification to the operator.

The new requirements for faster response times require increased SCADA data on the system to detect ruptures as well as retrofitted and new automatic valves that will respond to a rupture or large leak through rate of change or low-pressure sensors. While ANR at this time cannot specifically quantify the potential cost impact resulting from this proposed rulemaking, ANR expects that the requirements of the rule will result in modernization costs to improve leak detection and valve status on existing valves plus the installation of valves that are outfitted with the technologies needed to respond automatically or remotely to minimize gas release in Class 3, Class 4, or HCA locations.

Q. How is ANR affected by the PIPES Act of 2020?

A. PHMSA has not yet issued an Advanced Notice of Proposed Rulemaking detailing prescriptive regulations it proposes to implement in accordance with the PIPES Act of 2020. While there is a specific self-executing mandate in the PIPES Act to update operations and maintenance plans with efforts to eliminate hazardous leaks and minimize emissions, as well as replace or remediate pipelines known to leak, no specific targets or thresholds are provided. Nonetheless, ANR worked internally as well as with other operators through trade associations, and with PHMSA, to evaluate and respond to the requirements of the PIPES Act by the December 27, 2021 deadline to update our operations and maintenance plans. At this time, ANR does not expect impacts beyond our normal course of business.

Q. Does this conclude your testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-____-000

State of Texas)
) ss.
County of Harris)

AFFIDAVIT OF SCOTT CURRIER

Scott Currier, being first duly sworn, on oath states that he is the witness whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of Scott Currier"; that, if asked the questions which appear in the text of said testimony, he would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as Scott Currier's sworn testimony in this proceeding.

DocuSigned by:
Scott Currier
BF21E7815E454F5...

Scott Currier

SWORN TO AND SUBSCRIBED BEFORE ME THIS 24th DAY OF January, 2022. This notarial act was an online notarization.

Notary Seal

NOTARY PUBLIC STATE OF TEXAS
SHELIA O. COPUS
Notary ID
976876
My Commission Expires
2/22/2023

Digital Certificate

DocuSigned by:
Shelia Copus
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-___-000

Summary of the Prepared Direct Testimony of Garrett B. Word

Mr. Word is the Director of Storage Technical Services for TransCanada USA Services Inc. His testimony supports the inclusion of certain storage modernization projects as part of ANR Pipeline Company's ("ANR") Eligible Facilities Plan. Mr. Word describes the various storage modernization projects, which includes the Potential Well Abandonment & Storage Line Retirement Projects, the Potential New Drill Projects, and the Loreed Surface Reliability Program. Mr. Word explains how these projects comply with Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulations and will modernize certain of ANR's storage facilities that have become obsolete either in equipment or in design and operation. Mr. Word explains how these projects will increase system reliability, reduce operational costs, and enhance the safety and regulatory compliance of ANR's storage system.

Docket No. RP22-___-000
Exhibit No. ANR-0013

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22-___-000

PREPARED DIRECT TESTIMONY OF GARRETT B. WORD ON BEHALF OF ANR PIPELINE COMPANY

January 28, 2022

Glossary of Terms

ANR	ANR Pipeline Company
API	American Petroleum Institute
Bcf	Billion cubic feet
Commission	Federal Energy Regulatory Commission
EFP	Eligible Facilities Plan
FERC	Federal Energy Regulatory Commission
H_2S	Hydrogen Sulfide
IFR	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, Safety of Underground Natural Gas Storage Facilities, Interim Final Rule
PHMSA	Pipeline and Hazardous Materials Safety Administration
RP	Recommended Practice
SIMM	System Improvement Modernization Mechanism
Storage Final Rule	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, Safety of Underground Natural Gas Storage Facilities, Final Rule
STS	Storage Technical Services
TC Energy	TC Energy Corporation

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

ANR Pipeline Company Docket No. RP22-___-000

Prepared Direct Testimony of Garrett B. Word

Q: What is your name and business address?

A: My name is Garrett B. Word. My business address is TC Energy Corporation ("TC Energy"), 700 Louisiana Street, Suite 700, Houston, Texas, 77002-2700.

Q: What is your occupation?

A: I am presently employed by TransCanada USA Services Inc., an indirect subsidiary of TC Energy, as the Director of Storage Technical Services ("STS"). TransCanada USA Services Inc. employs all personnel in the United States who are involved in the operation and maintenance of TC Energy's U.S. energy systems and facilities, including ANR Pipeline Company ("ANR"). I am filing testimony on behalf of ANR.

Q: Please describe your educational background and your occupational experiences as they are related to your testimony in this proceeding.

A: I graduated from Texas Tech University in 2001 with a Bachelor of Science degree in Electrical Engineering and a Bachelor of Arts minor in Mathematics.

I have been employed by TC Energy, formerly TransCanada Corporation, since 2001. My career started on the technical side of the organization through various roles in engineering and project management on both pipeline and storage assets. In more recent years, I have filled several roles on the commercial side of the company leading various teams involved in business analytics, system planning, and asset optimization.

I am currently leading our STS team which has accountability over the physical performance and integrity of TC Energy's North American gas storage assets, including those of ANR. Asset performance encompasses parameters such as deliverability and available storage quantity.

Q: Have you ever testified before the Federal Energy Regulatory Commission ("FERC" or the "Commission") or any other energy regulatory commission?

A: Yes. I filed testimony with the Commission in *ANR Pipeline Company*, Docket No. RP16-440-000, and *Columbia Gas Transmission, LLC*, Docket No. RP20-1060-000.

Q: What is the purpose of your testimony in this proceeding?

A: My testimony provides the operational basis for the well abandonment and replacement projects as well as the Loreed Surface Reliability Program that ANR proposes to include in the Eligible Facilities Plan ("EFP"), Exhibit No. ANR-0016, sponsored by ANR witness Parks, such that the costs of those projects may be included in the System Improvement Modernization Mechanism ("SIMM") that ANR is proposing in this proceeding.

Q: Are you sponsoring any exhibits in addition to your testimony?

A: Yes. I am sponsoring the following exhibit:

Exhibit No. ANR-0014	Loreed Withdrawal Capability Charts

I. Storage Projects Included in the EFP

Q: Are you supporting any storage projects that are included in the EFP?

A: Yes. As shown in the EFP, Exhibit No. ANR-0016, ANR is proposing to include storage modernization projects: (1) the Potential Well Abandonment & Storage Line Retirement Projects; (2) the Potential New Drill Projects; and (3) the Loreed Surface Reliability Program.

The Potential Well Abandonment & Storage Line Retirement Projects and the Potential New Drill Projects are designed to comply with Section 8 of the Pipeline and Hazardous Materials Safety Administration ("PHMSA") Storage Final Rule,[1] "Risk Management for Gas Storage Operations," which addresses risk management for surface and subsurface storage facilities including the wells and reservoirs. I am supporting ANR's inclusion of these projects in the EFP.

I am also supporting ANR's inclusion in the EFP of one-time projects that are necessary pursuant to TC Energy's Storage Integrity Management Plan, which was developed in response to, and to be compliant with, the new requirements under the PHMSA Storage Final Rule. I am additionally supporting projects necessary to modernize various storage facilities that have become obsolete either in equipment or in design and operation.

Q: Please describe ANR's storage assets.

A: ANR has ten directly-owned storage fields and operates approximately 900 storage wells located in Michigan, many of which were drilled over 70 years ago with obsolete technology and capabilities. The maximum physical design day withdrawal capability from the storage fields that ANR owns is approximately 2.2 Bcf per day.[2] In addition to operating reservoirs, wells, and storage-related compression, ANR also operates various gas conditioning equipment which includes gas dehydration, sulphur treatment, hydrocarbon dewpoint control, and hydrocarbon liquids handling.

Q: Please describe the PHMSA IFR.

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[1] U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, *Pipeline Safety: Safety of Underground Natural Gas Storage Facilities*, 85 Fed. Reg. 8104 (Feb. 12, 2020) ("Storage Final Rule").

[2] As discussed by ANR witness Siddik, ANR has storage capacity under storage by other contracts as well, which makes the total winter peak design day withdrawal capacity 3.5 Bcf. The figures above relate only to storage fields owned by ANR.

A: The PHMSA Interim Final Rule ("IFR") became effective January 18, 2017, and implemented new standards for underground natural gas storage requirements, covering design, construction, material, testing, commissioning, reservoir monitoring, and recordkeeping for existing and newly-constructed underground natural gas storage facilities.

Q: Please explain the regulatory requirements associated with the Storage Final Rule.

A: As I discussed above, the PHMSA IFR implemented new standards for underground natural gas storage requirements, covering design, construction, material, testing, commissioning, reservoir monitoring, and recordkeeping for existing and newly-constructed underground natural gas storage facilities. PHMSA issued the Storage Final Rule on February 12, 2020, and it took effect on March 13, 2020. The Storage Final Rule made only minor changes to the IFR.

At a high level, the Storage Final Rule requires ANR to create an integrity risk management program for gas storage wells and reservoirs incorporating risk management principles contained in American Petroleum Institute's ("API") Recommended Practice ("RP") 1171, Section 8. The Storage Final Rule provides ANR and other storage operators some flexibility in how they implement their integrity management program, although specific program features and elements are required. Specifically, the Storage Final Rule states:

> Consistent with the IFR, this final rule maintains the incorporation by reference of American Petroleum Institute (API) Recommended Practices (RPs) 1170 and 1171 (the RPs) as the basis of the minimum safety standards in 49 CFR part 192. API RP 1170, ''Design and Operation of Solution mined Salt Caverns Used for Natural Gas Storage'' has recommended practices for solution-mined salt cavern facilities used for natural gas storage and covers facility geomechanical assessments, cavern well design and drilling, solution mining techniques, and operations, including monitoring and maintenance practices. API RP 1171, ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs'' has recommended

> practices for natural gas storage in depleted oil and gas reservoirs and aquifers, and focuses on storage well, reservoir, and fluid management for functional integrity in design, construction, operation, monitoring, maintenance, and documentation practices. Both RPs describe ways to maintain the functional integrity of design, construction, operation, monitoring, maintenance, and documentation practices for UNGSFs. The RPs contain numerous provisions that use the term ''shall'' to denote a minimum requirement necessary to comply with the RP. The RPs also use non-mandatory terms such as ''should,'' ''may,'' and ''can'' to denote a recommendation that is advised, but not required.
>
> Storage Final Rule, 85 Fed. Reg. 8104, 8105 (Feb. 12, 2020).

Q: Did ANR develop the Potential Well Abandonment & Storage Line Retirement Projects in order to comply with the Storage Final Rule?

A: Yes. The Storage Final Rule incorporates by reference two standards: (1) API RP 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage," and (2) API RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs." API RP 1171, Section 8 requires storage operators to assess well integrity risk by calculating both likelihood and consequence of failure, and to implement appropriate prevention and mitigation measures to reduce risk to a tolerable level, as discussed above. Certain wells do not have enough flow-drainage-observation value to warrant remedial or routine work to meet or maintain current integrity standards. Plugging and abandoning these wells, as is being proposed through the Potential Well Abandonment & Storage Line Retirement Projects, will reduce reservoir integrity risk in alignment with the Storage Final Rule, which incorporated API RP 1171. This program will serve to lower the overall safety risk of the ANR system and increase the overall reliability of ANR storage services. Planned work in this category includes the abandonment of surface piping used to tie wells into the field header system.

Q: Please describe the wells that are being abandoned as part of the Potential Well Abandonment & Storage Line Retirement Projects that ANR is proposing.

A: The EFP contains a detailed abandonment plan that is broken down by storage field. The plan lists the number of wells at each location that are identified as candidates for abandonment. ANR will use the latest integrity and performance data available to prudently execute the multi-year abandonment program.

Q: Is ANR undertaking the Potential New Drill Projects in order to comply with the Storage Final Rule?

A: Yes, in part. ANR is undertaking the Potential New Drill Projects in connection with the Potential Well Abandonment & Storage Line Retirement Projects. As I discuss above, ANR is abandoning certain storage wells that are part of the Potential Well Abandonment & Storage Line Retirement Projects in accordance with the pipeline integrity management principles required by API RP 1171, which are incorporated by reference into the Storage Final Rule. To maintain net deliverability and reliability following these abandonments, ANR will drill new wells pursuant to the in line with its Potential New Drill Projects in the EFP to replace the deliverability and reliability from the wells it is plugging and abandoning in accordance with the Potential Well Abandonment & Storage Line Retirement Projects in the EFP. New wells will be designed and constructed to new API standards. Therefore, the Potential New Drill Projects are necessary for ANR to maintain its storage deliverability and reliability as it undertakes the abandonments needed to comply with the Storage Final Rule. Due to the obsolete and low performing nature of the wells selected for abandonment, the EFP includes far fewer new drill replacements to maintain the same level of performance and reliability for ANR’s storage services, with the added safety benefit of modern facilities.

Q: Please generally describe the Potential New Drill Projects included in the EFP.

A: The EFP contains a detailed drilling program that is broken down by storage field. As indicated in the previous discussion, new wells are intended to offset deliverability losses from abandonment of large numbers of older, obsolete wells.

Q: Please describe the Loreed Storage Field.

A: ANR's Loreed Storage Field is a storage facility located in central Michigan with a 19 Bcf working gas capacity. Unlike many of ANR's depleted gas field facilities, Loreed is constructed from a previously depleted oil production reservoir. This unique characteristic means that the operation of Loreed as a storage facility must account for the production and handling of oil and associated byproducts in order to ensure that it can meet current system operations.

Q: What challenges does ANR face with regard to the operation of the Loreed Storage Field?

A: As described above, the physical characteristics of Loreed are unique among ANR's fields and require ANR to have equipment capable of ensuring that the gas withdrawn from the field meet the gas quality specifications in ANR's Tariff. ANR currently requires 80-MMcf/d of design day capacity from the Loreed facility to meet system requirements; however, recent studies have shown an approximate degradation of 60% capability from that number. Exhibit No. ANR-0014 (Loreed Withdrawal Capability Charts) depicts the deliverability design and the observed degradation.

This degradation is a result of the fact that current gas conditioning facilities at Loreed are obsolete or are wholly inadequate for the current system operation. The inadequate conditioning facilities and low pressure liquid handling systems results in gas quality that frequently puts Loreed gas out of ANR tariff specification and results in safety conditions due to the high presence of Hydrogen Sulfide ("H_2S") in the gas stream. An inability to meet gas quality standards during critical system demand impacts system reliability, because storage field withdrawals must be restricted to avoid further impacting gas quality issues. Additionally, poor gas quality leads to equipment and pipeline reliability concerns and can cause incompatibilities with the downstream delivery points. Finally, inadequate performance of conditioning facilities for oil and other liquids production can impact storage well and storage pipeline performance. Poor reliability of the low pressure system at Loreed impacts the station's ability to adequately handle these substances and contributes to the lack of design day performance.

Q: What has ANR done to manage these issues while still ensuring shippers receive their firm service?

A: ANR currently uses the following workarounds to mitigate the effects of the degradation of service at the Loreed Storage field: (1) use of Operational Balancing Agreements with other pipelines; (2) greater use of line pack instead of storage to satisfy market requirements; and (3) use of other fields in place of Loreed, which is suboptimal. However, these strategies are short-term in nature and cannot provide a long-term solution to these issues. The proposed Loreed Surface Reliability Program is necessary to replace the obsolete facilities to ensure safe, reliable, and efficient service.

Q: What work is part of the Loreed Surface Reliability Program that is included in the EFP to address the issues at the Loreed Storage Field?

A: In order to ensure safe and reliable service on ANR's system, replacement of the H_2S handling facilities, the heater treater system and a replacement of the obsolete flare system at the Loreed Storage Field are necessary. In order to adequately handle oil and other reservoir byproducts, the low-pressure pipeline and well system that acts in concert with the typical high-pressure storage facilities must also be replaced due to obsolescence that has contributed to the degradation of service and lack of reliability. In particular, the low-pressure system is served by a series of vapor recovery compressors that are obsolete due to vintage. The EFP includes replacement of these compressors. Additionally, the installation of a slug catcher to modernize the facility's ability to handle accumulations of produced liquids is also included. These modifications will make ANR's system more safe, efficient, and reliable.

Finally, in order to meet new PHMSA gas storage regulations that have increased the requirements for accurate field measurement, ANR is proposing to replace the measurement equipment at the field that is utilized for purposes of validating reservoir integrity and gas containment. The current equipment at Loreed is obsolete.

Q: Are there system reliability and other benefits provided by the various storage projects included in the EFP?

A: Yes, these projects will increase system reliability, reduce operational costs, and enhance the safety and regulatory compliance of the storage system. The Storage Final Rule requires operators to effectively manage and reduce risk at their storage facilities. The cornerstone of this risk management framework revolves around integrity planning and risk management at both the reservoir and well level. Some ANR fields have large number of wells and require a proportionally large program to address storage well integrity issues. This is particularly acute given that a portion of ANR's wells are older in vintage and have construction features that, while acceptable at the time of construction, present a large risk profile today. ANR's various programs recognize that certain wells should be considered for abandonment because they provide comparatively little deliverability on an individual basis that does not warrant the integrity risk of continued operations. These programs further recognize that, instead of retrofitting or otherwise reconstructing large numbers of low-performance wells, it is more cost-effective and efficient to drill new wells with modern technology and features. The Loreed Surface Reliability Program also provides system reliability benefits by ensuring that the storage field is able to meet its design day capacity. Additionally, addressing H_2S and other gas quality concerns will reduce future facility integrity risk and help avoid costly, emergent repairs.

Q: Does this conclude your testimony?

Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-____-000

State of Texas)
) ss.
County of Harris)

AFFIDAVIT OF GARRETT B. WORD

Garrett B. Word, being first duly sworn, on oath states that he is the witness whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of Garrett B. Word"; that, if asked the questions which appear in the text of said testimony, he would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as Garrett B. Word's sworn testimony in this proceeding.

DocuSigned by:
Garrett Word
2660335FCFE649A...
Garrett B. Word

SWORN TO AND SUBSCRIBED BEFORE ME THIS 18th DAY OF January, 2022. This notarial act was an online notarization.

Notary Seal

NOTARY PUBLIC
STATE OF TEXAS
SHELIA O. COPUS
Notary ID
976876
My Commission Expires
2/22/2023

Digital Certificate

DocuSigned by:
Shelia Copus
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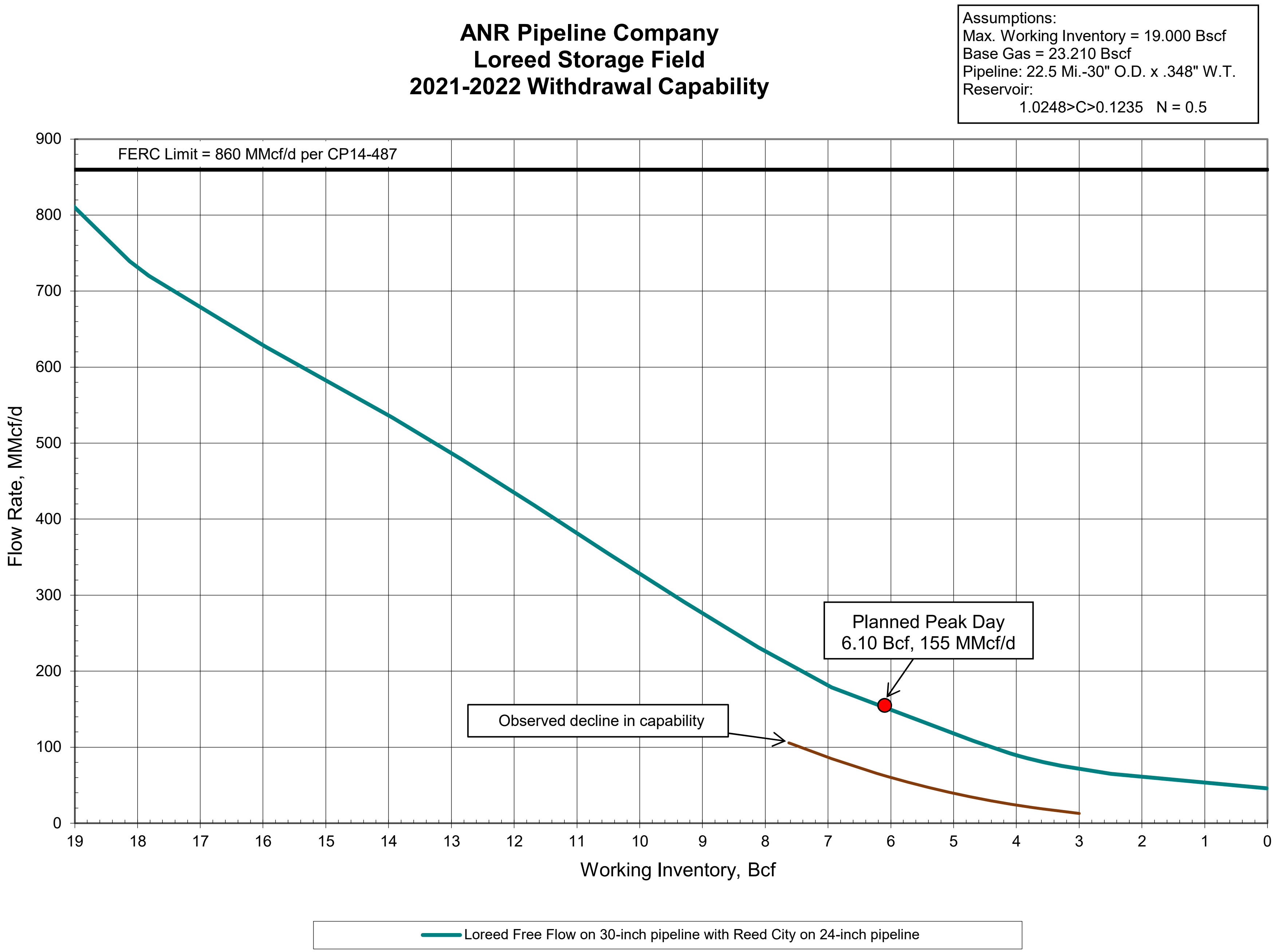
ANR Pipeline Company
Loreed Storage Field
2021-2022 Withdrawal Capability
Assumptions:
Max. Working Inventory = 19.000 Bscf
Base Gas = 23.210 Bscf
Pipeline: 22.5 Mi.-30" O.D. x .348" W.T.
Reservoir:
1.0248>C>0.1235 N = 0.5
FERC Limit = 860 MMcf/d per CP14-487
Planned Peak Day
6.10 Bcf, 155 MMcf/d
Observed decline in capability
Flow Rate, MMcf/d
Working Inventory, Bcf
0
100
200
300
400
500
600
700
800
900
19
18
17
16
15
14
13
12
11
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9
8
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5
4
3
2
1
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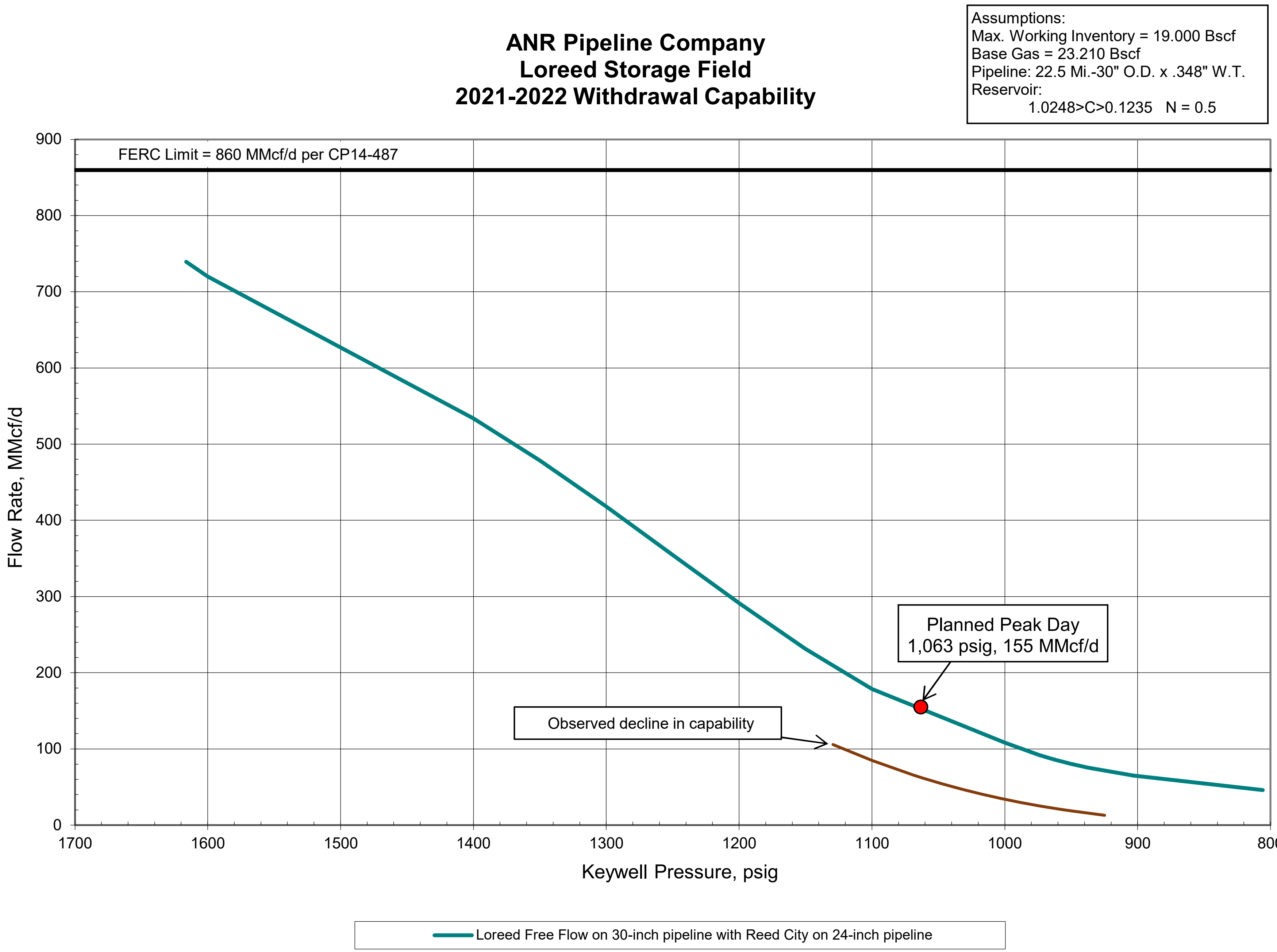
Loreed Free Flow on 30-inch pipeline with Reed City on 24-inch pipeline


ANR Pipeline Company
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Reservoir:
1.0248>C>0.1235 N = 0.5
FERC Limit = 860 MMcf/d per CP14-487
Planned Peak Day
1,063 psig, 155 MMcf/d
Observed decline in capability
Flow Rate, MMcf/d
Keywell Pressure, psig
900
800
700
600
500
400
300
200
100
0
1700
1600
1500
1400
1300
1200
1100
1000
900
800
Loreed Free Flow on 30-inch pipeline with Reed City on 24-inch pipeline

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22 -___-000

Summary of the Prepared Direct Testimony of Matt Parks

Mr. Parks is Vice President of Technical and Operations Services for U.S. Natural Gas for TransCanada USA Services Inc. Mr. Parks describes the modernization work ANR Pipeline Company ("ANR") undertook pursuant to its last settlement and the need for continued modernization of ANR's system. He provides an overview of the modernization projects ANR is planning to undertake over the next five years and describes, and sponsors, ANR's Eligible Facilities Plan ("EFP") that lists the modernization projects that ANR proposes to make eligible for cost recovery through the System Improvement Modernization Mechanism ("SIMM") that ANR is proposing in this proceeding.

Mr. Parks' testimony is divided into three sections. The first section provides an overview of ANR's system and the modernization work it completed pursuant to its last rate case settlement. The second section discusses ANR's need to continue to modernize its system. Mr. Parks states that ANR's modernization program is driven by several factors including (1) replacing aging compression to increase reliability with considerations of efficiency, emissions profiles, and cybersecurity; (2) the age and condition of certain pipeline, including vintage pipeline issues and storage; (3) newly-issued and upcoming regulatory and safety requirements; and (4) the overall need to continue to improve the safety and reliability of the system. Mr. Parks details some of the specific projects ANR plans to undertake including compressor facility replacements and upgrades, replacement of facilities constructed with legacy construction techniques, including

wrinkle bends and coating systems, increasing the piggability of its system, and improving pipeline and storage integrity and long-term reliability. Mr. Parks also discusses how pipeline safety and environmental regulatory initiatives, including compliance with the Storage Final Rule and the Mega Rule, are driving ANR's modernization program.

Finally, in the third section of his testimony, Mr. Parks describes ANR's EFP. Mr. Parks explains that the EFP provides an overview of the projects that ANR intends to undertake during the proposed five-year term of the SIMM that are necessary to continue to improve ANR's reliability, integrity, safety, and efficiency while simultaneously addressing compliance with existing and new regulatory requirements. Mr. Parks testifies that ANR used three criteria to identify the modernization projects to prioritize and include in the EFP: (1) the existing facility operates at a relatively high level of risk; (2) the facility will require upgrades to meet current or emerging regulations; and (3) the facility has a reliability that is lower than necessary to meet current or future service requirements. Finally, Mr. Parks explains that due to the ongoing nature of the modernization work, and the process by which ANR prioritizes projects, ANR has retained the discretion to undertake projects not specifically listed in the EFP and to determine the timing under which it will undertake certain modernization projects.

Docket No. RP22-___-000
Exhibit No. ANR-0015

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company) Docket No. RP22-___-000

PREPARED DIRECT TESTIMONY
OF MATT PARKS ON BEHALF OF
ANR PIPELINE COMPANY

January 28, 2022

Glossary of Terms

2011 Act	The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub. L. 112-90, 125 Stat. 1904 (Jan. 3, 2012)
2016 Filing	ANR's January 31, 2016 Natural Gas Act Section 4 rate filing
ANR	ANR Pipeline Company
Bcf	Billion cubic feet
Commission	Federal Energy Regulatory Commission
CS	Compressor Station
EFP	Eligible Facilities Plan
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
HCA	High Consequence Area
IFR	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, Safety of Underground Natural Gas Storage Facilities, Interim Final Rule
ILI	In-line Inspection
MAOP	Maximum Allowable Operating Pressure
Mega Rule	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines
NSPS	New Source Performance Standards
Part 1	Mega Rule Part 1 – Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines
PHMSA	Pipeline and Hazardous Materials Safety Administration

RP16-440 Settlement	The FERC-approved 2016 settlement in Docket No. RP16-440-000
SE Mainline	Southeast Mainline
SIMM	System Improvement Modernization Mechanism
SMSY	Specified Minimum Yield Strength
Storage Final Rule	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, Safety of Underground Natural Gas Storage Facilities, Final Rule
SW Mainline	Southwest Mainline
TC Energy	TC Energy Corporation
TSA	Transportation Security Administration

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22-___-000

Prepared Direct Testimony of Matt Parks

Q: Please state your name and business address.

A: My name is Matt Parks. My business address is TC Energy Corporation ("TC Energy"), 700 Louisiana Street, Houston, Texas, 77002.

Q: What is your occupation?

A: I am employed by TransCanada USA Services Inc., an indirect subsidiary of TC Energy, as the Vice President of Technical and Operations Services for U.S. Natural Gas. TransCanada USA Services Inc. employs all personnel in the United States who are involved in the operation and maintenance of TC Energy's U.S. energy systems and facilities, including ANR Pipeline Company ("ANR"). I am filing testimony on behalf of ANR.

Q: Please describe your educational background and experience as they are related to your testimony in this proceeding.

A: I hold a Bachelor of Science in Mechanical Engineering from Louisiana State University. Since joining in 2009, I have held various roles including Manager of System Reliability for East Assets, Director of Pipeline Integrity for East Assets, Director of Reliability/Compression for USNG, Vice President Operations for U.S. Gas West and currently as Vice President of Technical and Operational Services for U.S. Natural Gas.

Q: What are your present responsibilities?

A: I am currently responsible for the program management, procedural actions, and technical staff within the U.S. relative to pipeline integrity, compression, measurement, and storage.

Q: Have you ever testified before the Federal Energy Regulatory Commission ("FERC" or "Commission") or any other regulatory commission or agency?

A: Yes. I have filed testimony with the Commission in *Columbia Gas Transmission, LLC*, Docket No. RP20-1060-000.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to briefly describe the modernization work ANR undertook pursuant to the prior settlement approved in Commission Docket No. RP16-440 ("RP16-440 Settlement") and the need for continued modernization of ANR's system to improve safety, integrity, efficiency, and reliability, as well as to ensure compliance with existing and emerging regulatory requirements. As part of my testimony I will provide an overview of the modernization projects that ANR is planning to undertake over the next five years and for which ANR would recover project costs via the System Improvement Modernization Mechanism ("SIMM") that ANR is proposing in this proceeding. These modernization projects are contained in ANR's Eligible Facilities Plan ("EFP").

Q: Are you sponsoring any exhibits in addition to your testimony?

A: Yes, I am sponsoring the EFP, which is attached hereto as Exhibit No. ANR-0016.

I. ANR PIPELINE SYSTEM & MODERNIZATION OVERVIEW

Q: Please briefly describe the history of the ANR system.

A: As described by ANR witness Lakhani, ANR's system consists of approximately 9,000 miles of pipeline and nearly 203 billion cubic feet ("Bcf") of storage, including storage by others, and delivers more than 1 trillion cubic feet of natural gas annually. ANR's facilities include two main pipelines: the Southwest Mainline ("SW Mainline") extending from

Texas north through Oklahoma, Kansas, Missouri, Iowa, Illinois, and into Wisconsin with a segment extending through Indiana and into Michigan, and the Southeast Mainline ("SE Mainline") extending from Louisiana north through Arkansas, Mississippi, Tennessee, Kentucky, Indiana, Ohio, and into Michigan. The Tie Line connects the two main branches. ANR also owns storage facilities located in Michigan and purchases additional storage capacity from third-party storage providers.

A significant portion of the ANR system was originally constructed in the late 1940s through 1960s. Furthermore, as detailed by ANR witnesses Currier and Word, there have been extensive changes to the U.S. Department of Transportation's Pipeline Hazardous Material Safety Administration ("PHMSA") regulatory requirements that obligate ANR to incur significant modernization costs to ensure compliance with these new requirements.

Finally, as explained more fully by ANR witness Word, ANR operates approximately 900 storage wells located in Michigan. Some of these facilities exceed 70 years of age and have experienced degradation in performance or reliability. Additionally, PHMSA has issued a storage Final Rule ("Storage Final Rule"), which became effective on March 13, 2020. Many of ANR's older wells have been constructed with standards that will require remedial expenditure to meet current integrity standards envisioned by the Storage Final Rule.

Q: Please explain the focus of the RP16-440 Settlement's modernization work.

A: As described in more detail by ANR witness Linder, ANR's RP16-440 Settlement was the product of a Natural Gas Act section 4 general rate case filing that ANR made on January 31, 2016 ("2016 Filing"). As part of the global settlement that resolved all issues set for hearing in the 2016 Filing, ANR and the settling parties agreed that ANR would commit to making capital expenditures of at least $837 million over a three-year period from January 1, 2016 through December 31, 2018, for Reliability and Modernization Projects.

As part of the RP16-440 Settlement, ANR applied reliability assessment tools and enhanced integrity management principles to identify portions of its system in need of upgrade, retirement, or replacement in order to ensure ongoing safety and reliability and to address emerging regulations. ANR also identified aging compression facilities where there was little to no margin for outages before curtailment to firm service would occur. Reliability enhancement projects were developed and implemented for many of these facilities, including control system upgrades and the replacement and reconditioning of compression facilities. Overall, the modernization component of ANR's RP16-440 Settlement focused on increasing pipeline safety, service reliability, efficiency, and flexibility through the execution of high-priority projects.

Q: Please explain how ANR has implemented the modernization component of the RP16-440 Settlement.

A: As more fully set forth below and detailed by ANR witness Linder, ANR has made significant progress on modernizing its facilities, including, but not limited to, various compression upgrades by performing overhauls at 115 units across 43 stations, including unit replacements at LaGrange, Jena, and Brownsville. Additionally, ANR replaced five miles of pipeline due to class change and installed bi-directional pigging facilities. Lastly, ANR executed meter upgrades and updated gas quality monitoring equipment. In all, the modernization projects undertaken pursuant to the RP16-440 Settlement have permitted ANR to significantly improve the safety, reliability, and efficiency of its system.

II. NEED FOR CONTINUED MODERNIZATION

Q. Please describe why ANR intends to continue its efforts to modernize its system.

A. ANR's modernization program is driven by several factors: (1) replacing aging compression to increase reliability with considerations of efficiency, emissions profiles, and cybersecurity; (2) the age and condition of certain pipeline, including vintage pipeline issues detailed below, and storage facilities as detailed by ANR witness Word; (3) newly-issued and upcoming regulatory and safety requirements as detailed by myself and ANR witnesses Currier and Word; and (4) the overall need to continue to improve system safety and reliability.

Q: Please describe how improvements related to aging compressors support the need for ANR's modernization program.

A: ANR operates approximately 293 compressor units delivering approximately 1.0M horsepower. This fleet includes electric motors, turbines, and reciprocating engines. Approximately 75% of ANR's system compression was installed before 1970. As detailed by ANR witness Linder, as part of the RP16-440 Settlement, ANR overhauled 115 units across 43 stations and replaced three units entirely. ANR also installed 45 new control panels at eight compressor locations. Additionally, in 2017 ANR implemented real-time condition monitoring capability across much of the compression fleet. These upgrades and replacements improved reliability and increased system flexibility by allowing ANR to mitigate the effects of both planned and unplanned outages. However, additional work is still required to continue to improve on these metrics and, as discussed more below, ANR has identified additional compression facilities for upgrades or replacement in order to further alleviate system constraints and improve reliability. As part of these upgrades, ANR is considering the use of electric motor driven compression as well as modernizing automation by replacing obsolete control and instrumentation. Overall, these compressor modernization projects will increase reliability and further reduce fuel usage, thereby furthering emission reductions, as well as increase the efficiency of ANR's system.

Q: Please explain how automation controls and instrumentation are driving ANR's modernization of its compressor fleet.

A: Many of ANR's existing control systems are no longer supported by the manufacturers relying on ANR's limited sparing as systems are replaced. This will allow ANR to replace antiquated and unsupported control systems with new modern control systems that are more resilient to cyber targeting and provide improved reliability and increased efficiency of operations.

Q: Please explain how these compressor modernization projects will continue to increase energy efficiency as well as reduce emissions.

A: Station reliability is the primary consideration for selection and prioritization of compression-related projects in the EFP. The addition of new control systems and instrumentation allow ANR to predict unit failures as well as monitor emissions parameters that permit it to take action more quickly on either correcting an identified issue or taking the unit down for repair. As ANR progresses with project design and unit selection, it will consider the latest energy efficient and emission control technologies. Examples of such technologies may include evaluation of cleaner burning engines, electric motor drives, and elimination or capture and storage of emissions from station venting sources.

Q. Please describe why the age and condition of the pipeline supports the need for ANR's modernization program.

A. Over 75% of ANR's approximately 9,000 miles of pipeline network was installed before 1970, when federal pipeline safety standards were first enacted. As a result, portions of the system have reached a point in time where upgrade, retirement, or replacement is warranted and prudent. The older pipeline segments were not built to today's pipeline construction standards and may have been built using what is now considered obsolete design and construction techniques and as a result may require greater levels of maintenance and could pose a higher risk to public safety and service reliability.

Q. Please describe how the presence of pipeline built with legacy construction techniques, including pipeline constructed with wrinkle bends, supports the need for ANR's modernization program.

A. Certain portions of ANR's system contain wrinkle bends and cased crossings that may contribute to integrity issues. Wrinkle bends can create stress concentration areas on the pipeline and these areas of stress concentration can have a higher risk of failure especially in areas where the pipeline is at a higher risk of movement such as in unstable or disturbed soils, or in areas of land movement. Pipeline safety regulations prohibit wrinkle bends on new steel pipelines that are operated at pressures that produce a hoop stress of 30%, or more, of specified minimum yield strength ("SMYS"). 49 C.F.R. § 192.315(a).

Cased crossings have been, and in some cases still are, used to run a carrier pipeline through casing under roads and railroads. Pipelines inside of casings can create integrity concerns due to the threat of external corrosion of the carrier pipeline. Furthermore, the nature of a cased crossing makes external inspection of the carrier pipeline difficult.

ANR's ongoing modernization program is designed to upgrade these facilities in stages to improve the integrity and enhance the safety of the overall pipeline system. Continued replacement of facilities constructed with legacy techniques, including wrinkle bends and coating systems will reduce ANR's need to perform maintenance thereby reducing outages as well as improving the integrity of ANR's pipeline system. Furthermore, improving integrity will likely reduce overall methane emissions from venting and leaks resulting in a positive environmental benefit.

Q: Please explain how integrity issues on ANR's Southeast Mainline pipeline segment is driving ANR's modernization program.

A: As detailed in the EFP, there is active corrosion growth on the 501 pipeline system between the Delhi Compressor Station ("CS") and the Mississippi River. This corrosion growth is a result of multiple factors including coating that is shielding cathodic protection, historical operating parameters, and local environmental factors. Replacement and recoating is required on parts of the 501, 1-501, and 2-501 pipeline in this area to improve safety and reliability. While these pipe segments are being safely operated today, the corrosion growth rate is above typical growth rates that lend themselves to periodic monitoring and repair. These segments require more frequent in-line inspection and additional outages for remediation as a temporary measure with the pipe segments requiring replacement for long-term integrity assurance.

Q: Please describe how improving the ability to use in-line inspection ("ILI") on ANR's pipeline system supports the need for ANR's modernization program.

A. ILI tools, commonly referred to as "pigs," are presently the leading pipeline inspection technology; however, approximately 11% of ANR's system was not designed and constructed or subsequently modified to accommodate ILI tools and cleaning pigs. In many of these cases, the pipeline was constructed before ILI tools were widespread or common, before Part 192 PHMSA Gas Pipeline Safety Regulations were first promulgated in 1970, and also before Integrity Management regulations were promulgated in 2003. Certain design features of ANR's system, including tight radius pipeline bends, a lack of suitable pig launchers and receivers, and valves that may impede the passage of ILI tools, prohibit the use of ILI tools on some pipeline segments.

In response to these concerns, and as discussed more below, ANR's proposed modernization program will result in an increase in piggable facilities, thus allowing ANR to increase the miles of piggable pipeline resulting in improved safety and reliability. Furthermore, under the modernization program, ANR proposes the installation of pig launchers and receivers as well as the necessary pipeline modifications to several pipelines that support storage. These installations will allow routine cleaning and fluid removal for the prevention of future internal corrosion growth and will also permit in-line inspection ("smart pigging"), to ensure the safety, reliability, and integrity of these systems.

Q: Please describe how improvements to storage facilities support the need for ANR's modernization program.

A: As more fully described by ANR witness Word, ANR operates approximately 900 storage wells in Michigan, many of which were drilled over 70 years ago with now antiquated capabilities and technology. On January 18, 2017, PHMSA issued the Safety of Underground Natural Gas Storage Facilities Interim Final Rule ("IFR") which implemented new standards for underground natural gas storage facilities implicating covering design, construction, material, testing, commissioning, reservoir monitoring, and recordkeeping for existing and newly-constructed facilities. The corresponding Storage Final Rule became effective on March 13, 2020. As discussed by ANR witness Word, ANR is abandoning obsolete storage wells and replacing them with more efficient wells in order to comply with the IFR and Storage Final Rule. Additionally, these new wells will also offset deliverability losses from abandonment of some of the larger, older wells as well as maintain system reliability.

Storage modernization will also include improvements to storage integrity and long-term reliability by restoring performance that has declined over time due to the age of the facilities and the changing operating characteristics of ANR's system. Overall, these storage modernization projects will address storage system flexibility, efficiency, safety, and long-term reliability.

Q: Please explain how the Loreed modernization project advances ANR's modernization efforts.

A: As described more fully by ANR witness Word, ANR's Loreed storage facility is beset by both obsolete equipment and a design that does not function as intended based on the current utilization of the field. This results in performance that has declined over time to levels that do not support certificated capacity. Additionally, the current design has proven inadequate to reliably ensure that gas from Loreed meets the gas quality standards set forth in ANR's gas tariff.

Q: Are pipeline safety and environmental regulatory initiatives driving ANR's ongoing modernization program?

A: Yes. As described in detail by ANR witnesses Currier and Word, pipeline and storage safety regulations are undergoing significant changes. As ANR witness Currier notes, the pipeline-related changes are driven in part by several high-profile infrastructure failures over the last decade, including a large interstate natural gas pipeline explosion in San Bruno, California in 2010. These incidents have resulted in a significant increase in PHMSA's scrutiny of pipeline operators.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub. L. 112-90, 125 Stat. 1904 (Jan. 3, 2012) ("2011 Act"), required PHMSA to impose new requirements related to verification of pipeline Maximum Allowable Operating Pressure ("MAOP"), incident reporting, damage prevention, and public education and awareness. The 2011 Act also required PHMSA to study the potential expansion of other regulatory programs, including Integrity Management, and to study the creation of new requirements regarding leak detection and the use of remote-controlled or automatic valves. In direct response to the 2011 Act, PHMSA issued a final rule, otherwise known as Part 1 of the Mega Rule, that became effective on July 1, 2020, entitled "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines" ("Part 1").

As further explained by ANR witness Currier, Part 1 of the Mega Rule includes integrity management requirements and focuses on the actions a pipeline operator must take to reconfirm the MAOP of previously untested natural gas transmission pipelines and pipelines lacking certain test records. It also requires, among other things, the periodic assessment of pipelines in populated areas not designated as "high consequence areas" ("HCA") and mandates that threats be identified and remediated on a ten-year cycle with baselines completed ahead of 2034.

Additionally, ANR witness Currier discusses Part 2 of the Mega Rule, which is anticipated to be issued in the first half of 2022 and is expected to include, among other things, increased requirements related to cathodic protection. ANR witness Currier further describes the projects that ANR expects to undertake to comply with Part 2's requirements.

Moreover, as noted above, ANR witness Word describes the storage projects that ANR intends to undertake in response to PHMSA's issuance of the IFR and Final Storage Rule.

Finally, as discussed in more detail by ANR witness Currier, the Rupture Detection Rule and rulemaking required by the PIPES Act, once enacted, will likely have implications to the ANR system resulting in necessary modernization projects.

Q: Are there also non-PHMSA industry-wide environmental initiatives driving ANR's modernization proposal in this filing?

A: There is considerable and significant movement by the Biden Administration, as well as various state and local governments as detailed by ANR witness Kirk, to move towards net-zero emission targets. Furthermore, the Biden administration, along with various federal agencies, are specifically exploring legislation and regulatory initiatives to reduce methane emissions. For example, on November 2, 2021, the U.S. Environmental Protection Agency ("EPA") released a proposed "methane" rule to limit emissions of methane from facilities in the oil and gas sector. A supplemental methane rule proposal was released on November 15, 2021. This supplemental proposed rule follows a June 30, 2021 Congressional resolution signed by President Biden that defined natural gas transmission and storage facilities as applicable source categories under the EPA's New Source Performance Standards described in the current Clean Air Act regulations at 40 C.F.R. Part 60, subpart OOOOa. As a result of this resolution, ANR is now required to actively assess for leaks and take action to mitigate findings within a defined timeframe at new or modified facilities built since 2015. Additionally, the proposed rule, as supplemented, introduces subpart OOOOb as part of the Clean Air Act regulations, with similar leak management requirements and more stringent equipment requirements applicable to new or modified facilities built after November 15, 2021. Lastly, a general carbon tax has been proposed by various members of Congress. In September 2021, the U.S. House Energy and Commerce Committee advanced a revised version of its EPA-administered fee on methane admissions from oil and gas companies. If passed, this initiative alone would require significant capital investments by pipeline companies such as ANR and as a result, ANR's modernization program must be flexible enough to adapt to any future climate regulations.

Q: Please explain how new cybersecurity requirements are driving the need for modernization on ANR.

A: In the wake of recent cyber attacks specifically targeting pipeline infrastructure, the Transportation Security Administration ("TSA") issued two security directives to implement changes in pipeline cybersecurity practices. Some of these changes have had a far-reaching and significant impact on the operations of pipeline companies that are required to adhere to the directives. ANR is actively working with the TSA to understand and comply with these newly-released directives. As a result, while ANR is in the process of assessing the potential financial impact these directives may have, preliminary project estimates suggest that tens of millions of dollars would be required to ensure compliance with the directives with additional ongoing operational costs thereafter. Moreover, if certain requirements as written today are not modified or achieved through other less-costly alternative measures, the potential cost of compliance will far exceed these initial estimates.

Q: Please describe how upgrades to measurement facilities and meter controls and monitoring equipment are driving ANR's modernization program.

A: Many of ANR's existing control systems, metering, and gas quality equipment are no longer supported by the manufacturers. As a result, these systems utilize outdated technology that does not allow for real-time monitoring and advanced diagnostic capabilities and ANR must rely on its limited supply of spare parts as systems are replaced. Modernizing these systems will allow ANR to replace antiquated and unsupported control systems with new modern control systems that are more resilient to cyber targeting which yield improved reliability with advanced diagnostic capabilities.

Q: Please explain what other projects are relevant to the need for ANR's modernization program.

A: ANR is also proposing to replace existing vintage compression with more reliable, sustainable, energy efficient units and retain existing units, where applicable, to provide standby compression for use during both planned and unplanned outages. As detailed in the EFP, critical units have been identified for replacement at the Delhi CS, Jena CS, and St. John CS. The Delhi CS is located in Richland Parish, Lousiana and the units at this station range in age from 1959 to 1970s vintage. The Jena CS is located in La Salle Parish, Lousiana with one 1969 vintage unit. These older vintage units are costly to maintain and without replacement, these units can continue to experience unplanned outages. ANR proposes to replace these older vintage units on its system with more reliable, sustainable, and energy efficient units.

III. ELIGIBLE FACILITIES PLAN

Q: Does ANR plan to continue to modernize its system following the RP16-440 Settlement?

A: Yes. As I discussed above, the need for modernization on ANR's system remains today and ANR plans to continue to undertake modernization projects to meet that need.

Q: How does ANR anticipate recovering the costs of these future modernization projects?

A: As discussed by ANR witness Linder, ANR is proposing a SIMM that will allow ANR to recover specified costs related to the ongoing modernization of ANR's pipeline system, including projects undertaken to address ANR's modernization needs as detailed above.

Q: Please provide an overview of ANR's planned modernization work that it proposes to include in its SIMM.

A: As discussed by ANR witness Linder, the modernization work proposed to be included in the SIMM will allow ANR to continue to improve the reliability, integrity, safety, and efficiency of its system while simultaneously addressing compliance with existing and new regulatory requirements. The projects ANR currently anticipates executing as part of its modernization program are described in ANR's EFP in Exhibit No. ANR-0016 and will be functionalized as transmission- or storage-related projects.

Q: Please explain the contents of the EFP.

A: The EFP provides an overview of the projects that ANR intends to undertake during the proposed five-year term of the SIMM. The projects contained in the EFP are necessary for ANR to address the modernization needs discussed above.

With respect to the storage-related projects, ANR witness Word provides additional support for well abandonment and replacement projects and other storage-related projects that are included in the EFP. The EFP further includes projects in ANR's Measurement and Regulation Replacement Program, which will replace antiquated meters, control valves, and other related measurement equipment that are original to the construction of ANR's storage facilities. This modernization work will enhance ANR's ability to perform the PHMSA-mandated gas inventory analysis at the storage fields and will provide decreased measurement uncertainty, real-time monitoring and remote meter health analytics, improved reliability and enhanced control of flow.

The transmission-related projects in the EFP include the pipeline integrity work on the SE Mainline 501 system and the piggability projects necessary to maintain the safety and integrity of the system. Other EFP projects include remote monitoring modernization, replacing original orifice meters, control valves, gas quality monitoring, and other related measurement equipment that is original to the construction of the facility or antiquated. This modernization work will enhance ANR's ability to provide decreased measurement uncertainty, real-time monitoring and remote meter health analytics, improved reliability, and enhanced control of flow.

Finally, the EFP includes projects designed to address new and expected PHMSA requirements as discussed by ANR witnesses Currier and Word, as well as any future methane, carbon, or other emissions-related regulations as I discussed above.

Q: Please explain whether any of the projects listed in the EFP are expected to cause outages.

A: There are many projects listed in the EFP that may produce outages of service. As a company, ANR continually strives to minimize outages. Within the EFP there are two main types of projects that historically have experienced outages: pipeline replacements and compressor station unit replacements. The pipeline replacements and recoats for the 501 lines are an example of a project that is expected to experience a service outage. With the pipeline replacement project, ANR is expecting to experience a ten-day outage associated with the tie-in work when placing the replacement line into service. This project is currently expected to have two tie-in periods. As an example of outages associated with the compressor station unit replacements, the Delhi CS is expected to experience approximately five to ten days of outages. This is due to the tie-in process of placing the new unit into service. The same outage timeframe is expected for the Jena CS. ANR witness Siddik further discusses the potential impacts the above-mentioned outages may have on primary firm service.

Q: Please explain potential transportation alternatives to mitigate firm service interruptions.

A: ANR continually evaluates alternatives and timing to minimize outage impacts to the system. Stopple bypass additions may be utilized as part of pipeline replacements to minimize and/or eliminate operational downtime at additional cost to the project. ANR witness Siddik also discusses how ANR works collaboratively with its shippers to schedule the outage during low demand periods when feasible and works with interconnecting pipelines to support demand needs.

Q: How did ANR analyze projects to determine whether to include them in the EFP?

A: ANR continuously works to modernize its system by actively reviewing its facilities and undertaking projects that are most effective. ANR formulates this project list by evaluating factors such as internal and external corrosion, legacy manufacturing and construction practices, and equipment failure with potential significant impacts on its firm service obligations. ANR then relies on its subject matter experts in each area to review the list and rank the risk results for each category. Finally, ANR uses three criteria to determine which modernization projects to prioritize and include in the EFP. These criteria are: (1) the existing facility operates at a relatively high level of risk; (2) the facility will require upgrades to meet current or emerging regulations; and (3) the facility's reliability is lower than necessary to meet current or future service requirements. The projects contained in the EFP meet at least one of these three criteria.

Q: Does ANR propose to retain the discretion to construct Eligible Facilities that are not specifically listed in the EFP?

A: Yes. As ANR witness Linder explains, ANR is proposing to retain the discretion to construct Eligible Facilities that fit into one or more of the following categories: (1) projects to address issues that ANR believes could lead to imminent unsafe conditions; and (2) projects that ANR deems necessary to comply with new legislative and/or regulatory requirements.

Additionally, to the extent new circumstances arise that create the need for entirely unanticipated modernization projects, ANR witness Linder explains that ANR is proposing a tariff mechanism that allows it to treat such projects as Eligible Facilities upon obtaining either the consensus of a majority of shippers subject to the SIMM rate or approval by the Commission.

Q: Does ANR propose to retain discretion regarding the timing under which it will construct Eligible Faculties?

A: Yes. As noted above, ANR will retain the flexibility to determine the timing of Eligible Facilities projects based on risk assessment determinations. For example, as detailed in ANR witness Currier's testimony, PHMSA's Mega Rule requires assessment of ANR's assets which is an ongoing task. As a result, these assessments can reveal risks or problems that require immediate attention that were not known to the pipeline operator prior to the assessment, thereby necessitating flexibility in determining which projects to undertake when.

Moreover, some projects can be completed within a relatively short period of time, whereas others must be completed over several years and require developing complex schedules or milestones focused on placing the project into service. For these long-term projects, plans can and do change, particularly as the pipeline gains more information, responds to new regulations or permitting issues, or encounters unexpected conditions in implementing its plans. The plans must be based on sound information known at the time and flexible enough to adapt to unforeseen changes or new information. Additionally, the timelines for regulatory approvals related to such projects are uncertain, creating substantial risk of delay.

Lastly, ANR cannot control development in the vicinity of its pipeline facilities that may ultimately require ANR to undertake additional assessments and projects to ensure compliance with PHMSA regulations. ANR has developed the EFP to allow flexibility for timing as a result of these uncertainties.

Q: Please describe how ANR developed the cost estimates contained in the EFP.

A: The EFP provides high-level estimates of the costs associated with the projects contained in the EFP. The cost estimates are desktop estimates in recognition of the fact that the various projects have not been fully scoped at this time. To develop the estimates, ANR has utilized cost assumptions based on historical experience with similarly-configured projects, accounting for factors such as pipe diameter, mileage (for pipeline facilities), and horsepower (for compressor facilities). For certain projects, the estimates were further developed based on known site attributes, such as site geology and river crossings. The cost estimates of certain integrity-related projects included in the EFP are further supported by ANR witness Currier. Given the relatively early stage of the cost estimates included in the EFP, the estimates are not intended to constitute the final project costs.

Q. Does this conclude your testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22-____-000

State of Texas)
) ss.
County of Harris)

AFFIDAVIT OF MATT PARKS

Matt Parks, being first duly sworn, on oath states that he is the witness whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of Matt Parks"; that, if asked the questions which appear in the text of said testimony, he would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as Matt Parks's sworn testimony in this proceeding.

DocuSigned by:
Matt Parks
2DD11963202346D...

Matt Parks

SWORN TO AND SUBSCRIBED BEFORE ME THIS 18th DAY OF January, 2022. This notarial act was an online notarization.

Notary Seal

NOTARY PUBLIC STATE OF TEXAS
SHELIA O. COPUS
Notary ID
976876
My Commission Expires
2/22/2023

Digital Certificate

DocuSigned by:
Shelia Copus
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ANR's Modernization Program

Eligible Facilities Plan

Overview of ANR Assets

Originally conceived as the Michigan-Wisconsin Pipe Line in 1945 as part of America's post-war expansion, ANR Pipeline Company ("ANR") has for decades been a premier transporter of Gulf Coast, Texas, and Oklahoma production to the Midwest via its southeast and southwest mainlines ("SEML" and "SWML"), respectively. Markets including Wisconsin, Michigan, Ohio and the greater Chicago area have been the recipients of ANR's long-time service. In 2015, in response to an influx of Utica and Marcellus production, ANR undertook a major capital program to allow for reverse flow, north-to-south, from production areas in Indiana and Ohio to the Louisiana gulf on the SEML. With this new bi-directionality, ANR can provide its shippers with more market options as well as access to abundant shale supply in the wake of offshore production declines.

ANR operates approximately 9,000 miles of interstate pipeline extending from Texas and Oklahoma, as well as the producing areas in the Gulf Coast, to points in Wisconsin and Michigan. Additionally, the maximum physical design day withdrawal capability from the storage fields that ANR owns is approximately 2.2 Bcf per day. ANR provides storage, transportation, and various capacity related services on an open access basis to qualifying shippers delivering more than 1 trillion cubic feet of natural gas annually. ANR is a seven-zone system with the majority of its delivery locations in Zone 7, which includes Wisconsin, Michigan, and the Joliet Hub area, as well as Zone 1 along the U.S. Gulf Coast. It links the Gulf of Mexico, Mid-Continent, WCSB, Rockies, Utica, and Marcellus production to end-use markets in Wisconsin, Michigan, Illinois, Ohio, Indiana, and the U.S. Southeast.

ANR's Proposed Modernization Program

As part of ANR's prior settlement approved by the Commission in Docket No. RP16-440 ("RP16-440 Settlement"), ANR committed to spend at least $837 million for reliability and modernization projects including capital projects that enhance the efficiency, reliability, and/or safety of ANR's system. This proposed modernization program focuses on ANR's continued efforts to improve the reliability, integrity, safety, and efficiency of its system as well as address the numerous complex issues arising out of recent and anticipated regulatory changes in pipeline safety, reliability, integrity, and environmental requirements, as well as any additional legislative initiatives.

ANR's Eligible Facilities Plan ("EFP") is focused on continuing to improve the safety, integrity, and reliability of the system. The projects were selected based on ANR's prioritization of its modernization needs such that each of the projects is associated with a facility that meets one or more of the following criteria: (1) it operates at a relatively high level of risk; (2) it requires upgrades for ANR to meet current or emerging regulations; and/or (3) its reliability is lower than necessary to meet current or future service requirements. ANR has functionalized the Eligible Facilities into transmission related projects and storage related projects. These EFP projects are designed to allow ANR to modernize aging facilities in order to address reliability and integrity risk, to increase efficiencies, reduce emissions where feasible, and to address compliance with existing, newly promulgated, and future regulatory requirements.

The transmission related projects include, but are not limited to, projects such as the replacement of vintage pipe that contains wrinkle bends, cased crossings, and/or pipe with low cathodic protection or low performance coating. The Pipeline Safety: Safety of Gas Transmission Pipelines rulemaking ("Mega Rule Part 1") took effect July 1, 2020, and will require ANR to undertake projects to ensure continued compliance. Furthermore, additional rulemakings are anticipated in the future, including issuance of Part 2 of the Mega Rule as a Final Rule as well as other pipeline safety rulemakings that the Pipeline and Hazardous Material Safety Administration ("PHMSA") is currently progressing. The transmission related projects may also include projects in compliance with other regulations promulgated at either the federal, state, or Commission level including but not limited to methane, carbon, or other emission related regulations. Projects such as the installation of permanent launchers, receivers, and any modification points such as mainline valves, fittings, or other ancillary piping benefit the system by making the line piggable. Projects also include the replacement of vintage compression with more reliable, sustainable, and energy efficient units. ANR will evaluate electrification where appropriate. When reasonable, replaced horsepower ("HP") will be retained on site to provide standby compression for use during both planned and unplanned outages. Additionally, automation and controls will be upgraded on transmission related compressor units allowing remote monitoring, advanced analysis, and preventative maintenance as well as measurement remote monitoring, meter enhancements, and gas quality monitoring modernization.

The storage related projects include, but are not limited to, projects in compliance with the PHMSA Storage Final Rule (Docket 2016-0016) which took effect on March 13, 2020, and projects to modernize the gas processing and gas handling equipment, including the installation of permanent launchers, receivers, and any modification points such as mainline valves, fittings, or other ancillary piping to make storage related lines piggable.

The potential projects listed below have been identified and scoped with initial estimates and timeframes in recognition of the likelihood that project prioritization or timing will change as the program progresses and projects are scoped. ANR continues to identify projects based on risk prioritization and the ability to complete the work.

2023 Project Overview

Transmission:	
Mega Rule	2.5
Piggability Projects	4.0
Delhi CS HP Replacement	75.0
Jena CS HP Replacement	46.0
Automation & Control Upgrades	14.0
Transmission Estimated Total	$141.5
Storage:	
Well Abandonments & Storage Line Retirements	5.8
Piggability Projects	6.0
Storage Estimated Total	$11.8
2023 Estimated Total	$153.3

Transmission Projects

Potential Mega Rule Projects		
1	*Mega Rule Part 1 Non-HCA Assessments*	*~$1,500,000*
2	*Mega Rule Part 2 HCA Response Criteria*	*~$100,000*
3	*Mega Rule Part 2 Non-HCA Response Criteria*	*~$100,000*
4	*Mega Rule Part 2 Non-HCA External Corrosion*	*~$700,000*
5	*Mega Rule Part 2 Internal Corrosion Gas Quality*	*~$100,000*
	Total	***~$2,500,000***

The potential Mega Rule projects include projects in compliance with all parts of the PHMSA Mega Rule.

PHMSA Mega Rule Part 1: Assessment of Integrity Threats Outside of HCAs

These projects will be for assessing integrity threats of pipeline segments outside of HCAs that are operating at greater than or equal to 30% specified minimum yield strength ("SMYS") and are located in class 3 or 4 locations or in an MCA capable of accommodating an in-line inspection tool. Pipeline segments are expected to be prioritized using a risk-based approach and baseline assessments for already identified pipeline mileage are required by July 3, 2034.

PHMSA Mega Rule Part 2

Part 2 is anticipated to include new regulations addressing (1) increased requirements for cathodic protection surveys after backfilling; (2) required actions to take when low potentials are detected or stray currents are detected; (3) greater monitoring requirements for internal corrosion; (4) repair and response criteria for pipelines in non-HCAs operating at or above 40% SMYS; (5) required actions to be undertaken following severe weather events; and (6) requiring a defined methodology of engineering critical assessments for dents. Additionally, Part 2 imposes new requirements concerning HCA response criteria necessitating that ANR complete additional anomaly digs over a typical 10-year cycle. Finally, Part 2 imposes new requirements concerning non-HCA response criteria necessitating that ANR complete additional anomaly digs over a typical 10-year cycle.

Potential Piggability Projects		
1	Bi-directional launcher/receiver modification, Line 767/1-502 SEML - S of Eunice CS	~$2,000,000
2	Bi-directional launcher/receiver modification, Line - 0-501 Jena CS to Delhi CS	~$2,000,000
	Total	**~$4,000,000**

The potential piggability projects include the installation of permanent launchers, receivers, and any modification points such as mainline valves, fittings, or other ancillary piping to make the line piggable or, modifications to make existing launchers and receivers bi-directional. These projects will be prioritized based on ANR's continued risk evaluations.

Delhi Compressor Station ("CS") HP Replacement – ~$75 million

The Delhi CS is located in Richland Parish, LA. ANR is proposing to retire the seven (7) existing units and replace those units with more reliable, sustainable, and energy efficient units. The older vintage units are costly maintain and without replacement these units will continue to see unplanned outages.

Delhi Current HP				Delhi Proposed HP			
Make	**Model**	**Install Date**	**HP**	**Make**	**Model**	**Install Date**	**HP**
Clark	TLA-6	1959	2,000	Clark	TLA-6	1959	2,000
Clark	TLA-6	1959	2,000	Clark	TLA-6	1959	2,000
Clark	TLA-6	1959	2,000	Clark	TLA-6	1959	2,000
Clark	TLA-6	1959	2,000	Clark	TLA-6	1959	2,000
Clark	TLA-6	1964	2,000	Clark	TLA-6	1964	2,000
Clark	TLA-6	1964	2,000	Clark	TLA-6	1964	2,000
GE	Frame 3	1970	11,000	GE	Frame 3	1970	11,000
				TBD*		2023	15,900
				TBD*		2023	15,900
Total Certificated HP			**23,000**	**Total Proposed HP**			**23,000****

Grey = Retire
* To be determined ("TBD"). ANR will continue to evaluate unit selections, including electric driven compression where appropriate.
** ANR will govern the combined HP to match the currently existing HP.

Jena CS HP Replacement – ~$46 million

The Jena CS is located in La Salle Parish, LA. As part of the RP16-440 Settlement, ANR previously replaced five (5) units with a Solar Mars 100. This project is proposing to retire one (1) unit and replace it with a more reliable, sustainable, and energy efficient unit.

Jena Current HP				Jena Proposed HP			
Make	**Model**	**Install Date**	**HP**	**Make**	**Model**	**Install Date**	**HP**
Clark	TCVD-16	1969	7,800	Clark	TCVD-16	1969	7,800
Solar	Mars 100	2017	13,500	Solar	Mars 100	2017	13,500
				TBD*		2023	15,900
Total Certificated HP			**21,300**	**Total Proposed HP**			**21,300****

Grey = Retire
* ANR will continue to evaluate unit selections, including electric driven compression where appropriate.
** ANR will govern the combined HP to match the currently existing HP.

Potential Automation & Control Upgrade Projects		
1	*Janesville*	*~$3,000,000*
2	*EG Hill*	*~$11,000,000*
	Total	***~$14,000,000***

The potential automation and control upgrades on compressor units allow remote monitoring, advanced analysis, and preventative maintenance. These projects will be prioritized based on ANR's continued risk evaluations.

Storage Projects

Potential Well Abandonment & Storage Line Retirement Projects			
1	*Goodwell*	*an estimated 1 well*	*~$500,000*
2	*Lincoln*	*an estimated 1 well*	*~$500,000*
3	*Loreed*	*an estimated 10 wells*	*~$4,000,000*
4	*Reed City*	*an estimated 2 wells*	*~$500,000*
5	*South Chester*	*an estimated 1 well*	*~$300,000*
	Total		***~$5,800,000***

Certain storage wells do not provide significant value through either flow performance or for reservoir observation purposes to warrant remedial or continued maintenance work to meet or maintain current integrity standards. Plugging and abandoning these wells will reduce integrity risk and will be conducted in accordance with the PHMSA Storage Final Rule. There will be a minimal loss in deliverability that will be offset with the new drills. Planned work will also include the abandonment of surface piping used to tie wells into the field header system. These projects will be prioritized based on ANR's continued risk evaluations.

Potential Piggability Projects		
1	*Freeman Storage Field, launcher/receiver installation*	*~$2,000,000*
2	*Reed City Storage Field, launcher/receiver installation - South Header*	*~$2,000,000*
3	*Reed City Storage Field, launcher/receiver installation - North Header*	*~$2,000,000*
	Total	***~$6,000,000***

The potential storage related piggability projects include the installation of permanent launchers, receivers, and any modification points such as mainline valves, fittings, or other ancillary piping to make the line piggable or, modifications to make existing launchers and receivers bi-directional. These projects will be prioritized based on ANR's continued risk evaluations.

2024 Project Overview

Transmission:	
SEML 0-501 Pipeline Replacement Project, Phase I	230.0
Mega Rule	4.8
Road Casings	1.3
Piggability Projects	18.0
Automation & Control Upgrades	13.0
Transmission Estimated Total	$267.1
Storage:	
Well Abandonments & Storage Line Retirements	5.0
Piggability Projects	8.0
Storage Estimated Total	$13.0
2024 Estimated Total	$280.1

Transmission Projects

SEML 0-501 Pipeline Replacement Project, Phase I – ~$230 million

ANR has found a high concentration of external corrosion on the SEML 0-501 pipeline. The pipe has vintage coating with low cathodic protection performance capabilities and poor adhesion properties. Vintage manufacturing methods have made it susceptible to stress corrosion cracking and selective seam weld corrosion. This project proposes to target approximately 33 miles from Delhi to the Mississippi River and replace the pipe, recoat, and/or patch where necessary.

	Potential Mega Rule Projects	
1	*Mega Rule Part 1 Non-HCA Assessments*	*~$3,500,000*
2	*Mega Rule Part 2 HCA Response Criteria*	*~$100,000*
3	*Mega Rule Part 2 Non-HCA Response Criteria*	*~$100,000*
4	*Mega Rule Part 2 Non-HCA External Corrosion*	*~$1,000,000*
5	*Mega Rule Part 2 Internal Corrosion Gas Quality*	*~$100,000*
	Total	***~$4,800,000***

The potential Mega Rule projects include projects in compliance with all parts of the PHMSA Mega Rule.

Road Casings – ~$1.3 million

Cased crossings have been, and in some cases still are, used to run a carrier pipeline through a larger pipeline known as casing under roads and railroads. The casing functions to carry external loads and otherwise protect the carrier pipeline from damage. Pipelines inside of casings can create integrity concerns due to the threat of external corrosion of the carrier pipeline. Shorted casings will be assessed on an ongoing basis to evaluate the level of risk and consequence associated with type of short, features identified through in-line inspections, guided wave ultrasonic testing, and surveys.

Potential Piggability Projects		
1	*Bi-directional launcher/receiver modification, Line 2-501 MP 142.04 to MLV 12*	*~$2,000,000*
2	*Bi-directional launcher/receiver modification, Line 1-501 Red River Crossing (West)*	*~$2,000,000*
3	*Bi-directional launcher/receiver modification, Line 0-501 Red River Crossing (Middle)*	*~$2,000,000*
4	*Bi-directional launcher/receiver modification, Line 2-501 North of Madisonville to Ohio River*	*~$2,000,000*
5	*Bi-directional launcher/receiver modification, Line 2-501 MP 817.39 to Portland*	*~$2,000,000*
6	*Bi-directional launcher/receiver modification, Line 2-501 Brownsville to MLV 34*	*~$2,000,000*
7	*Bi-directional launcher/receiver modification, Line 2-501 Portland to MLV 64E*	*~$2,000,000*
8	*Bi-directional launcher/receiver modification, Line 0-501 Madisonville CS to Ohio River*	*~$2,000,000*
9	*Bi-directional launcher/receiver modification, Line 1-501 Sardis CS to Brownsville CS*	*~$2,000,000*
	Total	***~$18,000,000***

The potential piggability projects include the installation of permanent launchers, receivers, and any modification points such as mainline valves, fittings, or other ancillary piping to make the line piggable or modifications to make existing launchers and receivers bi-directional. These projects will be prioritized based on ANR's continued risk evaluations.

Potential Automation & Control Upgrade Projects		
1	*Gageby Creek*	*~$3,000,000*
2	*Custer*	*~$7,000,000*
3	*Moreland*	*~$3,000,000*
	Total	***~$13,000,000***

The potential automation and control upgrades on compressor units allow remote monitoring, advanced analysis, and preventative maintenance. These projects will be prioritized based on ANR's continued risk evaluations.

Storage Projects

Potential Well Abandonment & Storage Line Retirement Projects			
1	*Loreed*	*an estimated 13 wells*	*~$5,000,000*
	Total		***~$5,000,000***

The potential well abandonments and storage line retirements will be done in accordance with the PHMSA Storage Final Rule. These projects will be prioritized based on ANR's continued risk evaluations.

Potential Piggability Projects		
1	*Cold Springs Storage Field, launcher/receiver installation - Main Header*	*~$3,000,000*
2	*Goodwell Storage Field, launcher/receiver installation - Header*	*~$3,000,000*
3	*Goodwell Storage Field, launcher/receiver installation - Main Headers*	*~$2,000,000*
	Total	***~$8,000,000***

The potential storage related piggability projects include the installation of permanent launchers, receivers, and any modification points such as mainline valves, fittings, or other ancillary piping to make the line piggable or, modifications to make existing launchers and receivers bi-directional. These projects will be prioritized based on ANR's continued risk evaluations.

2025 Project Overview

Transmission:	
SEML 0-501 Pipeline Replacement Project, Phase II	170.0
SEML 1-501 Pipeline Recoat Project, Phase I	4.0
Mega Rule	5.7
Road Casings	1.3
Automation & Control Upgrades	9.0
Measurement	9.0
Transmission Estimated Total	$199.0
Storage:	
Well Abandonments & Storage Line Retirements	5.0
New Drills	7.0
Loreed Surface Reliability, Phase I	3.0
Measurement & Regulation Replacement	11.0
Piggability Projects	6.0
Storage Estimated Total	$32.0
2025 Estimated Total	$231.0

Transmission Projects

<u>SEML 0-501 Pipeline Replacement Project, Phase II – ~$170 million</u>

Phase II of the SEML 0-501 pipeline replacement project will continue to target approximately 33 miles from Delhi to the Mississippi River and replace the pipe, recoat, and/or patch where necessary.

<u>SEML 1-501 Pipeline Recoat Project, Phase I – ~$4 million</u>

The SEML 1-501 pipeline has similar material properties to the SEML 0-501 pipeline. The pipe has vintage coating with low cathodic protection performance capabilities and poor adhesion properties. This project proposes to recoat the pipeline with select pipeline replacements in targeted locations.

	Potential Mega Rule Projects	
1	*Mega Rule Part 1 Non-HCA Assessments*	*~$4,100,000*
2	*Mega Rule Part 2 HCA Response Criteria*	*~$100,000*
3	*Mega Rule Part 2 Non-HCA Response Criteria*	*~$200,000*
4	*Mega Rule Part 2 Non-HCA External Corrosion*	*~$1,200,000*
5	*Mega Rule Part 2 Internal Corrosion Gas Quality*	*~$100,000*
	Total	***~$5,700,000***

The potential Mega Rule projects include projects in compliance with all parts of the PHMSA Mega Rule.

Road Casings – ~$1.3 million

Shorted casings will be assessed on an ongoing basis to evaluate the level of risk and consequence associated with type of short, features identified through in-line inspections, guided wave ultrasonic testing, and surveys.

	Potential Automation & Control Upgrade Projects	
1	*Enterprise*	*~$9,000,000*
	Total	***~$9,000,000***

The potential automation and control upgrades on compressor units allow remote monitoring, advanced analysis, and preventative maintenance. These projects will be prioritized based on ANR's continued risk evaluations.

	Potential Gas Quality Monitoring Projects	
1	*La Grange*	*~$1,000,000*
	Total	***~$1,000,000***

These sites support gas quality monitoring that is integral to the safe and reliable operation of the system. Gas quality equipment at these facilities is antiquated and utilizes outdated communication methods. The gas quality equipment will be replaced with the latest analyzers, which provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. These projects will be prioritized based on ANR's continued risk evaluations.

	Potential Meter Enhancement Projects	
1	*Racine*	*~$3,000,000*
2	*Chester*	*~$3,000,000*
	Total	***~$6,000,000***

Metering equipment at these facilities is antiquated and utilizes outdated metering technology. Meters will be replaced with ultrasonic or Coriolis meters which provide higher accuracy and turndown, improved reliability, and advanced diagnostic capabilities. The meters provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. Accuracy improvements associated with the replacement of these meters may have the potential to contribute to a reduction of lost and unaccounted for gas ("LAUF") on the system. These projects will be prioritized based on ANR's continued risk evaluations.

Measurement Remote Monitoring – ~$2 million

Due to the age of assets on the system, equipment at various locations do not have the capability to be remotely monitored or provide diagnostics information. These types of equipment require manual inspection or validation to assess the health of equipment in the field, leading to inefficiencies in detection and response time of issues affecting overall system reliability. At critical sites, electronics upgrades will be performed to allow remote monitoring of equipment by analytics systems. Meter and analyzer electronics will be upgraded, legacy transmitters and manual gauges will be replaced with smart transmitters, and pressure differential monitoring will be added to equipment such as separators or other equipment that is prone to plugging that could result in service disruptions. These assets and those currently equipped with remote connectivity will be retrofitted to ensure that they meet the new TSA requirements for cyber security and remote connectivity. The sites will be prioritized based on ANR's continued risk evaluations.

Storage Projects

Potential Well Abandonment & Storage Line Retirement Projects			
1	*Loreed*	*an estimated 13 wells*	*~$5,000,000*
	Total		***~$5,000,000***

The potential well abandonments and storage line retirements will be done in accordance with PHMSA Storage Final Rule. These projects will be prioritized based on ANR's continued risk evaluations.

Potential New Drill Projects			
1	*Loreed*	*an estimated 2 wells*	*~$7,000,000*
	Total		***~$7,000,000***

To maintain deliverability and reliability, new storage wells will be drilled to replace plugged wells. New wells will be designed and constructed to comply with the latest PHMSA standards. The projects will also include any new drills necessary to replace deliverability lost because of the planned well abandonments. These projects will be prioritized based on ANR's continued risk evaluations.

Loreed Surface Reliability Program, Phase I – ~$3 million

The Loreed storage facility is obsolete and has suffered considerable performance degradation as a result of inefficient or poorly functioning equipment. ANR plans to modernize the gas processing and gas handling equipment, including wellhead separators, gas dehydration, slug catching systems, the low-pressure gas system, facilities to control hydrocarbon dew point, H_2S mitigation, the heater treater system, and a replacement of the obsolete flare system over a multi-year program.

Potential Measurement & Regulation Replacement Program		
1	*Reed City*	*~$4,000,000*
2	*Goodwell*	*~$3,000,000*
3	*Muttonville*	*~$4,000,000*
	Total	***~$11,000,000***

Storage metering and control equipment at these facilities is antiquated and utilizes outdated technology. Meters will be replaced with ultrasonic or Coriolis meters which provide higher accuracy and turndown, improved reliability, and advanced diagnostic capabilities. The meters provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. Accuracy improvements associated with the replacement of these meters may have the potential to contribute to a reduction of LAUF on the system. These sites also support gas quality monitoring that is integral to the safe and reliable operation of the system. These storage related sites monitor the gas coming from storage onto the system. Gas quality equipment at these facilities is antiquated and utilizes outdated communication methods. The gas quality equipment will be replaced with the latest analyzers, which provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. These projects will be prioritized based on ANR's continued risk evaluations.

Potential Piggability Projects		
1	*Lincoln Storage Field, launcher/receiver installation - South Header*	*~$2,000,000*
2	*Lincoln Storage Field, launcher/receiver installation - South Header*	*~$2,000,000*
3	*Lincoln Storage Field, launcher/receiver installation - East Header*	*~$2,000,000*
	Total	***~$6,000,000***

The potential storage related piggability projects include the installation of permanent launchers, receivers, and any modification points such as mainline valves, fittings, or other ancillary piping to make the line piggable or, modifications to make existing launchers and receivers bi-directional. These projects will be prioritized based on ANR's continued risk evaluations.

2026 Project Overview

Transmission:	
SEML 1-501 Pipeline Recoat Project, Phase II	17.0
Mega Rule	6.4
Road Casings	1.3
Measurement	9.0
Transmission Estimated Total	$33.7
Storage:	
Well Abandonments & Storage Line Retirements	5.3
New Drills	8.0
Loreed Surface Reliability, Phase II	19.0
Measurement & Regulation Replacement	9.0
Storage Estimated Total	$41.3
2026 Estimated Total	$75.0

Transmission Projects

SEML 1-501 Pipeline Recoat Project, Phase II – ~$17 million

This project proposes to continue to recoat the pipeline with select pipeline replacements in targeted locations.

Potential Mega Rule Projects		
1	*Mega Rule Part 1 Non-HCA Assessments*	*~$4,700,000*
2	*Mega Rule Part 2 HCA Response Criteria*	*~$100,000*
3	*Mega Rule Part 2 Non-HCA Response Criteria*	*~$200,000*
4	*Mega Rule Part 2 Non-HCA External Corrosion*	*~$1,300,000*
5	*Mega Rule Part 2 Internal Corrosion Gas Quality*	*~$100,000*
	Total	***~$6,400,000***

The potential Mega Rule projects include projects in compliance with all parts of the PHMSA Mega Rule.

Road Casings – ~$1.3 million

Shorted casings will be assessed on an ongoing basis to evaluate the level of risk and consequence associated with type of short, features identified through in-line inspections, guided wave ultrasonic testing, and surveys.

Potential Gas Quality Monitoring Projects		
1	*Portland*	*~$1,000,000*
2	*Celestine*	*~$1,000,000*
	Total	***~$2,000,000***

The gas quality equipment will be replaced with the latest analyzers, which provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. These projects will be prioritized based on ANR's continued risk evaluations.

Potential Meter Enhancement Projects		
1	*Menomonee Falls*	*~$3,000,000*
2	*West Green Bay*	*~$2,000,000*
	Total	***~$5,000,000***

These meters will be replaced in order to provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. These projects will be prioritized based on ANR's continued risk evaluations.

Measurement Remote Monitoring – ~$2 million

At critical sites, electronics upgrades will be performed to allow remote monitoring of equipment by analytics systems. The sites will be prioritized based on ANR's continued risk evaluations.

Storage Projects

Potential Well Abandonment & Storage Line Retirement Projects			
1	*Austin*	*an estimated 1 well*	*~$500,000*
2	*Loreed*	*an estimated 10 wells*	*~$4,000,000*
3	*Reed City*	*an estimated 1 well*	*~$500,000*
4	*South Chester*	*an estimated 1 well*	*~$300,000*
	Total		***~$5,300,000***

The potential well abandonments and storage line retirements will be done in accordance with PHMSA Storage Final Rule. These projects will be prioritized based on ANR's continued risk evaluations.

Potential New Drill Projects			
1	*Loreed*	*an estimated 2 wells*	*~$8,000,000*
	Total		***~$8,000,000***

The potential new drill projects will be designed and constructed to comply with the latest PHMSA standards. These projects will be prioritized based on ANR's continued risk evaluations.

Loreed Surface Reliability Program, Phase II – ~$19 million

The gas processing and gas handling equipment, including wellhead separators, gas dehydration, the low-pressure gas system, facilities to control hydrocarbon dew point, H_2S mitigation, the heater treater system, and the obsolete flare system at Loreed will continue to be modernized over a multi-year program.

Potential Measurement & Regulation Replacement Program		
1	*Woolfolk - Austin A*	*~$3,000,000*
2	*Woolfolk - Austin B*	*~$3,000,000*
3	*Woolfolk - Muskegon*	*~$3,000,000*
	Total	***~$9,000,000***

These meters will be replaced in order to provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. The gas quality equipment at these storage related sites will be replaced with the latest analyzers, which provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. These projects will be prioritized based on ANR's continued risk evaluations.

2027 Project Overview

Transmission:	
SEML 0-501 Pipeline Recoat Project	11.0
SEML 2-501 Pipeline Recoat Project	1.0
Mega Rule	7.4
Road Casings	1.3
Piggability Projects	6.0
St. John CS HP Replacement Project	90.0
Measurement	8.0
Transmission Estimated Total	$124.7
Storage:	
Well Abandonments & Storage Line Retirements	5.5
New Drills	15.0
Loreed Surface Reliability, Phase III	19.0
Measurement & Regulation Replacement	7.0
Storage Estimated Total	$46.5
2027 Estimated Total	$171.2

Transmission Projects

SEML 0-501 Pipeline Recoat Project – ~$11 million

This project proposes to recoat the pipeline in targeted locations.

SEML 2-501 Pipeline Recoat Project – ~$1 million

The SEML 2-501 pipeline has similar material properties to the SEML 0-501 and 1-501 pipelines. This project proposes to recoat the pipeline in targeted locations.

Potential Mega Rule Projects		
1	*Mega Rule Part 1 Non-HCA Assessments*	*~$5,400,000*
2	*Mega Rule Part 2 HCA Response Criteria*	*~$100,000*
3	*Mega Rule Part 2 Non-HCA Response Criteria*	*~$200,000*
4	*Mega Rule Part 2 Non-HCA External Corrosion*	*~$1,500,000*
5	*Mega Rule Part 2 Internal Corrosion Gas Quality*	*~$200,000*
	Total	***~$7,400,000***

The potential Mega Rule projects include projects in compliance with all parts of the PHMSA Mega Rule.

Road Casings – ~$1.3 million

Shorted casings will be assessed on an ongoing basis to evaluate the level of risk and consequence associated with type of short, features identified through in-line inspections, guided wave ultrasonic testing, and surveys.

Potential Piggability Projects		
1	*Bi-directional launcher/receiver modification, Line 1-501 Ohio River Crossing (Middle)*	*~$2,000,000*
2	*Bi-directional launcher/receiver modification, Line 0-501 Ohio River Crossing (West)*	*~$2,000,000*
3	*Bi-directional launcher/receiver modification, Line 2-501 Ohio River Crossing (East)*	*~$2,000,000*
	Total	***~$6,000,000***

The potential piggability projects include the installation of permanent launchers, receivers, and any modification points such as mainline valves, fittings, or other ancillary piping to make the line piggable or, modifications to make existing launchers and receivers bi-directional. These projects will be prioritized based on ANR's continued risk evaluations.

St. John CS HP Replacement – ~$90 million

The St. John CS is located in Lake County, IN. ANR is proposing to retire the seven (7) existing units and replace those units with more reliable, sustainable, and energy efficient units. The older vintage units are costly to maintain and without replacement these units will continue to see unplanned outages.

St. John Current HP				St. John Proposed HP			
Make	**Model**	**Install Date**	**HP**	**Make**	**Model**	**Install Date**	**HP**
Clark	HBA-6T	1951	1,500	Clark	HBA-6T	1951	1,500
Clark	HBA-6T	1951	1,500	Clark	HBA-6T	1951	1,500
Clark	HBA-6T	1951	1,500	Clark	HBA-6T	1951	1,500
Clark	HBA-6T	1951	1,500	Clark	HBA-6T	1951	1,500
Clark	TCVC-20M	1972	12,000	Clark	TCVC-20M	1973	12,000
Clark	TCVC-20M	1973	12,000	Clark	TCVC-20M	1974	12,000
Ingersoll-Rand	KVS-412	2005	2,000	Ingersoll-Rand	KVS-412	1985	2,000
				TBD*		2023	23,400
				TBD*		2023	15,900
Total Certificated HP			**32,200**	**Total Proposed HP**			**32,200****

Grey = Retire
* ANR will continue to evaluate unit selections, including electric driven compression where appropriate.
** ANR will govern the combined HP to match the currently existing HP.

Potential Gas Quality Monitoring Projects		
1	*South Maumee*	*~$1,000,000*
2	*Defiance*	*~$1,000,000*
	Total	***~$2,000,000***

The gas quality equipment will be replaced with the latest analyzers, which provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. These projects will be prioritized based on ANR's continued risk evaluations.

Potential Meter Enhancement Projects		
1	*Appleton*	*~$2,000,000*
2	*Weeks Island*	*~$2,000,000*
	Total	***~$4,000,000***

These meters will be replaced in order to provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. These projects will be prioritized based on ANR's continued risk evaluations.

Measurement Remote Monitoring – ~$2 million

At critical sites, electronics upgrades will be performed to allow remote monitoring of equipment by analytics systems. The sites will be prioritized based on ANR's continued risk evaluations.

Storage Projects

Potential Well Abandonment & Storage Line Retirement Projects			
1	*Austin*	*an estimated 1 well*	*~$500,000*
2	*Goodwell*	*an estimated 3 wells*	*~$1,000,000*
3	*Loreed*	*an estimated 8 wells*	*~$3,000,000*
4	*Reed City*	*an estimated 3 wells*	*~$1,000,000*
	Total		***~$5,500,000***

The potential well abandonments and storage line retirements will be done in accordance with PHMSA Storage Final Rule. These projects will be prioritized based on ANR's continued risk evaluations.

Potential New Drill Projects			
1	*Goodwell*	*an estimated 2 wells*	*~$7,500,000*
2	*Reed City*	*an estimated 2 wells*	*~$7,500,000*
	Total		***~$15,000,000***

The potential new drill projects will be designed and constructed to comply with the latest PHMSA standards. These projects will be prioritized based on ANR's continued risk evaluations.

Loreed Surface Reliability Program, Phase III – ~$19 million

The gas processing and gas handling equipment, including wellhead separators, gas dehydration, the low-pressure gas system, facilities to control hydrocarbon dew point, H_2S mitigation, the heater treater system, and the obsolete flare system at Loreed will continue to be modernized over a multi-year program.

Potential Measurement & Regulation Replacement Program		
1	*Woolfolk - Detroit A & B*	*~$4,000,000*
2	*Woolfolk - Goodwell*	*~$3,000,000*
	Total	***~$7,000,000***

These meters will be replaced in order to provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. The gas quality equipment at these storage related sites will be replaced with the latest analyzers, which provide the capability of being remotely monitored to allow for trending and advanced failure and issue reporting. These projects will be prioritized based on ANR's continued risk evaluations.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22-___-000

PREPARED DIRECT TESTIMONY OF ALEXANDER KIRK ON BEHALF OF ANR PIPELINE COMPANY

January 28, 2022

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)	Docket No. RP22-___-000

Summary of Prepared Direct Testimony of
Alexander Kirk
on behalf of ANR Pipeline Company

Mr. Alexander Kirk is a Vice President of Brown, Williams, Moorhead & Quinn, Inc. and advises and assists energy industry clients on matters relating to natural gas supply and demand, rate design, and cost of service modeling, and economic life determinations for natural gas pipelines. The purpose of Mr. Kirk's testimony is to determine an appropriate economic life for ANR Pipeline Company's ("ANR") system based on a review of relevant factors, including the requirements of public authorities, the demand for ANR's services, and the gas supplies available to ANR. Mr. Kirk's proposed economic life is used by ANR witness Crowley's testimony regarding depreciation.

Mr. Kirk first discusses the requirements of public authorities that will impact ANR. Numerous federal, state, and local policies will lead to a significant decline in natural gas consumption and transportation by 2050.

Mr. Kirk next discusses other factors that affect the demand for ANR's services, which must be considered in determining ANR's remaining economic life. Technological developments in alternative energies and energy storage are discussed, leading to

significant competition with natural gas as a source of energy in every sector of the economy in the next several decades.

To analyze the gas supplies available to ANR, Mr. Kirk presents estimates of the gas resources available within the Lower 48 U.S. states and Canada. After examining current annual production to assess the magnitude of the remaining gas supply resources in these regions, Mr. Kirk concludes that gas supplies are not likely to be the primary constraint to ANR's economic life.

Given the significant reduction in natural gas consumption, and transportation, which would be necessary by 2050, or earlier, to meet the requirements of public authorities at the federal, state, and local levels, Mr. Kirk proposes that ANR's economic life be truncated at 2050 for ratemaking purposes. In addition to the requirements of public authorities, Mr. Kirk's testimony demonstrates that significant competitive pressure exists from the declining cost of renewable energy, electrification, and battery storage prior to 2050. The gas supplies discussed by Mr. Kirk will support the continued use of ANR in the intervening years, allowing ANR to provide its shippers continued, reliable, access to a proven energy source during its remaining economic life. Mr. Kirk also provides an alternative depreciation proposal in the event the Federal Energy Regulatory Commission determines that a 2050 economic life truncation is too speculative at this time.

TABLE OF ACRONYMS

ANR	ANR Pipeline Company
AEO	Annual Energy Outlook
Bcf	Billion cubic feet
BWMQ	Brown, Williams, Moorhead & Quinn, Inc.
Commission or FERC	Federal Energy Regulatory Commission
Dth/day	Dekatherms per day
EIA	U.S. Energy Information Administration
GWh	Gigawatt hour
kW	Kilowatt
kWh	Kilowatt hour
ITC	Income tax credit
ISO	Independent System Operators
LCOE	Levelized cost of energy
LCOSs	Levelized cost of services
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
NGA	Natural Gas Act of 1938
NREL	National Renewable Energy Laboratory
PGC	Potential Gas Committee
RPS	Renewable Portfolio Standards

RTO	Regional Transmission Organizations
Tcf	Trillion cubic feet

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Table of Exhibits

Exhibit No.	**Description**	**Confidentiality Designation**
ANR-0017	Prepared Direct Testimony	Public
ANR-0018	*Curriculum Vitae* of Alexander Kirk	Public
ANR-0019	Executive Order 14008	Public
ANR-0020	Department of Energy's Berkeley National Laboratory January 27, 2021, News Release	Public
ANR-0021	Williams, J. H., Jones, R., Haley, B., Kwok, G., Hargreaves, J., Farbes, J., et al. (2021). Carbon-neutral pathways for the United States. AGU Advances, 2, e2020AV000284 https://doi.org/10.1029/2020AV000284	Public
ANR-0022	U.S. Department of State and the United States Executive Office of the President, *The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050* (November 2021)	Public
ANR-0023	Requirements of Public Authorities	Public
ANR-0024	Carbon Dioxide Emissions Projections by the EIA	Public
ANR-0025	National Renewable Energy Laboratory Report "U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020" (January 2021)	Public
ANR-0026	National Renewable Energy Laboratory, Annual Technology Baseline 2020 Summary Excerpt	Public
ANR-0027	Lawrence Berkeley National Laboratory, "Wind Energy Technology Data Update: 2020 Edition" (August 2020)	Public
ANR-0028	BloombergNEF Article published December 20, 2020	Public
ANR-0029	Energy Information Administration, "Battery Storage in the United States:	Public

	An Update on Market Trends" (August 2021)	
ANR-0030	Lower 48 States Non-Speculative Resources and Production	Public

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	)))	Docket No. RP22-___-000

PREPARED DIRECT TESTIMONY OF ALEXANDER KIRK

I. INTRODUCTION

Q. Please state your name, job title and business address.

A. My name is Alexander Kirk, and my business address is P.O. Box 10, Sunderland, MD 20689-0010. I am a Vice President of Brown, Williams, Moorhead & Quinn, Inc., ("BWMQ") a nationally recognized energy consulting firm based in the Washington, D.C. region.

Q. What is the nature of the work performed by your firm?

A. We offer technical, economic, and policy assistance to the various segments of the natural gas pipeline industry, oil pipeline industry, and electric utility industry on business and regulatory matters.

Q. On whose behalf are you submitting your prepared testimony in this proceeding?

A. I am submitting testimony on behalf of ANR Pipeline Company ("ANR").

Q. Are you sponsoring any exhibits with your prepared direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit No. ANR-0018	*Curriculum Vitae* of Alexander Kirk
Exhibit No. ANR-0019	*Tackling the Climate Crisis at Home and Abroad*, Executive Order 14008, 86 Fed. Reg. 7619 (Feb. 1, 2021) ("EO 14008")
Exhibit No. ANR-0020	News Release, Department of Energy's Berkeley National Laboratory, *Getting to Net Zero–and Even Net Negative–Is Surprisingly Feasible, and Affordable* (Jan. 27, 2021), https://newscenter.lbl.gov/2021/01/27/getting-to-net-zero-and-even-net-negative-is-surprisingly-feasible-and-affordable/
Exhibit No. ANR-0021	Williams, J. H., Jones, R., Haley, B., Kwok, G., Hargreaves, J., Farbes, J., et al. (2021). Carbon-neutral pathways for the United States. AGU Advances, 2, e2020AV000284 https://doi.org/10.1029/2020AV000284
Exhibit No. ANR-0022	U.S. Department of State and the United States Executive Office of the President, *The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050* (November 2021)
Exhibit No. ANR-0023	Requirements of Public Authorities
Exhibit No. ANR-0024	Energy Information Administration, *Carbon Dioxide Emissions Projections*, 2021 Annual Energy Outlook.
Exhibit No. ANR-0025	David Feldman, *et al.*, National Renewable Energy Laboratory Report, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020* (Jan. 2021), https://www.nrel.gov/docs/fy21osti/77324.pdf
Exhibit No. ANR-0026	National Renewable Energy Laboratory, Annual Technology Baseline 2020 Summary Excerpt
Exhibit No. ANR-0027	Ryan Wiser, *et al.*, Lawrence Berkeley National Laboratory, *Wind Energy Technology Data Update: 2020 Edition* (Aug. 2020), https://emp.lbl.gov/sites/default/files/2020_wind_energy_technology_data_update.pdf

Exhibit No. ANR-0028	BloombergNEF, *Battery Pack Prices Cited Below $100/kWh for the First Time in 2020, While Market Average Sits at $137/kWh* (Dec. 20, 2020), https://about.bnef.com/blog/battery-pack-prices-cited-below-100-kwh-for-the-first-time-in-2020-while-market-average-sits-at-137-kwh/
Exhibit No. ANR-0029	Energy Information Administration, “Battery Storage in the United States: An Update on Market Trends” (August 2021)
Exhibit No. ANR-0030	Lower 48 States Non-Speculative Resources and Production

Q. Please briefly state your professional experience and qualifications.

A. I earned a Bachelor of Science degree with majors in Mathematics and Economics from Linfield College in 2005, and a Master of Arts in Economics from the University of Washington in 2008. From September 2008 to May 2010, I was an instructor for Principles of Microeconomics and Natural Resource Economics courses at the University of Washington. I have been employed by BWMQ since 2007, where I have assisted clients with analyses of gas supply, natural gas pipeline rate cases, storage and pipeline market-based rate applications, business risk, rate design and both traditional and levelized cost-of-service modeling.

Q. Have you previously testified before the Federal Energy Regulatory Commission (“Commission” or “FERC”)?

A. Yes, I have provided a list of the cases in which I have provided testimony and/or testified during my career in my curriculum vitae, attached as Exhibit No. ANR-0018.

Q. What is the purpose of your prepared direct testimony in this proceeding?

A. The purpose of my testimony is to establish and support ANR's economic life. As part of the process to establish ANR's economic life, I will provide a comprehensive review of a multitude of requirements of public authorities, discuss the demand for ANR's services, and assess the gas supplies available to ANR. My analysis is used by ANR witness Crowley in developing proposed depreciation rates.

Q. Please briefly describe ANR's system.

A. ANR is an interstate pipeline system with a footprint that spans Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Nebraska, Ohio, Oklahoma, Tennessee, Texas, and Wisconsin. ANR also owns storage assets located in Michigan.

Q. What is the "economic life" for a natural gas pipeline asset?

A. The economic life for an asset refers to the time period for which the asset is expected to be profitable. To be profitable, a natural gas pipeline asset must receive both the *return of* its fixed costs through depreciation as well as a *return on* the investment of its fixed costs. A natural gas pipeline asset has reached the end of its economic life when it is no longer expected to return a profit. The economic life of a natural gas pipeline asset is used as a "truncation" in the calculation of its depreciation rate, as explained by ANR witness Crowley.

Q. What factors influence the economic life of a natural gas pipeline?

A. Part 201 of FERC's regulations sets forth an accounting system for natural gas companies under the Natural Gas Act that lists the economic life concepts that are to be considered in determining depreciation rates. In relevant part, the definition of depreciation in Part 201 provides that "[a]mong the causes to be given consideration [in determining depreciation] are wear and tear, decay, action of the elements, inadequacy, *obsolescence*, changes in the art, *changes in demand and requirements of public authorities*, and, in the case of natural gas companies, *the exhaustion of natural resources*." 18 C.F.R. pt. 201, Definitions, ¶ 12.B (2021) (emphasis added).

Q. How is your testimony organized?

A. In Section II, I review the requirements of public authorities that will be a primary driving factor in my economic life recommendation. In Section III, I discuss factors affecting the demand for ANR's services. In Section IV, I review gas supplies available to ANR. In Section V, I provide my recommended economic life truncation for ANR. I also provide an alternative depreciation proposal in Section VI in the event the Commission determines that my recommended economic life truncation is too speculative at this time.

II. REQUIREMENTS OF PUBLIC AUTHORITIES

Q. Why is it important to consider the requirements of public authorities when establishing ANR's economic life?

A. As mentioned earlier, "requirements of public authorities" is specified in Part 201 of FERC's regulations as a factor to consider in setting depreciation rates. There are many requirements of federal, state, and local public authorities that will affect the utilization of ANR's services. The regulations and requirements of public authorities may therefore impact ANR's economic life, and thereby impact the appropriate depreciation rates for ANR.

Q. What recent requirements by federal authorities will impact the utilization of ANR?

A. On January 27, 2021, the United States president issued Executive Order 14008 ("EO 14008"), which is provided in its entirety in Exhibit No. ANR-0019. In relevant part, Executive Order 14008, Section 201, states:

> **Sec. 201.** *Policy.* Even as our Nation emerges from profound public health and economic crises borne of a pandemic, we face a climate crisis that threatens our people and communities, public health and economy, and, starkly, our ability to live on planet Earth. Despite the peril that is already evident, there is promise in the solutions—opportunities to create well-paying union jobs to build a modern and sustainable infrastructure, deliver an equitable, clean energy future, and put the United States on a path to achieve net-zero emissions, economy-wide, by no later than 2050.
>
> We must listen to science—and act. We must strengthen our clean air and water protections. We must hold polluters accountable for their actions. We must deliver environmental justice in communities all across America. The Federal Government must drive assessment, disclosure, and mitigation of climate pollution and climate-related risks in every sector of our economy, marshaling the creativity, courage, and capital necessary to make our Nation resilient in the face of this threat. Together, we must combat the climate crisis with bold, progressive action that combines the full capacity of the Federal Government with efforts from every corner of our Nation, every level of government, and every sector of our economy.
>
> It is the policy of my Administration to organize and deploy the full capacity of its agencies to combat the climate crisis to implement a Government-wide approach that reduces climate pollution in every sector of the economy; increases resilience to the impacts of climate change; protects public health; conserves our lands, waters, and biodiversity; delivers environmental justice; and spurs well-paying union jobs and economic growth, especially through innovation, commercialization, and deployment of clean energy technologies and infrastructure. Successfully meeting these challenges will require the Federal Government to pursue such a coordinated approach from planning to implementation, coupled with substantive engagement by stakeholders, including State, local, and Tribal governments.

Section 201 of EO 14008 establishes that it is the policy of the federal government's agencies to implement government-wide approaches to achieve net-zero emissions, economy-wide, by no later than 2050. Additionally, Section 205 of EO 14008 establishes a plan to reach a "carbon pollution-free electricity sector no later than 2035":

> **Sec. 205**. *Federal Clean Electricity and Vehicle Procurement Strategy*. (a) The Chair of the Council on Environmental Quality, the Administrator of General Services, and the Director of the Office and Management and Budget, in coordination with the Secretary of Commerce, the Secretary of Labor, the Secretary of Energy, and the heads of other relevant agencies, shall assist the National Climate Advisor, through the Task Force established in section 203 of this order, in developing a comprehensive plan to create good jobs and stimulate clean energy industries by revitalizing the Federal Government's sustainability efforts.
>
> (b) The plan shall aim to use, as appropriate and consistent with applicable law, all available procurement authorities to achieve or facilitate:
>
> (i) a carbon pollution-free electricity sector no later than 2035; and
>
> (ii) clean and zero-emission vehicles for Federal, State, local, and Tribal government fleets, including vehicles of the United States Postal Service.
>
> (c) If necessary, the plan shall recommend any additional legislation needed to accomplish these objectives.
>
> (d) The plan shall also aim to ensure that the United States retains the union jobs integral to and involved in running and maintaining clean and zero-emission fleets, while spurring the creation of union jobs in the manufacture of those new vehicles. The plan shall be submitted to the Task Force within 90 days of the date of this order.

Q. How does EO 14008 constrain the economic life of ANR?

A. Achieving net-zero emissions by no later than 2050 will require a substantial decrease in the consumption of natural gas in the United States, and therefore, a substantial decrease in the amount of natural gas transported on ANR.

Q. How much will natural gas consumption need to decrease to achieve net-zero emissions by no later than 2050?

A. The Department of Energy provided insight on what would be needed to achieve such a goal. The same day EO 14008 was issued, the Department of Energy's Berkeley National Laboratory issued a news release (Exhibit No. ANR-0020, also found at https://newscenter.lbl.gov/2021/01/27/getting-to-net-zero-and-even-net-negative-is-surprisingly-feasible-and-affordable/) highlighting a recent analysis that it conducted with the University of San Francisco and the consulting firm Evolved Energy Research (Exhibit No. ANR-0021, also found at https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2020AV000284) titled

"Carbon-Neutral Pathways for the United States". The Department of Energy analysis shows that the least-cost carbon neutral pathway that can achieve zero net CO_2 emissions in 2050 will require U.S. energy supplied by natural gas to decline from 31.4 exajoules ("EJ") in 2020 to 8.3 EJ by 2050, a decline of approximately 74 percent. The "least-cost" scenario utilizes underground storage to sequester carbon dioxide, allowing for the continued use of some fossil fuels. To the extent that policy may disallow the continued use of fossil fuels, or additional methane-related limits develop, natural gas consumption may be required to decline more than 74 percent and do so sooner than 2050.

Q. How would such a decrease in gas consumption impact ANR?

A. If the 2050 goal is to be met, the large decrease in natural gas use under even the least-cost carbon neutral pathway will have both direct and indirect consequences. As a direct consequence, the demand for the services for ANR will decline proportionate to the decline in natural gas consumption. Indirectly, there will be feedback effects that will further decrease the demand for ANR's services. As the Department of Energy article explains, the "departure of gas customers leaves a shrinking customer base to pay the fixed costs of the system; at some point, gas rates can become prohibitive." If the amount of natural gas supplies transported on ANR is reduced by 74 percent and billing determinants decline by a proportional amount, this decline would result in transportation rates for the remaining customers increasing by almost 400 percent. The remaining customers will continue to evaluate whether transportation service on ANR continues to be both viable and financially preferable to alternatives. As a shrinking customer base causes those remaining customers to face an even higher burden of ANR's remaining fixed costs, more of them will decide to leave the system, causing a spiral of rate increases and more customers leaving the system. A similar issue will occur for local distribution companies served by ANR, which will also have shrinking customer bases, potentially further increasing the final cost of delivered natural gas and further impacting the demand for upstream transportation service on ANR.

Q. Has the federal government conducted any additional analysis on achieving net-zero emissions by 2050?

A. Yes. The U.S. Department of State and the United States Executive Office of the President recently published a report titled "The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050" (November 2021) ("2021 Long Term Strategy"). *See* Exhibit No. ANR-0022. The 2021 Long Term Strategy provides a general overview of the U.S. climate strategy to achieve net-zero emissions by 2050, and explains that the "transition pathways are not only affordable, but, because of the benefits from reduced climate change and improved public health, they will also create wide-ranging benefits."

Q. What requirements by state and local authorities will impact the utilization of ANR?

A. In addition to federal requirements, there are numerous state and local policies across ANR's footprint that will have a similar downward impact on natural gas use in the future. These standards generally reflect a goal of reducing fossil fuel use and typically emphasize the construction or utilization of renewable energy infrastructure in ANR's markets.

There are many requirements of public authorities located across ANR's footprint regarding energy and environmental policy, including (but not limited to):

1. Des Moines, Iowa: The city passed a resolution that commits to reach net-zero greenhouse gas emissions by the year 2050. Des Moines also commits to a community-wide goal of achieving 100% electricity from carbon-free sources by 2056. *See* Exhibit No. ANR-0023 at 1-3 and https://councildocs.dsm.city/Resolutions/20210111/32.pdf

2. Iowa City, Iowa: Resolution 19-218 resolves to adopt the Intergovernmental Panel on Climate Change targets of 45% reduction in carbon emissions by 2030 and reach net-zero emissions by 2050. *See* Exhibit No. ANR-0023 at 4-9 and https://www8.iowa-city.org/WebLink/0/edoc/1944166/100%20Day%20Report%20-%20approved%20April%202020.pdf

3. Illinois: The Climate and Equitable Jobs Act (SB2408) adopts statewide targets of 40% renewable energy by 2030, 50% renewable energy by 2040, and 100% clean energy by 2050. *See* Exhibit No. ANR-0023 at 10-12 and https://www.illinois.gov/news/press-release.23893.html.

4. Chicago, Illinois: The Chicago Climate Change Action Plan has a primary goal of reducing Chicago's greenhouse gas emissions by 80% below 2005 levels by 2050. *See* Exhibit No. ANR-0023 at 13-14 and https://www.chicago.gov/content/dam/city/progs/env/CCAP/CCAP.pdf.

5. Chicago, Illinois: Resolution R2019-157 commits Chicago "to transition to 100% clean renewable energy community-wide beginning with 100% renewable electricity in buildings by 2035..." *See* Exhibit No. ANR-0023 at 15-18 and https://chicago.legistar.com/LegislationDetail.aspx?ID=3886265&GUID=081AC4BD-E6F4-4789-AD80-53BF25764855&Options=Advanced&Search=&FullText=1 .

6. Evanston, Illinois: The city adopted the Climate Action and Resilience Plan that calls for carbon neutrality by 2050 and 100% renewable electricity by 2030. *See* Exhibit No. ANR-0023 at 19-22 and https://www.cityofevanston.org/home/showdocument?id=45170

7. Greensburg, Kansas: The Greensburg Sustainable Comprehensive Plan outlines strategies to ensure that the town would be powered by 100% renewable sources. Currently the City is 100% powered by wind energy. *See* Exhibit No. ANR-0023 at 23-26 and https://www.greensburgks.org/residents/recovery-planning/sustainable-comprehensive-master-plan/view and https://www.greensburgks.org/sustainability/how-we-put-the-green-in-greensburg

8. Louisville, Kentucky: The Sustain Louisville progress report states that Louisville has set a target to reduce its greenhouse gas emissions 80% by 2050. *See* Exhibit No. ANR-0023 at 27-30 and https://louisvilleky.gov/document/sustainlouisville2017-18progressreportfinalpdf

9. Louisville, Kentucky: The Louisville Greenhouse Gas Emissions Reduction Plan set a goal to reduce city greenhouse gas emissions 80% by 2050. *See* Exhibit No. ANR-0023 at 31-32 and https://louisvilleky.gov/document/ghgerpfinaldraft202004220pdf

10. Louisiana: Enacted August 2020, Executive Order JBE 2020-18 established a goal of reaching net zero greenhouse gas emissions by 2050, as well as other interim targets. *See* Exhibit No. ANR-0023 at 33-36 and https://gov.louisiana.gov/assets/ExecutiveOrders/2020/JBE-2020-18-Climate-Initiatives-Task-Force.pdf.

11. Abita Springs, Louisiana: The town council has adopted a resolution to commit to 100% renewable energy by 2030. *See* Exhibit No. ANR-0023 at 37-45 and https://www.townofabitasprings.com/clubs.

12. Petoskey, Michigan: The city of Petoskey adopted a resolution which commits to achieving 100% renewable energy by 2040. *See* Exhibit No. ANR-0023 at 46-49 and https://cms3.revize.com/revize/petoskeymi/City%20Council/Agendas/2019/06-17-19.pdf

13. Traverse City, Michigan: The city unanimously adopted a resolution to commit to transitioning to 100% renewable electricity. *See* Exhibit No. ANR-0023 at 50-55 and https://www.traversecitymi.gov/news.asp?aid=446, https://d3n8a8pro7vhmx.cloudfront.net/miclimateaction/pages/109/attachments/original/1487620503/TC_100__Resolution.pdf?1487620503 and https://www.tclp.org/Page/History.

14. Grand Rapids, Michigan: The City of Grand Rapids Strategic Plan FY2020-FY2023 sets a goal of achieving 100% of City electricity supplied by renewable sources by the year 2025. *See* Exhibit No. ANR-0023 at 56-57 and https://www.grandrapidsmi.gov/Government/Departments/Office-of-the-City-Manager/Strategic-Plan

15. Kansas City, Missouri: The city's Climate Protection Plan outlines goals including, inter alia, adopting a long-term goal of reducing community-wide greenhouse gas emissions by 80% by 2050. *See* Exhibit No. ANR-0023 at 58-59 and https://www.kcmo.gov/Home/ShowDocument?id=3338.

16. St. Louis, Missouri: The city sets a goal to transitioning the city to 100% clean energy in the form of wind, solar, and energy efficient measures within the electricity sector by 2035 and an 80% reduction in citywide greenhouse gas emissions by 2050. *See* Exhibit No. ANR-0023 at 60-63 and https://www.stlouis-mo.gov/government/departments/aldermen/clean-energy-advisory-board/index.cfm.

17. Cincinnati, Ohio: In the Clean Energy Commitment and the 2018 Green Cincinnati Plan, Cincinnati commits to shifting the city to 100% renewable energy by 2035, and to develop 25 MW of solar power during the first phase of this plan. *See* Exhibit No. ANR-0023 at 64-65 and https://www.cincinnati-oh.gov/sites/oes/assets/File/2018%20Green%20Cincinnati%20Plan(1).pdf .

18. Cleveland, Ohio: The city has committed to having 25% of electricity use in the city provided by renewable sources by 2030, 100% of electricity demands from renewable energy sources by 2050, and to reduce greenhouse gas emissions 80% by 2050. *See* Exhibit No. ANR-0023 at 66-70 and https://www.sustainablecleveland.org/climate_action and http://www.city.cleveland.oh.us/09.18.2018ClimateActionPlan .

19. Lakewood, Ohio: Lakewood has committed to using 100% clean, renewable energy in its facilities by 2025, and 100% clean, renewable energy community-wide by 2035. *See* Exhibit No. ANR-0023 at 71-74 and http://www.onelakewood.com/wp-content/uploads/2016/02/CouncilMinutes_102119.pdf.

20. Columbus, Ohio: The City voted in 2020 to create a green-energy aggregation plan that will supply 100% of the city's power needs with renewable energy by 2022. The city is also committed to a community-wide goal to be carbon neutral by 2050. *See* Exhibit No. ANR-0023 at 75-80 and https://www.columbus.gov/sustainable/aggregation and https://columbus.legistar.com/LegislationDetail.aspx?ID=4595555&GUID

=6C1CEEFE-E997-4753-B6F2-FD33E08BAF2F&Options=Advanced&Search=&FullText=1.

21. Norman, Oklahoma: Resolution R-1718-120 Ready for 100 established a goal to transition the city to 100% renewable electricity by 2035, with a goal of all energy-use sectors including heating and transportation to be from 100% renewable resources by 2050. *See* Exhibit No. ANR-0023 at 81-82 and https://www.normanok.gov/sites/default/files/documents/2020-10/R-1718-120%20Ready%20for%20100.pdf

22. Knoxville, Tennessee: Knoxville has a goal to reduce greenhouse gas emissions by 80% of its 2005 emissions by 2050. *See* Exhibit No. ANR-0023 at 83-87 and http://knoxvilletn.gov/government/city_departments_offices/sustainability.

23. Memphis, Tennessee: The Memphis Area Climate Action Plan provides a goal and plan to reduce greenhouse gas emissions by 71% by 2050. The plan also calls to increase the percentage of carbon-free energy in the electric grid to 100% by 2050, with a focus on solar and wind. *See* Exhibit No. ANR-0023 at 88-97 and https://cleanenergy.org/blog/memphis-city-council-adopts-climate-action-plan/.

24. Nashville, Tennessee: Mayor John Cooper announced in December 2019 that Nashville will work towards reducing its community-wide emissions 70% by 2050. *See* Exhibit No. ANR-0023 at 98-100 and https://www.nashville.gov/News-Media/News-Article/ID/9133/Mayor-Cooper-Announces-Multiple-Initiatives-to-Combat-Climate-Change-and-Promote-Sustainability-Signs-Global-Covenant-of-Mayors.aspx.

25. Oak Ridge, Tennessee: The city's Climate Action Plan set goals to reduce municipal greenhouse gas emissions by 80% by 2050 and community-wide emissions by 50% by 2050. *See* Exhibit No. ANR-0023 at 101-103 and http://oakridgetn.gov/images/uploads/Documents/Departments/CommDev/Sustainability%20Page/Oak%20Ridge%20Climate%20Action%20Plan.pdf.

26. Austin, Texas: Resolution No. 20140410-024 established a goal of reaching net zero community-wide greenhouse gas emissions by 2050. *See* Exhibit No. ANR-0023 at 104-108 and http://austintexas.gov/sites/default/files/files/Sustainability/Climate/Resolution_No_20140410-024.pdf.

27. Austin, Texas: The Austin Community Climate Plan's goals are to achieve net zero community-wide greenhouse gas emissions by 2050. Currently the city has seen a 68% reduction of GHG from their baseline and all City-

owned buildings are powered by 100% renewable energy. *See* Exhibit No. ANR-0023 at 109-112 and http://austintexas.gov/sites/default/files/files/Sustainability/FINAL_-_OOS_AustinClimatePlan_061015.pdf

28. Denton, Texas: In 2020 the city of Denton developed Simply Sustainable: A Framework for Denton's Future, which outlines goals to create and implement a Greenhouse Gas Mitigation Program and to have under contract sufficient renewable energy supplies to achieve a 100% renewable energy supply objective. *See* Exhibit No. ANR-0023 at 113-119 and https://www.cityofdenton.com/CoD/media/City-of-Denton/Residents/Make%20a%20Difference/Sustainable%20Denton/Exhibit-2-Simply-Sustainable-Framework-Final-Copy_1.pdf

29. Georgetown, Texas: As of February 2019, Georgetown had 100% renewable energy, putting more renewable energy into the grid than it consumed. The city is now selling renewable energy credits to generate revenue. *See* Exhibit No. ANR-0023 at 120-124 and https://georgetown.org/2019/02/22/why-georgetown-is-100-percent-renewable/

30. Wisconsin: Executive Order #38 committed to the goal of ensuring all electricity consumed within the State of Wisconsin is 100% carbon-free by 2050 and charged the Office of Sustainability and Clean energy to ensure that the state fulfills the carbon reduction goals of the 2015 Paris Climate Accord. *See* Exhibit No. ANR-0023 at 125-126 and https://content.govdelivery.com/attachments/WIGOV/2019/08/16/file_attachments/1268023/EO%20038%20Clean%20Energy.pdf

31. Eau Claire, Wisconsin: The Renewable Energy Action Plan details steps to meet the goals of carbon neutrality and 100% renewable energy by 2050. *See* Exhibit No. ANR-0023 at 127-130 and https://www.eauclairewi.gov/home/showdocument?id=30746

32. La Crosse, Wisconsin: The city adopted a resolution in 2019 which set forth sustainability goals transitioning to carbon neutrality and 100% renewable energy by 2050. *See* Exhibit No. ANR-0023 at 131-132 and http://cityoflacrosse.legistar.com/LegislationDetail.aspx?ID=3926780&GUID=B34D11C1-7372-4F3A-A98E-A06C2B6D3465

33. Madison, Wisconsin: The city passed a resolution accepting the 100% Renewable Madison Report, which set forward the goals of reaching 100% renewable energy and zero net carbon by 2030. *See* Exhibit No. ANR-0023 at 133-136 and

https://madison.legistar.com/LegislationDetail.aspx?ID=3877297&GUID=7ED9B236-7691-4350-8588-A01E33818C0F&Options=ID%7CText%7C&Search=renewable&FullText=1

34. Monona, Wisconsin: Monona City Council passed a resolution to meet 100% of all City operations energy needs with renewable energy by 2040, and to meet 100% of all community-wide energy needs with renewable energy by 2050. *See* Exhibit No. ANR-0023 at 137-139 and http://mymonona.com/DocumentCenter/View/9035/100-Percent-Clean-Energy-Resolution

35. Middleton, Wisconsin: Middleton passed a resolution which sets goals of meeting 100% of all city operations energy needs with renewable energy by 2040, and 100% of community-wide energy needs with renewable energy by 2050. *See* Exhibit No. ANR-0023 at 140-142 and https://www.cityofmiddleton.us/DocumentCenter/View/5624/100-Percent-Clean-Energy-Resolution

Many of these policies establish emission targets similar to EO 14008, with some targeting dates even earlier than 2050. Achieving the renewable energy targets and reductions in greenhouse gas emissions of these magnitudes will require a significant decrease in natural gas use, and consequently, a significant decrease in natural gas transportation.

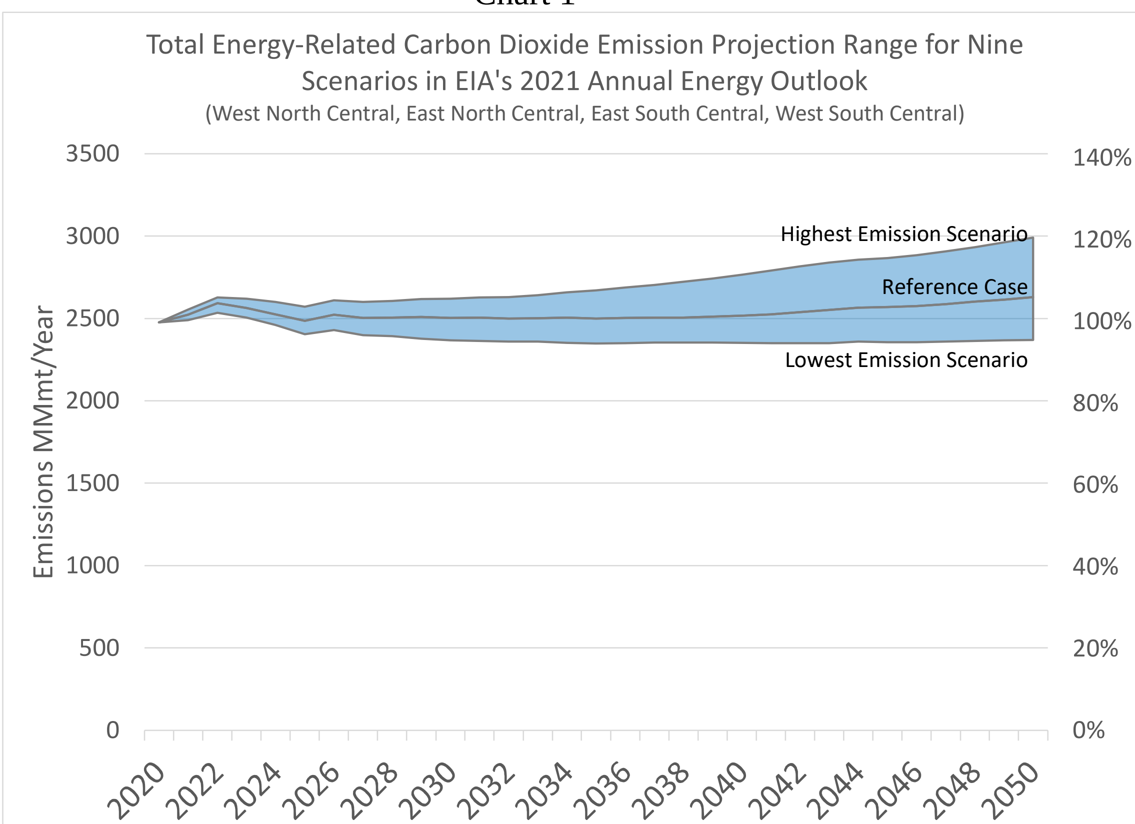
Q. Does the U.S. Energy Information Administration ("EIA") offer projections of natural gas demand that incorporate these requirements of public authorities?

A. The EIA does offer energy projections through 2050 in its Annual Energy Outlook ("AEO"); however, there is no indication that EO 14008 has been incorporated into these projections. To the extent the EIA incorporates any policies into its model, the EIA's projections clearly do not generally meet the requirements of public authorities outlined in this section.

Q. How have you determined that the requirements of public authorities you outlined in this section are not reflected in the EIA's projections?

A. The EIA projected carbon dioxide emissions as part of its 2021 AEO, but the carbon dioxide emission projections under all of EIA's nine projection scenarios do not approach the declines required by the policies listed above. The emission projections for the footprint of ANR broadly includes four Census regions: West North Central, East North Central, East South Central, and West South Central. The range of aggregated greenhouse gas emissions projections for these regions for the EIA's nine projection scenarios are shown below in Chart 1.

Chart 1



Under the EIA's Reference Case, energy-related carbon dioxide emissions are projected to *increase* by a total of 6.2 percent by 2050. Of the nine scenarios, the

EIA projects that emissions may drop by a maximum of 4.3 percent or may increase by a maximum of 20.7 percent by 2050. See Exhibit No. ANR-0024 for the EIA's carbon dioxide emission projections tabulated for each of its scenarios. It can therefore only be concluded that since none of the EIA projection scenarios meet the multitude of public authority requirements described above, none of the EIA projection scenarios should be relied upon in order to determine the future natural gas demand considered for depreciation ratemaking purposes.

III. DEMAND FOR ANR'S SERVICES

Q. Why is it important to consider the demand for ANR's services?

A. Even if sufficient gas supplies exist, which I will review in Section IV of this testimony, factors affecting demand may limit the amount of gas supplies that will be produced and utilize ANR. It is therefore important when evaluating a pipeline's economic life to not only evaluate factors of supply to determine the amount of relevant gas supplies that exist, but to also evaluate whether there is sufficient demand to cause such supplies to be produced and utilize a pipeline's services. A depreciation rate based on evidence that failed to forecast the future reserves "which actually may be expected to be added to [the pipeline's] system" was rejected by the United States Court of Appeals for the District of Columbia Circuit in *Memphis Light, Gas and Water Division v. Federal Power Commission*, 504 F.2d 225, 232 (D.C. Cir. 1974).

Q. How does this section relate to your previous section involving the requirements of public authorities?

A. Meeting the various requirements of public authorities will cause constraints in the demand for, and possibly supply of, natural gas. This section, however, focuses on other factors that will impact demand even in the absence of the requirements of public authorities I discussed in Section II. As I mentioned earlier, *changes in demand* is also specified in Part 201 of FERC's regulations as a factor to consider in setting depreciation rates, and is listed separately from *requirements of public authorities*.

Q. Please outline the connection between the demand for natural gas, the demand for ANR's services, and ANR's economic life.

A. The demand for ANR's services is driven by the demand for natural gas, the natural gas price dynamics over time, the markets that ANR serves, and competition from alternative energy sources and from competing pipelines. A decline in the demand for natural gas broadly will reduce price differentials and shippers' willingness to pay for the transportation of natural gas. A pipeline's economic life is over once it is unlikely to recover its remaining fixed costs and is no longer expected to make a profit. The consumption of natural gas need not fall to zero for this to occur. Long before natural gas consumption falls to zero, increasing competition from alternative energy sources and excess capacity will prevent pipelines from recovering their full costs of service. Increasingly, pipelines will be compelled to enter into contracts at discounted rates until they are able to cover only marginal costs. The pipeline may even cease to have shippers willing to contract for firm service. At such a point, even though there may still be natural gas available to be transported and some natural gas supplies may still be transported, the pipeline's economic life is effectively over.

Q. Can you provide an example of an interstate natural gas pipeline which had reached the end of its economic life due to declining demand for its services?

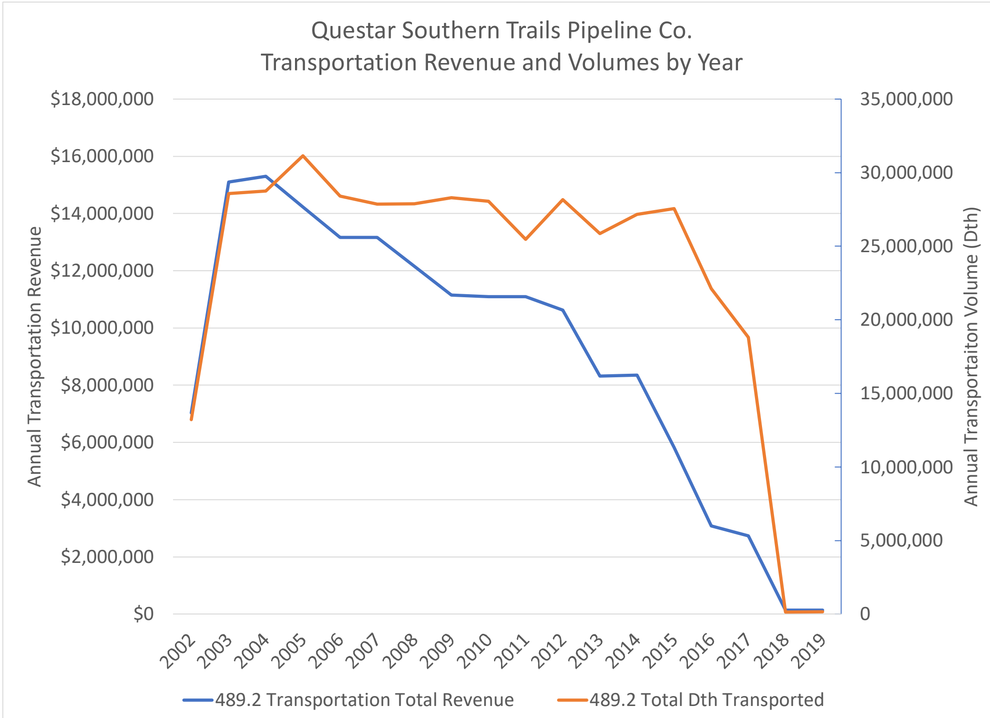
A. Yes, Dominion Energy, Inc.'s Questar Southern Trails Pipeline Co. ("Questar Southern Trails") reached the end of its economic life due to declining demand rather than lack of supply. Questar Southern Trails began transportation services into California from the San Juan Basin in 2002. At the time, natural gas consumption was expected to continue to increase for the foreseeable future. Data from the EIA shows that pipeline capacity into California grew from 7,542 million cubic feet per day ("MMcf/d") in 1998 to 10,701 MMcf/d in 2016. However, the California Public Utilities Commission later projected that demand for natural gas will diminish through 2035 (the end of its projection period) as renewable energy production increases. *See* California Gas and Electric Utilities, *2018 California Gas Report*, at 17-18, at https://www.socalgas.com/regulatory/documents/cgr/2018_California_Gas_Report.pdf. The result of the declining California demand in combination with excess pipeline capacity caused firm contracts to California on Questar Southern Trails to fall to zero.

On December 22, 2017, Questar Southern Trails filed an application with FERC (Docket No. CP18-39-000) to abandon, partially by sale and partially in-place, all its certificated facilities dedicated to providing jurisdictional transportation service, including approximately 488 miles of natural gas pipeline and related facilities in California, Arizona, Utah, and New Mexico. The facilities to be sold were those that had provided service to Questar Southern Trails' one remaining firm shipper, the Navajo Tribal Utility Authority, which had a contract for only 1,000 dekatherms per day ("Dth/day"). The Navajo Tribal Utility Authority contract had a negotiated rate of $0.10 per Dth/day, significantly below Questar Southern Trails' 100 percent load factor recourse rate of approximately $0.38 per Dth/day. Questar Southern Trails stated that it could no longer justify continued operation of its 80,000 Dth/day system based on this one remaining contract, coupled with the projected declining demand for natural gas in California. The Commission issued an order on May 9, 2018, authorizing Questar Southern Trails to abandon the pipeline. *See generally Questar Southern Trails Pipeline Co.*, 163 FERC ¶ 62,086 (2018). This is a prime example of how a pipeline's economic life may be over even when some quantity of natural gas may still be consumed in its destination markets and gas supply may still be available.

Q. Have you examined Questar Southern Trails' transportation revenue and volumes in the years preceding its abandonment filing?

A. Yes. I have examined data from Questar Southern Trails' annual Form 2 filings since it entered service in 2002. A chart showing Questar Southern Trails' Account 489.2 transportation revenue and volumes is shown below.

Chart 2



As can be seen above, total transportation volumes varied from about 25,000,000 Dth to 31,000,000 Dth a year from 2003 to 2015, after which they fell quickly. During those 12 years, even though transported volumes did not fall a significant amount (about 3.6 percent), revenue decreased approximately 61 percent. In the following three years revenue and transported volumes decreased quickly and the pipeline would be abandoned. Questar Southern Trails' *total life* from in-service to abandonment was 15 years; however, its *economic life* was even shorter since Questar Southern Trails was no longer able to collect its cost-of-service sometime prior to 2018.

Q. What are some of the factors that will influence natural gas demand in the future?

A. The demand for any good or service is influenced by the prices of alternatives and substitutes, as well as other factors called "demand shifters." This section focuses on the technological developments in alternative energies and energy storage and their ability to impact the demand for natural gas.

Alternative energies currently provide significant competition to natural gas, competition that will only increase in the coming years. Large declines in the price of energy produced by wind and solar facilities are likely to lead to increased wind and solar capacity in ANR's markets. Large declines in the cost of battery storage technology will also support increased reliance on renewable energy in the coming decades. Increases in the availability and capacity of renewable resources and battery storage, not only driven by the requirements of public authorities but also through competitive prices, will likely decrease the demand for natural gas as a fuel source.

Q. Does an opportunity exist for a substantial amount of renewable energy to be built across ANR's footprint that could diminish demand for firm deliveries of natural gas?

A. Yes. A substantial amount of renewable energy potential exists across the ANR States (defined here as Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Nebraska, Ohio, Oklahoma, Tennessee, Texas, and Wisconsin) that could reduce the demand for natural gas, as well as firm transportation and storage of natural gas, in the coming decades. The National Renewable Energy Laboratory ("NREL") assessed the amount of potential alternative energy generation in each U.S. state (https://www.nrel.gov/gis/re-potential.html). As I show in Table 1 below, the NREL identified 205,988,794 gigawatt hours of potential renewable energy production in the ANR States. To put this energy potential in context, EIA data indicates that the ANR States had a total of 1,538,222 gigawatt hours of actual electricity sales across all sectors (residential, commercial, industrial, and transportation) in 2020.

Table 1

ANR States Renewable Energy Potential and 2020 Total Sales

Potential Energy from Renewable Sources	Gigawatt Hours
Urban Utility-scale Photovoltaics	1,029,428
Rural Utility-scale Photovoltaics	129,415,300
Rooftop Photovoltaics	308,497
Concentrating Solar Power	40,675,971
Onshore Wind	17,180,116
Offshore Wind	4,606,287
Biopower-Solid	217,942
Biopower-Gaseous	33,372
Geothermal Hydrothermal	0
Enhanced Geothermal Systems	12,465,673
Hydropower	56,207
TOTAL	**205,988,794**
2020 Total Retail Sales of Electricity (All Sectors)	1,538,222

Therefore, the potential energy from renewable sources within the ANR States equals approximately 134 times those states' current electricity consumption. Furthermore, EIA data regarding *total* energy use for all energy sources (not just electricity) in 2019 across the ANR States amounted to an equivalent of 13,346,249 gigawatt hours of electricity. The potential energy from renewable sources within the ANR States therefore equals 15.4 times those states' *total* energy use, across all fuel sources. Since most end-use consumption of natural gas can ultimately be electrified and utilize electricity generated from renewable sources, this shows that there is an ample potential supply of renewable energies to significantly diminish demand for natural gas. The data indicates that if renewable energy is price-competitive, ample renewable energy potential exists within the ANR States alone to displace all energy consumption within these states.

Q. Do you have any recent examples showing that the costs of alternative energy have decreased?

A. Yes. The price of solar power from photovoltaic systems has fallen significantly over time. The NREL, in a January 2021 report titled "U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020," stated "[f]rom 2010 to 2020, residential [photovoltaic] LCOE ["levelized cost of energy"] declined 74%, …resulting in an unsubsidized LCOE of $0.11-$0.14/kWh ["kilowatt hour"] ($0.07-$0.09 when including the federal ITC ["Investment Tax Credit"])." Exhibit No. ANR-0025 at 46 (see also https://www.nrel.gov/docs/fy21osti/77324.pdf).

Commercial and utility scale photovoltaic systems have similarly fallen in price and are cheaper than residential photovoltaic systems. While underlying technology may be similar for residential, commercial, and utility scale photovoltaic, both commercial photovoltaic and utility scale photovoltaic benefit from growing economies of scale, driven by hardware, labor, and related markups. See, *e.g.*, Exhibit No. ANR-0025 at 34-35, 48-50, and 60-61. Commercial photovoltaic systems have "an unsubsidized LCOE of $0.08–$0.10/kWh ($0.05–$0.07/kWh when including the federal ITC)" and utility-scale photovoltaic systems have "an unsubsidized LCOE of $0.04–$0.05/kWh ($0.025–$0.035/kWh when including the federal ITC)." Exhibit No. ANR-0025 at 58 and 65. These costs will likely continue to fall. The NREL's 2020 Annual Technology Baseline projects under a "moderate" scenario that by 2050 the unsubsidized cost of energy will be reduced to $0.014/kWh, $0.026/kWh, and $0.030/kWh for utility-scale photovoltaic, commercial photovoltaic, and residential photovoltaic respectively in 2018 U.S. dollars. *See* Exhibit No. ANR-0026 at 1 (see also https://atb.nrel.gov/). For illustrative purposes, the EIA states that the average price of electricity for residential electricity was $0.132/kWh in the United States in 2020 (https://www.eia.gov/electricity/data/browser/).

Wind power prices have also fallen significantly and are projected to become increasingly competitive in the years to come. A report by the Department of Energy's Lawrence Berkeley National Laboratory titled "Wind Energy Technology Data Update: 2020 Edition" (August 2020) shows that the average "installed wind power project costs" have declined from over $2500/kW in 2010 to below $1500/kW in 2018. *See* Exhibit No. ANR-0027 at 54 and https://emp.lbl.gov/sites/default/files/2020_wind_energy_technology_data_update.pdf. The report also compared the wind power purchase agreement prices from 2020 through 2050 and compared this to the EIA's 2020 AEO projections of the fuel cost for natural gas generation and found that the median wind power purchase agreement prices extending for the entire 2020 to 2050 period are cheaper than the *entire range* of the 2020 AEO natural gas fuel cost projection scenarios. *See* Exhibit No. ANR-0027 at 71.

Q. Wind and solar offer only variable generation and cannot always be dispatched as needed. How are these sources of generation going to compete with natural gas?

A. Currently, the variability of wind and solar generation can require that other dispatchable sources of generation, such as from natural gas, be available to stabilize the electricity grid. A solution to the variability of wind and solar generation is battery storage, which is now being installed at a significantly increased rate. Battery storage resources allow wind and solar generation to be stored during times of peak production and dispatched when needed. Thus, battery storage can allow variable generation to potentially serve both peak and baseload demand. The Commission recognized the importance of battery storage and acted to reduce existing barriers to enable battery storage operators to compete within wholesale electric markets in *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (2018) ("Order No. 841"). *See also Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841-A, 167 FERC ¶ 61,154 (2019).

Q. What has the Commission done to reduce barriers to entry for electric storage resources?

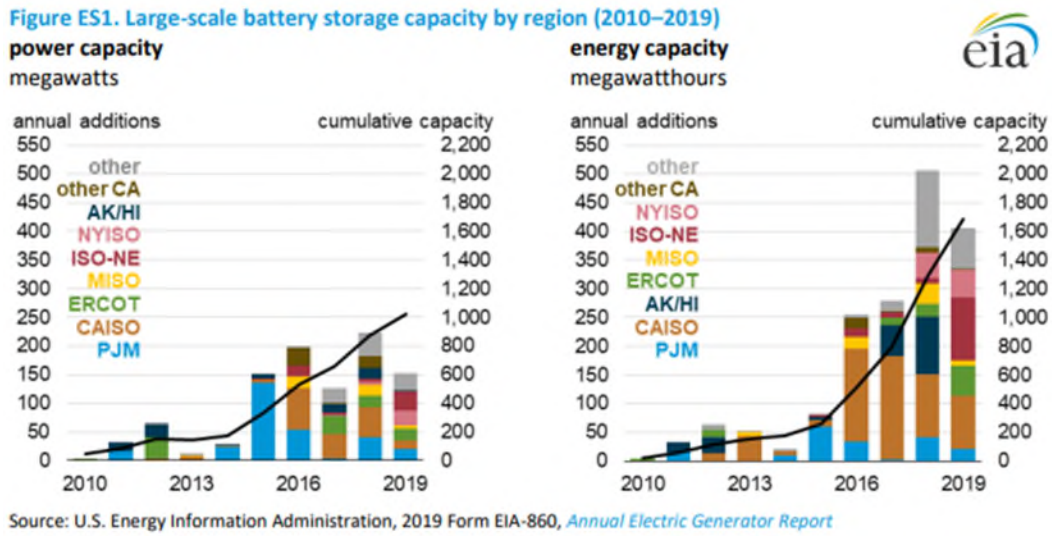
A. Order No. 841 amends the Commission's regulations to remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets operated by Regional Transmission Organizations ("RTO") and Independent System Operators ("ISO"). These changes have allowed electric storage operators to capture additional value within RTO/ISO markets previously unavailable to them and increase their profitability.

Q. Are the costs associated with battery storage declining?

A. Yes. An article by BloombergNEF published on December 20, 2020, states that "[l]ithium-ion battery pack prices, which were above $1,100 per kilowatt-hour in 2010, have fallen 89% in real terms to $137/kWh in 2020" and that by 2023 "average prices will be close to $100/kWh." *See* Exhibit No. ANR-0028 (also publicly available at https://about.bnef.com/blog/battery-pack-prices-cited-below-100-kwh-for-the-first-time-in-2020-while-market-average-sits-at-137-kwh/). BloombergNEF expects battery pack prices to fall to $58/kWh by 2030. *Id.*

The benefits of battery storage coupled with declining costs have led to an increasing amount of battery storage capacity across the U.S. in recent years. A chart published by the EIA in a report titled "U.S. Battery Storage Trends" (August 2021) shows a significant increase in battery storage capacity within the last decade.

Chart 3



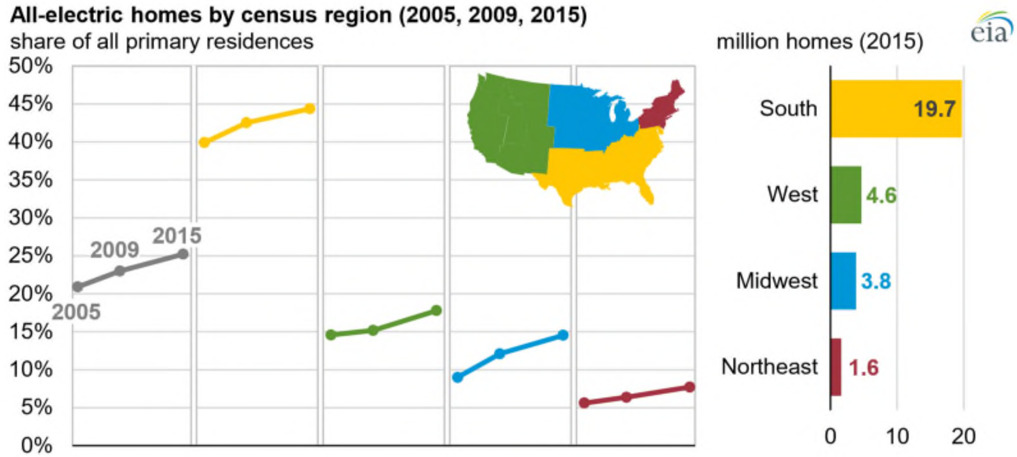
*S*ee Exhibit No. ANR-0029 at 7 (also publicly available at https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf). Furthermore, the EIA noted in the report that "[b]ased on planning data we collect, an additional 10,000 megawatts of large-scale battery storage's ability to contribute electricity to the grid is likely to be installed between 2021 and 2023 in the United States—10 times the total amount of maximum generation capacity by all systems in 2019." *See* Exhibit No. ANR-0029 at 9.

The continued decline in battery storage costs, combined with renewable generation from solar and wind, will cause renewable energy to be significantly more competitive by 2030 or earlier.

Q. Is there reason to believe that the adoption of renewable energy can displace natural gas demand in the residential, commercial, and industrial sectors?

A Yes. Renewable energy sources already displace a multitude of traditional sources of natural gas demand. Regarding residential demand for natural gas, an EIA article from May 2019 illustrates that one out of four homes in the United States are *all electric* (*i.e.*, they do not directly consume any natural gas), and this percentage has been growing as shown on Chart 5 below:

Chart 5



See https://www.eia.gov/todayinenergy/detail.php?id=39293.

The EIA data demonstrate that not only is it possible for members of the residential sector to directly consume no natural gas, the percentage of the sector that utilizes no natural gas is growing.

NREL has also done significant research regarding the electrification of all sectors of the U.S. economy. A report by NREL released in December 2017 titled "Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050" (accessible at https://www.nrel.gov/docs/fy18osti/70485.pdf) was "designed to examine electric technology advancement and adoption for end uses in all major economic sectors as well as electricity consumption growth and load profiles, future power system infrastructure development and operations, and the economic and environmental implications of widespread electrification." Regarding the residential sector, NREL finds that air-source heat pumps and heat pump water heaters, offering electric-based space-heating and water-heating, could achieve cost-parity with natural gas space-heating and water-heating between 2020 and 2030, and are likely to be "substantially lower cost" between 2040 and 2050. *Id.* at 51. NREL projects there to be substantial economic benefits for the residential sector to electrify its energy consumption within the next 10 to 30 years.

NREL also finds electrification possibilities in the commercial sector. NREL states that in the commercial sector "heat pump technologies for space heating applications in warm or moderate climates can become cost-competitive by the end of 2040 with only limited improvement and within the next 10 years with faster improvements." *Id.* at 51. NREL concludes:

> The LCOSs … demonstrate that with only modest improvements in cost and performance, residential and commercial heat pump technologies could achieve cost parity with incumbent technologies. Cost parity would likely result in substantial increases in adoption. Of course, cost parity is not the sole determinant of adoption, and other beneficial attributes of heat pumps could induce increased their uptake, including their dual functionality (both heating and cooling services), superior safety relative to combustion based technologies, and increased controllability, while additional barriers to adoption, such as lack of customer awareness and installer knowledge of heat pump systems, and split-incentive or landlord-tenant problems could limit adoption even with achievement of cost parity.

Id. at 52. NREL notes several additional non-cost related benefits to electrification.

The NREL report also examined the Department of Energy's Industry Assessment Center's database in its evaluation of the industrial sector. NREL found that many industrial electrification-related projects would result in cost savings within 5 years. The payback period, representing the time period until cost savings overtake a project's costs, for the following projects are five years or less:

- Use Immersion Heating in Tanks, Melting Pots, etc.: **2 Years**
- Convert Liquid Heaters from Underfiring to Immersion or Submersion Heating: **3 Years**
- Replace Fossil Fuel Equipment with Electrical Equipment: **2 Years**
- Use Electric Heat in Place of Fossil Fuel Heating System: **1 Year**
- Replace Hydraulic/Pneumatic Equipment with Electrical Equipment: **2 Years**
- Replace Gas- Fired Absorption Air Conditioners with Electric Units: **4 Years**
- Use Heat Pump for Space Conditioning: **5 Years**

Id. at 59.

Thus, NREL did identify possible areas for the economic electrification of many sources of industrial energy demand, though it did note that "the literature on future electric technologies is insufficient to develop informed and plausible cost and efficiency sensitivity cases" and it did find that electric boilers were not economic under 2015 electric and natural gas prices. *Id.* at 66 and 63.

Q. What are your conclusions concerning the future demand for ANR's services?

A. The factors discussed throughout Section III demonstrate that future demand for natural gas is highly uncertain and natural gas is likely to be increasingly displaced by renewable energy and battery storage. In addition to the requirements of public authorities discussed earlier, market forces arising from the dramatic declines in the prices of wind and solar power and battery storage are likely to reduce the demand for ANR's services.

IV. GAS SUPPLY

Q. Please explain how you selected the appropriate regions to analyze as the basis of your gas supply study.

A. Historically, the Commission has required pipelines to file gas supply information supporting the economic life of their pipeline systems by analyzing the potential recoverable natural gas reserves in a pipeline's gas supply area. *See, e.g., Trunkline Gas Co.*, 90 FERC ¶ 61,017, 61,057 (2000). Given the footprint of ANR, its interconnectivity, and receipt quantities shown in its publicly available Index of Customers, I determined that ANR's supply regions should include the Lower 48 U.S. states that form the contiguous United States ("Lower 48 States") and Canadian gas supplies.

A. Lower 48 States

i. Description of Data Used for the Lower 48 States

Q. What is the source of the data you used to analyze gas supply?

A. I utilized data from the EIA and the Potential Gas Committee ("PGC"). I examined proved reserves data from the EIA's Form EIA-23L and estimates of probable and possible resources from the PGC's August 2021 report entitled "Potential Supply of Natural Gas in the United States" ("PGC Report"). Complete details regarding all EIA sources are available on the agency's web site, www.eia.gov.

Q. What is the PGC?

A. The PGC is an independent organization that works closely with the Potential Gas Agency at the Colorado School of Mines and consists of volunteer members from all segments of the oil and gas industry, government agencies, and academic institutions. The PGC offers biennial estimates of the potential gas supply of the United States which can be used to estimate the long-term gas supply. As discussed below, the Commission has previously relied upon PGC estimates to assess gas supply.

Q. Please describe the PGC estimates.

A. The estimates of the PGC represent potential gas resources that, in the judgment of its members, can be recovered by future drilling under: (a) adequate economic incentives in terms of price and cost, and (b) current foreseeable technology. The PGC projects resources based on knowledge of areas of proved reserves. The PGC's estimates included in this study represent "Most Likely" values derived from statistically aggregated mean values. The "Most Likely" estimates, as described by the PGC, "represent the best judgment of individual Committee members and are considered the most credible assessments for purposes of analysis, planning and exploration." *See PGC Report* at 2. The Commission has explicitly relied upon PGC estimates in *Trunkline Gas Co.*, 90 FERC ¶ 61,017, 61,057 (2000).

Q. What is the difference between proved reserves, probable resources, and possible resources?

A. Proved reserves are defined by the EIA as "the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions." See Form EIA-23L, *Annual Survey of Domestic Oil and Gas Reserves*. Probable, possible, and speculative resources are estimated by the PGC. As defined by the PGC:

> Probable resources are associated with known fields and are the most assured of potential supplies. Relatively large amounts of geologic and engineering information are available to aid in the estimation of resources existing in this category. Probable resources bridge the boundary between discovered and undiscovered resources. The discovered portion includes the supply from future extensions of existing pools in known productive reservoirs … Although the pools containing this gas have been discovered, their extent has not been completely delineated by development drilling. Therefore, the existence of quantity of gas in the undrilled area of the pool are as yet unconfirmed. The undiscovered part is expected to come from future new pool discoveries within existing fields either in reservoirs productive in the field or in shallower or deeper formations known to be productive elsewhere within the same geologic province or subprovince.
>
> (See *PGC Report* at 78. Endnotes omitted.)

By contrast,

> Possible resources are a less assured supply because they are postulated to exist outside known fields, but they are associated with a productive formation in a productive province. Their occurrence is indicated by a projection of plays or trends of a producing formation into a less well explored area of the same geologic province or subprovince. The resources are expected to arise from new field discoveries, postulated to occur within these trends or plays under both similar and different geologic

> conditions—that is, the types of traps and/or structural settings may be either the same or different in some aspect.
>
> (*See PGC Report* at 78. Endnotes omitted.)

The PGC defines speculative resources as:

> Speculative resources, the most nebulous category, are expected to be found in formations or geologic provinces that have not yet proved productive. Geologic analogs are developed in order to ensure reasonable evaluation of these unknown quantities. The resources are anticipated from new pool or new field discoveries within a productive province or sub-province and from new field discoveries within a province not previously productive.
>
> (*See PGC Report* at 78-79. Endnotes omitted.)

Summing proved reserves, probable resources, and possible resources, I calculated total remaining non-speculative resources. Thus, consistent with Commission precedent, I excluded speculative resources from my analysis due to the "nebulous" nature of their existence. The Commission has stated that it is appropriate to rely on "the PGC's most likely estimates for probable and possible resources in [a pipeline's] gas supply areas." *See Trunkline Gas Co.*, 90 FERC ¶ 61,017, 61,057 (2000). Speculative resources should only be included in a gas supply analysis if and when the resources are reclassified as proved, probable, or possible.

ii. Discussion of Remaining Non-Speculative Resources

Q. What is the estimated quantity of remaining natural gas resources in the Lower 48 States?

A. I calculated an estimate of what I term remaining "non-speculative resources" by summing proved reserves, probable resources, and possible resources, using the latest available data. Estimated total non-speculative resources equal 2,945,121 billion cubic feet ("Bcf"), which is derived by adding: (1) the EIA's estimate of remaining proved reserves for the Lower 48 States of 485,531 Bcf; and (2) the PGC's latest independent estimate of probable and possible resources for the Lower 48 States of 2,459,590 Bcf. The tabulation of resources is shown in Exhibit No. ANR-0030.

iii. Production and Supply Availability

Q. How much actual natural gas production occurred in the Lower 48 States in the most recent year of data available?

A. The EIA reports that wet gas production in the states that comprise the Lower 48 States in 2020 was 37,184 Bcf. *See* Exhibit No. ANR-0030.

Q. What are your primary findings with regard to natural gas supply in the Lower 48 States?

A. The Lower 48 States contained approximately 2,945,121 Bcf of non-speculative resources, while 2020 annual production amounted to 37,184 Bcf. If production continued at its current pace, non-speculative resources would not be depleted for many years. Given my previous discussions regarding the requirements of public authorities and the demand for ANR's services, it is not likely that supply from the Lower 48 States will be the primary constraint to ANR's economic life.

B. Canadian Supplies

i. Description of Data Used for Canada

Q. What is the source of data you used to analyze the Canadian gas supply?

A. Estimates of remaining marketable resources and Canadian production are from the Canada Energy Regulator ("CER"), formerly the National Energy Board of Canada. The CER oversees Canada's oil and gas pipelines and electric powerlines.

ii. Discussion of Remaining Marketable Resources

Q. What is the estimated quantity of remaining natural gas resources in Canada?

A. The CER provides an estimate of remaining marketable gas resources in Canada in the appendix to its report titled "Canada's Energy Future 2020", accessible at https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA. The CER identifies estimates of remaining marketable resources for three scenarios: 1,378 Tcf in its Reference Case, 928 Tcf in its low case, and 1,948 Tcf in its high case as of the end of 2018.

Q. How does the CER define marketable resources?

A. The CER defines marketable resources as "[t]he volume of gas that can be sold to the market after impurities are removed and volumes used to power surface facilities are subtracted." See https://www.cer-rec.gc.ca/en/data-analysis/glossary/index.html#M.

iii. Production and Supply Availability

Q. What does the CER report as current Canadian production?

A. The CER reports that Canada produced about 15.47 Bcf/d in 2020, or a total of 5.64 Tcf throughout the entire year.

Q. What are your primary findings with regard to natural gas supply in Canada?

A. Canada has approximately 1,378 Tcf of marketable resources, while 2020 annual production amounted to 5.64 Tcf. If production continued at its current pace, marketable gas resources will not be depleted for many years. Given my previous discussions regarding the requirements of public authorities and the demand for ANR's services, it is not likely that supply from Canada will be the primary constraint to ANR's economic life.

Q. Are there other considerations that are relevant regarding Canadian gas supplies?

A. Yes, most gas supplies produced in Canada are located in the Western Canada Sedimentary Basin, and there is considerable uncertainty regarding the economics of transporting such supplies to the United States for consumption, as well as uncertainty associated with Canadian energy and environmental regulations in the future that may impact the delivered price of Canadian supplies. While I conservatively do not factor in this uncertainty directly into my testimony as part of the economic life testimony, such uncertainty may have other implications regarding the economics of Canadian supplies delivered to end-users on ANR.

V. ECONOMIC LIFE OF ANR

Q. Based on the factors you have discussed, what is ANR's economic life?

A. The requirements of public authorities discussed in Section II of my testimony provide a clear, known, and measurable truncation period over which ANR should be allowed to recover its fixed costs. Given the significant reduction in natural gas consumption, and transportation, which would be necessitated by the federal, state, and local requirements that target 2050, and earlier, I support 2050 as ANR's economic life truncation for ratemaking purposes. Additionally, Section III further demonstrates the significant competitive pressure that exists due to the declining cost of renewable energy, electrification, and battery storage, prior to 2050. Gas supplies discussed in Section IV will support the continued use of ANR in the intervening years, allowing ANR to provide continued, reliable, access to a proven energy source.

VI. ALTERNATIVE DEPRECIATION PROPOSAL – CLIMATE POLICY CHARGE

Q. What is the purpose of this section?

A. As I explain in Section V, my primary proposal is that that 2050 should be used as ANR's economic life truncation for ratemaking purposes, reflecting the currently known and measurable changes in demand and the requirements of public authorities with respect to the continued utilization of natural gas in the United States generally, and in ANR's markets in particular. However, I am providing an alternative proposal in the event the Commission determines that a 2050 economic life truncation should not be adopted at this time and instead adopts a longer economic life. In that circumstance, I propose the inclusion of a "Climate Policy Charge" in ANR's annual cost of service.

Q. What is the Climate Policy Charge depreciation alternative you are proposing?

A. This Climate Policy Charge would provide ANR a reasonable opportunity to collect the return of its rate base investments in light of the requirements of public authorities that support a 2050 economic truncation date, while providing a mechanism to recognize that these requirements may change over time. As further discussed below, by collecting the annual Climate Policy Charge and recording this amount as a regulatory liability, such amounts collected could be refunded to customers in a future period should circumstances change in the future. In the interim, shippers would benefit from an offset to rate base equal to the amounts collected under the charge and booked as a regulatory liability.

The Climate Policy Charge would be established as follows:

- Depreciation will be booked annually based on the economic life that the Commission determines to be just and reasonable.
- An annual amount will be calculated based on what the annual depreciation expense would be if based on a 2050 economic life truncation.
- The annual difference between (1) book depreciation and (2) the annual amount that depreciation would be if based on a 2050 economic life truncation will be defined as the annual Climate Policy Charge.
- The Climate Policy Charge would be included in ANR's annual cost of service, recorded under FERC Account 407.3, and would also be booked to FERC Account 254 as a regulatory liability.

Regarding the future treatment of the Climate Policy Charge and the related deferred regulatory liability:

- The requirements of public authorities that drive the 2050 target discussed in this testimony may be reviewed in the pipeline's future rate cases.
  - In a future rate case, if the target dates of the requirements of public authorities are removed, then the Climate Policy Charge will be removed, and the regulatory liability will be amortized and refunded to shippers over the then-determined remaining economic life of the pipeline.
  - In a future rate case, if the target dates of the requirements of public authorities are modified, but not removed, then the Climate Policy Charge can be re-calculated based on the new target.
- If 2050 is reached and the pipeline's economic life has ended as currently contemplated, the regulatory liability is dissolved, and the pipeline's investors will have effectively recovered their investment.
- If 2050 is reached, no rate case in the intervening years has made any changes to depreciation, and the pipeline's economic life is not over, the Climate Policy Charge is removed, and the existing regulatory

liability will be amortized and refunded to shippers over the then-determined remaining economic life of the pipeline.

Q. Does the Climate Policy Charge approach offer any benefits to stakeholders?

A. Yes, this proposal offers several benefits. Current rates will reflect the known and measurable climate policies that are currently enacted. As I have discussed in detail herein, while significant quantities of gas supplies are available, there is nevertheless significant growing uncertainty with respect to natural gas demand, and an increasing number of requirements of public authorities that pose significant risk to natural gas pipelines by 2050. Reaching net-zero emissions by 2050 would necessarily require a dramatic decline in the consumption, and therefore transportation, of natural gas. Although business-as-usual scenarios may suggest that the economic life of natural gas pipelines may extend further in the future than 2050, these requirements of public authorities pose significant risk to the ability of natural gas pipelines to collect their undepreciated plant investment by 2050. The proposed Climate Policy Charge is a novel strategy to recover all plant investment by 2050 given today's existing climate policies while allowing for some flexibility should climate policies evolve in the future. If climate policies are modified in the future, rates can then be re-evaluated at that point in time such that those future rates reflect the climate policies that are enacted at that time.

Second, the Climate Policy Charge seeks to reflect the true cost of providing service by incorporating the known and measurable climate policy requirements of federal, state, and local governments. The Climate Policy Charge provides the market with price transparency, such that the cost of climate policies will be clearly presented within the cost of service. This would allow the Commission, shippers, state public utility commissions, and the public to have a transparent representation of the cost of climate policies on pipeline transportation and provide an opportunity for these parties to react to these price signals accordingly. The charge also seeks to avoid inter-generational subsidies by collecting the return of investment over a time horizon which reflects current legislation.

Q. Does the creation of the Climate Policy Charge and the corresponding regulatory liability meet the requirements set forth in *Revisions to Uniform System of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A*, Order No. 552, FERC Stats. & Regs. ¶ 30,967 (1993) ("Order No. 552")?

A. Yes, the proposed Climate Policy Charge and the related deferred regulatory liability is consistent with Order No. 552. The Commission explained in *Portland Natural Gas Transmission System*, 76 FERC ¶ 61,123 (1996) at p. 18:

> …[i]n Order No. 552, the Commission established accounting requirements for regulatory assets (and liabilities) that require the recognition of an asset (or liability) for any item that would normally be included in net income determinations under the requirements of the USofA, but for it being probable that the item will be recovered from (or returned to) customers in future rates. The term "probable" as used in Order No. 552 for the definition of regulatory assets (or liabilities), refers to that which can reasonably be expected or believed on the basis of available evidence or logic but is neither certain nor proved.

Thus, if the Commission determines it is unlikely that the regulatory liability will be returned to customers in the future due to the pipeline's economic life being over in 2050, then the Commission should instead adopt the 2050 economic life truncation I propose. If, however, the Commission determines that a later truncation period is just and reasonable for book depreciation, it would follow that the Commission would be recognizing that it is "probable" that the item will be returned to customers in the future – though it is "neither certain nor proved."

Q. Are there other cost-of-service mechanisms that have been adopted by the Commission that are similar to your alternative depreciation proposal?

A. Yes, the mechanism provided here shares similarities with (1) pipelines that have levelized depreciation in order to levelize the annual cost-of-service, and (2) the treatment of accumulated deferred income taxes following an income tax rate change.

Q. Please explain the similarities of your alternative deprecation proposal to other mechanisms pipelines have used to levelize cost of service.

A. The proposal here shares similarities with the Commission's treatment of levelized depreciation, which has occasionally been utilized by pipelines to levelize rates. For example, the Commission accepted Portland Natural Gas Transmission System's ("PNGTS") proposal to levelize its rates through the creation of a regulatory asset with the annual difference between levelized and book depreciation being reflected in its annual cost of service and booked to FERC Account 407.3 and 407.4. *See Portland Natural Gas Transmission System,* 76 FERC ¶ 61,123 (1996). The mechanism I propose in this section records the difference between a 2050 depreciation rate and book depreciation to FERC account 407.3, will be collected in the pipeline's annual cost of service, and will create a regulatory liability, rather than a regulatory asset. While levelization creates a regulatory asset, and my proposal creates a regulatory liability, my proposal is functionally similar to the accounting mechanism the Commission has previously accepted for levelized rates.

Q. Please explain the similarities of your proposal to the treatment of accumulated deferred income taxes following an income tax rate change.

A. This proposal shares similarities with the Commission's treatment of income tax rate changes. The Commission explained in *Accounting For Income Taxes*, Docket No. AI93-5-000 (April 23, 1993), *available at* https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/ai93-5-000 (AI93-5-000 Guidance) how to treat an income tax rate change:

> **Question:** How should an entity record the effect of a change in tax law or rates that occurs after the year of initial implementation of SFAS 109?
>
> **Response:** The entity shall adjust its deferred tax liabilities and assets for the effect of the change in tax law or rates in the period that the change is enacted. The adjustment shall be recorded in the proper deferred tax balance sheet accounts (Accounts 190, 281, 282 and 283) based on the nature of the temporary difference and the related classification requirements of the accounts. If as a result of action by a regulator, it is probable that the future increase or decrease in taxes payable due to the change in tax law or rates will be recovered from or returned to customers through future rates, an asset or liability shall be recognized in Account 182.3, Other Regulatory Assets, or Account 254, Other Regulatory Liabilities, as appropriate, for that probable future revenue or reduction in future revenue. That asset or liability is also a temporary difference for which a deferred tax asset or liability shall be recognized in Account 190, Accumulated Deferred Income Taxes or Account 283, Accumulated Deferred Income Taxes Other, as appropriate.

This treatment was recently recognized by the Commission following the December 22, 2017, passage of the Tax Cuts and Jobs Act (An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018, Pub. L. No. 115-97, 131 Stat. 2054 (2017)) in, for example, *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate*, Order No. 849, 164 FERC ¶ 61,031 at P 136-142 (2018) ("Order No. 849"). This accounting methodology is similar to the proposal I have put forward in this section, as a policy change (tax law, in this case) triggers the creation of a regulatory asset or liability recognized in Account 182.3, Other Regulatory Assets, or Account 254, Other Regulatory Liabilities, as appropriate. Following the creation of a regulatory liability, the amount would then be amortized for flow-back through the appropriate income statement accounts. *See, e.g.*, Order No. 849, 164 FERC ¶ 61,031 at P 142.

Q. Does this conclude your Prepared Direct Testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ANR Pipeline Company	§ § §	Docket No. RP21-___-000

AFFIDAVIT OF
ALEXANDER KIRK

Alexander Kirk, being first duly sworn, on oath states that he is the witness whose testimony appears on the preceding pages entitled "Prepared Direct Testimony of Alexander Kirk" and that, if asked the questions which appear in the text of said testimony, he would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as Alexander Kirk's sworn testimony in this proceeding.

Alex Kirk
Alexander Kirk

Subscribed and sworn to before me, a Notary Public in and for District of Columbia,

this 23rd day of January 2022.

STEPHANIE J. WILKERSON NOTARY PUBLIC EXP. 9-14-24 DISTRICT OF COLUMBIA

Stephanie J Wilkerson
Notary Public

My Commission expires:

STEPHANIE J. WILKERSON
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires September 14, 2024

BROWN, WILLIAMS, MOORHEAD & QUINN, INC.
ENERGY CONSULTANTS

CURRICULUM VITAE

NAME	Alexander Kirk
BUSINESS ADDRESS	Brown, Williams, Moorhead & Quinn, Inc. P.O. Box 10 Sunderland, MD 20689-0010
PRESENT POSITION	Vice President
EDUCATION	Master of Arts in Economics: 2008, University of Washington, Seattle, WA - Concentrations: Econometrics and Natural Resources Bachelor of Science in Economics and Mathematics: 2005, Linfield College, McMinnville, OR
NATURE OF WORK PERFORMED WITH FIRM	Alex Kirk has testified on issues involving natural gas supply and demand, pipeline competition, and cost-of-service levelization for natural gas pipeline rate cases. I have also assisted clients with natural gas storage, pipeline, and electric generator market-based rate applications, economic life determinations, business risk, rate design, cost-of-service modeling, and other issues.
PREVIOUS EMPLOYMENT	September 2006 – May 2010: **University of Washington, Dept. of Economics** UW Economics, 1100 Campus Parkway, Condon Hall Room 401, Seattle, WA 98195 Title: TA and Independent Instructor Duties: I assisted a lecturing professor in a Principles of Microeconomics (Econ 200) course by providing additional lecture and instruction to 50 undergraduate students for two credit hours per week. From 2008 to 2010, I was an independent instructor for Principles of Microeconomics and Natural Resource Economics courses. October 2006 – March 2007: **Greenfield Advisors** 2601 Fourth Ave., Seattle, WA 98121 Title: Research Analyst Duties: I estimated hedonic models to measure damages to real estate value from environmental contamination. The results were used in testimony of class action lawsuits filed

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against polluters. Settlements and litigation resulted in awards in excess of a hundred million dollars.

Summer 2006: **Federal Energy Regulatory Commission**
888 First St. NE, Washington, D.C. 20426
Title: Economist Intern
Duties: As a member of the Competition Analysis Group, I determined market competitiveness and provided analysis for a case involving an oil pipeline which applied for market-based rates. The economic impact of the case was approximately $90 million per year.

June 2004 – December 2005: **Oregon Economic and Community Development Department**
775 Summer St., NE, Suite 200, Salem, Oregon 97301-1280
Title: Research Analyst

TECHNICAL SKILLS

- Computer Applications: MS Office, Stata, Eviews, Matlab, Mathematica, IMPLAN, and various GIS software.
- Econometrics/Regression analysis
- Knowledgeable on Census, BLS, BEA, EIA, and various energy data
- Analysis of industry clusters
- Experience with geo-coded data
- Energy sector analysis
- Competition and regulatory analysis

AWARDS / SCHOLARSHIPS / TAships

- Trustee Scholarship (Linfield College)
- Psychology Competitive Scholarship (Linfield College)
- Dean's List (Linfield College, 4 semesters)
- Senior Economics Aware (Linfield College, Awarded by merit to one graduating senior)
- Steven Langton Teaching Award (University of Washington)

STUDY ABROAD

- Vienna, Austria (Fall 2002)
- Ghana (January 2004)
- Moscow and St. Petersburg, Russia (January 2005)

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#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	POSITION	SUBJECT MATTER
Formal Proceedings in Which Alex Kirk Testified					
50	FERC	RP21-1187	Eastern Gas Transmission and Storage, Inc.	Witness	Natural Gas Supply and Demand, Economic Life
49	FERC	RP21-1188	Texas Eastern Transmission, LP	Witness	Natural Gas Supply and Demand, Economic Life
48	FERC	RP21-1146	Southwest Gas Storage Company	Witness	Reference to Market Power Study Supporting Petition for Market-Based Rates for Storage Service in Docket No. RP20-1088 to support Market-Based Rates for No-notice Storage, Firm Parking, Firm Loan, and Interruptible Gas Balancing Services
47	FERC	RP21-1143	Transcontinental Gas Pipe Line Company, LLC	Witness	Market Power Study Supporting Market-Based Rates for Transcontinental Gas Pipe line Company, LLC's Washington Storage Field
46	FERC	RP21-1001	Texas Eastern Transmission, LP	Witness	Natural Gas Supply and Demand, Economic Life
45	FERC	PR21-27, et al.	JEFFERSON ISLAND STORAGE & HUB, L.L.C.	Witness	Market Power Study Supporting Continued authorization for Market-Based Rates for Storage and Wheeling Service and Petition for Market Based Rates for Firm Wheeling Service
44	FERC	RP21-441	FLORIDA GAS TRANSMISSION COMPANY, LLC	Witness	Natural Gas Supply and Demand, Economic Life
43	FERC	CP21-44	LA STORAGE, LLC	Witness	Market Power Study Supporting Petition for Market-Based Rates for Storage and Wheeling Service
42	FERC	RP20-1088	SOUTHWEST GAS STORAGE COMPANY	Witness	Market Power Study Supporting Petition for Market-Based Rates for Storage Service
41	FERC	RP20-1060	COLUMBIA GAS TRANSMISSION, LLC	Witness	Natural Gas Supply and Demand, Economic Life

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#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	POSITION	SUBJECT MATTER
40	FERC	RP20-980	EAST TENNESSEE NATURAL GAS SYSTEM	Witness	Natural Gas Supply and Demand, Economic Life
39	FERC	RP20-921	MARITIMES & NORTHEAST PIPELINE, LLC	Witness	Natural Gas Supply and Demand, Economic Life
38	FERC	RP20-908	ALLIANCE PIPELINE, LP	Witness	Natural Gas Demand
37	FERC	RP20-631	TENNESSEE GAS PIPE LINE COMPANY, LLC	Witness	Market Power Study Supporting Petition for Market-Based Rates for Storage Service
36	FERC	RP20-467	DOMINION ENERGY COVE POINT LNG, LP	Witness	Natural Gas Supply and Demand, Economic Life
35	FERC	RP20-233	SOUTHWEST GAS STORAGE COMPANY	Witness	Market Power Study Supporting Petition for Market-Based Rates for Storage Service
34	FERC	RP20-131	ENABLE MISSISSIPPI RIVER TRANSMISSION COMPANY	Witness	Natural Gas Supply and Demand, Economic Life
33	FERC	RP19-1426	NATIONAL FUEL GAS SUPPLY CORPORATION	Witness	Natural Gas Supply and Demand, Economic Life
32	FERC	RP19-1523	PANHANDLE EASTERN PIPE LINE COMPANY	Witness	Natural Gas Supply and Demand, Economic Life
31	FERC	RP19-78	PANHANDLE EASTERN PIPE LINE COMPANY	Witness	Natural Gas Supply and Demand, Economic Life
30	FERC	RP19-343	TEXAS EASTERN TRANSMISSION	Witness	Natural Gas Supply and Demand, Economic Life
29	FERC	RP19-165	WBI ENERGY TRANSMISSION	Witness	Natural Gas Supply and Demand, Economic Life
28	FERC	RP18-940	EMPIRE PIPELINE INC.	Witness	Natural Gas Supply and Demand
27	FERC	RP18-922	TRAILBLAZER PIPELINE COMPANY LLC	Witness	Natural Gas Supply and Demand

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#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	POSITION	SUBJECT MATTER
26	FERC	RP18-877	MOGAS PIPELINE LLC	Witness	Natural Gas Supply and Demand
25	FERC	PR18-59	KINDER MORGAN TEJAS PIPELINE LLC	Witness	Market-Power Study Supporting Petition for Market-based Rates for Interruptible Wheeling Services at Banquette Hub
24	FERC	RP18-293	ENABLE – MRT	Witness	Natural Gas Supply and Demand
23	FERC	RP18-1126	TRANSCONTINENTAL GAS PIPE LINE	Witness	Natural Gas Supply and Demand, Economic Life
22	FERC	RP18-1115	SALTVILLE GAS STORAGE COMPANY	Witness	Natural Gas Supply and Demand, Economic Life
21	FERC	RP17-598	GREAT LAKES GAS TRANSMISSION LP	Witness	Delivered Price Analysis for Natural Gas, Natural Gas Supply and Demand
20	FERC	RP17-363	EASTERN SHORE NATURAL GAS COMPANY	Witness	Natural Gas Supply and Demand
19	FERC	RP17-197	DOMINION COVE POINT LNG, LP	Witness	Natural Gas Supply and Demand
18	FERC	RP17-13 and RP17-254	JEFFERSON ISLAND STORAGE AND HUB, LLC AND GOLDEN TRIANGLE STORAGE INC.	Witness	Market-power Study Supporting Continued Market-based Rates for Wheeling and Storage Services and Two Facilities
17	FERC	RP17-1050	ARLINGTON STORAGE COMPANY, LLC	Witness	Market-power Study Supporting Market-based Rates for Firm Wheeling Service
16	FERC	RP16-440	ANR PIPELINE COMPANY	Witness	Natural Gas Supply and Demand
15	FERC	RP16-137	TALLGRASS INTERSTATE GAS TRANSMISSION, LLC	Witness	Natural Gas Supply and Demand
14	FERC	RP15-65	GULF SOUTH PIPELINE COMPANY	Witness	Natural Gas Supply and Demand

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#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	POSITION	SUBJECT MATTER
13	FERC	RP15-1225	TRES PALACIOS GAS STORAGE LLC	Witness	Market-power Study Supporting Petition for Market-based Rates for Firm Wheeling Services
12	FERC	RP15-1218	CENTRAL NEW YORK OIL AND GAS COMPANY	Witness	Market-power Study Supporting Market-based Rates for Parking and Lending Services
11	FERC	ER14-15	CES PLACERITA, INC.	Witness	Updates Market Power Analysis of Category 1 Electric Generator
10	FERC	RP14-1214	VIKING GAS TRANSMISSION COMPANY	Witness	Natural Gas Supply and Demand
9	FERC	RP14-118	WBI ENERGY TRANSMISSION, INC.	Witness	Natural Gas Supply and Demand, Economic Life
8	FERC	RP13-941	SOUTHERN STAR CENTRAL GAS PIPELINE	Witness	Natural Gas Supply and Demand, Economic Life
7	FERC	RP13-185	VIKING GAS TRANSMISSION COMPANY	Witness	Natural Gas Supply and Demand, Economic Life
6	FERC	RP13-1031	TRAILBLAZER PIPELINE COMPANY LLC	Witness	Natural Gas Supply and Demand, Economic Life
5	FERC	RP12-955	CENTERPOINT ENERGY – MRT	Witness	Natural Gas Supply and Demand
4	FERC	RP12-479	ANR STORAGE COMPANY	Witness	Market-based Rate Application for Existing Storage Facility
3	FERC	RP11-1823	PUBLIC UTILITIES COMMISSION OF NEVADA AND SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY V. TUSCARORA GAS TRANSMISSION COMPANY	Witness	Natural Gas Supply and Demand, Pipeline Competition

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#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	POSITION	SUBJECT MATTER
2	FERC	RP10-729	PORTLAND NATURAL GAS TRANSMISSION SYSTEM	Witness	Natural Gas Supply, Cost of Service Levelization
1	FERC	RP06-568 and RP07-373 (consolidated)	TRANSCONTINENTAL GAS PIPE LINE CORPORATION	Witness	Natural Gas Storage, Opportunity Cost, Rolled-in and Incremental Rates

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	SUBJECT MATTER
		Other Proceedings In Which Alex Kirk Participated		
8	FERC	RP09-427	SOUTHERN NATURAL GAS COMPANY	
7	FERC	RP08-426	EL PASO NATURAL GAS COMPANY	
6	FERC	RP08-306	PORTLAND NATURAL GAS TRANSSMISION SYSTEM	
5	FERC	CR08-431 OR07-21	COLUMBIA GAS TRASNMSISION CORP. AND MOBIL PIPELINE COMPANY, RESPECTIVELY	*Abbreviated Application for Certificates of Columbia Gas Transmission Corporation for a Certificate of Public Convenience and Necessity.*
4	FERC	RM08-1-000	COMMENTS OF SPECTRA ENERGY TRANSMISSION LLC AND SPECTRA ENERGY PARTNERS	Promotion of a More Efficient Capacity Release Market

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#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	POSITION	SUBJECT MATTER
3	FERC	PR08-7	BAY GAS STORAGE COMPANY LTD.		*Abbreviated Application for Certificates of Public Convenience and Necessity Authorizing Construction and Operation of a Natural Gas Storage Facility, for Blanket Certificates, and for Related Authorizations and Waivers*
2	FERC	CP08-15	STECKMAN RIDGE, LP		*Abbreviated Application for Certificates of Public Convenience and Necessity Authorizing Construction and Operation of a Natural Gas Storage Facility, for Blanket Certificates, and for Related Authorizations and Waivers*
1	FERC	CP07-405	TEXAS GAS TRANSMISSION, LLC		*Abbreviated Application for Certificates of Public Convenience and Necessity Authorizing Construction and Operation of a Natural Gas Storage Facility, for Blanket Certificates, and for Related Authorizations and Waivers*

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Presidential Documents

Executive Order 14008 of January 27, 2021

Tackling the Climate Crisis at Home and Abroad

The United States and the world face a profound climate crisis. We have a narrow moment to pursue action at home and abroad in order to avoid the most catastrophic impacts of that crisis and to seize the opportunity that tackling climate change presents. Domestic action must go hand in hand with United States international leadership, aimed at significantly enhancing global action. Together, we must listen to science and meet the moment.

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered as follows:

PART I—PUTTING THE CLIMATE CRISIS AT THE CENTER OF UNITED STATES FOREIGN POLICY AND NATIONAL SECURITY

Section 101. *Policy.* United States international engagement to address climate change—which has become a climate crisis—is more necessary and urgent than ever. The scientific community has made clear that the scale and speed of necessary action is greater than previously believed. There is little time left to avoid setting the world on a dangerous, potentially catastrophic, climate trajectory. Responding to the climate crisis will require both significant short-term global reductions in greenhouse gas emissions and net-zero global emissions by mid-century or before.

It is the policy of my Administration that climate considerations shall be an essential element of United States foreign policy and national security. The United States will work with other countries and partners, both bilaterally and multilaterally, to put the world on a sustainable climate pathway. The United States will also move quickly to build resilience, both at home and abroad, against the impacts of climate change that are already manifest and will continue to intensify according to current trajectories.

Sec. 102. *Purpose.* This order builds on and reaffirms actions my Administration has already taken to place the climate crisis at the forefront of this Nation's foreign policy and national security planning, including submitting the United States instrument of acceptance to rejoin the Paris Agreement. In implementing—and building upon—the Paris Agreement's three overarching objectives (a safe global temperature, increased climate resilience, and financial flows aligned with a pathway toward low greenhouse gas emissions and climate-resilient development), the United States will exercise its leadership to promote a significant increase in global climate ambition to meet the climate challenge. In this regard:

(a) I will host an early Leaders' Climate Summit aimed at raising climate ambition and making a positive contribution to the 26th United Nations Climate Change Conference of the Parties (COP26) and beyond.

(b) The United States will reconvene the Major Economies Forum on Energy and Climate, beginning with the Leaders' Climate Summit. In cooperation with the members of that Forum, as well as with other partners as appropriate, the United States will pursue green recovery efforts, initiatives to advance the clean energy transition, sectoral decarbonization, and alignment of financial flows with the objectives of the Paris Agreement, including with respect to coal financing, nature-based solutions, and solutions to other climate-related challenges.

(c) I have created a new Presidentially appointed position, the Special Presidential Envoy for Climate, to elevate the issue of climate change and underscore the commitment my Administration will make toward addressing it.

(d) Recognizing that climate change affects a wide range of subjects, it will be a United States priority to press for enhanced climate ambition and integration of climate considerations across a wide range of international fora, including the Group of Seven (G7), the Group of Twenty (G20), and fora that address clean energy, aviation, shipping, the Arctic, the ocean, sustainable development, migration, and other relevant topics. The Special Presidential Envoy for Climate and others, as appropriate, are encouraged to promote innovative approaches, including international multi-stakeholder initiatives. In addition, my Administration will work in partnership with States, localities, Tribes, territories, and other United States stakeholders to advance United States climate diplomacy.

(e) The United States will immediately begin the process of developing its nationally determined contribution under the Paris Agreement. The process will include analysis and input from relevant executive departments and agencies (agencies), as well as appropriate outreach to domestic stakeholders. The United States will aim to submit its nationally determined contribution in advance of the Leaders' Climate Summit.

(f) The United States will also immediately begin to develop a climate finance plan, making strategic use of multilateral and bilateral channels and institutions, to assist developing countries in implementing ambitious emissions reduction measures, protecting critical ecosystems, building resilience against the impacts of climate change, and promoting the flow of capital toward climate-aligned investments and away from high-carbon investments. The Secretary of State and the Secretary of the Treasury, in coordination with the Special Presidential Envoy for Climate, shall lead a process to develop this plan, with the participation of the Administrator of the United States Agency for International Development (USAID), the Chief Executive Officer of the United States International Development Finance Corporation (DFC), the Chief Executive Officer of the Millennium Challenge Corporation, the Director of the United States Trade and Development Agency, the Director of the Office of Management and Budget, and the head of any other agency providing foreign assistance and development financing, as appropriate. The Secretary of State and the Secretary of the Treasury shall submit the plan to the President, through the Assistant to the President for National Security Affairs and the Assistant to the President for Economic Policy, within 90 days of the date of this order.

(g) The Secretary of the Treasury shall:

(i) ensure that the United States is present and engaged in relevant international fora and institutions that are working on the management of climate-related financial risks;

(ii) develop a strategy for how the voice and vote of the United States can be used in international financial institutions, including the World Bank Group and the International Monetary Fund, to promote financing programs, economic stimulus packages, and debt relief initiatives that are aligned with and support the goals of the Paris Agreement; and

(iii) develop, in collaboration with the Secretary of State, the Administrator of USAID, and the Chief Executive Officer of the DFC, a plan for promoting the protection of the Amazon rainforest and other critical ecosystems that serve as global carbon sinks, including through market-based mechanisms.

(h) The Secretary of State, the Secretary of the Treasury, and the Secretary of Energy shall work together and with the Export-Import Bank of the United States, the Chief Executive Officer of the DFC, and the heads of other agencies and partners, as appropriate, to identify steps through which the United States can promote ending international financing of carbon-intensive fossil fuel-based energy while simultaneously advancing sustainable development and a green recovery, in consultation with the Assistant to the President for National Security Affairs.

(i) The Secretary of Energy, in cooperation with the Secretary of State and the heads of other agencies, as appropriate, shall identify steps through which the United States can intensify international collaborations to drive innovation and deployment of clean energy technologies, which are critical for climate protection.

(j) The Secretary of State shall prepare, within 60 days of the date of this order, a transmittal package seeking the Senate's advice and consent to ratification of the Kigali Amendment to the Montreal Protocol on Substances that Deplete the Ozone Layer, regarding the phasedown of the production and consumption of hydrofluorocarbons.

Sec. 103. *Prioritizing Climate in Foreign Policy and National Security*. To ensure that climate change considerations are central to United States foreign policy and national security:

(a) Agencies that engage in extensive international work shall develop, in coordination with the Special Presidential Envoy for Climate, and submit to the President, through the Assistant to the President for National Security Affairs, within 90 days of the date of this order, strategies and implementation plans for integrating climate considerations into their international work, as appropriate and consistent with applicable law. These strategies and plans should include an assessment of:

(i) climate impacts relevant to broad agency strategies in particular countries or regions;

(ii) climate impacts on their agency-managed infrastructure abroad (e.g., embassies, military installations), without prejudice to existing requirements regarding assessment of such infrastructure;

(iii) how the agency intends to manage such impacts or incorporate risk mitigation into its installation master plans; and

(iv) how the agency's international work, including partner engagement, can contribute to addressing the climate crisis.

(b) The Director of National Intelligence shall prepare, within 120 days of the date of this order, a National Intelligence Estimate on the national and economic security impacts of climate change.

(c) The Secretary of Defense, in coordination with the Secretary of Commerce, through the Administrator of the National Oceanic and Atmospheric Administration, the Chair of the Council on Environmental Quality, the Administrator of the Environmental Protection Agency, the Director of National Intelligence, the Director of the Office of Science and Technology Policy, the Administrator of the National Aeronautics and Space Administration, and the heads of other agencies as appropriate, shall develop and submit to the President, within 120 days of the date of this order, an analysis of the security implications of climate change (Climate Risk Analysis) that can be incorporated into modeling, simulation, war-gaming, and other analyses.

(d) The Secretary of Defense and the Chairman of the Joint Chiefs of Staff shall consider the security implications of climate change, including any relevant information from the Climate Risk Analysis described in subsection (c) of this section, in developing the National Defense Strategy, Defense Planning Guidance, Chairman's Risk Assessment, and other relevant strategy, planning, and programming documents and processes. Starting in January 2022, the Secretary of Defense and the Chairman of the Joint Chiefs of Staff shall provide an annual update, through the National Security Council, on the progress made in incorporating the security implications of climate change into these documents and processes.

(e) The Secretary of Homeland Security shall consider the implications of climate change in the Arctic, along our Nation's borders, and to National

Critical Functions, including any relevant information from the Climate Risk Analysis described in subsection (c) of this section, in developing relevant strategy, planning, and programming documents and processes. Starting in January 2022, the Secretary of Homeland Security shall provide an annual update, through the National Security Council, on the progress made in incorporating the homeland security implications of climate change into these documents and processes.

Sec. 104. *Reinstatement.* The Presidential Memorandum of September 21, 2016 (Climate Change and National Security), is hereby reinstated.

PART II—TAKING A GOVERNMENT-WIDE APPROACH TO THE CLIMATE CRISIS

Sec. 201. *Policy.* Even as our Nation emerges from profound public health and economic crises borne of a pandemic, we face a climate crisis that threatens our people and communities, public health and economy, and, starkly, our ability to live on planet Earth. Despite the peril that is already evident, there is promise in the solutions—opportunities to create well-paying union jobs to build a modern and sustainable infrastructure, deliver an equitable, clean energy future, and put the United States on a path to achieve net-zero emissions, economy-wide, by no later than 2050.

We must listen to science—and act. We must strengthen our clean air and water protections. We must hold polluters accountable for their actions. We must deliver environmental justice in communities all across America. The Federal Government must drive assessment, disclosure, and mitigation of climate pollution and climate-related risks in every sector of our economy, marshaling the creativity, courage, and capital necessary to make our Nation resilient in the face of this threat. Together, we must combat the climate crisis with bold, progressive action that combines the full capacity of the Federal Government with efforts from every corner of our Nation, every level of government, and every sector of our economy.

It is the policy of my Administration to organize and deploy the full capacity of its agencies to combat the climate crisis to implement a Government-wide approach that reduces climate pollution in every sector of the economy; increases resilience to the impacts of climate change; protects public health; conserves our lands, waters, and biodiversity; delivers environmental justice; and spurs well-paying union jobs and economic growth, especially through innovation, commercialization, and deployment of clean energy technologies and infrastructure. Successfully meeting these challenges will require the Federal Government to pursue such a coordinated approach from planning to implementation, coupled with substantive engagement by stakeholders, including State, local, and Tribal governments.

Sec. 202. *White House Office of Domestic Climate Policy.* There is hereby established the White House Office of Domestic Climate Policy (Climate Policy Office) within the Executive Office of the President, which shall coordinate the policy-making process with respect to domestic climate-policy issues; coordinate domestic climate-policy advice to the President; ensure that domestic climate-policy decisions and programs are consistent with the President's stated goals and that those goals are being effectively pursued; and monitor implementation of the President's domestic climate-policy agenda. The Climate Policy Office shall have a staff headed by the Assistant to the President and National Climate Advisor (National Climate Advisor) and shall include the Deputy Assistant to the President and Deputy National Climate Advisor. The Climate Policy Office shall have such staff and other assistance as may be necessary to carry out the provisions of this order, subject to the availability of appropriations, and may work with established or ad hoc committees or interagency groups. All agencies shall cooperate with the Climate Policy Office and provide such information, support, and assistance to the Climate Policy Office as it may request, as appropriate and consistent with applicable law.

Sec. 203. *National Climate Task Force*. There is hereby established a National Climate Task Force (Task Force). The Task Force shall be chaired by the National Climate Advisor.

(a) Membership. The Task Force shall consist of the following additional members:

(i) the Secretary of the Treasury;

(ii) the Secretary of Defense;

(iii) the Attorney General;

(iv) the Secretary of the Interior;

(v) the Secretary of Agriculture;

(vi) the Secretary of Commerce;

(vii) the Secretary of Labor;

(viii) the Secretary of Health and Human Services;

(ix) the Secretary of Housing and Urban Development;

(x) the Secretary of Transportation;

(xi) the Secretary of Energy;

(xii) the Secretary of Homeland Security;

(xiii) the Administrator of General Services;

(xiv) the Chair of the Council on Environmental Quality;

(xv) the Administrator of the Environmental Protection Agency;

(xvi) the Director of the Office of Management and Budget;

(xvii) the Director of the Office of Science and Technology Policy;

(xviii) the Assistant to the President for Domestic Policy;

(xix) the Assistant to the President for National Security Affairs;

(xx) the Assistant to the President for Homeland Security and Counterterrorism; and

(xxi) the Assistant to the President for Economic Policy.

(b) Mission and Work. The Task Force shall facilitate the organization and deployment of a Government-wide approach to combat the climate crisis. This Task Force shall facilitate planning and implementation of key Federal actions to reduce climate pollution; increase resilience to the impacts of climate change; protect public health; conserve our lands, waters, oceans, and biodiversity; deliver environmental justice; and spur well-paying union jobs and economic growth. As necessary and appropriate, members of the Task Force will engage on these matters with State, local, Tribal, and territorial governments; workers and communities; and leaders across the various sectors of our economy.

(c) Prioritizing Actions. To the extent permitted by law, Task Force members shall prioritize action on climate change in their policy-making and budget processes, in their contracting and procurement, and in their engagement with State, local, Tribal, and territorial governments; workers and communities; and leaders across all the sectors of our economy.

USE OF THE FEDERAL GOVERNMENT'S BUYING POWER AND REAL PROPERTY AND ASSET MANAGEMENT

Sec. 204. *Policy*. It is the policy of my Administration to lead the Nation's effort to combat the climate crisis by example—specifically, by aligning the management of Federal procurement and real property, public lands and waters, and financial programs to support robust climate action. By providing an immediate, clear, and stable source of product demand, increased transparency and data, and robust standards for the market, my Administration will help to catalyze private sector investment into, and accelerate the advancement of America's industrial capacity to supply, domestic clean energy, buildings, vehicles, and other necessary products and materials.

Sec. 205. *Federal Clean Electricity and Vehicle Procurement Strategy.* (a) The Chair of the Council on Environmental Quality, the Administrator of General Services, and the Director of the Office and Management and Budget, in coordination with the Secretary of Commerce, the Secretary of Labor, the Secretary of Energy, and the heads of other relevant agencies, shall assist the National Climate Advisor, through the Task Force established in section 203 of this order, in developing a comprehensive plan to create good jobs and stimulate clean energy industries by revitalizing the Federal Government's sustainability efforts.

(b) The plan shall aim to use, as appropriate and consistent with applicable law, all available procurement authorities to achieve or facilitate:

(i) a carbon pollution-free electricity sector no later than 2035; and

(ii) clean and zero-emission vehicles for Federal, State, local, and Tribal government fleets, including vehicles of the United States Postal Service.

(c) If necessary, the plan shall recommend any additional legislation needed to accomplish these objectives.

(d) The plan shall also aim to ensure that the United States retains the union jobs integral to and involved in running and maintaining clean and zero-emission fleets, while spurring the creation of union jobs in the manufacture of those new vehicles. The plan shall be submitted to the Task Force within 90 days of the date of this order.

Sec. 206. *Procurement Standards.* Consistent with the Executive Order of January 25, 2021, entitled, "Ensuring the Future Is Made in All of America by All of America's Workers," agencies shall adhere to the requirements of the Made in America Laws in making clean energy, energy efficiency, and clean energy procurement decisions. Agencies shall, consistent with applicable law, apply and enforce the Davis-Bacon Act and prevailing wage and benefit requirements. The Secretary of Labor shall take steps to update prevailing wage requirements. The Chair of the Council on Environmental Quality shall consider additional administrative steps and guidance to assist the Federal Acquisition Regulatory Council in developing regulatory amendments to promote increased contractor attention on reduced carbon emission and Federal sustainability.

Sec. 207. *Renewable Energy on Public Lands and in Offshore Waters.* The Secretary of the Interior shall review siting and permitting processes on public lands and in offshore waters to identify to the Task Force steps that can be taken, consistent with applicable law, to increase renewable energy production on those lands and in those waters, with the goal of doubling offshore wind by 2030 while ensuring robust protection for our lands, waters, and biodiversity and creating good jobs. In conducting this review, the Secretary of the Interior shall consult, as appropriate, with the heads of relevant agencies, including the Secretary of Defense, the Secretary of Agriculture, the Secretary of Commerce, through the Administrator of the National Oceanic and Atmospheric Administration, the Secretary of Energy, the Chair of the Council on Environmental Quality, State and Tribal authorities, project developers, and other interested parties. The Secretary of the Interior shall engage with Tribal authorities regarding the development and management of renewable and conventional energy resources on Tribal lands.

Sec. 208. *Oil and Natural Gas Development on Public Lands and in Offshore Waters.* To the extent consistent with applicable law, the Secretary of the Interior shall pause new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of Federal oil and gas permitting and leasing practices in light of the Secretary of the Interior's broad stewardship responsibilities over the public lands and in offshore waters, including potential climate and other impacts associated with oil and gas activities on public lands or in offshore waters. The Secretary of the Interior shall complete that review in consultation with the Secretary of Agriculture, the Secretary of Commerce, through the National Oceanic and Atmospheric Administration, and the Secretary of Energy. In conducting this analysis, and to the extent consistent with applicable law, the Secretary of the Interior shall consider whether to adjust royalties associated with coal, oil, and gas resources extracted from public lands and offshore waters, or take other appropriate action, to account for corresponding climate costs.

Sec. 209. *Fossil Fuel Subsidies*. The heads of agencies shall identify for the Director of the Office of Management and Budget and the National Climate Advisor any fossil fuel subsidies provided by their respective agencies, and then take steps to ensure that, to the extent consistent with applicable law, Federal funding is not directly subsidizing fossil fuels. The Director of the Office of Management and Budget shall seek, in coordination with the heads of agencies and the National Climate Advisor, to eliminate fossil fuel subsidies from the budget request for Fiscal Year 2022 and thereafter.

Sec. 210. *Clean Energy in Financial Management*. The heads of agencies shall identify opportunities for Federal funding to spur innovation, commercialization, and deployment of clean energy technologies and infrastructure for the Director of the Office of Management and Budget and the National Climate Advisor, and then take steps to ensure that, to the extent consistent with applicable law, Federal funding is used to spur innovation, commercialization, and deployment of clean energy technologies and infrastructure. The Director of the Office of Management and Budget, in coordination with agency heads and the National Climate Advisor, shall seek to prioritize such investments in the President's budget request for Fiscal Year 2022 and thereafter.

Sec. 211. *Climate Action Plans and Data and Information Products to Improve Adaptation and Increase Resilience*. (a) The head of each agency shall submit a draft action plan to the Task Force and the Federal Chief Sustainability Officer within 120 days of the date of this order that describes steps the agency can take with regard to its facilities and operations to bolster adaptation and increase resilience to the impacts of climate change. Action plans should, among other things, describe the agency's climate vulnerabilities and describe the agency's plan to use the power of procurement to increase the energy and water efficiency of United States Government installations, buildings, and facilities and ensure they are climate-ready. Agencies shall consider the feasibility of using the purchasing power of the Federal Government to drive innovation, and shall seek to increase the Federal Government's resilience against supply chain disruptions. Such disruptions put the Nation's manufacturing sector at risk, as well as consumer access to critical goods and services. Agencies shall make their action plans public, and post them on the agency website, to the extent consistent with applicable law.

(b) Within 30 days of an agency's submission of an action plan, the Federal Chief Sustainability Officer, in coordination with the Director of the Office of Management and Budget, shall review the plan to assess its consistency with the policy set forth in section 204 of this order and the priorities issued by the Office of Management and Budget.

(c) After submitting an initial action plan, the head of each agency shall submit to the Task Force and Federal Chief Sustainability Officer progress reports annually on the status of implementation efforts. Agencies shall make progress reports public and post them on the agency website, to the extent consistent with applicable law. The heads of agencies shall assign their respective agency Chief Sustainability Officer the authority to perform duties relating to implementation of this order within the agency, to the extent consistent with applicable law.

(d) To assist agencies and State, local, Tribal, and territorial governments, communities, and businesses in preparing for and adapting to the impacts of climate change, the Secretary of Commerce, through the Administrator of the National Oceanic and Atmospheric Administration, the Secretary of Homeland Security, through the Administrator of the Federal Emergency Management Agency, and the Director of the Office of Science and Technology Policy, in coordination with the heads of other agencies, as appropriate, shall provide to the Task Force a report on ways to expand and improve climate forecast capabilities and information products for the public. In addition, the Secretary of the Interior and the Deputy Director for Management of the Office of Management and Budget, in their capacities as the Chair and Vice-Chair of the Federal Geographic Data Committee, shall assess and provide to the Task Force a report on the potential development of a consolidated Federal geographic mapping service that can facilitate public access to climate-related information that will assist Federal, State, local, and Tribal governments in climate planning and resilience activities.

EMPOWERING WORKERS THROUGH REBUILDING OUR INFRASTRUCTURE FOR A SUSTAINABLE ECONOMY

Sec. 212. *Policy.* This Nation needs millions of construction, manufacturing, engineering, and skilled-trades workers to build a new American infrastructure and clean energy economy. These jobs will create opportunities for young people and for older workers shifting to new professions, and for people from all backgrounds and communities. Such jobs will bring opportunity to communities too often left behind—places that have suffered as a result of economic shifts and places that have suffered the most from persistent pollution, including low-income rural and urban communities, communities of color, and Native communities.

Sec. 213. *Sustainable Infrastructure.* (a) The Chair of the Council on Environmental Quality and the Director of the Office of Management and Budget shall take steps, consistent with applicable law, to ensure that Federal infrastructure investment reduces climate pollution, and to require that Federal permitting decisions consider the effects of greenhouse gas emissions and climate change. In addition, they shall review, and report to the National Climate Advisor on, siting and permitting processes, including those in progress under the auspices of the Federal Permitting Improvement Steering Council, and identify steps that can be taken, consistent with applicable law, to accelerate the deployment of clean energy and transmission projects in an environmentally stable manner.

(b) Agency heads conducting infrastructure reviews shall, as appropriate, consult from an early stage with State, local, and Tribal officials involved in permitting or authorizing proposed infrastructure projects to develop efficient timelines for decision-making that are appropriate given the complexities of proposed projects.

EMPOWERING WORKERS BY ADVANCING CONSERVATION, AGRICULTURE, AND REFORESTATION

Sec. 214. *Policy.* It is the policy of my Administration to put a new generation of Americans to work conserving our public lands and waters. The Federal Government must protect America's natural treasures, increase reforestation, improve access to recreation, and increase resilience to wildfires and storms, while creating well-paying union jobs for more Americans, including more opportunities for women and people of color in occupations where they are underrepresented. America's farmers, ranchers, and forest landowners have an important role to play in combating the climate crisis and reducing greenhouse gas emissions, by sequestering carbon in soils, grasses, trees, and other vegetation and sourcing sustainable bioproducts and fuels. Coastal communities have an essential role to play in mitigating climate change and strengthening resilience by protecting and restoring coastal ecosystems, such as wetlands, seagrasses, coral and oyster reefs, and mangrove and kelp forests, to protect vulnerable coastlines, sequester carbon, and support biodiversity and fisheries.

Sec. 215. *Civilian Climate Corps.* In furtherance of the policy set forth in section 214 of this order, the Secretary of the Interior, in collaboration with the Secretary of Agriculture and the heads of other relevant agencies, shall submit a strategy to the Task Force within 90 days of the date of this order for creating a Civilian Climate Corps Initiative, within existing appropriations, to mobilize the next generation of conservation and resilience workers and maximize the creation of accessible training opportunities and good jobs. The initiative shall aim to conserve and restore public lands and waters, bolster community resilience, increase reforestation, increase carbon sequestration in the agricultural sector, protect biodiversity, improve access to recreation, and address the changing climate.

Sec. 216. *Conserving Our Nation's Lands and Waters*. (a) The Secretary of the Interior, in consultation with the Secretary of Agriculture, the Secretary of Commerce, the Chair of the Council on Environmental Quality, and the heads of other relevant agencies, shall submit a report to the Task Force within 90 days of the date of this order recommending steps that the United States should take, working with State, local, Tribal, and territorial governments, agricultural and forest landowners, fishermen, and other key stakeholders, to achieve the goal of conserving at least 30 percent of our lands and waters by 2030.

(i) The Secretary of the Interior, the Secretary of Agriculture, the Secretary of Commerce, through the Administrator of the National Oceanic and Atmospheric Administration, and the Chair of the Council on Environmental Quality shall, as appropriate, solicit input from State, local, Tribal, and territorial officials, agricultural and forest landowners, fishermen, and other key stakeholders in identifying strategies that will encourage broad participation in the goal of conserving 30 percent of our lands and waters by 2030.

(ii) The report shall propose guidelines for determining whether lands and waters qualify for conservation, and it also shall establish mechanisms to measure progress toward the 30-percent goal. The Secretary of the Interior shall subsequently submit annual reports to the Task Force to monitor progress.

(b) The Secretary of Agriculture shall:

(i) initiate efforts in the first 60 days from the date of this order to collect input from Tribes, farmers, ranchers, forest owners, conservation groups, firefighters, and other stakeholders on how to best use Department of Agriculture programs, funding and financing capacities, and other authorities, and how to encourage the voluntary adoption of climate-smart agricultural and forestry practices that decrease wildfire risk fueled by climate change and result in additional, measurable, and verifiable carbon reductions and sequestration and that source sustainable bioproducts and fuels; and

(ii) submit to the Task Force within 90 days of the date of this order a report making recommendations for an agricultural and forestry climate strategy.

(c) The Secretary of Commerce, through the Administrator of the National Oceanic and Atmospheric Administration, shall initiate efforts in the first 60 days from the date of this order to collect input from fishermen, regional ocean councils, fishery management councils, scientists, and other stakeholders on how to make fisheries and protected resources more resilient to climate change, including changes in management and conservation measures, and improvements in science, monitoring, and cooperative research.

EMPOWERING WORKERS THROUGH REVITALIZING ENERGY COMMUNITIES

Sec. 217. *Policy*. It is the policy of my Administration to improve air and water quality and to create well-paying union jobs and more opportunities for women and people of color in hard-hit communities, including rural communities, while reducing methane emissions, oil and brine leaks, and other environmental harms from tens of thousands of former mining and well sites. Mining and power plant workers drove the industrial revolution and the economic growth that followed, and have been essential to the growth of the United States. As the Nation shifts to a clean energy economy, Federal leadership is essential to foster economic revitalization of and investment in these communities, ensure the creation of good jobs that provide a choice to join a union, and secure the benefits that have been earned by workers.

Such work should include projects that reduce emissions of toxic substances and greenhouse gases from existing and abandoned infrastructure and that prevent environmental damage that harms communities and poses a risk to public health and safety. Plugging leaks in oil and gas wells and reclaiming abandoned mine land can create well-paying union jobs in coal, oil, and gas communities while restoring natural assets, revitalizing recreation economies, and curbing methane emissions. In addition, such work should include efforts to turn properties idled in these communities, such as brownfields, into new hubs for the growth of our economy. Federal agencies should therefore coordinate investments and other efforts to assist coal, oil and gas, and power plant communities, and achieve substantial reductions of methane emissions from the oil and gas sector as quickly as possible.

Sec. 218. *Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization.* There is hereby established an Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization (Interagency Working Group). The National Climate Advisor and the Assistant to the President for Economic Policy shall serve as Co-Chairs of the Interagency Working Group.

(a) Membership. The Interagency Working Group shall consist of the following additional members:

(i) the Secretary of the Treasury;

(ii) the Secretary of the Interior;

(iii) the Secretary of Agriculture;

(iv) the Secretary of Commerce;

(v) the Secretary of Labor;

(vi) the Secretary of Health and Human Services;

(vii) the Secretary of Transportation;

(viii) the Secretary of Energy;

(ix) the Secretary of Education;

(x) the Administrator of the Environmental Protection Agency;

(xi) the Director of the Office of Management and Budget;

(xii) the Assistant to the President for Domestic Policy and Director of the Domestic Policy Council; and

(xiii) the Federal Co-Chair of the Appalachian Regional Commission.

(b) Mission and Work.

(i) The Interagency Working Group shall coordinate the identification and delivery of Federal resources to revitalize the economies of coal, oil and gas, and power plant communities; develop strategies to implement the policy set forth in section 217 of this order and for economic and social recovery; assess opportunities to ensure benefits and protections for coal and power plant workers; and submit reports to the National Climate Advisor and the Assistant to the President for Economic Policy on a regular basis on the progress of the revitalization effort.

(ii) As part of this effort, within 60 days of the date of this order, the Interagency Working Group shall submit a report to the President describing all mechanisms, consistent with applicable law, to prioritize grantmaking, Federal loan programs, technical assistance, financing, procurement, or other existing programs to support and revitalize the economies of coal and power plant communities, and providing recommendations for action consistent with the goals of the Interagency Working Group.

(c) Consultation. Consistent with the objectives set out in this order and in accordance with applicable law, the Interagency Working Group shall seek the views of State, local, and Tribal officials; unions; environmental justice organizations; community groups; and other persons it identifies who may have perspectives on the mission of the Interagency Working Group.

(d) Administration. The Interagency Working Group shall be housed within the Department of Energy. The Chairs shall convene regular meetings of the Interagency Working Group, determine its agenda, and direct its work. The Secretary of Energy, in consultation with the Chairs, shall designate an Executive Director of the Interagency Working Group, who shall coordinate the work of the Interagency Working Group and head any staff assigned to the Interagency Working Group.

(e) Officers. To facilitate the work of the Interagency Working Group, the head of each agency listed in subsection (a) of this section shall assign a designated official within the agency the authority to represent the agency on the Interagency Working Group and perform such other duties relating to the implementation of this order within the agency as the head of the agency deems appropriate.

SECURING ENVIRONMENTAL JUSTICE AND SPURRING ECONOMIC OPPORTUNITY

Sec. 219. *Policy*. To secure an equitable economic future, the United States must ensure that environmental and economic justice are key considerations in how we govern. That means investing and building a clean energy economy that creates well-paying union jobs, turning disadvantaged communities—historically marginalized and overburdened—into healthy, thriving communities, and undertaking robust actions to mitigate climate change while preparing for the impacts of climate change across rural, urban, and Tribal areas. Agencies shall make achieving environmental justice part of their missions by developing programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts. It is therefore the policy of my Administration to secure environmental justice and spur economic opportunity for disadvantaged communities that have been historically marginalized and overburdened by pollution and underinvestment in housing, transportation, water and wastewater infrastructure, and health care.

Sec. 220. *White House Environmental Justice Interagency Council*. (a) Section 1–102 of Executive Order 12898 of February 11, 1994 (Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations), is hereby amended to read as follows:

"(a) There is hereby created within the Executive Office of the President a White House Environmental Justice Interagency Council (Interagency Council). The Chair of the Council on Environmental Quality shall serve as Chair of the Interagency Council.

"(b) Membership. The Interagency Council shall consist of the following additional members:

(i) the Secretary of Defense;

(ii) the Attorney General;

(iii) the Secretary of the Interior;

(iv) the Secretary of Agriculture;

(v) the Secretary of Commerce;

(vi) the Secretary of Labor;

(vii) the Secretary of Health and Human Services;

(viii) the Secretary of Housing and Urban Development;

(ix) the Secretary of Transportation;

(x) the Secretary of Energy;

(xi) the Chair of the Council of Economic Advisers;

(xii) the Administrator of the Environmental Protection Agency;

(xiii) the Director of the Office of Management and Budget;

(xiv) the Executive Director of the Federal Permitting Improvement Steering Council;

(xv) the Director of the Office of Science and Technology Policy;

(xvi) the National Climate Advisor;

(xvii) the Assistant to the President for Domestic Policy; and

(xviii) the Assistant to the President for Economic Policy.

"(c) At the direction of the Chair, the Interagency Council may establish subgroups consisting exclusively of Interagency Council members or their designees under this section, as appropriate.

"(d) Mission and Work. The Interagency Council shall develop a strategy to address current and historic environmental injustice by consulting with the White House Environmental Justice Advisory Council and with local environmental justice leaders. The Interagency Council shall also develop clear performance metrics to ensure accountability, and publish an annual public performance scorecard on its implementation.

"(e) Administration. The Office of Administration within the Executive Office of the President shall provide funding and administrative support for the Interagency Council, to the extent permitted by law and within existing appropriations. To the extent permitted by law, including the Economy Act (31 U.S.C. 1535), and subject to the availability of appropriations, the Department of Labor, the Department of Transportation, and the Environmental Protection Agency shall provide administrative support as necessary.

"(f) Meetings and Staff. The Chair shall convene regular meetings of the Council, determine its agenda, and direct its work. The Chair shall designate an Executive Director of the Council, who shall coordinate the work of the Interagency Council and head any staff assigned to the Council.

"(g) Officers. To facilitate the work of the Interagency Council, the head of each agency listed in subsection (b) shall assign a designated official within the agency to be an Environmental Justice Officer, with the authority to represent the agency on the Interagency Council and perform such other duties relating to the implementation of this order within the agency as the head of the agency deems appropriate."

(b) The Interagency Council shall, within 120 days of the date of this order, submit to the President, through the National Climate Advisor, a set of recommendations for further updating Executive Order 12898.

Sec. 221. *White House Environmental Justice Advisory Council*. There is hereby established, within the Environmental Protection Agency, the White House Environmental Justice Advisory Council (Advisory Council), which shall advise the Interagency Council and the Chair of the Council on Environmental Quality.

(a) Membership. Members shall be appointed by the President, shall be drawn from across the political spectrum, and may include those with knowledge about or experience in environmental justice, climate change, disaster preparedness, racial inequity, or any other area determined by the President to be of value to the Advisory Council.

(b) Mission and Work. The Advisory Council shall be solely advisory. It shall provide recommendations to the White House Environmental Justice Interagency Council established in section 220 of this order on how to increase the Federal Government's efforts to address current and historic environmental injustice, including recommendations for updating Executive Order 12898.

(c) Administration. The Environmental Protection Agency shall provide funding and administrative support for the Advisory Council to the extent permitted by law and within existing appropriations. Members of the Advisory Council shall serve without either compensation or reimbursement of expenses.

(d) Federal Advisory Committee Act. Insofar as the Federal Advisory Committee Act, as amended (5 U.S.C. App.), may apply to the Advisory Council, any functions of the President under the Act, except for those in section 6 of the Act, shall be performed by the Administrator of the Environmental Protection Agency in accordance with the guidelines that have been issued by the Administrator of General Services.

Sec. 222. *Agency Responsibilities*. In furtherance of the policy set forth in section 219:

(a) The Chair of the Council on Environmental Quality shall, within 6 months of the date of this order, create a geospatial Climate and Economic Justice Screening Tool and shall annually publish interactive maps highlighting disadvantaged communities.

(b) The Administrator of the Environmental Protection Agency shall, within existing appropriations and consistent with applicable law:

(i) strengthen enforcement of environmental violations with disproportionate impact on underserved communities through the Office of Enforcement and Compliance Assurance; and

(ii) create a community notification program to monitor and provide real-time data to the public on current environmental pollution, including emissions, criteria pollutants, and toxins, in frontline and fenceline communities—places with the most significant exposure to such pollution.

(c) The Attorney General shall, within existing appropriations and consistent with applicable law:

(i) consider renaming the Environment and Natural Resources Division the Environmental Justice and Natural Resources Division;

(ii) direct that division to coordinate with the Administrator of the Environmental Protection Agency, through the Office of Enforcement and Compliance Assurance, as well as with other client agencies as appropriate, to develop a comprehensive environmental justice enforcement strategy, which shall seek to provide timely remedies for systemic environmental violations and contaminations, and injury to natural resources; and

(iii) ensure comprehensive attention to environmental justice throughout the Department of Justice, including by considering creating an Office of Environmental Justice within the Department to coordinate environmental justice activities among Department of Justice components and United States Attorneys' Offices nationwide.

(d) The Secretary of Health and Human Services shall, consistent with applicable law and within existing appropriations:

(i) establish an Office of Climate Change and Health Equity to address the impact of climate change on the health of the American people; and

(ii) establish an Interagency Working Group to Decrease Risk of Climate Change to Children, the Elderly, People with Disabilities, and the Vulnerable as well as a biennial Health Care System Readiness Advisory Council, both of which shall report their progress and findings regularly to the Task Force.

(e) The Director of the Office of Science and Technology Policy shall, in consultation with the National Climate Advisor, within existing appropriations, and within 100 days of the date of this order, publish a report identifying the climate strategies and technologies that will result in the most air and water quality improvements, which shall be made public to the maximum extent possible and published on the Office's website.

Sec. 223. *Justice40 Initiative*. (a) Within 120 days of the date of this order, the Chair of the Council on Environmental Quality, the Director of the

Office of Management and Budget, and the National Climate Advisor, in consultation with the Advisory Council, shall jointly publish recommendations on how certain Federal investments might be made toward a goal that 40 percent of the overall benefits flow to disadvantaged communities. The recommendations shall focus on investments in the areas of clean energy and energy efficiency; clean transit; affordable and sustainable housing; training and workforce development; the remediation and reduction of legacy pollution; and the development of critical clean water infrastructure. The recommendations shall reflect existing authorities the agencies may possess for achieving the 40-percent goal as well as recommendations on any legislation needed to achieve the 40-percent goal.

(b) In developing the recommendations, the Chair of the Council on Environmental Quality, the Director of the Office of Management and Budget, and the National Climate Advisor shall consult with affected disadvantaged communities.

(c) Within 60 days of the recommendations described in subsection (a) of this section, agency heads shall identify applicable program investment funds based on the recommendations and consider interim investment guidance to relevant program staff, as appropriate and consistent with applicable law.

(d) By February 2022, the Director of the Office of Management and Budget, in coordination with the Chair of the Council on Environmental Quality, the Administrator of the United States Digital Service, and other relevant agency heads, shall, to the extent consistent with applicable law, publish on a public website an annual Environmental Justice Scorecard detailing agency environmental justice performance measures.

PART III—GENERAL PROVISIONS

Sec. 301. *General Provisions*. (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget, relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

THE WHITE HOUSE,
January 27, 2021.

[FR Doc. 2021–02177
Filed 1–29–21; 8:45 am]
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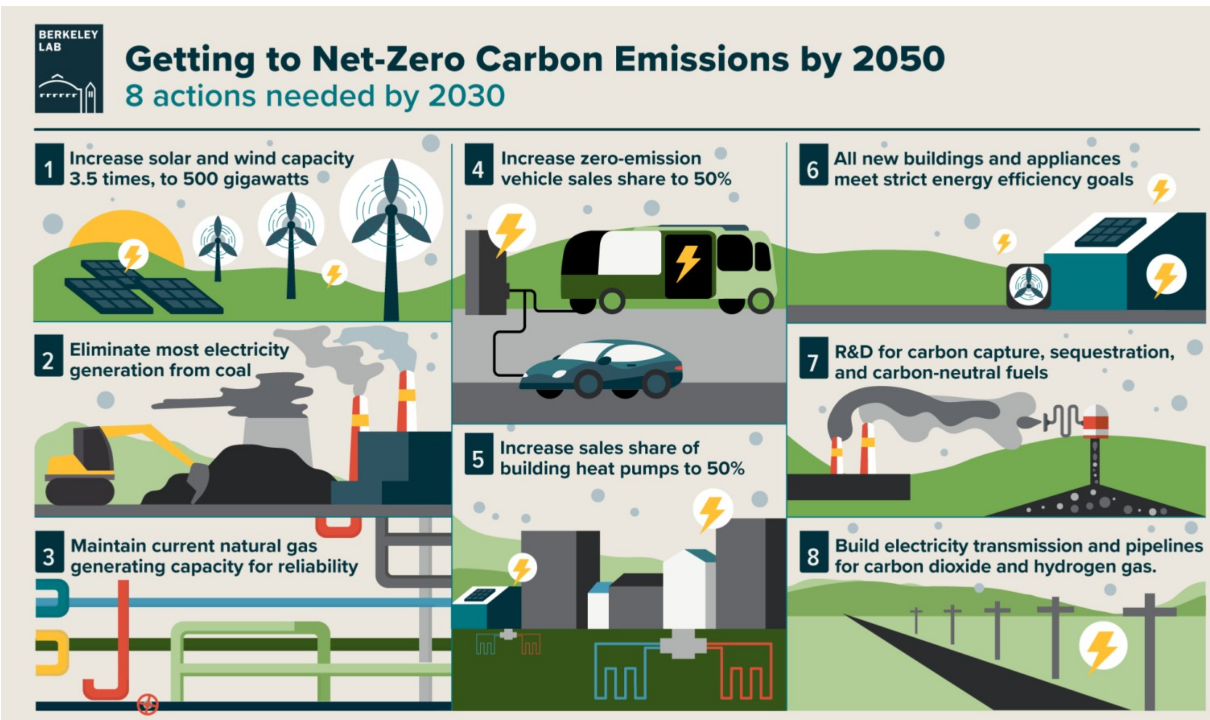
NEWS CENTER

Getting to Net Zero – and Even Net Negative – is Surprisingly Feasible, and Affordable

New analysis provides detailed blueprint for the U.S. to become carbon neutral by 2050

News Release Julie Chao (510) 486-6491 • **January 27, 2021**



Regardless of the pathway we take to become carbon neutral by 2050, the actions needed in the next 10 years are the same. (Credit: Jenny Nuss/Berkeley Lab)

REACHING ZERO NET EMISSIONS OF CARBON DIOXIDE from energy and industry by 2050 can be accomplished by rebuilding U.S. energy infrastructure to run primarily on renewable energy, at a net cost of about $1 per person per day, according to new research published by the Department of Energy's Lawrence Berkeley National Laboratory (Berkeley Lab), the University of San Francisco (USF), and the consulting firm Evolved Energy Research.

The researchers created a detailed model of the entire U.S. energy and industrial system to produce the first detailed, peer-reviewed study of how to achieve carbon-neutrality by 2050. According to the Intergovernmental Panel on Climate Change (IPCC), the world must reach zero net CO2 emissions by mid-century in order to limit global warming to 1.5 degrees Celsius and avoid the most dangerous impacts of climate change.

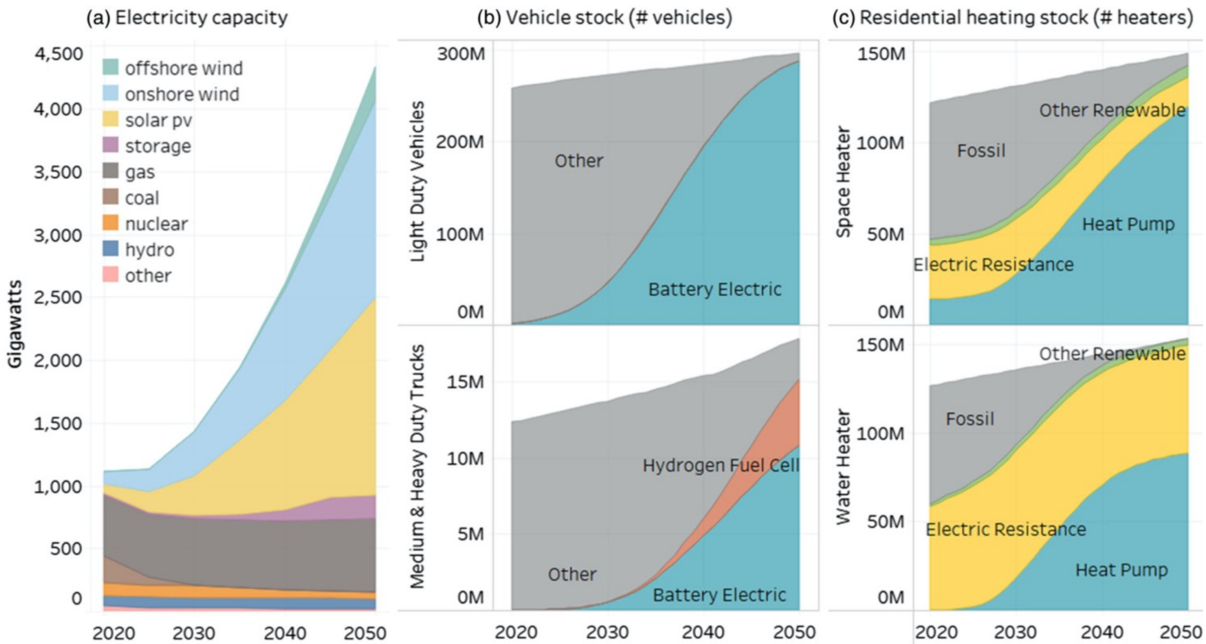
The researchers developed multiple feasible technology pathways that differ widely in remaining fossil fuel use, land use, consumer adoption, nuclear energy, and bio-based fuels use but share a key set of strategies. "By methodically increasing energy efficiency, switching to electric technologies, utilizing clean electricity (especially wind and solar power), and deploying a small amount of carbon capture technology, the United States can reach zero emissions," the authors write in "Carbon Neutral Pathways for the United States," published recently in the scientific journal AGU Advances.

Transforming the infrastructure

"The decarbonization of the U.S. energy system is fundamentally an infrastructure transformation," said Berkeley Lab senior scientist Margaret Torn, one of the study's lead authors. "It means that by 2050 we need to build many gigawatts of wind and solar power plants, new transmission lines, a fleet of electric cars and light trucks, millions of heat pumps to replace conventional furnaces and water heaters, and more energy-efficient buildings – while continuing to research and innovate new technologies."

In this transition, very little infrastructure would need "early retirement," or replacement before the end of its economic life. "No one is asking consumers to switch out their brand-new car for an electric vehicle," Torn said. "The point is that efficient, low-carbon technologies need to be used when it comes time to replace the current equipment."

The pathways studied have net costs ranging from 0.2% to 1.2% of GDP, with higher costs resulting from certain tradeoffs, such as limiting the amount of land given to solar and wind farms. In the lowest-cost pathways, about 90% of electricity generation comes from wind and solar. One scenario showed that the U.S. can meet all its energy needs with 100% renewable energy (solar, wind, and bioenergy), but it would cost more and require greater land use.



In the least-cost scenario to achieve net zero emissions of CO2 by 2050, wind, solar, and battery storage capacity will have to increase several-fold (left chart). Vehicles will need to be mostly electric, powered either by batteries or fuel cells (middle charts). Residential space and water heaters will also need to be electrified, powered either by heat pumps or electric heaters (right charts). (Credit: Williams, et al., 2021)

"We were pleasantly surprised that the cost of the transformation is lower now than in similar studies we did five years ago, even though this achieves much more ambitious carbon reduction," said Torn. "The main reason is that the cost of wind and solar power and batteries for electric vehicles have declined faster than expected."

The scenarios were generated using new energy models complete with details of both energy consumption and production – such as the entire U.S. building stock, vehicle fleet, power plants, and more – for 16 geographic regions in the U.S. Costs were calculated using projections for fossil fuel and renewable energy prices from DOE Annual Energy Outlook and the NREL Annual Technology Baseline report.

The cost figures would be lower still if they included the economic and climate benefits of decarbonizing our energy systems. For example, less reliance on oil will mean less money spent on oil and less economic uncertainty due to oil price fluctuations. Climate benefits include the avoided impacts of climate change, such as extreme droughts and hurricanes, avoided air and water pollution from fossil fuel combustion, and improved public health.

The economic costs of the scenarios are almost exclusively capital costs from building new infrastructure. But Torn points out there is an economic upside to that spending: "All that infrastructure build equates to jobs, and potentially jobs in the U.S., as opposed to sending money overseas to buy oil from other countries. There's no question that there will need to be a well-thought-out economic transition strategy for fossil fuel-based industries and communities, but there's also no question that there are a lot of jobs in building a low-carbon economy."

The next 10 years

An important finding of this study is that the actions required in the next 10 years are similar regardless of long-term differences between pathways. In the near term, we need to increase generation and transmission of renewable energy, make sure all new infrastructure, such as cars and buildings, are low carbon, and maintain current natural gas capacity for now for reliability.

"This is a very important finding. We don't need to have a big battle now over questions like the near-term construction of nuclear power plants, because new nuclear is not required in the next ten years to be on a net-zero emissions path. Instead we should make policy to drive the steps that we know are required now, while accelerating R&D and further developing our options for the choices we must make starting in the 2030s," said study lead author Jim Williams, associate professor of Energy Systems Management at USF and a Berkeley Lab affiliate scientist.

The net negative case

Another important achievement of this study is that it's the first published work to give a detailed roadmap of how the U.S. energy and industrial system can become a source of negative CO2 emissions by mid-century, meaning more carbon dioxide is taken out of the atmosphere than added.

According to the study, with higher levels of carbon capture, biofuels, and electric fuels, the U.S. energy and industrial system could be "net negative" to the tune of 500 million metric tons of CO2 removed from the atmosphere each year. (This would require more electricity generation, land use, and interstate transmission to achieve.) The authors calculated the cost of this net negative pathway to be 0.6% of GDP – only slightly higher than the main carbon-neutral pathway cost of 0.4% of GDP. "This is affordable to society just on energy grounds alone," Williams said.

When combined with increasing CO2 uptake by the land, mainly by changing agricultural and forest management practices, the researchers calculated that the net negative emissions scenario would put the U.S. on track with a global trajectory to reduce atmospheric CO2 concentrations to 350 parts per million (ppm) at some distance in the future. The 350 ppm endpoint of this global trajectory has been described by many scientists as what would be needed to stabilize the climate at levels similar to pre-industrial times.

The study was supported in part by the Sustainable Development Solutions Network, an initiative of the United Nations.

# # #

Founded in 1931 on the belief that the biggest scientific challenges are best addressed by teams, Lawrence Berkeley National Laboratory and its scientists have been recognized with 14 Nobel Prizes. Today, Berkeley Lab researchers develop sustainable energy and environmental solutions, create useful new materials, advance the frontiers of computing, and probe the mysteries of life, matter, and the universe. Scientists from around the world rely on the Lab's facilities for their own discovery science. Berkeley Lab is a multiprogram national laboratory, managed by the University of California for the U.S. Department of Energy's Office of Science.

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TAGS: climate, Earth sciences, negative emissions

ADVANCING EARTH AND SPACE SCIENCE

AGU Advances

RESEARCH ARTICLE
10.1029/2020AV000284

Key Points:
- The United States can reach zero net CO_2 emissions from energy and industry in 2050 at a net cost of 0.2–1.2% of GDP, not counting climate benefits
- Multiple feasible pathways exist, all based on energy efficiency, clean electricity, electrification, and carbon capture for use or storage
- Least-cost electricity systems obtain >80% of their energy from wind and solar, with existing types of thermal generation for reliability

Supporting Information:
- Supporting Information S1
- Original Version of Manuscript
- Peer Review History
- Authors' Response to Peer Review Comments
- First Revision of Manuscript
- Second Revision of Manuscript [Accepted]

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(continued)

Carbon-Neutral Pathways for the United States

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Abstract The Intergovernmental Panel on Climate Change (IPCC) Special Report on Global Warming of 1.5°C points to the need for carbon neutrality by mid-century. Achieving this in the United States in only 30 years will be challenging, and practical pathways detailing the technologies, infrastructure, costs, and tradeoffs involved are needed. Modeling the entire U.S. energy and industrial system with new analysis tools that capture synergies not represented in sector-specific or integrated assessment models, we created multiple pathways to net zero and net negative CO_2 emissions by 2050. They met all forecast U.S. energy needs at a net cost of 0.2–1.2% of GDP in 2050, using only commercial or near-commercial technologies, and requiring no early retirement of existing infrastructure. Pathways with constraints on consumer behavior, land use, biomass use, and technology choices (e.g., no nuclear) met the target but at higher cost. All pathways employed four basic strategies: energy efficiency, decarbonized electricity, electrification, and carbon capture. Least-cost pathways were based on >80% wind and solar electricity plus thermal generation for reliability. A 100% renewable primary energy system was feasible but had higher cost and land use. We found multiple feasible options for supplying low-carbon fuels for non-electrifiable end uses in industry, freight, and aviation, which were not required in bulk until after 2035. In the next decade, the actions required in all pathways were similar: expand renewable capacity 3.5 fold, retire coal, maintain existing gas generating capacity, and increase electric vehicle and heat pump sales to >50% of market share. This study provides a playbook for carbon neutrality policy with concrete near-term priorities.

Plain Language Summary We created multiple blueprints for the United States to reach zero or negative CO_2 emissions from the energy system by 2050 to avoid the most damaging impacts of climate change. By methodically increasing energy efficiency, switching to electric technologies, utilizing clean electricity (especially wind and solar power), and deploying a small amount of carbon capture technology, the United States can reach zero emissions without requiring changes to behavior. Cost is about $1 per person per day, not counting climate benefits; this is significantly less than estimates from a few years ago because of recent technology progress. Models with more detail than used in the past revealed unexpected synergies, counterintuitive results, and tradeoffs. The lowest-cost electricity systems get >80% of energy from wind and solar power but need other resources to provide reliable service. Eliminating fossil fuel use altogether is possible but higher cost. Restricting biomass use and land for renewables is possible but could require nuclear power to compensate. All blueprints for the United States agree on the key tasks for the 2020s: increasing the capacity of wind and solar power by 3.5 times, retiring coal plants, and increasing electric vehicle and electric heat pump sales to >50% of market share.

1. Introduction

The Paris Agreement calls for "holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C (UNFCCC, 2015)." Moreover, avoiding the worst impacts of climate change may require not only staying below 1.5°C but a return to 1°C by 2100 (Hansen et al., 2013). Climate outcomes of 2°C, 1.5°C, and 1°C are associated with end of century atmospheric CO_2 concentrations of roughly 450, 400, and 350 ppm, respectively, entailing global net CO_2 emissions trajectories that reach zero by roughly 2070, 2055, and 2040 and are negative thereafter (Hansen et al., 2017; IPCC, 2018).

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Table 1
Summary of Scenarios Used in This Analysis

Scenario	Description
Reference	Business-as-usual case based on DOE *Annual Energy Outlook*
Central	Least-cost carbon-neutral pathway
Central, Low Fossil Fuel Price	Central case sensitivity using low fossil fuel price forecast
Central, Low Renewables Cost	Central case sensitivity using low renewable technology cost forecast
Low Land	Limited bioenergy and land for siting renewables and transmission
Delayed Electrification	Slow consumer uptake of electric technologies
Low Demand	High conservation resulting in reduced demand for energy services
100% Renewable Primary Energy	No fossil fuels or nuclear power allowed by mid-century
Net Negative	Least-cost pathway to negative emissions consistent with 1°C/350 ppm

This paper examines specific pathways by which emissions reductions consistent with these trajectories can be achieved in the United States. We focus on reductions in energy and industrial (E&I) CO_2, which constitutes more than 80% of current gross U.S. greenhouse gas (GHG) emissions (U.S. EPA, 2019a). We combined our modeled results for E&I with published values for non-CO_2 GHG emissions and the land CO_2 sink to obtain a range of economy-wide CO_2e values for comparison to global trajectories and policy targets adopted by United States and other jurisdictions, including "80% by 2050," "net zero by 2050," and "350 ppm by 2100" (Le Quéré et al., 2018; U.S. Climate Alliance, 2020).

Our objective in this paper was to develop realistic deep decarbonization scenarios that reach net zero or net negative E&I CO_2 emissions by 2050 while meeting all forecast demand for energy services at the lowest possible cost, using only technologies that are commercial or have been demonstrated at large pilot scale. The scope of the analysis includes all energy flows through the U.S. economy, from primary energy inputs, such as petroleum and natural gas, to energy conversion processes, such as oil refining and power generation, to end uses in buildings, transportation, and industry that consume final energy in the form of electricity and solid, liquid, and gaseous fuels. We modeled the transition pathways in all these areas in detail to answer high-level questions of interest to policy makers—technical feasibility, infrastructure requirements, cost, the implications of different assumptions and tradeoffs, and the required types and scale of policy interventions—as well as technical questions of interest to specialists, for example, how to optimally integrate high levels of variable renewable energy (VRE), produce low-carbon fuels from biomass and electricity, decarbonize challenging end uses in industry and freight transport, and incorporate carbon capture, utilization, and storage (CCUS) into the overall E&I system (Bataille, 2020; Davis et al., 2018; Dessens et al., 2016; Rogelj et al., 2015).

2. Scenarios

We modeled eight different deep decarbonization scenarios for the United States (Table 1) using a bottom-up approach similar to our previous work (Haley et al., 2018; Williams et al., 2012, 2015). The scenarios were designed to explore the effects of societal choices and resource constraints on decarbonization strategies and outcomes. A business-as-usual scenario (hereafter, *reference case*) based on the *Annual Energy Outlook (AEO)* of the U.S. Department of Energy (DOE) (U.S. EIA, 2019) was developed for comparison to the decarbonized cases in terms of CO_2 emissions, cost, energy mix, infrastructure requirements, and land use (Table 2). The scenario that achieves zero net E&I CO_2 emissions in 2050 at the lowest cost is called the (i) *central case*. The (ii) *low fossil fuel price* and (iii) *low renewables cost* scenarios test the sensitivity of the central case results to changes in cost input assumptions.

Three other scenarios also reach zero net emissions in 2050, while meeting additional constraints. The (iv) *low land case* tests the effect of limitations on land use in response to concerns about the sustainability of biomass use (Fletcher et al., 2011; IPCC, 2019; Searchinger et al., 2008; Smith et al., 2013) and the land requirements for siting renewable energy and transmission facilities (Hise et al., 2020; Kahn, 2000; McDonald et al., 2009; Wu et al., 2016, 2020). In this scenario, the land area of onshore wind and utility-scale solar was limited to 50% of the central case value, and the biomass supply was limited to 50% of its technical potential (Langholtz et al., 2016). The (v) *delayed electrification case* evaluates the impact

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Table 2
Emissions, Energy, and Cost Results for Reference and Deep Decarbonization Scenarios in 2050

Indicator	Units	2020	2050 reference	Central	Delayed electrification	100% renewable	Low land	Low demand	Net negative
Emissions									
Gross E&I CO_2	Mt CO_2	5,580	4,571	840	904	147	1,204	635	489
Product and Bunker CO_2	Mt CO_2	390	553	524	524	524	524	395	524
Net E&I CO_2	Mt CO_2	5,190	4,018	0	0	−377	0	0	−500
Cumulative Net E&I CO_2	Mt CO_2	NA	140.5	78.9	78.9	74.8	78.9	78.8	72.9
"Low Mitigation" Total CO_2e	Mt CO_2	NA	4,518	500	500	123	500	500	0
"High Mitigation" Total CO_2e	Gt CO_2	NA	4,018	0	0	−377	0	0	−500
Carbon Capture, Utilization, and Sequestration									
E&I CO_2 Captured	Mt CO_2	0	1	787	1,060	664	794	640	1,063
E&I CO_2 Utilized	Mt CO_2	0	1	471	680	664	115	400	598
E&I CO_2 Sequestered	Mt CO_2	0	0	316	380	0	680	240	465
Primary Energy Supply									
Petroleum	EJ	39.0	37.1	4.4	5.3	0	10.3	2.4	0.6
Natural Gas	EJ	31.4	29.3	8.3	7.8	0	8.1	7.4	5.7
Coal	EJ	15.1	5.5	0	0.5	0	0	0.2	0
Biomass	EJ	3.6	3.2	12.2	17.5	16.1	10.3	10.4	17.1
Nuclear	EJ	8.9	4.3	4.3	4.4	0	13.4	4.3	4.4
Solar	EJ	0.4	3.7	12.5	12.5	18.9	11.2	9	13.7
Wind	EJ	1.3	8.2	28.3	30.4	36.3	17.2	22.8	30.6
Hydro	EJ	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Geothermal	EJ	0.05	0.05	0.05	0.05	0.11	0.06	0.05	0.05
Total	EJ	100.8	92.4	71.1	79.5	72.4	71.6	57.6	73.2
Final Energy Demand									
Residential	EJ	11.83	11.02	6.54	7.39	6.54	6.54	5.52	6.54
Commercial	EJ	9.08	10.92	7.34	7.85	7.34	7.34	6.30	7.34
Transportation	EJ	28.50	26.00	13.85	16.43	13.85	13.85	10.15	13.85
Industry	EJ	19.79	25.72	23.24	23.43	23.24	23.24	18.23	23.24
Total	EJ	69.20	73.66	50.97	55.10	50.97	50.97	40.20	50.97
Electricity Share of Final Energy									
Buildings—Residential	%	46%	56%	87%	74%	87%	87%	88%	87%
Buildings—Commercial	%	52%	51%	91%	78%	91%	91%	92%	91%
Light-Duty Vehicles	%	0%	4%	93%	54%	93%	93%	93%	93%
Transport Other	%	0%	0%	26%	18%	26%	26%	26%	26%
Industry	%	17%	18%	25%	23%	25%	25%	26%	25%
Total	%	20%	23%	49%	40%	49%	49%	50%	49%
Electric Generation									
Total Generation	TWh	4,170	5,430	12,040	12,420	15,190	9,570	9,550	12,840
Wind	%	9%	41%	63%	66%	64%	49%	64%	64%
Solar	%	3%	19%	28%	27%	34%	32%	26%	29%
Hydro	%	7%	6%	3%	2%	2%	3%	3%	2%
Biomass	%	1%	0%	0%	0%	0%	0%	0%	0%
Nuclear	%	19%	7%	3%	3%	0%	13%	4%	3%
Coal	%	31%	7%	0%	0%	0%	0%	0%	0%
Gas	%	31%	20%	3%	1%	1%	3%	3%	2%
Gas w/CCS	%	0%	0%	0%	0%	0%	0%	0%	0%
Thermal Capacity Factor	%	44%	33%	12%	11%	2%	27%	13%	11%
Fuels									
Total Production	EJ	55.5	56.7	21.9	28.1	20.2	22.1	17.5	20.9
Fossil Share	%	98%	98%	43%	41%	0%	67%	41%	23%
Biomass Share	%	2%	2%	25%	29%	41%	23%	27%	40%
Electric Fuel Share	%	0%	0%	31%	30%	59%	9%	32%	38%
Consumed as Liquid	%	66%	63%	60%	67%	65%	59%	58%	63%
Consumed as Gas	%	32%	35%	39%	31%	34%	40%	41%	36%
Indicators									
U.S. population	Million	334	397	397	397	397	397	397	397
Utility Wind and Solar Land Use	MHa	2.0	9.7	36.0	38.6	47.7	16.6	29.0	38.8

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Table 2
Continued

Indicator	Units	2020	2050 reference	Central	Delayed electrification	100% renewable	Low land	Low demand	Net negative
Interstate Transmission Capacity	GW-kmile	145	176	368	365	462	319	287	389
Per Capita Energy Use Rate	GJ/per	209	188	131	141	131	131	103	131
Per Capita Emissions	tCO_2/per	15.5	10.1	0.0	0.0	−0.9	0.0	0.0	−1.3
U.S. GDP	$T	22.2	38.4	38.4	38.4	38.4	38.4	38.4	38.4
E&I Net System Cost 2050	$B	NA	NA	145	225	340	161	NA	214
Net Cost as Share of GDP	%	NA	NA	0.38%	0.59%	0.89%	0.42%	NA	0.56%
E&I Net System Cost NPV	$B	NA	NA	1,728	2,496	2,644	1,799	NA	2,215
Economic Energy Intensity	MJ/$	4.5	2.4	1.9	2.1	1.9	1.9	1.5	1.9
Economic Emission Intensity	kg CO_2/$	0.23	0.10	0.00	0.00	−0.01	0.00	0.00	−0.01
Electric Emission Intensity	gCO_2/kWh	475.6	154.1	16.2	8.8	0	14.7	16.3	9.9

on mitigation strategies if consumers are slow to adopt low-carbon technologies (McCollum et al., 2014; Sugiyama, 2012). In this scenario, full uptake of electrified end use technologies such as electric vehicles and heat pumps was delayed by 15 years relative to the central case. The (vi) *low-demand case* explores high levels of conservation (Dietz et al., 2009; Grubler et al., 2018; Van Vuuren et al., 2018). In this scenario, energy service demand in key end uses such as driving and flying was reduced 20–40% below *AEO* levels.

Two other scenarios resulted in negative net E&I CO_2 emissions. The (vii) *100% renewable primary energy case* was designed to test the much-debated feasibility and cost of an E&I system based entirely on renewable energy (Breyer et al., 2018; Brick & Thernstrom, 2016; Clack et al., 2017; Jacobson et al., 2015, 2017; Shaner et al., 2018). By 2050, this scenario has no nuclear power remaining, no fossil fuel remaining, even for feedstocks, and no geologic carbon sequestration. In this case only, the energy mix constraint was binding and emissions were a result rather than a constraint. The (viii) *net negative* case was designed to explore the requirements of deeper emissions reductions consistent with a trajectory that peaks below 1.5°C and returns to 1°C/350 ppm by 2100 (Hansen et al., 2013, 2017; Rogelj et al., 2015; Van Vuuren et al., 2018). We report the scenario that achieves net E&I emissions of −500 Mt CO_2 in 2050 at lowest cost.

All cases except the low-demand case were constrained to meet the same demand for energy services as the reference case and to use *AEO* assumptions for population, GDP, and industrial production. (See Tables S2, S7, and S9 in the Supporting Information for further details on scenario definitions and input values).

3. Modeling Approach

Energy models are designed to address specific research questions that determine which aspects of a problem can be simplified and which require greater fidelity; they typically perform better within the scope of the research questions for which they were designed and less well when extended past that scope. In U.S. public policy making, the most widely used energy models (e.g., the National Energy Modeling System (NEMS), the Integrated Planning Model (IPM), and MARKAL) were designed decades ago when the research questions (e.g., forecasting near-term oil prices or criteria air pollutants from power plants) led to decisions about model structure that while appropriate at the time, make them less useful for studying the transition to low-carbon energy systems (Pfenninger et al., 2014). A key concern is the temporal representation of electricity operations, which requires much greater fidelity when variable renewable generation is involved (Poncelet et al., 2016). Similarly, integrated assessment models, the most common type of tool used today in academic climate policy research, were designed to answer questions about global climate trajectories as a function of policy scenarios. However, because answering these questions requires representing not only the energy system but also the climate system, the economy, land use, and all GHGs, the fidelity with which the energy system is represented is not adequate for making physical infrastructure plans that can be implemented, for example, by an electric utility. Finally, sectoral models (e.g., of electricity,

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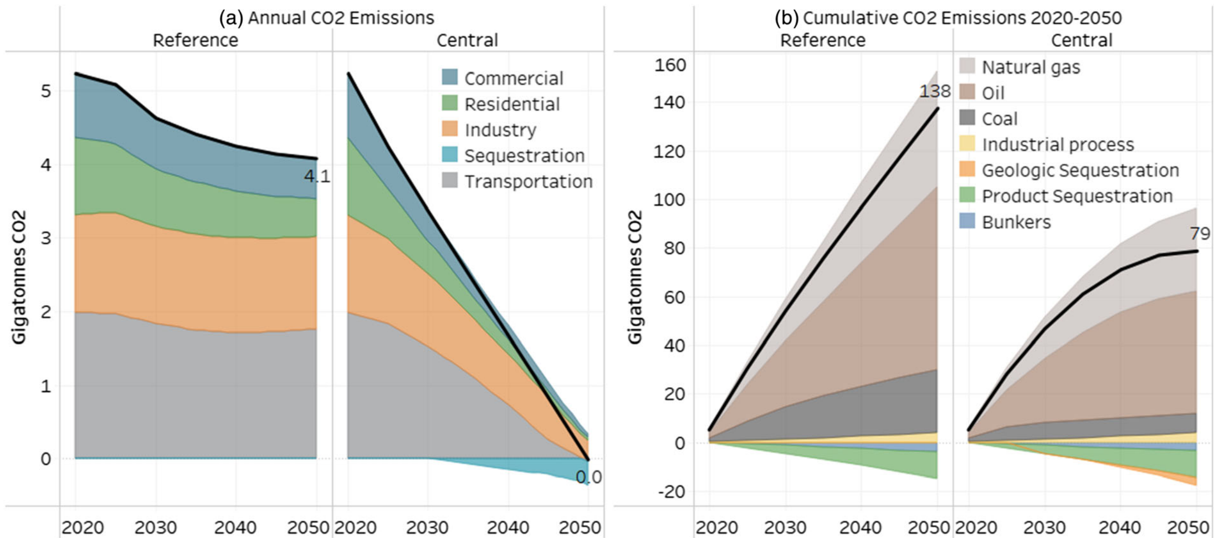

Figure 1. (a) Annual E&I CO_2 emissions for the reference and central cases. (b) Cumulative emissions. Solid black lines show net emissions. Right-hand figures show offsets from products and bunkers. Left-hand figures allocate these to end use sectors.

transportation, and buildings) used in the business and regulatory domains generally lack any representation of the whole energy system transition, which is essential for providing boundary conditions and other inputs needed to analyze sectoral decarbonization.

Recognizing these shortcomings, we built two new models, EnergyPATHWAYS (EP) and RIO, to address them. These models are run in series within a partial equilibrium framework and together analyze energy system decarbonization with sufficient accuracy to make implementable infrastructure plans. The analysis starts with bottom-up development of economy-wide final energy demand in EP, a detailed stock-rollover accounting model, with 64 different demand subsectors and 25 final energy types, for 16 geographic regions in the United States (for map, see Figure S42). In EP, the modeler makes demand-side technology choices (e.g., the rate of consumer uptake of electric vehicles) that determine the composition of the technology fleets used to meet demand for energy services (e.g., vehicle miles traveled), which are taken from the *AEO*.

Time-varying electricity and fuel demand from EP are input into RIO, a linear programming model that combines capacity expansion (planning of new facilities) with sequential hourly operations over a sampling of representative days to find the lowest-cost solution for decarbonized energy supply. RIO is unique in its high-resolution modeling of the interactions among electricity generation, fuel production, and CCUS; this allows it to determine the optimal decarbonization investment across these sectors and the optimal allocation of scarce resources, such as biomass, between them. RIO uses the same geographic regions as EP, and all infrastructure decisions are solved at 5-year time steps with perfect foresight and perfect coordination between supply sectors. The state of charge of electricity and fuels storage is tracked over an entire year, providing unique accuracy in modeling reliability and coproduction of fuels in electricity systems with very high VRE. Fuel and technology cost and performance inputs were all from public sources. The cost of producing and delivering energy from RIO is combined with the demand-side technology transition cost from EP to estimate energy system transition cost over the study period. This is done without the explicit economic feedbacks of a full-equilibrium framework, in which changes in relative prices drive consumer choices (DeCarolis et al., 2010; Pye et al., 2020). (For details of the EP and RIO methodologies, see Supporting Information sections S5 and S6.)

4. Emissions

4.1. Emissions Trajectories

Emissions trajectories for the reference and central cases are shown in Figure 1. In the reference case, net E&I CO_2 emissions decreased 22% below the 2020 level by mid-century, reflecting expected declines in

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coal-fired power generation. For the central and all other carbon-neutral scenarios, net emissions were constrained to follow a straight-line path from 2020 to 2050, for the sake of comparability and to avoid trajectories that require even steeper reduction rates during some part of the period in order to achieve the same cumulative emissions. Following UNFCCC accounting rules, emissions were calculated as gross E&I CO_2 emissions minus negative E&I CO_2 emissions, which consist of geologic sequestration, sequestration in durable products such as plastics, and bunker offsets; the latter are credits for reductions in emissions from fuels used in international shipping and air travel, which do not count as national emissions. In the central case, modeled gross emissions in 2050 were 840 Mt CO_2/year, a reduction of 84% below the 2020 level (5,190 Mt/year), offset by products and bunkers of −524 Mt/year and geologic sequestration of −316 Mt/year. Cumulative emissions from 2020 to 2050 were 79 Gt CO_2, compared to 138 Gt in the reference case (Table 2).

4.2. Total GHG Emissions

Reaching net zero emissions for E&I CO_2 alone will not be sufficient to reach net zero in total GHG emissions. For example, if U.S. emissions of non-CO_2 GHGs and the U.S. land sink were maintained at their current values (roughly +1,250 and −750 Mt/year CO2e, respectively), these sum to +500 Mt/year CO_2e, and total U.S. emissions would be +500 Mt CO_2e in 2050 even though E&I CO_2 was zero (U.S. EPA, 2019a). More ambitious but plausible levels of mitigation found in the literature, in which the combination of non-CO_2 and the land sink sum to zero—for example, a 10% reduction in non-CO_2 GHGs to +1,125 Mt/year and a 50% increase in the land sink to −1,125 Mt/year—are required for total CO_2e to reach net zero, consistent with a 1.5°C trajectory (Fargione et al., 2018; IPCC, 2018; Paustian et al., 2016; White House, 2016; Williams et al., 2014).

4.3. The 1°C/350 ppm Trajectory

In the net negative scenario, net E&I CO_2 emissions were constrained to follow a straight-line path to −500 Mt in 2050. The modeled result achieved this with gross emissions of 489 Mt, offset by products and bunkers of −524 Mt and geologic sequestration of −465 Mt. Cumulative E&I emissions 2020–2050 summed to 73 Gt CO_2 in the net negative scenario. If net emissions were maintained at the −500 Mt CO_2/year level over the latter half of the 21st century, cumulative E&I CO_2 emissions from 2020 to 2100 would decline to 48 Gt CO_2. This is consistent with a global trajectory peaking below 1.5°C and returning to 1°C/350 ppm CO_2 by 2100, if done in parallel with more ambitious mitigation of the land sink and non-CO_2 emissions, as described above (Haley et al., 2018; Hansen et al., 2017).

5. The Low-Carbon Transition

5.1. Four Pillars of Deep Decarbonization

The emissions objectives were reached in all scenarios, while meeting all energy needs. As in previous deep decarbonization pathways studies, the transition from a high-carbon to a low-carbon energy system was based on the strategies of (1) *using energy more efficiently*, (2) *decarbonizing* electricity, and (3) *switching* from fuel combustion in end uses to *electricity* (Bataille et al., 2016; White House, 2016; Williams et al., 2012, 2015). Since the emissions reduction impacts of these strategies are multiplicative, they must be simultaneously applied to achieve their full potential. This study further shows that reaching net zero E&I emissions, including non-energy CO_2 from industrial processes, requires an additional strategy: (4) *capturing carbon*, which can either be sequestered geologically or utilized in making carbon-neutral fuels and feedstocks (section 7.3) (Haley et al., 2018). Benchmark values for the four strategies are shown in Figure 2 (Figure S11). Per capita energy use declined 40% in 2050 compared to 2020, and energy intensity of GDP declined by two thirds. The carbon intensity of electricity was reduced 95%, while electricity's share of end use energy tripled, from 20% to 60%, including electrically derived fuels. Carbon capture reached almost 800 Mt CO_2/year, up from negligible levels today; of this, about 60% was utilized and about 40% was geologically sequestered.

The energy system transformation resulting from applying the four strategies is shown for two bookend cases in Figure 3. The 100% renewable primary energy case has no fossil fuels remaining in 2050, while the central case with low fossil fuel prices has the highest residual fossil fuel use. In both scenarios, both primary and final energy uses are lower in 2050 than in today's system, despite meeting higher energy service

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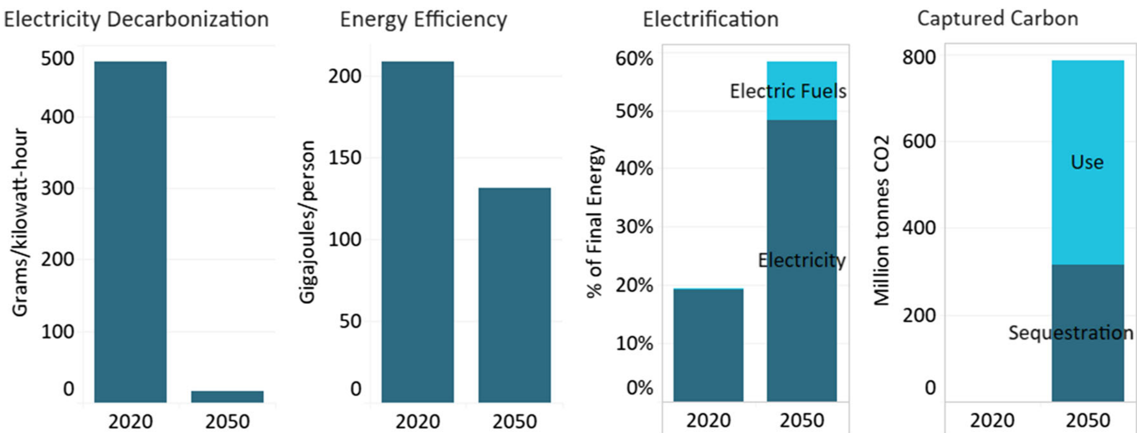

Figure 2. Metrics for the four main strategies of deep decarbonization, 2050 central case compared to current levels.

demand due to rising population and GDP. The shares of coal, oil, and natural gas in primary energy supply decrease dramatically from today's level, replaced primarily by wind, solar, and biomass. Low-carbon electricity and fuels replace fossil fuels in most final energy uses. Conversion processes that currently play a minimal role—biomass refining and production of hydrogen and synthetic fuels from electricity—become important in the decarbonized energy system, replacing most or all petroleum refining (Figures S1–S4). Contrasts between the decarbonized cases are discussed in section 5.3 (Table 2).

5.2. Infrastructure Changes

Deep decarbonization entails an infrastructure transition over the next three decades in which high-emitting, low-efficiency, and fuel-consuming technologies are replaced by low-emitting, high-efficiency, and electricity-consuming technologies, at the scale and pace necessary to reach the emission targets (Davis et al., 2010, 2018; Davis & Socolow, 2014; Shearer et al., 2020). The required scale and pace are illustrated in Figure 4 for three sectors that together comprise two thirds of current E&I CO_2 emissions: electric power generation, vehicles, and space and water heating in buildings (Figures S12–S14 and S22) (U.S. EPA, 2019a). By 2050, electric generation capacity increased by 3,200 GW; virtually all of the net increase was wind and solar (section 6.4). Coal was fully retired. Out of 296 million cars and light trucks, more than 280 million were battery electric vehicles. In residential buildings, electric heat pumps constituted 119 million out of 147 million space heating units and 88 million out of 153 million water heating units, with electric resistance heaters comprising most of the remainder. This transition was accomplished over a period of 30 years by replacement of equipment at the end of its normal lifetime, without early retirement.

5.3. Alternate Pathways

The constrained scenarios demonstrate that feasible alternate pathways to the same carbon target exist even in the face of limits on technology choices and resource availability. However, these scenarios required compensating changes in other areas, resulting in higher net cost and greater use of other resources (Table 2):

1. *Low land*. As a result of limiting the land area available for siting wind and solar, this case had the lowest renewable capacity among all scenarios and was forced to adopt higher-cost forms of electricity generation. It was the only case in which new nuclear capacity was economic and had the highest share of offshore wind generation. Electric fuel production was less than a third the level of the central case. With biomass also limited by definition, this scenario had substantially higher fossil fuel use and consequently geological carbon sequestration, than the central case. It was one of only two cases, along with the low fossil fuel price sensitivity, to require extensive direct air capture (DAC) (126 Mt CO_2/year) (Figure S30).
2. *Delayed electrification*. Delaying consumer adoption of electrified end use technologies and consequently lower economy-wide electrification resulted in the highest fuel demand, biomass use, carbon capture, and carbon utilization among the cases that met the net zero goal. Perhaps counterintuitively, this case required more electricity generation than the central case because of the need to produce fuels derived from electricity (electric fuels); accordingly, this scenario also had higher generating capacity and land requirements.

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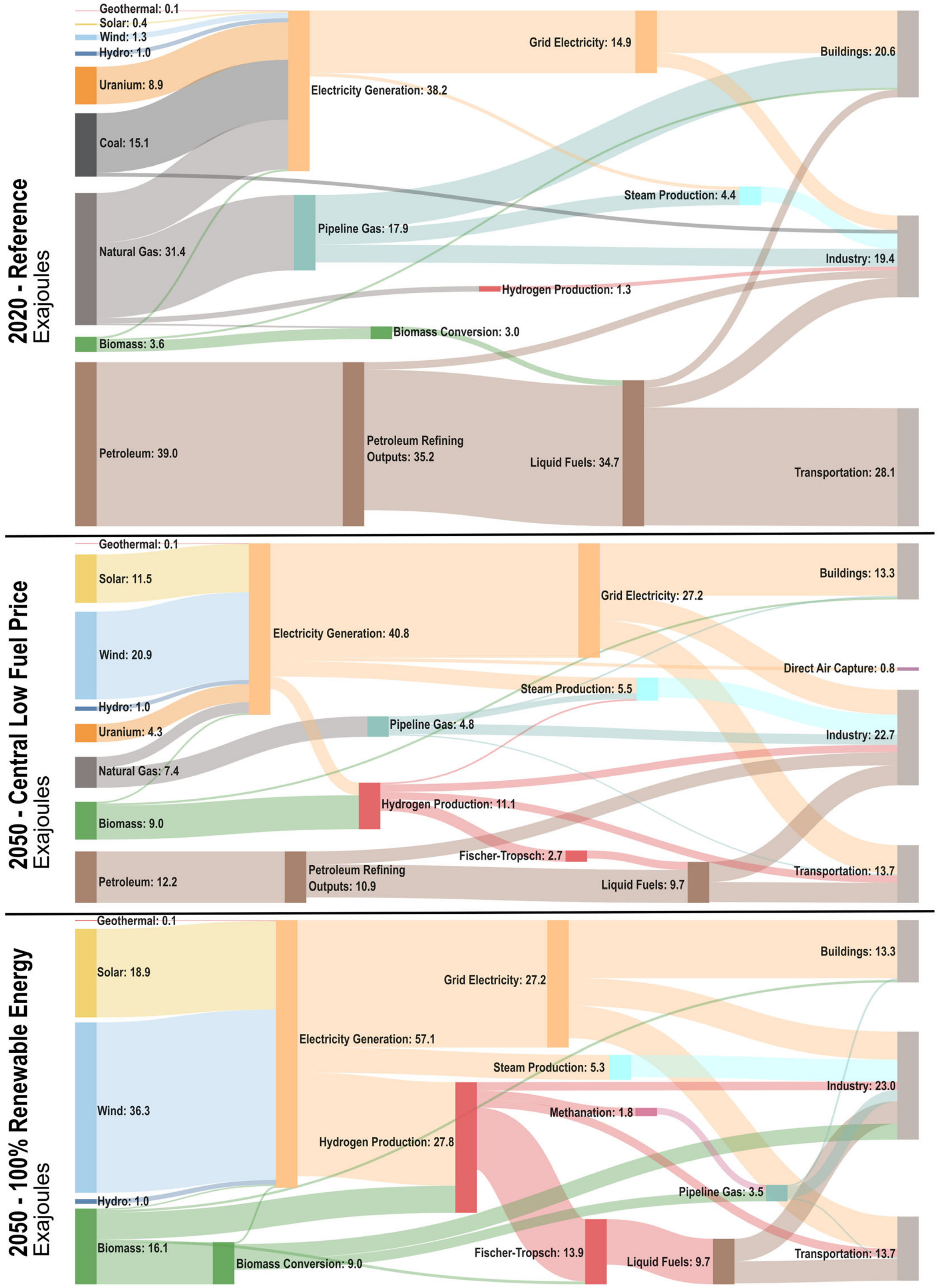

Figure 3. Sankey diagrams for (top) the current U.S. energy system, (middle) the central carbon-neutral case with low fossil fuel prices, and (bottom) the 100% renewable primary energy case. Primary energy supplies are on the left, conversion processes in the middle, and final energy consumption on the right. Line widths are proportional to magnitude of energy flows.

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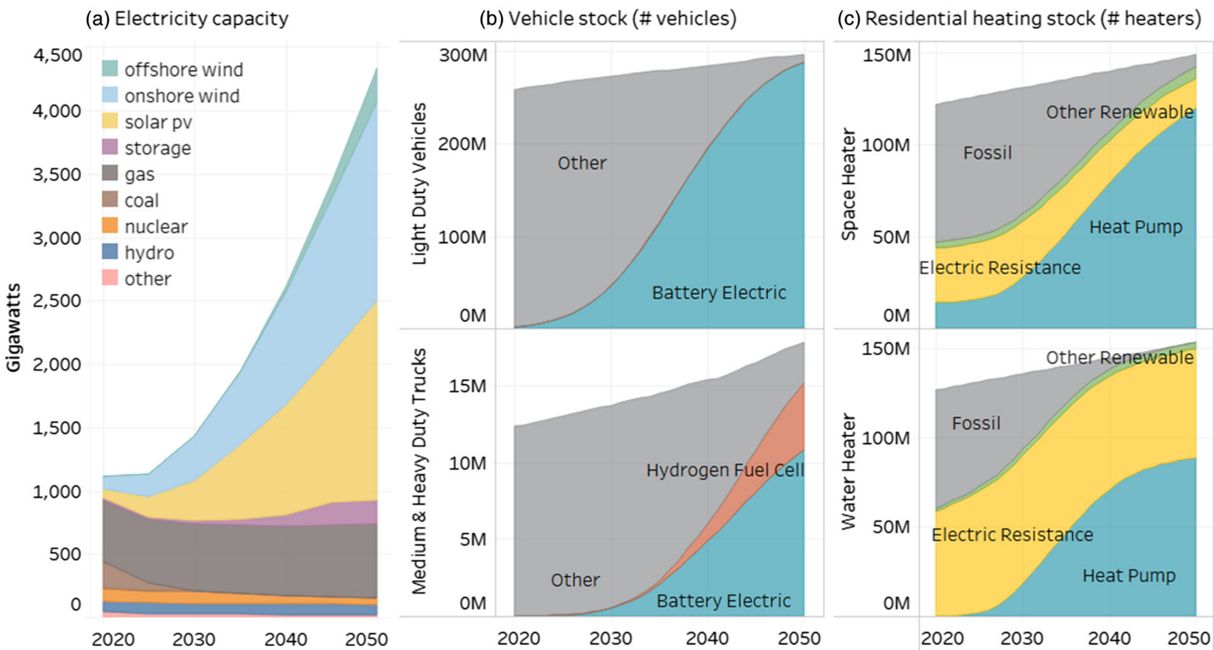

Figure 4. Infrastructure transition in central case for (a) power generating capacity, (b) vehicles, and (c) space and water heating.

3. *Low demand*. This case demonstrated that reducing consumer demand for energy services such as driving and flying lowers the infrastructure requirements of mitigation but does not eliminate the need for large-scale deployment of other decarbonization measures such as electrification and electricity decarbonization. In other words, energy efficiency and conservation alone were not sufficient to achieve the target. That said, this case had the lowest primary and final energy (both ~20% lower than the central case), along with the lowest electricity generation, fuel demand, carbon capture, interstate transmission, and overall infrastructure build. It also had lower land area and geological sequestration requirements than the central case. Net cost was not calculated for this scenario, as the cost of voluntary conservation is difficult to estimate, and there was no low-demand reference scenario to compare it to.
4. *100% renewable primary energy*. Because this case had no fossil fuels, the choices for producing fuels and feedstocks were limited to biomass and electricity. When combined with the effect of having no nuclear power, this scenario required the highest level of electricity generation, electric fuel production, wind and solar capacity, electrolysis capacity, interstate transmission, and land area across scenarios. It also had higher biomass use than the central case. Although geologic sequestration was not permitted, a relatively high level of carbon capture was required to supply the carbon needed for fuel production. Because some biogenic carbon in feedstocks was sequestered in durable products, this scenario had net negative CO_2 emissions in 2050 (−377 Mt/year).
5. *Net negative*. In order to reach net negative emissions of −500 Mt CO_2/year in 2050, this scenario had the lowest fossil fuel use of all cases except for the 100% renewable primary energy case. It compensated for this by consuming higher levels of biomass and electric fuels and, consequently, required more electricity generation, land area, and interstate transmission than the central case. It had the highest level of carbon capture across cases, with higher levels of both utilization and geologic sequestration than the central case. DAC was small (−7 Mt CO_2/year). On most measures, the requirements of this case fell within the same range as other scenarios, though toward the upper end, suggesting it is feasible if mitigation options are not limited.

5.4. Cost

The levelized net energy system cost of this transformation for the central case was $145 billion in 2050, equivalent to 0.4% of GDP in that year (Figures 5 and S7–S10). This is the difference in the annualized capital and operating costs of supplying and using energy in the central case compared to the reference case, plus the net cost of reducing or offsetting non-energy industrial process emissions. Except where noted, cost

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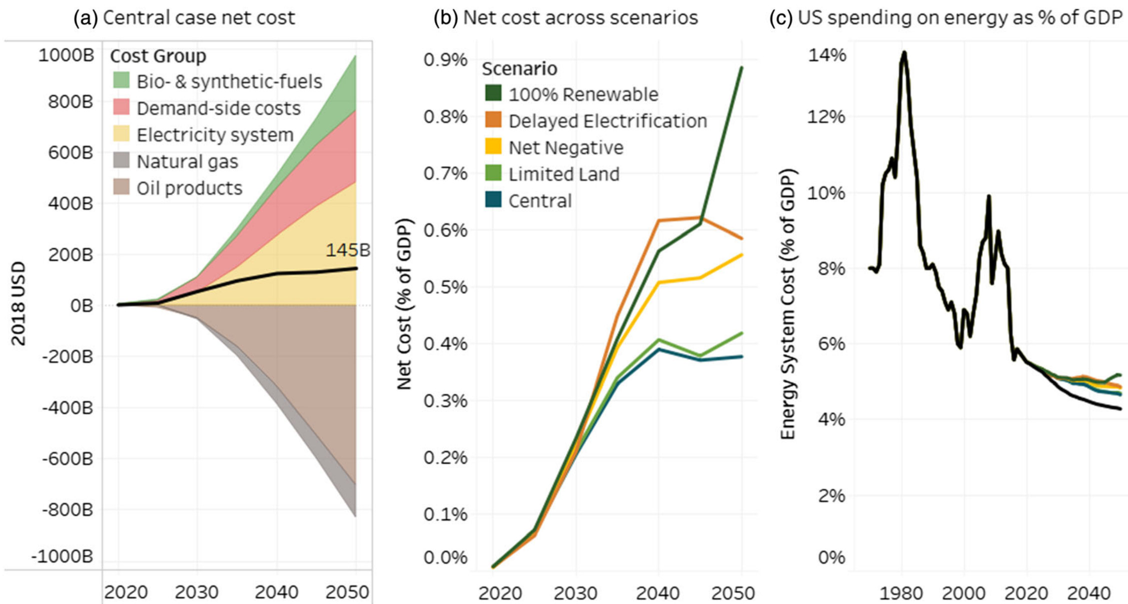

Figure 5. (a) Net annual levelized system cost of central case (black line), (b) net cost across scenarios as share of GDP, and (c) total U.S. spending on energy as share of GDP, historical and modeled for reference and decarbonized cases. Note: Forecast GDP growth average is 1.84% per year, 2020–2050, following AEO (U.S. EIA, 2019).

inputs were the reference values of DOE long-term fossil fuel price and technology cost forecasts (NREL, 2019; U.S. EIA, 2019). The net present value of net system cost was $1.7 trillion over the 2020–2050 period, using a 2% societal discount rate. In the central case, increased spending on incremental capital costs for low-carbon, efficient, and electrified technologies ($980 billion in 2050) was offset by reduced spending on fossil fuels and incumbent technologies (−$835 billion in 2050). A sensitivity case using the DOE low fossil fuel price forecast raised the central case net cost to 1.2% of GDP in 2050 (net cost is higher because the counterfactual reference case cost is lower); using the low technology cost forecasts for renewables lowered it to 0.2% of GDP. The net costs of all other scenarios ranged from about 0.45% in the low land case up to 0.9% in the 100% renewable primary energy case. The net negative case consistent with a 1°C/350 ppm trajectory had a net cost of less than 0.6% of GDP in 2050.

Historical total U.S. spending on energy has ranged between 5.5% and 13% of GDP from 1970 to the present. In the reference case, this is projected to decline to 4.3% in 2050. With deep decarbonization, the spending could reach as high as 5.2% of GDP depending on the scenario but would still be well below the historical range.

6. Electricity

6.1. Electricity Generation

Until recently, it was unclear whether VRE, nuclear, or fossil fuel with CCS would become the main form of generation in a decarbonized electricity system. Analyses of U.S. economy-wide deep decarbonization (~80% GHG reductions) have generally shown roughly equal shares of generation from each of these sources, with the proportions changing depending on policy and cost assumptions (Bistline et al., 2018; Clarke et al., 2014; White House, 2016; Williams et al., 2012, 2015). The cost decline of VRE over the last few years, however, has definitively changed the situation.

Our analysis shows that electricity from VRE is the least-cost form, not only of power generation but of primary energy economy wide, even when that requires investment in complementary technologies and new operational strategies to maintain reliability. All cost-minimizing pathways to deep decarbonization are organized around using VRE to the maximum feasible extent, to supply both traditional loads and new loads such as EVs, heat pumps, and hydrogen production. As a result, electricity demand increases dramatically, to roughly three times the current level by 2050 (230% to 360% across cases; Figure 6b and Table 2). This demand is met primarily by VRE in all cases. In the central case, the generation mix was 90% wind and

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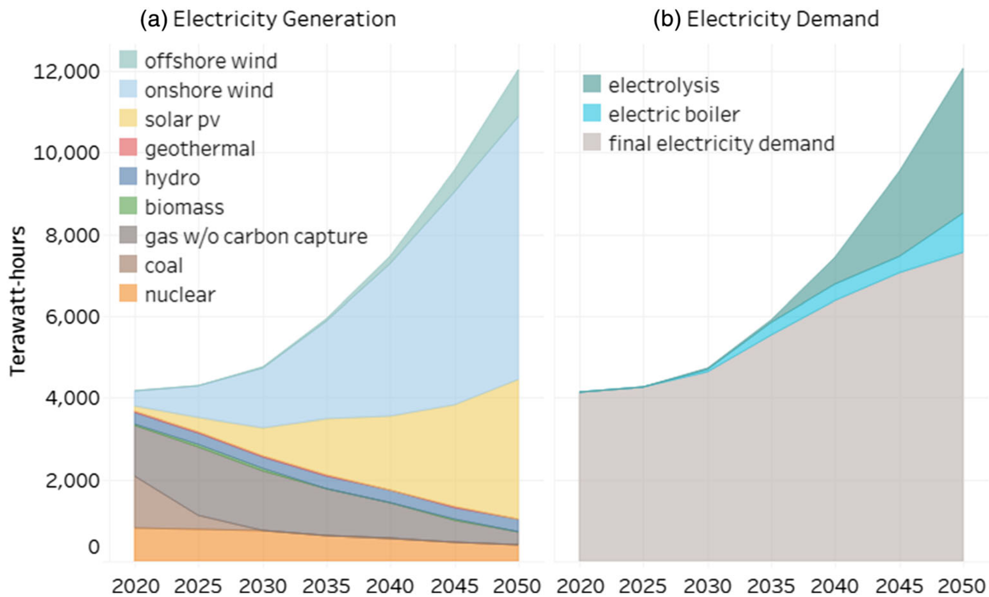

Figure 6. (a) Electricity generation by type, central case, and (b) electricity demand, central case.

solar (Figure 6a); the minimum level was 81% in the limited-land case (Figures S23–S25 and S27). It is possible that dramatic cost breakthroughs in new generating technologies such as Allam Cycle CCS and Gen IV nuclear could result in a reduced VRE share, but the breakthroughs would need to happen soon in order to deploy them at the pace and scale required in these scenarios.

6.2. Reliability in High Renewables Systems

There has been a vigorous debate over the feasibility of electricity systems with very high levels of VRE generation (Brown, Bischof-Niemz, et al., 2018; Clack et al., 2017; Diesendorf & Elliston, 2018; Heard et al., 2017; Jacobson et al., 2015, 2017; Jenkins et al., 2018). In our view, this debate's focus on "100% wind-water-sunlight" electricity systems per se is less useful than what electricity system configuration is most cost effective in reliably meeting the overall energy needs of a carbon-neutral or carbon-negative economy. In other words, the economics and reliable operation of a high VRE electricity system boil down to what technologies are deployed to balance supply and demand in all hours of the year. The technologies required depend on the time scale of the imbalance and whether there is an energy deficit or surplus (Figure S18). Analyzing across multiple time scales and geographies, we found that balancing was most cost effectively addressed through a combination of thermal generation to provide reliable capacity during times of deficit, along with transmission, energy storage, and flexible loads to move surplus energy in time or space, plus renewable curtailment.

The provision of reliable capacity (MW) in a decarbonized electricity system is fundamentally separate from the provision of energy (MWh). The capacity resource that pairs best with a high VRE system is one with very low capital cost, because its role is to provide reliability for a limited number of hours per year (average capacity factors ~10%; Figures 7b and S17), rather than zero-carbon energy in bulk. In this analysis, reliable capacity came mostly from thermal generation using gas without carbon capture (Figure S28). The much higher initial capital cost of CCS and nuclear plants as currently forecast could not be justified for such low utilization rates, and at the same time, they were uncompetitive with VRE for the bulk of operating hours unless VRE buildout was constrained. The gas generation fleet in the central case was 590 GW and ranged between 470 and 675 GW across scenarios, compared to 480 GW today (Figure 7a). To remain within carbon constraints, gas-fired plants without carbon capture either burned carbon-neutral fuels or natural gas for which emissions were offset elsewhere, depending on the carbon budget, resource constraints, and relative costs (see section 7.2).

The reason gas generating capacity comparable to today's is needed in a carbon-neutral energy system is illustrated in Figure 8, which shows hourly balancing in a high renewables system in a northeastern state that

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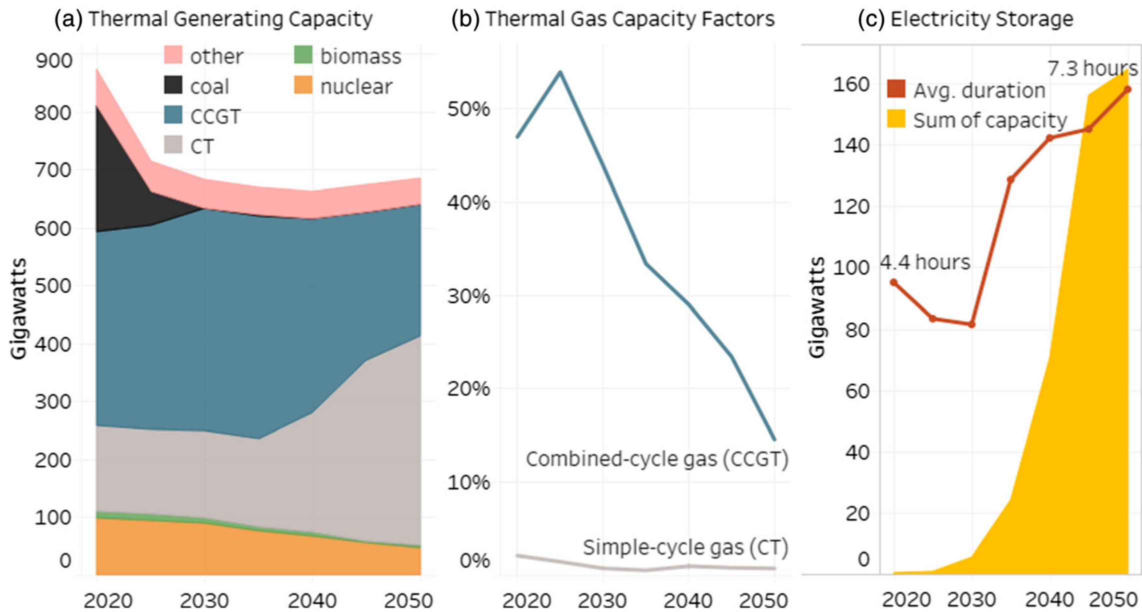

Figure 7. Central case (a) thermal generating capacity, (b) thermal capacity factors for gas, and (c) energy storage.

relies primarily on offshore wind for decarbonized electricity. On a high-wind, low-load day, wind and solar production exceed load in most hours of the day, with excess generation being partly curtailed, partly exported, partly converted to hydrogen by means of electrolysis, partly used to heat water in industrial boilers, and partly shifted in time with storage and flexible loads. No gas generation was required. On a

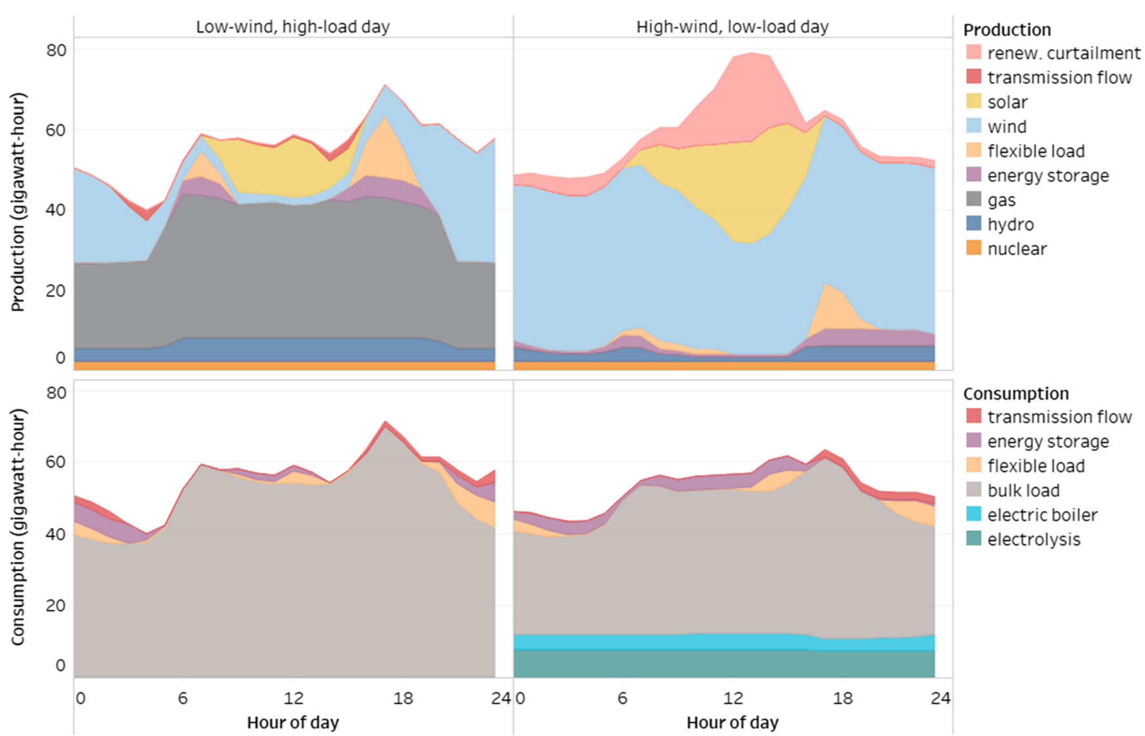

Figure 8. Balancing in a northeastern state in 2050, central case, with production (top) and consumption (bottom) for a low-wind, high-load day (left) and a high-wind, low-load day (right).

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low-wind, high-load day, by contrast, significant gas generation was required during every hour of the day. In general, extended periods of low renewables output combined with high loads determine the amount of thermal capacity required for reliably meeting demand in each electricity region (Figures S16 and S28). Energy storage was not competitive in meeting sustained energy deficits because the large quantity of energy needed required a large investment in storage, while the infrequent occurrence of such events resulted in very low storage utilization. These results illustrate why proposals for rapid retirement of gas-fired capacity are ill advised.

6.3. Additional Balancing Resources

Transmission enables VRE systems to take advantage of geographically diverse load and generation profiles. Interregional transmission capacity increased 168% in the central case (85–217% across scenarios; Figure S32). Most transmission was built between wind-rich and wind-poor regions, generally from the wind belt in the center of the United States toward the Southeast and Mid-Atlantic (Figure S33). This is because wind resource quality and potential in the United States has much higher disparity between regions than does solar, which in nearly all of the United States is more economic to develop locally than import from another region.

Batteries can economically time-shift renewable generation from surplus to deficit periods over the course of a day; battery capacity ranged 80–217 GW across scenarios (Figures 7c and S29). As noted above, batteries were not cost effective for long duration balancing. Moreover, flexible consumer loads (e.g., EVs and water heaters) were cost competitive with batteries in providing peak-load reduction, with 74–116 GW across scenarios (Sepulveda et al., 2018).

High-VRE systems designed to provide sufficient energy in high-demand months will over-generate in other months. Large-scale industrial loads that can operate flexibly while producing a useful product from electricity allow energy demand to change to match available VRE supply across a wide range of conditions. For example, electrolysis of water was used to balance the system and produce fuels for applications that were hard to electrify (Figures 8, S15, S31, and S34). This allows for the economic overbuilding of renewables to reduce the need for other balancing resources on energy-constrained days, increasing the competitiveness of VRE against other low-carbon generation. Flex-fuel boilers were also built economically and dispatched flexibly. Many other large industrial loads, such as desalination, could play a similar role but were not analyzed here. As a result of the balancing measures employed, renewable curtailment was only 2–5% across scenarios (Figure S21).

6.4. Electricity Infrastructure Buildout

The greatest challenge for a very high VRE electricity system is probably neither cost nor reliability but achieving the scale and rate of infrastructure construction required. In the central case, the average build rate of wind and solar in the 2040s was more than 160 GW per year; in the 100% renewable primary energy case, it was almost 260 GW per year; in the low land case, it was still nearly 90 GW per year (Figure 9b). For comparison, the total current U.S. wind and solar capacity is less than 150 GW (U.S. EIA, 2020). Using rule of thumb metrics for wind and solar land requirements (Miller & Keith, 2018, 2019; Ong et al., 2013; Wu et al., 2016, 2020), the total land used was 36 MHa in the central case, 17 MHa in the low land case, and 48 MHa in the 100% renewable primary energy case (Table 2), equivalent to 2–6% of contiguous U.S. land area.

In this light, we found that the 100% renewable primary energy case, employing the balancing measures described above, was technically reliable but entailed a larger infrastructure buildout and higher cost, driven in part by increasing the VRE share of generation from 90% to nearly 100% (Table 2) and in part by demand for electrically-produced fuels.

7. Fuels and CCUS

7.1. Fuel Demand

In the central case, about 50% of final energy demand was met with electricity (Table 2 and Figure S1). The remaining 50% was met with fuels (hydrocarbons and hydrogen), primarily in applications where volumetric or gravimetric energy-density requirements make electrification difficult (e.g., aviation), in industries where high process temperatures are needed, in thermal power generation, and in industrial feedstocks

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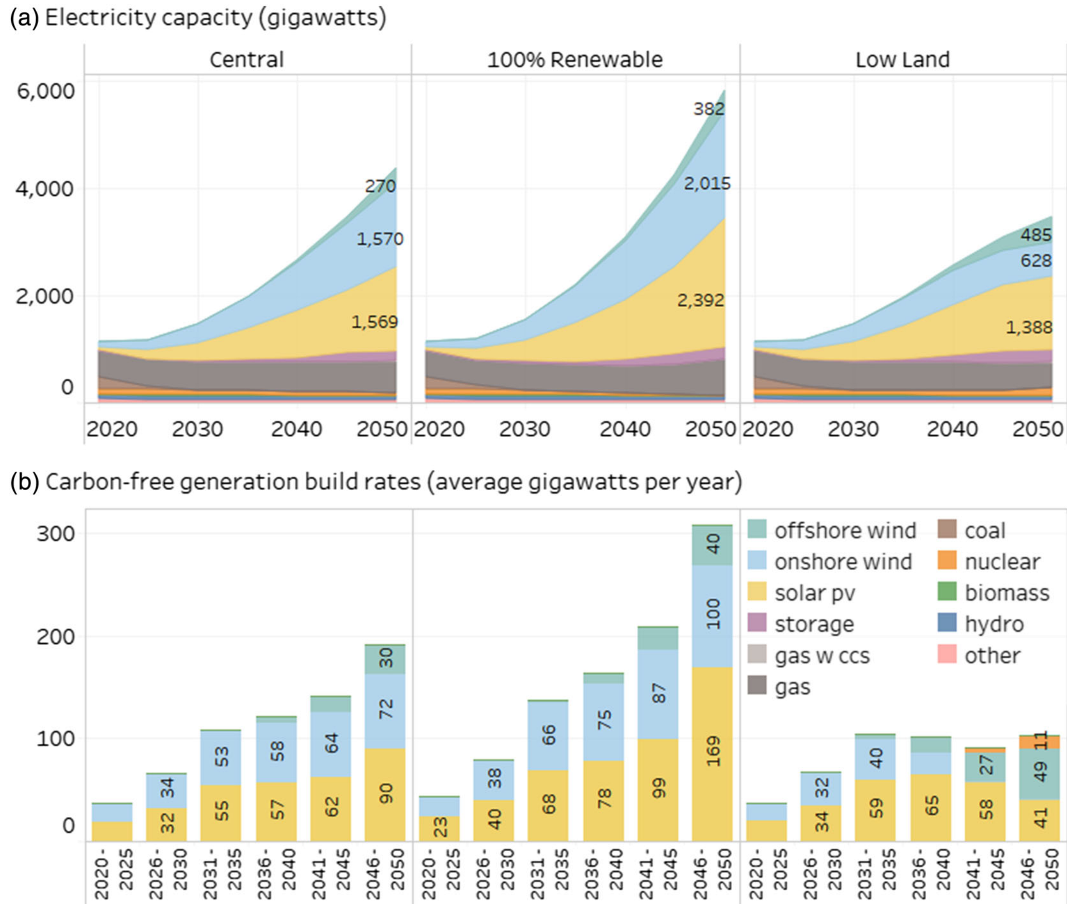

Figure 9. (a) Total electric generating capacity and (b) build rates for carbon-free generating capacity in the central, 100% renewable primary energy, and low land cases.

where hydrocarbons are required (e.g., petrochemicals). Since electricity was almost completely decarbonized, the production and use of fuels was the main source of gross CO_2 emissions economy wide, which were either captured in situ or offset by negative emissions elsewhere to achieve carbon neutrality within the E&I system as a whole.

While the share of fuels in final energy demand remained significant, the absolute quantity decreased dramatically. In the central case, total fuel demand declined >60% below today's level due to the combined effects of increased energy efficiency and increased electrification. Conservation in the low-demand scenario decreased both final energy and fuel demand an additional 20% below the central case but did not eliminate the need for industrial-scale fuel production (Table 2). Lower electrification had the opposite effect. Slow consumer uptake of EVs and heat pumps in the delayed electrification scenario reduced the electricity share of final energy to 40%, increasing fuel demand more than 25% relative to the central case (Table 2). This substantially raised the net cost and increased fossil fuel use, biomass use, electricity generation for fuel production, land requirements, and carbon sequestration.

An electrification share greater than 50% and proportionally lower fuel use may be possible but will require further research and market development. Since a large share of final energy demand in the central case was for feedstocks that cannot use electricity as a substitute, the effective electrification rate of the other end uses is already high (about 70%). How much additional electrification could occur likely depends on how industry changes its products and processes in response to increases in the price of fuel relative to electricity (Bataille, 2020; Jadun et al., 2017).

The main fuels for meeting residual fuel demand after electrification are hydrocarbons and hydrogen. Hydrocarbons have intrinsic advantages as a fuel including high energy density, high boiling point, high

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combustion temperature, ease of storage, and ability to be synthesized into products such as plastics. Hydrocarbons in these scenarios were either fossil fuels or synthetic carbon-neutral "drop-in" fuels that required minimal retooling of the current end use technology; all required some form of carbon management to be consistent with net zero or net negative E&I CO_2 emissions. Hydrogen was limited by low density and difficulty of storage to 2–3 EJ of direct end use across scenarios; it had a much larger role as an intermediate product in hydrocarbon production. Ammonia, a possible alternative to hydrocarbon fuels, has less attractive technical properties and its own array of environmental concerns (Galloway et al., 2003); it was not included in our scenarios but could play an important role in end uses such as shipping (Kobayashi et al., 2019).

7.2. Fuel Supply

Drop-in fuels in our scenarios were derived from three main energy sources: (1) biomass, mainly by gasification and synthesis using the Fischer-Tropsch process; (2) electricity, by electrolysis to produce hydrogen and subsequent chemical synthesis; and (3) natural gas, by steam methane reforming (SMR) with carbon capture to produce hydrogen and subsequent chemical synthesis (Figure S34). The specific conversion technologies adopted for fuel production depend on uncertain cost and performance assumptions, but the technological details are relatively unimportant from an energy system perspective because well-established alternative conversion pathways exist. More important is that the three energy sources all have resource constraints that form upper limits to the amount of fuel that can be sustainably produced with that resource, including annual production of biomass feedstocks, overall land requirements for electricity generation and transmission, and carbon sequestration rates, respectively.

For biomass, the main constraint is the quantity of feedstocks that can be sustainably produced (IPCC, 2019; Searchinger et al., 2008; Smith et al., 2013). For this study, potentially available biomass primary energy was capped at the technical potential of the DOE *Billion Ton Study* (21.6 EJ/year) in all cases except the low land scenario, which was capped at 50% of that level (10.8 EJ/year) (Langholtz et al., 2016). The biomass used in our scenarios included all identified waste streams plus purpose-grown feedstocks that were assumed to shift to more sustainable crops (e.g., switchgrass and miscanthus) grown within the existing land footprint currently used for corn ethanol (Robertson et al., 2017; Williams et al., 2014). The central case used only about 60% (12.2 EJ) of the biomass technical potential; the maximum usage across scenarios was 80% (17.5 EJ) in the delayed electrification case (Table 2 and Figures S34 and S36).

The maximum annual CO_2 injection rate into belowground storage was capped at 1.2 Gt CO_2/year based on a Department of Energy study and CO_2 transport across regions (e.g., from the Midwest to the Gulf Coast) was not allowed (National Energy Technology Laboratory, 2017). In the central case, the sequestration rate reached 30% of the injection limit (360 Mt CO_2/year) in 2050; the low land scenario was highest across cases at 680 Mt CO_2/year (Figure 10b and Table 2). As described earlier, the land requirements for wind and solar electricity based on rules of thumb in the literature ranged from 17 to 48 MHa (Table 2). For comparison, a recent study by The Nature Conservancy found an area of 36 MHa to be suitable for wind development with low environmental impacts in the 17-state wind belt in the central United States (Hise et al., 2020).

While the shares of electricity generation by technology were broadly similar across scenarios, the shares of biomass-, electricity-, and fossil-derived fuels in the fuel mix differed widely as a function of resource constraints, price assumptions, and the quantity and type of end use fuel required (e.g., jet fuel and diesel) (Figures S34–S36). Each type of fuel supply had a cost curve that increased with production volume as a function of primary energy cost, processing cost, transport cost, end use efficiency, and carbon content. As a result, the least-cost mix of fuels in each scenario was a different blend of carbon-neutral drop-in fuels plus direct combustion of fossil fuel with carbon capture or offsetting (Figures 10a and S37 and Table 2).

The coupling of the electricity and fuel sectors in electric fuel production plays an important role in limiting the cost of deep decarbonization (Brown, Schlachtberger, et al., 2018; Buttler & Spliethoff, 2018). In the central case, electrolysis consumed 3,500 TWh in 2050, similar in scale to all U.S. electricity sales today, at an average capacity factor of 52%. These results show that sector coupling is not simply absorbing marginal amounts of renewable generation that might otherwise be curtailed, nor is it simply building dedicated renewables to serve fuel demand (Figures S18 and S19). Rather, sector coupling has elements of both, in which optimized integration of fuel production with electricity increased transmission-connected

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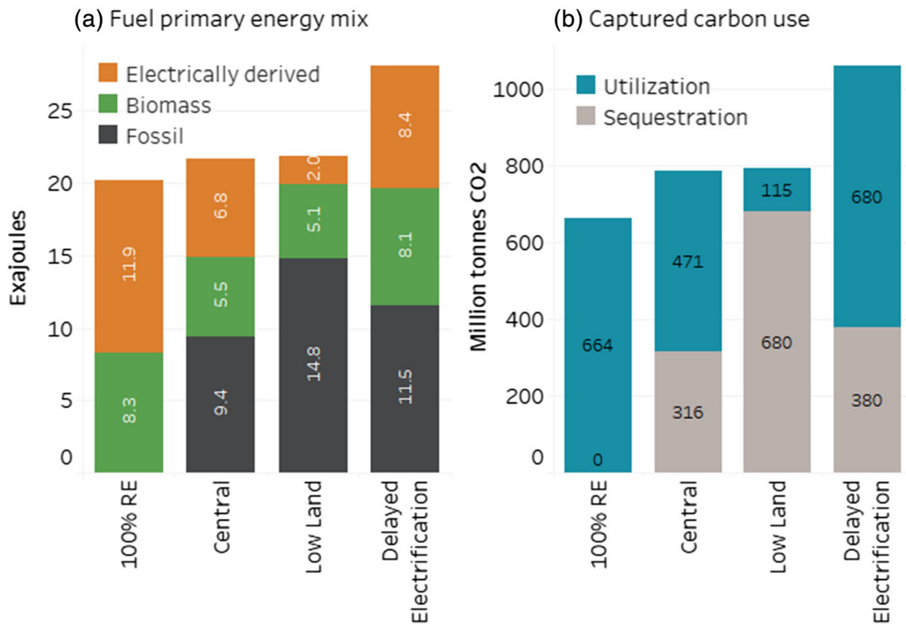

Figure 10. (a) Fuel primary energy mixes in 2050 and (b) carbon captured, utilized, and sequestered in 2050, in the central, delayed electrification, 100% renewable, and low land scenarios.

renewables to serve larger fuel production loads, but these loads were turned off about half of the time, during energy-constrained periods, to reduce the need for other balancing resources. In the central case, 9 EJ of H_2 was produced by electrolysis, with a range of 2 EJ (low fossil fuel price) to 17 EJ (100% renewable primary energy) across scenarios (Figure S34). Electrolysis capacity (electricity input) was 777 GW in the central case and ranged from 304 to 1,352 GW across scenarios (Figure S31).

Among fossil fuels, natural gas was the last to be replaced in a least-cost system because it is the least expensive per unit of energy and has the lowest carbon content. With higher renewables costs, SMR with carbon capture using natural gas displaced electrolysis for production of hydrogen. For petroleum, with higher prices oil products were replaced by drop-in carbon-neutral fuels and with lower prices, it was more economic to use fossil fuels with emissions offsetting for some applications, such as feedstocks. Our results demonstrate that there are many possible fuel pathways consistent with carbon neutrality; the optimal pathway will depend on future fossil fuel price trajectories, the cost and potential of biomass and geologic sequestration, the cost of producing fuels from electricity, and the societal and environmental constraints. However, the scenarios in this study did not require low-carbon fuels and CCUS in bulk until the 2030s to reach their emissions targets, indicating that there is still time for discovery and refinement of these strategies.

7.3. CCUS

All carbon-neutral scenarios required technological (i.e., nonbiological) carbon capture (Table 2 and Figure S38) (Keith et al., 2018; Socolow et al., 2011). Carbon capture can occur at three points in the fuel lifecycle: in making the fuel, in the exhaust stream from combusting the fuel, or from the air once CO_2 is released to the atmosphere. Post-combustion "end-of-pipe" capture was applied to concentrated, high-volume CO_2 streams from sources like cement and biofuel refineries. Once captured, the CO_2 was either *sequestered* geologically or *utilized* to make carbon-neutral drop-in fuels and feedstocks.

We found that carbon capture is a "fourth pillar" of deep decarbonization because a net zero or net negative E&I CO_2 target could not be met without it. The general relationship between fuels, emissions, and carbon capture is illustrated in Figure 11. If fossil fuels are used without carbon capture at some point in the system (end of pipe or offsetting), emissions by definition will exceed net zero. If synthetic hydrocarbon fuels are used, without carbon capture it is infeasible to supply the carbon required to produce them without

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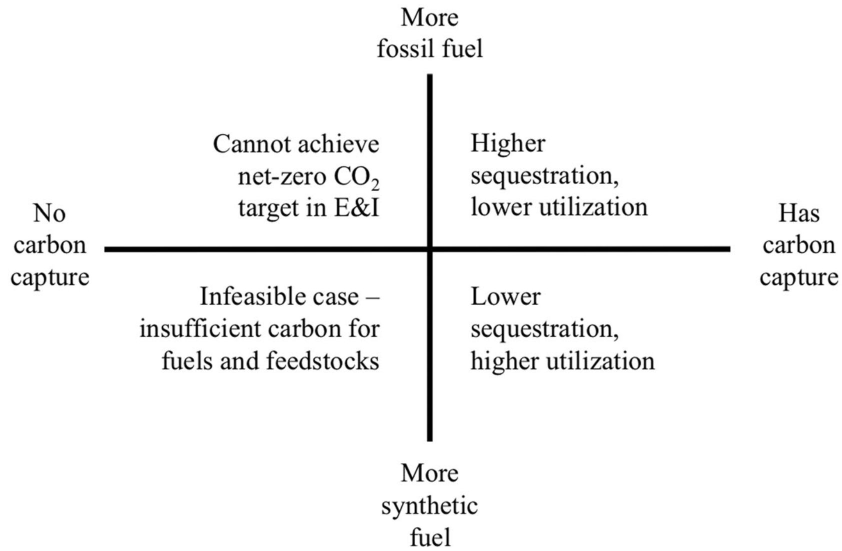

Figure 11. The relationship between fuels and carbon capture, utilization, and storage.

exceeding the biomass sustainability limit. With carbon capture, the more fossil fuel is used, the greater the share of captured carbon that must also be sequestered. Conversely, the more synthetic fuel is used, the more the captured carbon is utilized.

For these reasons, the amount of carbon capture and the split between utilization and sequestration varied dramatically across cases (Figure 10b). Even the 100% renewable primary energy case, which uses no fossil fuels, required 664 Mt/year of carbon capture in 2050 to provide the carbon for renewable fuel and feedstock production; all captured carbon in this case was utilized, and none was stored geologically. In the central case, 787 Mt/year was captured from industrial processes, biofuel refining, and hydrogen production from natural gas. Of this, 60% was used to make fuels, and 40% was geologically sequestered. The highest level of carbon capture was in the net negative case, with 1,063 Mt/year in 2050, of which 465 Mt/year was geologically sequestered (Table 2).

7.4. Negative Emissions Technologies

Offsetting of small or widely dispersed CO_2 sources for which CCS or drop-in fuels were not economic was done with negative emissions technologies (NETs), specifically bioenergy with CCS (BECCS) and DAC (Breyer et al., 2019; Clarke et al., 2014; Keith et al., 2018; McQueen et al., 2020; Sanz-Perez et al., 2016). NETs were most economic when tightly coupled to the E&I system, where the captured carbon could be flexibly used for fuels and products (e.g., plastics) or sequestered as needed. We found that the most economic form of BECCS was not in power plants, in contrast to many integrated assessment modeling studies (Clarke et al., 2014; IPCC, 2014; Smith et al., 2016; Van Vuuren et al., 2013) but in biorefineries. This is because BECCS power plants have both higher capital cost and higher operating cost than VRE, competing on the margin for a limited biomass resource that has higher value uses in making fuel and feedstocks (Figure S36). DAC costs were minimized by deployment in locations with low-cost complementary renewable generation (e.g., solar by day and wind by night) allowing DAC installations, which have high capital costs, to have utilization rates up to 85%. Overall, the use of NETs is limited by cost (DAC), sustainable biomass availability (BECCS), and sequestration injection rates (both). While NETs are necessary components of a least-cost decarbonization strategy, it is uneconomic to achieve carbon neutrality through a strategy of continuing high levels of gross fossil fuel CO_2 emissions offset by NETs.

8. Demand Sectors

In the transition to a carbon-neutral E&I system, the decarbonization of energy supplies was accompanied by parallel changes in demand-side infrastructure, for example, electrification of vehicles (Figure 4). The composition of final energy demand in the buildings, transportation, and industrial sectors (Figure 12)

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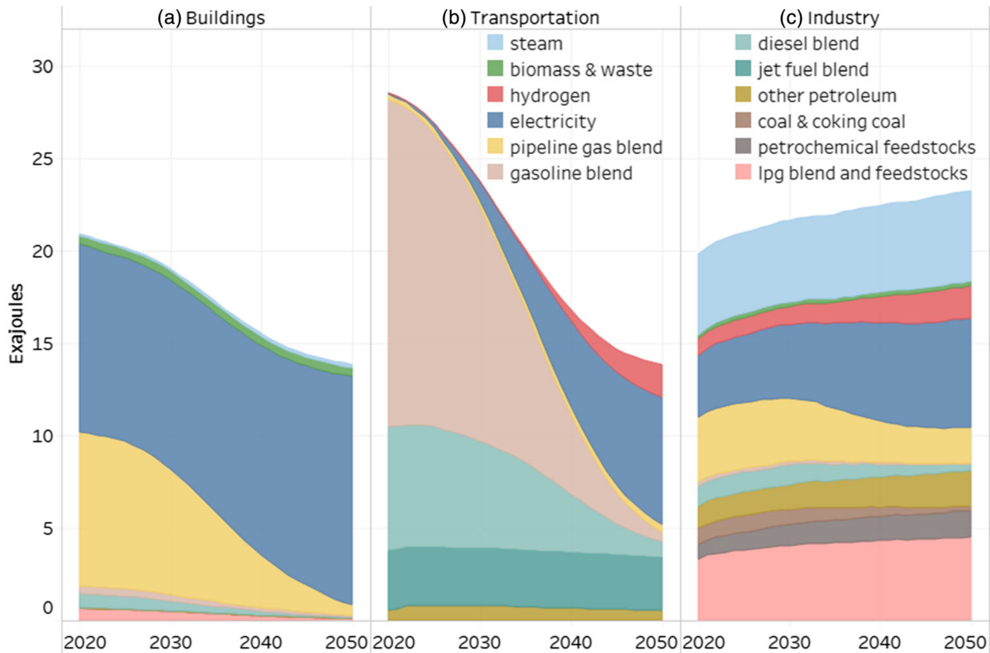

Figure 12. Composition of final energy demand in the central case in (a) buildings, (b) transportation, and (c) industry. Fuels that change composition over time, for example, when carbon-neutral fuels are mixed with fossil fuels to reduce their overall carbon intensity, are called "blends." The legend applies to all parts of the figure.

reflects these changes, differing in the extent of electrification, type of fuels used, and change in energy demand over time. The transition strategies within each subsector were based on expert judgment that took into account the types of final energy that can be used in a given application; the relative cost of different forms of decarbonized energy; the capital cost of end use technologies; infrastructure inertia; and the cost of energy delivery.

As decarbonization proceeds, final energy costs tend to drive a transition from fuel-using to electric technologies. This is because, in general, electricity is less costly to provide in decarbonized form than are fuels. In 2019, the average marginal costs of electricity, gaseous fuels, and liquid fuels were \$9/MMBtu, \$3/MMBtu, and \$18/MMBtu, respectively, ignoring delivery charges (\$1/MMBtu = \$0.95/GJ). In 2050, the average marginal costs of the decarbonized versions of these same fuels were \$11/MMBtu, \$11/MMBtu, and \$26/MMBtu, respectively. The competiveness of electricity vis-a-vis natural gas improved dramatically, from a 3:1 cost ratio today to 1:1 under deep decarbonization. Electrification's advantage was magnified by an intrinsic energy efficiency improvement due to thermodynamics, as is the case with electric drivetrains versus internal combustion engines; equal per-unit energy prices combined with a threefold improvement in energy efficiency to give EVs a much lower operating cost. Additionally, electricity-using technologies with flexibility in time of use were able to take advantage of electricity costs that were significantly lower than average at certain times of the day or year. Together, these advantages account for why virtually complete adoption of electric technologies in buildings and light-duty vehicles by mid-century was assumed.

In some applications, electrification was not attractive, for example, in cases where the cost or weight of battery storage was too high, as in aviation; in high temperature process heat, where there was no thermodynamic advantage and no assumed flexibility in time of use, and in feedstock chemistry that allowed no practical alternative to a hydrocarbon fuel. Fuel cell technologies using hydrogen were adopted in some transportation applications, and hydrogen was also added to combustion fuels to reduce their carbon intensity, for example, hydrogen-methane blends used in thermal power plants (Figure S20). In applications where electrification and hydrogen were not feasible or were less competitive, end use technologies that burn hydrocarbon fuels or use them as feedstocks, with improved efficiency when possible, continued to be used. This is reflected in the amount and composition of industrial energy demand (Figures 12 and S2) (Bataille, 2020; Jadun et al., 2017).

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The rate of the demand-side transition was constrained by infrastructure inertia, meaning that we modeled end use equipment with a vintage and an economic lifetime, only after which it was retired and replaced by more energy efficient equipment using lower carbon energy supplies. On the demand side, all replacement was at the "natural retirement" time; on the supply side, coal and oil power plants, most long past their anticipated lifetimes, were allowed to retire economically. The time required for fleet turnover under the inertia constraint means that the process of electrification—for example, consumer adoption of EVs and heat pumps—must begin many years before a fully electrified fleet is required to meet the net zero target (Figure 4).

The delivery infrastructure that links energy supply and end uses, today and in the future, forms a large share of energy costs. A major shift toward one form of final energy and away from another entails the expansion of one delivery infrastructure and the contraction of another, with positive and negative impacts on the net cost of the transition. Building electrification, for example, entails both the expansion of the electricity distribution system and the contraction of the natural gas distribution system. The departure of gas customers leaves a shrinking customer base to pay the fixed costs of the system; at some point, gas rates can become prohibitive. Planning an orderly transition to electricity, with due attention to equity, can ameliorate this effect (Aas et al., 2020). Planning can also limit the impact of electrification on electricity distribution costs, controlling increases in peak demand through measures such as building shell improvements and flexible vehicle charging. In our modeling, load management of this kind improved distribution infrastructure utilization, lowering the delivery cost component of electricity rates.

9. Conclusions

9.1. Carbon Neutrality Is Affordable

We have shown that achieving net zero and net negative CO_2 emissions from energy and industry in the U.S. by mid-century can be done at low net cost. Recent declines in solar, wind, and vehicle battery prices have made decarbonizing the U.S. economy increasingly affordable on its own terms, without counting the economic benefits of avoided climate change and air pollution (Garcia-Menendez et al., 2015; Hsiang et al., 2017; Nemet et al., 2010; West et al., 2013; Risky Business Project, 2016). The net cost of deep decarbonization, even to meet a 1°C/350 ppm trajectory, is substantially lower than estimates for less ambitious 80% by 2050 scenarios a few years ago (Clarke et al., 2014; Williams et al., 2015); even with decarbonization, future energy costs as a share of GDP are expected to be lower than today's.

9.2. Renewable Electricity Is the Foundation of an Affordable Transition

The least-cost decarbonized electricity system combines high VRE generation (>80% share) with low-cost reliable capacity such as natural gas without carbon capture operating infrequently. If renewables and transmission cannot be built at the scale required, for example, due to difficulty in siting, nuclear and fossil CCS generation become important. Implementing high VRE systems may require changes in wholesale electricity markets to allow cost recovery for thermal generation needed for reliability but operated <15% of the time and to provide incentives for industrial loads such as electrolysis and electric boilers to operate flexibly on renewable over-generation (Jones et al., 2018).

9.3. The Social Effects of Changes in the Energy Economy Need to Be Managed

Deep decarbonization entails a major shift in the U.S. energy economy. The variable costs of fossil fuels will be replaced by the capital cost of low-carbon technologies. Incremental capital investment averaging $600B per year represents about 10% of current U.S. annual capital investment of $6 T in all sectors, indicating that finance per se is not a barrier if policies that limit risk and allow cost recovery are in place (Federal Reserve Bank of St. Louis, 2019). A greater challenge is likely to be the political economy of effectively redirecting > $800B/year from fossil fuels into low-carbon technologies. The distributional impacts of such a transition could be ameliorated through policies that support communities and sectors dependent on fossil fuel extraction, while new jobs emerge under policies that ensure a significant domestic share of the manufacturing-based low-carbon economy (Busch et al., 2018).

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9.4. Consumer Incentives Are Needed to Support Timely Electrification

Carbon neutrality is aided by complete consumer adoption of electric end use technologies in light-duty transportation and buildings. Slow adoption that leads to delayed or incomplete electrification will result in greater cost and resource use. Direct mandates and/or carbon prices can drive decarbonization of electricity and fuels production, since utilities and industrial enterprises are responsive to such signals. Different policies may be required to influence consumers who are sensitive only to upfront cost. As demonstrated historically with solar PV, one option is customer incentives such as rebates that effectively lower the purchase price of EVs and heat pumps. These have the potential to dramatically increase sales, drive innovation, reduce manufacturing costs, and lower purchase prices in a self-sustaining market transformation (Nemet, 2019).

9.5. Recognizing Tradeoffs Between Decarbonization Strategies Is Essential

The scale and pace of infrastructure buildout and demands on the land in a low-carbon transition imply competition among social, environmental, and economic priorities. Our scenarios illustrate the kinds of tradeoffs that can be anticipated and their impacts. The use of biomass and of land for renewable siting are indispensable for all net zero pathways, but the amount required can differ by a factor of 2 or more. It needs to be understood that reducing biomass and land for siting implies increasing fossil fuels, nuclear power, and negative emissions. In addition to siting and biomass, increasing the land carbon sink is another element of the competing priorities among climate mitigation, food production, and other land uses (Griscom et al., 2017).

Given the regional character of energy use and resources and the U.S. system of government, many of the tradeoffs faced will need be resolved at the state and local level (Betsill & Rabe, 2009; Williams et al., 2015). Rigid positions on tradeoffs will not be helpful for informed decision-making as they may lead to over-constrained problems and policy paralysis; better public participation, analysis, and data are more likely to improve outcomes. Recent work in California, where conflicts between renewables siting, biodiversity conservation, and agriculture have emerged, points to the potential of incorporating geospatial analysis into energy planning to help reconcile competing land uses in large-scale wind, solar, and transmission buildouts (Wu et al., 2016, 2020).

9.6. The Actions Required in the Next 10 Years Are Known With High Confidence

Carbon-neutral pathways diverge in energy strategy, resource use, and cost primarily after 2035. The highest-priority near-term actions are similar across pathways and have clear quantitative benchmarks for policy: renewables build-out (>500 GW total wind and solar capacity by 2030); coal retirement (<1% of total generation by 2030); maintaining current nuclear and natural gas capacity; and electrification of light-duty vehicles (EVs > 50% of LDV sales by 2030) and buildings (heat pumps >50% of residential HVAC sales by 2030). Longer-term uncertainties are related mainly to fuels and CCUS, areas in which technical potential, costs, and environmental impacts at large scale need to be better known before specific strategies are adopted. There is time for society to explore different approaches to these questions and learn from the results before solutions are needed in bulk in the 2030s, but the solutions will only be ready if the preparatory work—R&D, demonstrations, early commercial subsidies—is begun now. In other words, taking decisive near-term action in the areas that are well understood, combined with laying the necessary groundwork in the areas of uncertainty, puts the United States on a carbon-neutral pathway right away while allowing the most difficult decisions and tradeoffs to be made with better information in the future.

Conflict of Interest

The author declares no conflicts of interest relevant to this study.

Data Availability Statement

The input data used in this research were drawn from publicly accessible published sources. These are described and referenced with in-text citations in the supporting information section S4, with full citations in the reference section of the main text. The sources are listed below by broad input data category. Individual subcategories within these broad categories are mapped to the specific sources in the supporting information tables cited.

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1. The data sources for demand-side equipment stocks in the residential, commercial, and transportation sectors (Table S13) were Brooker et al. (2015), U.S. Energy Information Administration (2012), U.S. Energy Information Administration (2013), and U.S. Energy Information Administration (2019).
2. The data sources for energy service demand in the residential, commercial, and transportation sectors (Tables S14–S16) were Ashe et al. (2012), U.S. Energy Information Administration (2013), U.S. Energy Information Administration (2017), and U.S. Energy Information Administration (2019).
3. The data sources for demand-side technology characteristics including efficiency and cost in the residential, commercial, and transportation sectors (Table S17) were Bloomberg New Energy Finance (2019), Brooker et al. (2015), Den Boer et al., Dentz et al. (2014), Fulton and Miller (2015), Jadun et al. (2017), Lutsey and Nicholas (2019), TA Engineering (2017), U.S. Energy Information Administration (2015), U.S. Energy Information Administration (2017), and U.S. Energy Information Administration (2019).
4. The data source for service efficiency of carbon capture in the industrial sector (Table S19) was Kuramochi et al. (2012).
5. The data sources for energy demand in the residential, commercial, transportation, and productive (industry and agriculture) sectors (Table S20) were U.S. Energy Information Administration (2017) and U.S. Energy Information Administration (2019).
6. The data sources for demand drivers for the overall economy, industrial production, and the residential, commercial, transportation, and industrial sectors (Table S21) were National Weather Service (2019), U.S. Bureau of Economic Analysis (2012), U.S. Census Bureau (2018), U.S. Census Bureau and U.S. Bureau of Transportation Statistics (2015), U.S. Energy Information Administration (2019), U.S. Environmental Protection Agency (2019b) and U.S. Federal Highway Administration (2018).
7. The data sources for load shapes in the residential, commercial, transportation, and productive (industry and agriculture) sectors (Table S22) were De Vita et al. (2018) and secondary analyses performed by the authors, as described in Table S22.
8. The data sources for supply-side resource potential, product costs, delivery infrastructure costs, and technology cost and performance (Table S23) were Del Alamo et al. (2015), IEAGHG (2017), Eurek et al. (2016), Federal Energy Regulatory Commission (2019), Johnson et al. (2006), Keith et al. (2018), Langholtz et al. (2016), National Energy Technology Laboratory (2017), National Renewable Energy Laboratory (2015), and National Renewable Energy Laboratory (2019), U.S. Energy Information Administration (2017), U.S. Energy Information Administration (2018), U.S. Energy Information Administration (2019), U.S. Environmental Protection Agency (2018), and Wiser et al. (2015).

The summary model output data for results discussed in this paper are shown in Table 2 in the main text and in the supporting information section S1. Additional model results have been submitted to the IPCC Working Group III data compilation for AR6. Extended model results and input data, including cost data, are registered in a GitHub repository with an open access license (https://github.com/EvolvedEnergyResearch/AGU_carbon_neutral_pathways). The primary data for this research comes from model simulations. Supporting information section S5 contains the governing equations for EnergyPATHWAYS and a detailed description of the model. EnergyPATHWAYS is registered in a GitHub repository (https://github.com/energyPATHWAYS/EnergyPATHWAYS/tree/agu). Supporting information section S6 contains a detailed description of the RIO model.

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THE LONG-TERM STRATEGY OF THE UNITED STATES

Pathways to Net-Zero Greenhouse Gas Emissions by 2050

NOVEMBER 2021

The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050.

Published by the United States Department of State and the United States Executive Office of the President, Washington DC. November 2021.

CONTENTS

PREFACE

In the United States and around the world, we are already feeling the impacts of a changing climate. Here at home, in 2021 alone we have seen historic droughts and wildfires in the West, unprecedented storms and flooding in the Southeast, and record heatwaves across the country. We see the same devastating evidence around the world in places like the fire-ravaged Amazon, the sweltering urban center of Delhi, and the shrinking coastlines of island nations like Tuvalu. The science is clear: we are headed toward climate disaster unless we achieve net-zero global emissions by midcentury. We also know this crisis presents vast opportunities to build a better economy, create millions of good-paying jobs, clean our waters and air, and ensure all Americans can live healthier, safer, stronger lives.

The time is now for decisive action, and the United States is boldly tackling the climate challenge. In 2021, we rejoined the Paris Agreement, set an ambitious Nationally Determined Contribution to reduce net greenhouse gas emissions by 50-52% in 2030, launched the Global Methane Pledge, and have undertaken additional concrete actions to advance climate action domestically and internationally. These investments are critical to immediately accelerate our emissions reductions.

This 2021 Long-Term Strategy represents the next step: it lays out how the United States can reach its ultimate goal of net-zero emissions no later than 2050. Achieving net-zero emissions is how we—and our fellow nations around the globe—will keep a 1.5°C limit on global temperature rise within reach and prevent unacceptable climate change impacts and risks.

The Long-Term Strategy shows that reaching net-zero no later than 2050 will require actions spanning every sector of the economy. There are many potential pathways to get there, and all path-ways start with delivering on our 2030 Nationally Determined Contribution. This will put the United States firmly on track to reach net-zero by 2050 and support the overarching vision of building a more sustainable, resilient, and equitable economy.

The benefits of a net-zero future will not only be felt by future generations. Mobilizing to achieve net-zero will also deliver strong net benefits for all Americans starting today. Driving down greenhouse gases will create high-quality jobs, improve public health in every community, and spur investments that modernize the American economy while reducing costs and risks from climate change. Reducing air pollution through clean energy will alone help avoid 300,000 premature deaths in the United States—alleviating these and other severe impacts that also fall disproportionately on communities of color and low-income communities. Investments in emerging clean industries will enhance our competitiveness and propel sustained economic growth.

Modernizing the American economy to achieve net-zero can fundamentally improve the way we live, creating more connected, more accessible, and healthier communities. That does not mean it will happen quickly or without hard work. There will be many challenges on our path to net-zero that will require us to marshal all our ingenuity and dedication. But it can, and must, be done. And even as we invest at home, the new technologies and investments outlined in this strategy will also help scale up low-cost, carbon-free solutions for the world.

We can create a healthy, vibrant, and abundant world for our children. This plan is our promise to them—and it is one we must keep.

JOHN KERRY
SPECIAL PRESIDENTIAL ENVOY FOR CLIMATE

GINA MCCARTHY
NATIONAL CLIMATE ADVISOR

EXECUTIVE SUMMARY

Addressing the climate crisis requires immediate and sustained investment to eliminate net global greenhouse gas emissions by mid-century—and this presents a transformational opportunity for the United States and the world. Investing in the clean technologies, infrastructure, workforce, and systems of the future creates an unprecedented opportunity to improve quality of life and create vibrant, sustainable, resilient, and equitable economies.

As we undertake this global transformation, the United States and other major economies must act quickly to keep a safer climate within reach. Across the United States and around the world, climate change is already harming communities—particularly the most vulnerable that are least equipped to cope, rebuild, and adapt. Wildfires, storms, floods, extreme heat, and other climate-fueled impacts are causing deaths, injuries, degraded health, economic hardship, and damage to the earth's ecosystems—all from warming of only roughly 1.0°C. Failure to immediately curtail emissions will condemn the world to nearly triple that level of warming, unleashing far more frequent and severe climate impacts and far more extreme downside risks.

The most recent report from the Intergovernmental Panel on Climate Change (IPCC) vividly illustrates, with robust scientific confidence, the need to limit warming to 1.5°C, or as close as possible to that crucial benchmark, to avoid these severe climate impacts. Achieving this target will require cutting global greenhouse gas (GHG) emissions by at least 40% below 1990 levels by 2030, reaching global net-zero GHG emissions by 2050 or soon after, and moving to net negative emissions thereafter **[1]**. To meet these global milestones, we must retool the global energy economy, transform agricultural systems, halt and reverse deforestation, and decisively address non-carbon dioxide emissions—focusing particular attention on methane (CH_4), which accounts roughly 0.5°C of the current observed net warming of 1.0°C.[1] We must also pursue negative emissions through robust and verifiable nature-based and technological carbon dioxide removal.

IN LIGHT OF THIS URGENCY, THE UNITED STATES HAS SET A GOAL OF NET-ZERO GREENHOUSE GAS EMISSIONS BY NO LATER THAN 2050.

[1] Greenhouse gas emissions in total have contributed 150% of the observed warming of 1.0°C, but emissions of cooling aerosols have counteracted some of that warming.

THIS U.S. NET-ZERO 2050 GOAL IS AMBITIOUS. It puts the United States ahead of the trajectory required to keep 1.5°C within reach through three decades of investment in clean power, electrification of transportation and buildings, industrial transformation, reductions in methane and other potent non-carbon dioxide climate pollutants, and bolstering of our natural and working lands.

DELIVERING ON OUR 2030 NATIONALLY DETERMINED CONTRIBUTION (NDC) WILL PUT THE UNITED STATES FIRMLY ON TRACK TO NET-ZERO. The United States has committed to an ambitious and achievable goal to reduce net GHG emissions 50-52% below 2005 levels in 2030.[2] This is the decisive decade to deliver on a set of new policies **[2]** to accelerate existing emissions reduction trends—for example, expanding rapidly the deployment of new technologies like electric vehicles and heat pumps, and building the infrastructure for key systems like our national power grid. These types of near-term actions will put us on firm footing to meet our 2050 goal (as illustrated by **Figure ES-1**).

2 The United States formally communicated this 2030 target in its Nationally Determined Contribution on April 21, 2021.

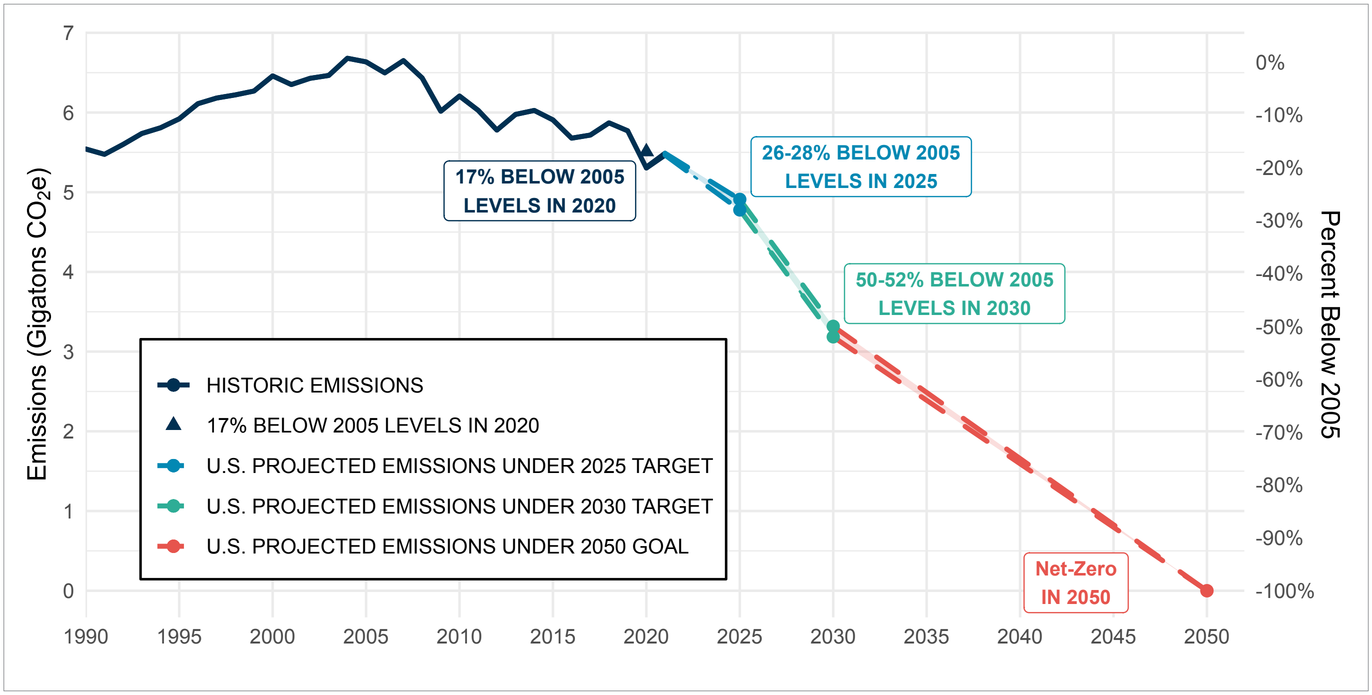


Figure ES-1: United States historic emissions and projected emissions under the 2050 goal for net-zero. This figure shows the historical trajectory of U.S. net GHG emissions from 1990 to 2019, the projected pathway to the 2030 NDC of 50-52% below 2005 levels, and the 2050 net-zero goal. The United States has also set a goal for 100% clean electricity in 2035; that goal is not an economy-wide emissions goal so does not appear in this figure, but it will be critical to support decarbonization in the electricity sector, which will in turn help the U.S. reach its 2030 and 2050 goals in combination with broad electrification of end uses.

THIS REPORT PRESENTS THE 2021 LONG-TERM STRATEGY (LTS) OF THE UNITED STATES.
It illustrates multiple pathways to a net-zero economy no later than 2050 **[3] [4] [5]**. It confirms how actions taken now and through this decade are critical to make these net-zero pathways possible. The report draws from a diverse analytical toolkit,[3] including a global integrated assessment model covering all GHGs and economic sectors, a national carbon dioxide (CO_2) model with high energy sector resolution, models of the U.S. land sector, and a rich set of non-governmental literature. Pursuant to Article 4.19 of the Paris Agreement, this report also serves to communicate our Long-Term Strategy to the international community.

MOBILIZING TO ACHIEVE NET-ZERO WILL DELIVER STRONG NET BENEFITS FOR ALL AMERICANS.
Driving down GHGs will spur investments that modernize the American economy, address the distributional inequities of environmental pollution and climate vulnerability, improve public health in every community, and reduce the severe costs and risks from climate change. Benefits include:

- **PUBLIC HEALTH.** Reducing air pollution through clean energy will avoid 85,000–300,000 premature deaths, and health and climate damages of $150–$250 billion through 2030. It will avoid $1–3 trillion in damages through 2050 in the United States alone. These measures will also help alleviate the pollution burdens disproportionately borne by communities of color, low-income communities, and indigenous communities.

- **ECONOMIC GROWTH.** Investments in nascent clean industries will enhance competitiveness and propel sustained growth. The United States can lead in crucial clean technologies like batteries, electric vehicles, and heat pumps, without sacrificing critical worker protections.

- **REDUCED CONFLICT.** Drought, floods, and other disasters fueled by climate change have caused large-scale displacements and conflict. The U.S. Department of Defense recognizes climate change as a vital, globally destabilizing national security threat **[6]**. Early action by the United States will encourage faster climate action globally, including by driving down the costs of carbon-free technologies. These actions will ultimately support security and stability worldwide.

- **QUALITY OF LIFE.** Modernizing the American economy to achieve net-zero can fundamentally improve the way we live. Measures like high-speed rail and transit-oriented development not only reduce emissions but also create more connected, accessible, and healthier communities.

THE 2050 NET-ZERO EMISSIONS GOAL IS ACHIEVABLE.
The United States can deliver net-zero emissions across all sectors and GHGs through multiple pathways, but all viable routes to net-zero involve five key transformations:

1. **DECARBONIZE ELECTRICITY.** Electricity delivers diverse services to all sectors of the American economy. The transition to a clean electricity system has been accelerating in recent years—driven by plummeting costs for solar and wind technologies, federal and subnational policies, and consumer demand. Building on this success, the United States has set a goal of 100% clean electricity by 2035, a crucial foundation for net-zero emissions no later than 2050.

2. **ELECTRIFY END USES AND SWITCH TO OTHER CLEAN FUELS.** We can affordably and efficiently electrify most of the economy, from cars to buildings and industrial processes. In areas where electrification presents technology challenges—for instance aviation, shipping, and some industrial processes—we can prioritize clean fuels like carbon-free hydrogen and sustainable biofuels.

[3] The core analyses presented in this report are shared with the U.S. National Climate Strategy and the U.S. National Communication and Biennial Report to the UN Framework Convention on Climate Change (UNFCCC).

3. **CUT ENERGY WASTE.** Moving to cleaner sources of energy is made faster, cheaper, and easier when existing and new technologies use less energy to provide the same or better service. This can be achieved through diverse, proven approaches, ranging from more efficient appliances and the integration of efficiency into new and existing buildings, to sustainable manufacturing processes.

4. **REDUCE METHANE AND OTHER NON-CO_2 EMISSIONS.** Non-CO_2 gases such as methane, hydrofluorocarbons (HFCs), nitrous oxide (N_2O), and others, contribute significantly to warming—with methane alone contributing fully half of current net global warming of 1.0°C. There are many profitable or low-cost options to reduce non-CO_2 sources, such as implementing methane leak detection and repair for oil and gas systems and shifting from HFCs to climate-friendly working fluids in cooling equipment. The U.S. is committed to taking comprehensive and immediate actions to reduce methane domestically. And through the Global Methane Pledge, the U.S. and partners seek to reduce global methane emissions by at least 30% by 2030, which would eliminate over 0.2°C of warming by 2050. The U.S. will also prioritize research and development to unlock the innovation needed for deep emissions reductions beyond currently available technologies.

5. **SCALE UP CO_2 REMOVAL.** In the three decades to 2050, our emissions from energy production can be brought close to zero, but certain emissions such as non-CO_2 from agriculture will be difficult to decarbonize completely by mid-century. Reaching net-zero emissions will therefore require removing carbon dioxide from the atmosphere, using processes and technologies that are rigorously evaluated and validated. This requires scaling up land carbon sinks as well as engineered strategies.

Figure ES-2 illustrates how the five key transformations can combine in different pathways to achieve net-zero emissions by 2050. The exact pathway will depend on how quickly change occurs across different sectors. Nevertheless, some broad patterns are clear. For example, energy system transformations contribute roughly 4.5 gigatons of CO_2 equivalent per year (Gt CO_2e/yr.) of overall emissions reductions, or about 70% of overall reductions. These energy emissions reductions are delivered by cutting energy waste, decarbonizing electricity, and transitioning energy sources including through fuel switching and electrification. Addressing non-CO_2 gases, including methane, nitrous oxide, and fluorinated gases, reduces another 1 Gt of annual emissions. Enhancing land sinks and scaling up CO_2 removal technologies also deliver about 1 Gt of negative emissions. While these figures are a helpful rough guide, the exact contribution from each area varies between pathways (as shown in **Figure ES-2**). The eventual U.S. pathway to net-zero emissions will depend on the evolution of technologies, the specifics of policy and regulatory packages, and factors such as economic growth, sociodemographic shifts, and market prices for commodities and fuels across the next three decades.

ACHIEVING NET-ZERO BY NO LATER THAN 2050 REQUIRES SUSTAINED, COORDINATED ACTION SPANNING FOUR STRATEGIC PILLARS:

1. **FEDERAL LEADERSHIP.** Federal leadership is critical to reduce emissions 50-52% below 2005 levels in 2030 and set up the economy to achieve net-zero emissions by 2050. This could include investments and incentives that support the deployment of clean technologies in all sectors, policies to enhance and support our natural and working lands, partnerships to catalyze market transformation, improved integration of climate into financial markets including enhanced climate risk disclosure, and the promulgation and enforcement of new and existing regulations rooted in law.

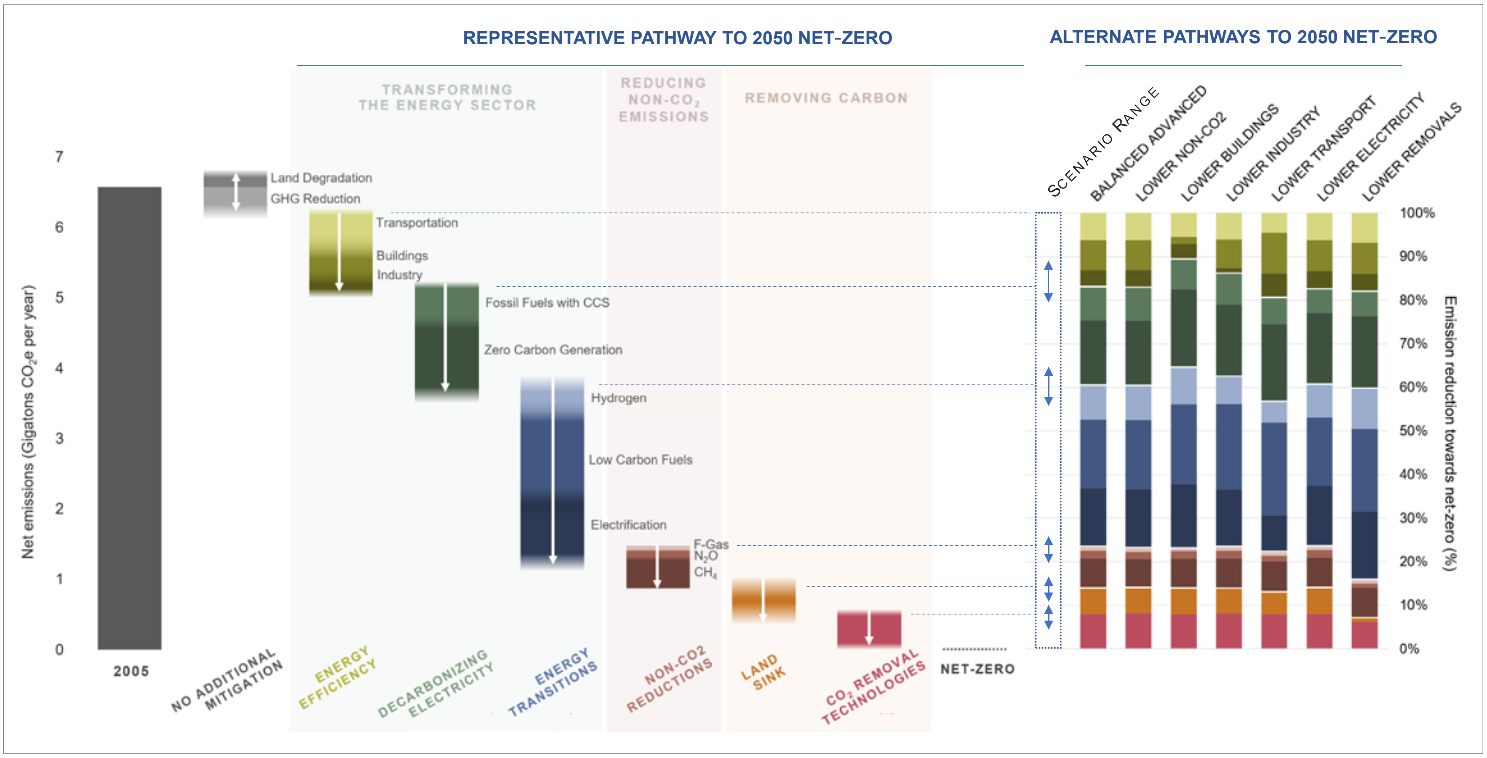


Figure ES-2: Emissions Reductions Pathways to Achieve 2050 Net-Zero Emissions in the United States. Achieving net-zero across the entire U.S. economy requires contributions from all sectors, including: efficiency, clean power, and electrification; reducing methane and other non-CO_2 gases; and enhancing natural and technological CO_2 removal. The left side of the figure shows a representative pathway with high levels of action across all sectors to achieve net-zero by 2050. The right side shows a set of alternative pathways depending on variations in uncertain factors such as trends in relative technology costs and the strength of the land sector carbon sink.

2. **INNOVATION.** In driving the deployment of currently competitive technologies as rapidly as possible, federal policies will serve to further reduce costs through economies of scale and learning-by-doing. In addition, new technologies will be necessary to drive deeper reductions in the late 2020's through 2050. Federally-supported research, development, demonstration, and deployment can be the prime mover—along with federal, subnational, and private sector procurement—to carry new carbon-free technologies and processes from the lab to U.S. factories to the market. Research and development today will lay the technology foundation necessary to maximize economic benefits from the post-2030 transformation to net-zero.

3. **NON-FEDERAL LEADERSHIP.** The U.S. federal system is based on the national government sharing power with elected governments at subnational levels. In our system, policy authorities related to economic activity, energy, transportation, land use, and more are shared with Tribal governments, states, cities, counties, and others. U.S. climate action therefore necessarily spans all levels of government. Recent trends demonstrate the significant impacts that these subnational policies can have on the overall U.S. emissions trajectory, in ways that complement national policies and can provide a broader base for learning and for accelerating action.

4. **ALL-OF-SOCIETY ACTION.** The long-term transformations to get to 2050 net-zero emissions will require the United States to bring all its greatest strengths to bear, including innovation, creativity, and diversity. Already, many non-governmental organizations are acting ambitiously to address climate change within their own operations or support the overall transition of the U.S. economy. Even more broad-based engagement on research, education, and implementation through our universities, cultural institutions, investors, businesses, and other non-governmental organizations will be required to reach our 2050 goal.

IMPLEMENTATION IS UNDERWAY.

These four principles form the core of our strategy to achieve our 2030 NDC and 100% clean electricity by 2035. We are moving rapidly, rooted in actions from across the federal government and other governmental and non-governmental actors. These actions and policies are part of our Long-Term Strategy and are described in a forthcoming companion report to this document, *The U.S. National Climate Strategy* (NCS) [2]. The NCS describes an overarching approach that covers all aspects of federal action, which will also support broader non-federal and all-of-society efforts. Both the NCS and this Long-Term Strategy have been informed by a robust stakeholder engagement process. These actions provide the near-term implementation momentum to achieve the 2030 NDC, 2035 100% clean electricity goal, and the 2050 net-zero goal.

IF OTHER MAJOR ECONOMIES ADOPT SIMILAR AMBITION, WE CAN KEEP 1.5°C WITHIN REACH.

The U.S. currently emits 11% of annual global GHGs (second to China, which emits 27% of the global total). Cutting our emissions at least in half by 2030 and eliminating our emissions by 2050 will therefore make an important direct contribution to keeping a safer 1.5°C future within reach. These efforts will also spur cost reductions for clean technologies through scale and learning-by-doing. More importantly, U.S. climate leadership has already helped propel other major economies to adopt 2030 NDCs that are aligned with the imperative to cut global emissions at least 40% by 2030 to improve our chances of limiting global warming to less than 1.5°C. At the Leaders' Summit on Climate in April of 2021, President Biden announced our ambitious NDC, joined by Canadian and Japanese leaders who also set strong new 2030 targets. The European Union (EU) and United Kingdom (UK) had already set strong targets and, since the Summit, others, including the Republic of Korea and South Africa, have come forward with NDCs that achieve the pace of reductions that would be needed globally to keep 1.5°C within reach. These countries represent well over half of the global economy, but further action by other major economies will be necessary to ensure the 1.5°C target is met.

Globally, this is the moment for all the world's major economies to act to rapidly reduce emissions to meet ambitious 2030 NDC targets and to develop and communicate strategies to achieve ambitious 2050 net-zero goals.

FOUR COMPONENTS OF U.S. REPORTING ON CLIMATE ACTIONS AND STRATEGY

Communicating actions and progress toward climate goals is a critical component of transparency to support global ambition under the Paris Agreement. The United States is committed to these principles and, accordingly, is issuing four reports detailing complementary aspects of our current climate activities and planned strategy. The same key assumptions and methodologies are shared in the analytics that inform all four reports. Each report serves a different role in communicating the overall situation and strategy of the United States, and there are details in each that are not reproduced across all reports. Together they present a vision for our climate strategy and emissions pathways.

1. **The U.S. National Climate Strategy** details how we will deliver our U.S. NDC for 2030 [2]. It focuses on the immediate policies and actions that will put America on track to reduce emissions by 50-52% below 2005 levels in 2030 and put in place the technology and infrastructure necessary to achieve net-zero emissions no later than 2050.

2. **The Long-Term Strategy of the United States to Reach Net-Zero Emissions by 2050** (this report), pursuant to Article 4.19 of the Paris Agreement, shows how these current and near-term policies and other actions across the country, as described in the NCS, deliver a pathway through the 2030s and 2040s to reach our 2050 net-zero goal. As a contribution under the Paris Agreement, it is part of a process that serves to support enhanced global action and ambition.

3. **The U.S. National Communication and Biennial Report** provides detailed information on existing policies and measures across all areas of U.S. climate action as of December 2020 [7]. It fulfills our obligations for reporting and transparency under the UN Framework Convention on Climate Change (UNFCCC) and fits into a broader international reporting framework in which other countries also participate.

4. **The U.S. Adaptation Communication** provides forward-looking priorities for accelerating adaptation and building resilience domestically and abroad [8]. It outlines domestic climate impacts and vulnerabilities, progress on adaptation, lessons learned, and immediate policies and other approaches that will increase adaptive capacity, enhance resilience, and reduce vulnerability to climate change. It complements and builds upon resilience and adaptation actions laid out in the National Climate Strategy and U.S. National Communication and Biennial Report.

CHAPTER 1:

AN INTEGRATED U.S. CLIMATE STRATEGY TO REACH NET-ZERO EMISSIONS BY 2050

Climate change already inflicts serious damage on the United States and the world, particularly the most vulnerable that are least equipped to adapt—and the science is clear that, without faster global action, these impacts will become much more frequent and severe. Two recent reports from the Intergovernmental Panel on Climate Change [1] [9] affirm with robust scientific confidence the need to keep warming under 1.5°C to reduce the greatest global risks and avoid significant, wide-ranging, and severe impacts. To keep 1.5°C within reach, the United States has a goal of achieving net-zero emissions economy-wide by no later than 2050 [3] [4] [5].

The Paris Agreement establishes a framework to rapidly increase global ambition to hold warming well below 2°C while pursuing efforts to limit warming to 1.5°C. This framework includes nationally determined contributions (NDCs)—commitments that target near-term emissions reductions, review progress, and seek to extend and strengthen their NDCs in regular 5-year cycles. The Paris Agreement also specifically calls on all countries to "formulate and communicate their long-term, low GHG emission development strategies." Such Long-Term Strategies support global ambition by encouraging countries to understand their options and set their own longer-term emissions reduction goals [10]. In developing and communicating these strategies [11], countries can foresee and address challenges such as slow infrastructure turnover or the need for just transitions from fossil fuels and other high-emission technologies. Developing and sharing publicly these near- and long-term strategies helps elucidate and manage path dependencies and better connect short-term and long-term objectives. Accordingly, this process can both guide national action and encourage greater global ambition over time.

The United States is simultaneously pursuing multiple climate mitigation goals **(Figure 1)**. Each goal serves as an important milestone toward rapidly reducing our GHG emissions to net-zero. While this report emphasizes the longer period of 2021-2050, the overall U.S. strategy integrates actions for both near-term and 2050 goals:

- The 2030 NDC of 50-52% reductions below 2005 levels, covering all sectors and all gases
- The goal for 100% carbon pollution-free electricity by 2035
- The goal for net-zero emissions no later than 2050.

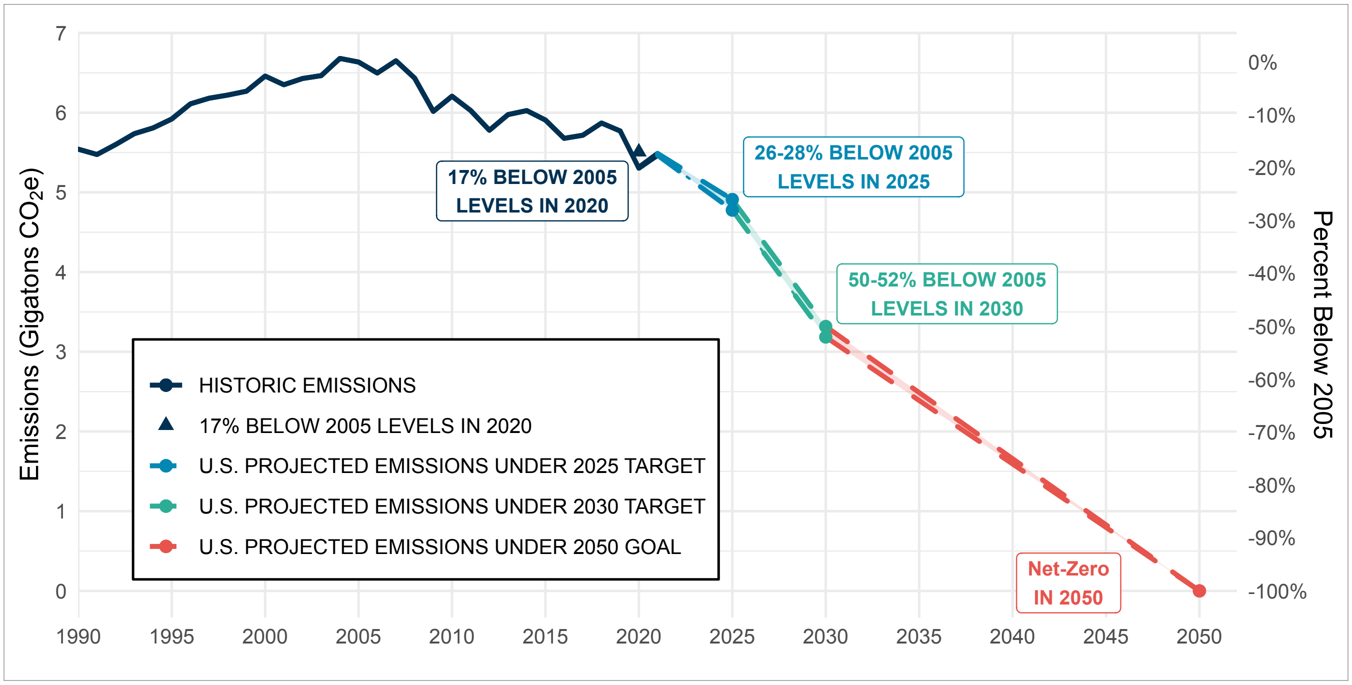


Figure 1: United States historic emissions and projected emissions under the 2050 goal for net-zero. This figure shows historical U.S. GHG emissions from 1990 to 2019, the projected pathway to the 2030 NDC of 50-52% below 2005 levels, and the 2050 net-zero goal. The United States has also set a goal for 100% clean electricity in 2035. That goal is not an economy-wide emissions goal so does not appear in this figure, but it will be critical to support decarbonization in the electricity sector, which will in turn help the U.S. reach its 2030 and 2050 goals.

These near-term actions are being implemented rapidly, rooted in policies from across the federal government and other governmental and non-governmental actors in the United States. These actions and policies are described in detail in a companion to this document, *The U.S. National Climate Strategy* (NCS) **[2]**. The NCS lays out an overarching policy approach being undertaken today that covers all aspects of federal action, in support of all-of-society efforts. These actions provide the near-term implementing momentum to achieve the 2030 NDC, meet the 2035 100% clean electricity goal, and put the U.S. in a strong position to take the additional actions necessary to achieve net-zero by 2050. The information on near-term implementation in the NCS should therefore be viewed as integral to the U.S. Long-Term Strategy. Accordingly, although this report focuses on the period from 2021 to 2050, it refers to the NCS for further descriptions of near-term implementation of long-term goals.

The Biden Administration consulted diverse stakeholders to inform the overall U.S. climate strategy that is reflected in the U.S. Long-Term Strategy (LTS) report. This consultation covered a wide range of stakeholders from major unions that work on behalf of millions of American workers, to groups representing tens of millions of advocates, fence line communities, and young Americans. Engagement to develop our strategy also included groups representing scientists; hundreds of governmental leaders like governors, mayors, and Native American leaders; hundreds of businesses; hundreds of schools and institutions of higher education; as well as with many specialized researchers focused on questions of pollution reduction. NCS report referenced above has similarly been developed through extensive consultations of diverse stakeholders, whose perspectives and input have informed the overall climate strategy that is reflected in this LTS report.

The United States presented its first Long-Term Strategy report in 2016 **[12]**, focused on reducing net GHGs 80-90% below 2005 levels by 2050. In 2021, the United States put forward a new, ambitious goal of net-zero emissions no later than 2050. This report presents an updated 2021 Long-Term Strategy of the United States that defines multiple pathways for the American economy to achieve net-zero emissions by 2050. It includes analysis of what transformational pathways to net-zero could look like over time for emissions in different sectors and for different GHGs. The report draws from a diverse analytical toolkit,[4] integrating insights from a global integrated assessment model covering all greenhouses and economic sectors, a national CO_2 model with high resolution on the electricity sector, models of U.S. land sector, and more. The analysis presented here was based on an interagency effort and is grounded in a broader body of existing scholarship and literature for how to understand both near- and long-term high-ambition emissions pathways in the national and global context. While the analyses presented here provide new and original insights, they also draw from and reference this broader body of work.

[4] These core analyses in this report are shared with two companion volumes, the U.S. National Climate Strategy and the U.S. National Communication and Biennial Report to the UNFCCC.

This report is organized as follows. **Chapter 2** focuses on the decisive decade from now to 2030 and highlights the U.S. priorities which will both dramatically reduce GHG emissions and lay the foundation for achieving net-zero emissions no later than 2050. **Chapter 3** gives an overview of the economy-wide emissions pathways to 2050. **Chapter 4** describes pathways for energy-related CO_2 emissions reduction across electricity, transportation, buildings, and industry. **Chapter 5** presents the key opportunities for methane and other non-CO_2 emissions reductions, including in the energy, waste, agriculture, and industrial sectors. **Chapter 6** focuses on CO_2 removals through lands and technologies for carbon dioxide removal. **Chapter 7** presents a vision of the many benefits that will be created on the path to a net-zero emissions economy, including transformative improvements in public health, avoided climate damages, enhanced climate security, and job growth. Finally, **Chapter 8** concludes with a vision of the U.S. accelerating global climate progress with ambitious domestic climate action.

THE U.S. 2050 NET-ZERO GOAL

The United States has set a goal of net-zero emissions by no later than 2050.

The goal includes all major GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, NF_3) and is economy-wide. The goal is on a net basis, including both sources of emissions and removals. It does not include emissions from international aviation or international shipping. At this time, the United States does not expect to use international market mechanisms toward achievement of this net-zero goal. Progress toward the goal will be assessed and the U.S. LTS may be updated, as appropriate.

CHAPTER 2:

THE DECISIVE DECADE TO 2030

Putting the United States on a path to net-zero emissions economy-wide no later than 2050 requires taking transformative actions this decade and achieving near-term milestones in line with this goal. This is why the United States set an economy-wide target of reducing its net GHG emissions by 50-52% below 2005 levels in 2030 **(Figure 2)**. The United States will also soon release a complementary report, *The U.S. National Climate Strategy* (NCS) **[2]**, following this 2021 Long-Term Strategy, to provide additional detail on the steps the United States is taking to achieve our 2030 target—and in doing so, to put the United States on a track to achieve its 2050 net-zero goal. This 2030 commitment anchors the U.S. approach during this decade to build a sustainable, resilient, and equitable economy by rapidly deploying widely available low-carbon technologies and investing in the infrastructure, innovation, and workforce that is the foundation of this economic transformation.

This decade will be decisive—and the benefits of achieving our 2030 goal will be significant. Transitioning to a clean energy economy will create between 500,000 and one million net new jobs across the country this decade **[13] [14]**. Moreover, reducing air pollution through these efforts will avoid 85,000–300,000 premature deaths **[14] [15]**. This transition will require a multi-pronged approach involving the private sector, sub-national governments, and federal government to generate new regulations, direct investment, and programs at all levels of government.

Near-term actions to accelerate this transition are being implemented rapidly, rooted in actions from across the federal government and other governmental and non-governmental actors in the United States. These actions and policies are described in detail in the NCS report, which lays out an overarching policy approach being undertaken today—informed by ongoing engagement of diverse stakeholders—that covers all aspects of federal action, in support of all-of-society efforts. These actions provide the near-term implementing momentum to achieve the 2030 NDC, 2035 100% clean electricity goal, and the 2050 net-zero goal. A summary of these elements is provided below.

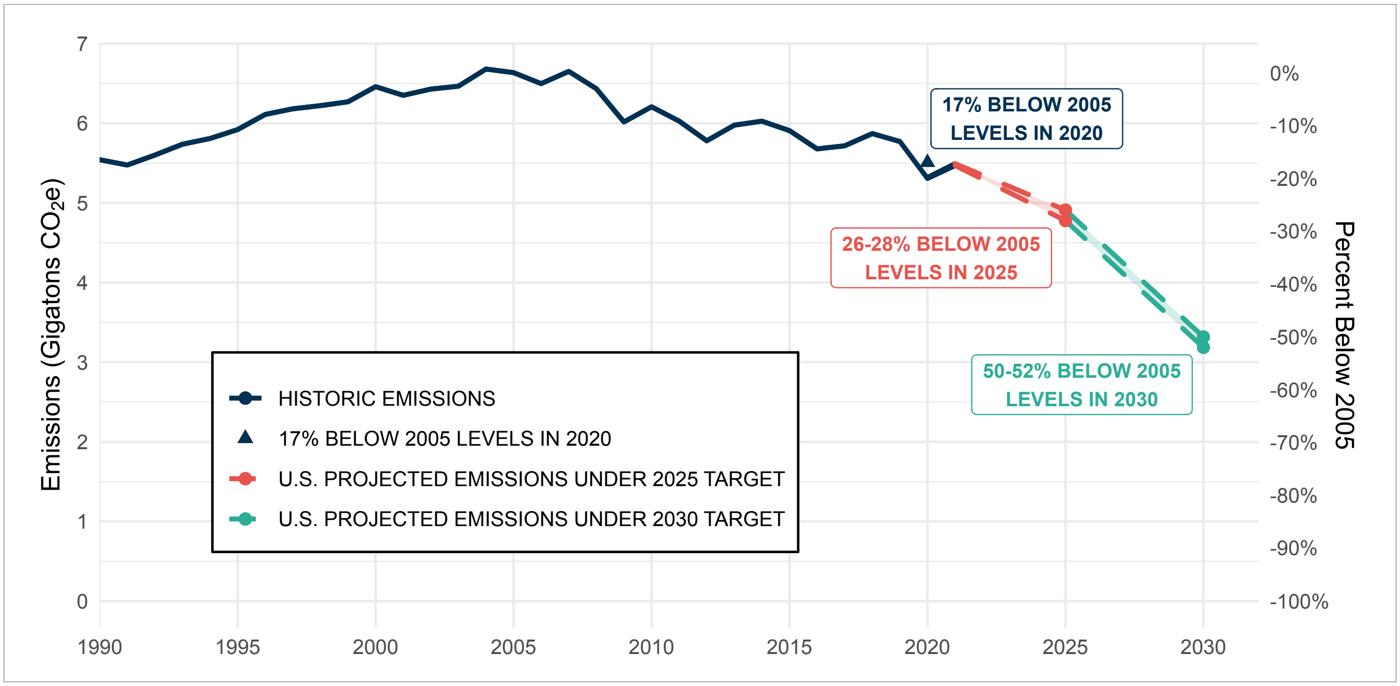


Figure 2: United States historic emissions and projected emissions under the 2030 NDC target. This figure shows the historical trajectory of U.S. GHG emissions and the pathway to the 2030 GHG reduction targets. The 2030 NDC target is ambitious, and policies and measures have put the American economy on a declining emissions trend consistent with these goals. The 2030 targets put the United States on a faster track than a straight-line path to net-zero in 2050 would require.

2.1 ELECTRICITY

Fast and cost-effective emission-reducing investments are available in the electric power sector, which is currently the second-largest producer of emissions in the United States. That is why the United States set a goal to reach a 100% carbon pollution-free electricity system by 2035, which can be achieved through multiple cost-effective technology and investment pathways. In fact, this transition has already been accelerating in recent years—driven by plummeting costs of key technologies like solar, onshore wind, offshore wind, and batteries, as well as enhanced policies and increased consumer demand for clean, reliable, and affordable power. Further acceleration of clean energy deployment can be catalyzed through providing incentives and standards to reduce pollution from power plants; investing in technologies to increase the flexibility of the electricity system, such as transmission, energy efficiency, energy storage, smart and connected buildings, and non-emitting fuels; and leveraging carbon capture and storage (CCS) and nuclear. Significant deployment of energy efficiency reduces overall demand and can lower peak load, reducing grid capital costs and making investments in carbon-free power generation go further. Research, development, demonstration, and deployment of new software and hardware solutions will further support the transformation to a carbon pollution-free, resilient, reliable, and affordable electricity system.

2.2 TRANSPORTATION

Vehicles have become the largest emissions source in the United States—driven by fossil fuel use in light-duty cars, trucks, and SUVs, followed by medium- and heavy-duty trucks, buses, air, off-road vehicles, rail, and shipping. There are many opportunities to reduce GHG emissions from transportation while also saving money for households and businesses, improving environmental quality and health in communities, and providing more choices for moving people and goods. At its core, this requires electrifying most vehicles to run on ever-cleaner electricity and shifting to low-carbon or carbon-free biofuels and hydrogen in applications like long-distance shipping and aviation.

To support this outcome, the United States set a goal for half of all new light-duty cars sold in 2030 to be zero-emission vehicles, to produce 3 billion gallons of sustainable aviation fuel by 2030, and to accelerate deployment and reduce costs in every mode of transportation. This will occur through lower vehicle costs; fuel economy and emissions standards in light-, medium- and heavy-duty vehicles; incentives for zero-emission vehicles and clean fuels; investment in a new charging infrastructure to support multi-unit dwellings, public charging, and long-distance travel; scaling up biorefineries; comprehensive innovation investments to reduce hydrogen costs; and investment in infrastructure that supports all modes of clean transportation—such as transit, rail, biking, micro mobility, and pedestrian options.

Making progress this decade requires investing in domestic manufacturing and reliable supply chains for clean fuels, batteries, and vehicles. In addition, research, development, demonstration, and deployment of electrification and zero- or low-carbon fuels for aviation and shipping will ensure we have the technology to continue reducing emissions across the entire transportation sector in the years leading to 2050.

2.3 BUILDINGS

Buildings and their energy-consuming systems—electricity used and fossil fuels burned on site for heating air, heating water, and cooking—have long lifetimes. Therefore, the priority in this decade is to rapidly improve energy efficiency and increase the sales share of clean and efficient electric appliances—including heat pumps for space conditioning, heat pump water heaters, electric and induction stoves, and electric clothes dryers—while also improving the affordability of energy and the equitable access to efficient appliances, efficiency retrofits, and clean distributed energy resources in buildings. This includes investment in public buildings such as public housing, government facilities, schools, and universities. Research and demonstration investments now will also advance new solutions for efficient, grid-interactive, and electrified buildings.

Achieving 100% clean power generation by 2035 will also eliminate upstream emissions from electricity and facilitate carbon-free and efficient electrification of appliances and equipment in buildings. Moreover, partnerships like the Environmental Protection Agency (EPA) ENERGY STAR and the advancement of building energy codes and appliance standards will ensure that building envelopes, electric appliances, and other equipment become increasingly efficient over time. Efficient electric space heating and cooling and water heating offer important opportunities to employ grid-interactive demand to lower energy bills for households and businesses while more cost-effectively utilizing carbon-free electricity.

2.4 INDUSTRY

The industrial sector emits GHGs through multiple complex pathways. This includes CO_2 emitted indirectly through electricity and directly through on-site fossil fuel combustion and power generation, as well as emissions of CO_2 and non-CO_2 GHGs leaked from on-site use or emitted through industrial processes (such as cement production). Industrial decarbonization can be delivered through energy efficiency; industrial electrification; low-carbon fuels, feedstock, and energy sources; and industrial CCS. Achieving clean power by 2035 will eliminate the emissions from grid power consumed by industry and make possible the carbon-free electrification of certain industrial processes that are currently dominated by fossil fuel use. Low- and medium-temperature process heat are candidates for industrial electrification in the near term through increased use of industrial heat pumps, electric boilers, or electromagnetic heating processes.

Additional technologies and process innovations are also needed to address other industrial emissions, including high-temperature heat and process emissions from steel, petrochemical, and cement production. Fundamentally new processes will be needed to address the chemical process emissions associated with the production of these commodity materials that have large GHG emissions footprints. Energy efficiency measures make carbon-free electricity and other low-carbon industrial fuels stretch as far as possible and as early as possible.

The United States will also scale support for related research, development, demonstration, commercialization, and deployment of zero-carbon industrial innovations. This includes incentives for carbon capture and new sources of clean hydrogen—produced from renewable energy, nuclear energy, or waste—to power industrial facilities. To drive the market for these solutions, the United States government will also use its procurement power to support early markets for these very low- and zero-carbon industrial goods.

Additionally, monitoring and control technologies are needed to prevent the release to the atmosphere of non-CO_2 GHGs from industrial operations, including methane, fluorinated gases, black carbon, and other potent short-lived climate pollutants. The United States has finalized regulations to phase down the use of fluorinated gases consistent with our obligations under the Kigali Amendment to the Montreal Protocol. Addressing methane emissions will also require setting stringent standards for oil and gas production and investing in plugging leaks from coal, oil, and gas mines and wells.

2.5 AGRICULTURE, FORESTRY, AND LAND USE

America's vast lands provide opportunities to both reduce emissions and sequester carbon. Capitalizing on these opportunities includes: continuing to expand forest area, extending rotation lengths, protecting forest area, integrating trees into urban areas and agriculture, scaling up climate-smart agricultural practices such as cover crops, and employing rotational grazing on our agricultural lands. Even more leverage can be derived through programs and incentives to improve agricultural productivity; such practices and technologies can free up land for other uses as well as reduce agricultural methane and N_2O emissions through, for example, improved manure management and improved cropland nutrient management. Enhanced investment in forest protection and forest management, along with science-based and sustainable efforts to reduce the scope and intensity of catastrophic wildfires and to restore fire-damaged forest land, are vital to protecting and growing the largest land sink. Alongside these efforts, the United States will support nature-based coastal resilience projects including pre-disaster planning as well as efforts to increase carbon sequestration in waterways and oceans by pursuing "blue carbon." Finally, climate-smart practices can also lower the emissions intensity of biofuels needed for decarbonizing transportation. Actions taken now and through this decade will ensure we maximize the potential of our lands and waters to sequester carbon to the greatest extent possible by 2050.

Across these sectors, the U.S. federal government is working with Tribal governments, states, and localities to support rapid deployment of new carbon-pollution-free technologies and facilities while ensuring they meet robust and rigorous standards for workers, public and environmental safety, and environmental justice. Accomplishing the goals this decade and setting up the economy for further reductions after 2030 also requires investment in innovation and U.S. manufacturing to lower the cost of new technologies needed in the future, grow the domestic manufacturing base and supply chains for those technologies, and train the workforce needed.

CHAPTER 3:

PATHWAYS TO 2050 NET-ZERO EMISSIONS IN THE UNITED STATES

The decisive decade through 2030 is central to setting the United States—and the world—on a pathway that keeps warming of 1.5°C within reach. For all countries, 2030 is an essential waypoint that is part of a longer path to reach global net-zero emissions by mid-century. The ambitious policies and goals described in **Chapter 2** will set the United States on a pathway to achieve our 2030 target. At the same time, these actions will also catalyze the longer-term changes in the American energy, industrial, and land systems required to achieve net-zero by 2050.

This chapter presents the results of a comprehensive analysis undertaken to assess potential pathways to net-zero emissions in the United States by no later than 2050. These pathways are all grounded in our strategy to achieve our 2030 NDC and our goal of 100% carbon pollution-free electricity by 2035. These transition pathways are not only affordable, but, because of the benefits from reduced climate change and improved public health, they will also create wide-ranging benefits **(see Chapter 7)**. It will require ambitious action and investment grounded in intensive engagement with communities, workers, and businesses to ensure that the benefits of the transition are equitably distributed—with a focus on those communities that remain overburdened and underserved.

3.1 ASSESSING MITIGATION OPPORTUNITIES TO ACHIEVE NET-ZERO EMISSIONS

Achieving rapid emissions reductions requires integrating near-term policy drivers with a strategy to assess and manage longer-term factors like capital stock turnover and technological innovation. To this end, this LTS employs diverse analytical approaches to project the impact of alternate assumptions about policies, technologies, and other drivers. These afford a broad understanding for what long-term net-zero technology transformations would look like globally **[16]** as well as providing roadmaps for how to affect those transitions rapidly **[17]**.

In light of the Paris goals to develop and communicate national emissions reductions pathways, such analytical approaches have also been applied to understanding specific national circumstances and opportunities, including those within the United States. Some of these U.S.-specific studies focus on policy frameworks to drive near-term action that would set the U.S. on a pathway to longer-term net-zero or 1.5°C-compatible emissions **[18] [19] [20]**. In parallel, others look at the potential for integrating all-of-society strategies that include diverse levels of government and other actors **[21]**.

Others have focused on overall long-term technological transformations and associated emission reduction strategies that would be necessary for reduction to net-zero in the U.S. by 2050. Many of these 2050 studies address emissions reduction across the entire economy and for all gases **[14] [22] [23]**; others focus on specific areas or sectors such as energy, electricity **[13] [24]**, transportation **[25]**, or manufacturing **[26]**. This research has advanced thinking about what is possible within the United States and what robust strategies to reach 2050 net-zero could look like. The assessment and analytical approaches presented here are original to this report but also recognize the many insights offered in this wider literature, including but not limited to studies specifically on 2050 net-zero pathways. Insights from this literature are consistent in what they tell us about the critical elements supporting the long-term emissions reduction trajectory for the United States.

This trajectory rests on the integration of five complementary technological transformations:

1. **DECARBONIZE ELECTRICITY.** Electricity delivers diverse services to all sectors of the American economy. The transition to a clean electricity system has been accelerating in recent years—driven by plummeting costs for solar and wind technologies, federal and subnational policies, and consumer demand. Building on this success, the United States has set a goal of 100% clean electricity by 2035, a crucial foundation for net-zero by 2050.

2. **ELECTRIFY END USES AND SWITCH TO OTHER CLEAN FUELS.** We can affordably and efficiently electrify most of the economy—from cars to buildings and industrial processes. In areas where electrification presents technology challenges—for instance aviation, shipping, and some industrial processes—we can prioritize clean fuels like carbon-free hydrogen and sustainable biofuels.

3. **CUT ENERGY WASTE.** Moving to cleaner sources of energy is made faster, cheaper, and easier when existing and new technologies use less energy to provide the same or better service. This can be achieved through diverse, proven approaches, ranging from new and more efficient appliances and the integration of efficiency into new and existing buildings, to sustainable alternate manufacturing processes and the integration of efficiency into new and existing buildings.

4. **REDUCE METHANE AND OTHER NON-CO_2 EMISSIONS.** Non-CO_2 gases such as methane, HFCs, nitrous oxide, and others contribute significantly to warming, with methane alone contributing fully half of current net global warming of 1.0°C. There are many profitable or low-cost options to reduce non-CO_2 sources, such as implementing methane leak detection and repair for oil and gas systems and shifting from HFCs to climate-friendly working fluids in cooling equipment. The U.S. is committed to taking comprehensive and immediate actions to reduce methane domestically. And through the Global Methane Pledge, the U.S. and partners seek to reduce global methane emissions by at least 30% by 2030, which would eliminate over 0.2°C of warming by 2050. The U.S. will also prioritize research and development to unlock the innovation needed for deep emissions reductions beyond currently available technologies.

5. **SCALE UP CO_2 REMOVAL.** In the three decades to 2050, our emissions from energy production can be brought close to zero but certain emissions such as non-CO_2 from agriculture will be difficult to decarbonize completely by mid-century. Reaching net-zero emissions will therefore require removing carbon dioxide from the atmosphere, using processes and technologies that are rigorously evaluated and validated. This requires scaling up land carbon sinks as well as engineered strategies.

There are many plausible pathways through 2050 to achieving a net-zero emissions economy. However, developments in these sectors over time are interdependent. For example, widespread adoption in leading energy efficiency practices in buildings could significantly impact overall electricity demand, reducing the amount of new clean energy installations required. The insight that sectors are interdependent demonstrates the importance of policy and incentives to realize the benefits of decarbonization across the economy. Recent developments in energy, manufacturing, and information technology have made swift and substantial reductions possible. Well-designed policies can help to ensure rapid and affordable economy-wide decarbonization. For example, accelerated shifting to carbon-free power makes end-use electrification an even more effective strategy to drive down emissions. In addition, policies can maximize the benefits of decarbonization and ensure that underserved communities benefit equitably from the transition to a clean energy system. For example, inclusive investment programs to scale up financing for efficient electric home upgrades can help level the playing field for underserved households and ensure effective consumer protections.

3.2 CURRENT U.S. GHG EMISSIONS TRENDS IN 2021

Net U.S. GHG emissions peaked in 2007 [27] after growing through much of the previous century, driven mainly by combustion of fossil fuels to meet growing demand for energy services. Since their peak, net U.S. GHG emissions have declined, driven by a combination of forces. Federal policy has played a crucial role, including through sustained research and development investments which propelled an initial shift from coal to gas power and the simultaneous and now dominant growth of renewables; incentives for renewables and zero-emission vehicles; and sector-specific regulations such as emissions standards for power plants, fuel economy standards, and appliance efficiency standards. Tribal governments, U.S. states, cities, counties, and other non-federal actors have played a similarly crucial role across all sectors of the economy. Moreover, this federal and subnational investment and policy has propelled a virtuous cycle of technology cost reductions inducing even larger markets for key carbon-free technologies which, in turn, drives further cost reductions through scale and learning.

3.3. ANALYSIS OF POTENTIAL U.S. TRAJECTORIES TO NET-ZERO EMISSIONS BY 2050

The new analysis presented here offers insights into what the overall emissions profile for the United States could look like between now and 2050 under a set of alternate assumptions about the evolution of technological costs, economic growth, and other drivers to 2050. We use two economy-wide models (GCAM and OP-NEMS), a range of sensitivity scenarios, supplemental models for key sectors, and comparisons to the growing literature on pathways to net-zero emissions. This provides transparency on what the possible pathways to 2050 net-zero might look like, and how those different pathways would affect the evolution of specific sectors and rates of deployment for specific technologies.

The assessment presented in this chapter reflects model outputs that are subject to several types of uncertainty. The goal of showing these outputs is to illustrate the evolution of the U.S. economy and resulting emissions over time. While the technology assumptions and policy goals for the decade to 2030 are largely understood, there is increasing uncertainty after 2030 on how any individual technology or sector will evolve. We show several different pathways based on alternate assumptions. These sensitivities illustrate a range of credible and plausible pathways to net-zero by 2050.

3.3.1 DESCRIPTIONS OF THE MODELS

Global Change Assessment Model (GCAM)

The LTS scenarios were produced in the Global Change Analysis Model (GCAM) by the Pacific Northwest National Laboratory. The Global Change Analysis Model (GCAM) is an integrated assessment model covering all major GHGs and all sectors of the economy, linking the world's energy, agriculture, and land use systems with a climate model. It is used to explore the interactions of emissions-reducing investments and activities across the U.S. and global economy. The model is designed to assess climate change policies and technology strategies for the globe over long time scales. GCAM runs in 5-year time steps from 2005 to 2100 and includes 32 geopolitical regions in the energy and economy module and 384 land regions in the agriculture and land use module. The model tracks emissions and atmospheric concentrations of GHGs (CO_2 and non-CO_2), carbonaceous aerosols, sulfur dioxide, and reactive gases and provides estimates of the associated climate impacts, such as global mean temperature rise and sea level rise. GCAM can incorporate emissions pricing and emission constraints in conjunction with the numerous technology options including solar, wind, nuclear, and carbon capture and sequestration. The model has been exercised extensively to explore the effect of technology and policy on climate change and the cost of mitigating climate change. GCAM is a community model primarily developed and maintained at the Joint Global Change Research Institute, a partnership between Pacific Northwest National Laboratory (PNNL) and the University of Maryland **[28]**.

Office of Policy – National Energy Modeling System (OP-NEMS)

The LTS scenarios were constructed using a version of the National Energy Modeling System (NEMS) developed by the U.S. Department of Energy (DOE) Office of Policy (OP-NEMS). NEMS is an integrated energy-economy modeling system for the United States that projects the production, imports, conversion, and consumption of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, cost and performance characteristics of energy technologies, and demographics. The version of NEMS used in this report has been run by OnLocation, Inc., with modeling approach determined with input from the DOE Office of Policy and other DOE technology offices. Because OP-NEMS projects only CO_2 emissions related to the energy sector, external assumptions were provided regarding non-CO_2 GHGs and land use, land-use change, and forestry. OP-NEMS includes enhancements for clean hydrogen, sustainable biofuels, and industrial carbon capture, transport, and storage **[29]**.

Global Timber Model (GTM)

The Global Timber Model (GTM) is a dynamic intertemporal optimization economic model that determines timber harvests, timber investments, and land use optimally over time under assumed future market, policy, and environmental conditions. This model's approach provides a simulation of harvesting, planting, and management intensity decisions that landowners might undertake in response to timber and carbon market demands, including future price expectations. These activities include afforestation and land use change, forest management, and forest products activity in response to policies and markets. The model generates projections using detailed biophysical and economic forestry data for different countries or regions globally, including the U.S., China, Canada, Russia, and Japan. It used macroeconomic data from Annual Energy Outlook 2021 for the U.S. and global parameters from Shared Socioeconomic Pathway 2 (SSP2) **[30]**. The model has been widely used to assess forest dynamics and carbon outcomes under various demand and land carbon sink scenarios, climate impacts, and other applications **[31] [32]**.

Forestry and Agriculture Sector Optimization Model with Greenhouse Gases (FASOM-GHG)

The Forestry and Agriculture Sector Optimization Model with Greenhouse Gases (FASOM-GHG) model is a partial-equilibrium dynamic intertemporal, price-endogenous, mathematical programming model depicting land transfers and other resource allocations between and within the agricultural and forest sectors in the United States. FASOM-GHG includes detailed representations of agricultural and forest product markets, contemporary forest inventories, intersectoral resource competition and land change costs, and costs of mitigation strategies. The results from FASOM-GHG yield a dynamic simulation of prices, production, management, consumption, GHG effects, and other environmental and economic indicators within these two sectors, under the chosen policy scenario. The result provides insight into cross-sectoral inter- and intra-regional responses to policy stimuli reflecting the spatial heterogeneity in production of agriculture and forestry products across the U.S. To date, FASOM-GHG and its predecessor models have been used to examine the effects of GHG mitigation policy, climate change impacts, public timber harvest policy, federal farm program policy, bioenergy prospects, and pulpwood production by agriculture among other policies and environmental changes **[33]**.

U.S. Department of Agriculture Forest Service Resources Planning Act (RPA) modeling system

The LTS scenarios reflect results from the U.S. Department of Agriculture (USDA) Forest Service Resources Planning Act (RPA) modeling system which comprises the Forest Dynamics model, integrated and harmonized with the USDA Forest Service RPA Land Use Change Model and the Forest Resource Outlook Model (FOROM) Global Trade Model **[34]**. This modeling system supports the projections of renewable resources across the U.S. in the USDA 2020 Resources Planning Act Assessment. Projections were developed under current climate conditions without CO_2 fertilization and values are added to USDA agriculture soils projections. The storage and flux of carbon in harvested wood products and solid waste disposal sites was projected using FOROM.

U.S. EPA Non-CO_2 Marginal Abatement Cost (MAC) Model and Report

The U.S. EPA Non-CO_2 Marginal Abatement Cost (MAC) Model is a bottom-up engineering cost model that evaluates the cost and abatement potential of non-CO_2 mitigation technologies **[35]**. The associated non-CO_2 mitigation report **[36]** provides a comprehensive economic analysis on the costs of technologies to reduce non-CO_2 gases and the potential to reduce them by sector.

3.3.2 SCENARIO DESCRIPTIONS & KEY ASSUMPTIONS

The LTS analysis includes multiple scenarios highlighting different pathways for achieving net-zero GHG emissions by 2050. The figures in this chapter present results for a range of assumptions including the land sink, technologies (i.e., carbon dioxide removal, sector-specific technologies, and non-CO_2 mitigation technologies), energy prices, population, and economic growth. The advanced LTS scenario assumptions account for currently available opportunities as we build back from the pandemic by using advanced assumptions for electricity, transportation, industry, and buildings as modeled in GCAM and OP-NEMS.

The underlying assumptions in the scenario sets are as follows. Carbon removal levels represent the sum of the net land sink, derived from modeled projections of land use, land use change, and forestry (LULUCF), and plausible levels of carbon dioxide removal technology adoption such as biomass energy with CCS and direct air capture from the literature **[37] [38]**. The combined carbon removals from these sources are roughly 1,000, 1,400, and 1,800 $MtCO_2$ per year in 2050 over the low, medium, and advanced cases, respectively. The advanced and lower technology assumptions for the electricity and transportation sectors rely largely upon the National Renewable Energy Laboratory's Annual Technology Baseline. The advanced assumptions for the buildings and industrial sectors draw on the existing literature and programmatic goals for the advanced cases and slower improvements in the lower cases, which are more aligned with standard model parameters. For non-CO_2 reductions, the advanced technology assumptions accelerate the availability of low-cost technologies but do not alter long-term costs. Oil and natural gas prices are calibrated to the 2021 EIA Annual Energy Outlook's oil and gas supply cases in the reference scenario, i.e., without a net-zero 2050 target. Population and GDP, the final set of assumptions, span compound annual growth rates from 2020 to 2050 of 0.5% to 0.7% for population and 1.1% to 1.8% for GDP. Also, the LULUCF modeling effort included the use of 5 different models to generate business as usual and potential mitigation outcomes from different land-based activities, including afforestation, improved forest management, harvested wood products storage, and fire reduction techniques. This exercise included alignment of several key inputs and parameters, including use of input data from the Forest Inventory and Analysis database and, in some cases, application

LTS Scenario	Technology Assumptions by Sector						Model(s) Used	
	Carbon Removal	*Electricity*	*Transportation*	*Industry*	*Buildings*	*Non-CO_2*	*GCAM*	*OP-NEMS*
Balanced Advanced	Medium	Advanced	Advanced	Advanced	Advanced	Advanced	x	
Lower Non-CO_2	Medium	Advanced	Advanced	Advanced	Advanced	**Lower**	x	
Lower Buildings	Medium	Advanced	Advanced	Advanced	**Lower**	Advanced	x	
Lower Industry	Medium	Advanced	Advanced	**Lower**	Advanced	Advanced	x	
Lower Transportation	Medium	Advanced	**Lower**	Advanced	Advanced	Advanced	x	
Lower Electricity	Medium	**Lower**	Advanced	Advanced	Advanced	Advanced	x	
Lower Removals	**Lower**	Advanced	Advanced	Advanced	Advanced	Advanced	x	x
Higher Removals / Lower Technology	**Higher**	Advanced	**Lower**	**Lower**	**Lower**	**Lower**	x	x
High Oil & Gas Price	Medium	Advanced	Advanced	Advanced	Advanced	Advanced	x	
Low Oil & Gas Price	Medium	Advanced	Advanced	Advanced	Advanced	Advanced	x	
High Population & GDP	Medium	Advanced	Advanced	Advanced	Advanced	Advanced	x	
Low Population & GDP	Medium	Advanced	Advanced	Advanced	Advanced	Advanced	x	

Table 1: Long-Term Strategy Scenarios. To explore multiple ways to reach our net-zero emissions goal in 2050, this analysis includes twelve scenarios (shown in the left most column of the table). The 'Balanced Advanced' scenario includes medium levels of carbon removals from the atmosphere through our land use, land use change, and forestry (LULUCF) sink and carbon dioxide removal (CDR) technologies, and advanced technology assumptions allowing for a balanced approach across sectors. The next six scenarios explore lower technology assumptions for electricity, transportation, industry, buildings, non-CO_2, and carbon removals, respectively. Next is a scenario that includes higher levels of carbon removals combined with lower technology assumptions for multiple sectors. The last four scenarios explore high and low oil and gas price sensitivities, and high and low population and GDP growth projections.

of Shared Socioeconomic Pathway (SSP) 2 information for macroeconomic drivers. The land use models applied in this analysis did not incorporate assumptions of demand of CCS or bioenergy as mitigation options, as these modeling aspects were accommodated in GCAM and OP-NEMS.

3.4 ECONOMY-WIDE PATHWAYS TO 2050 NET-ZERO EMISSIONS

Achieving the 2050 net-zero goal will require reducing net U.S. emissions from roughly 6.6 Gt CO_2e in 2005 (and 5.7 Gt CO_2e in 2020), to zero by no later than 2050. As described above, this reduction can result from combinations of five major categories of action: energy efficiency; decarbonizing electricity; fuel switching and energy transitions; sequestering carbon through forests, soils, and CO_2 removal technologies; and reducing non-CO_2 emissions. **Figure 3** presents a vision for how such categories of action can combine to reach net-zero. This figure shows a representative pathway from 2005 net emissions levels through 2050 in the form of a waterfall chart (the left-hand side of the figure). This representative pathway provides a rough approximation for reaching net-zero emissions using contributions from all sectors.

The right-hand side of the figure shows seven additional scenarios from our analysis that are based on different assumptions about how technologies and policies will evolve over time. This includes a "balanced advanced" scenario with high levels of action across all sectors, as well as scenarios where one of the sectors (buildings, industry, transportation, electricity, non-CO_2, land sink) contributes a lower level of reductions. These alternate scenarios serve to illustrate how the balance across technologies and policy strategies could vary while still reaching the net-zero 2050 goal.

Several broad lessons from this figure are clear. First, in the absence of additional policies, emissions would remain largely flat moving forward. Results in the figure show reductions from a baseline scenario to 2050—that means that only reductions beyond the baseline scenario are reflected in the colored bars. Achieving net-zero emissions will require actions that go far beyond business as usual.

Second, roughly 4.5 Gt of the 6.5 Gt annual reduction from 2005 levels will likely come from transforming the energy system. This starts with decarbonizing

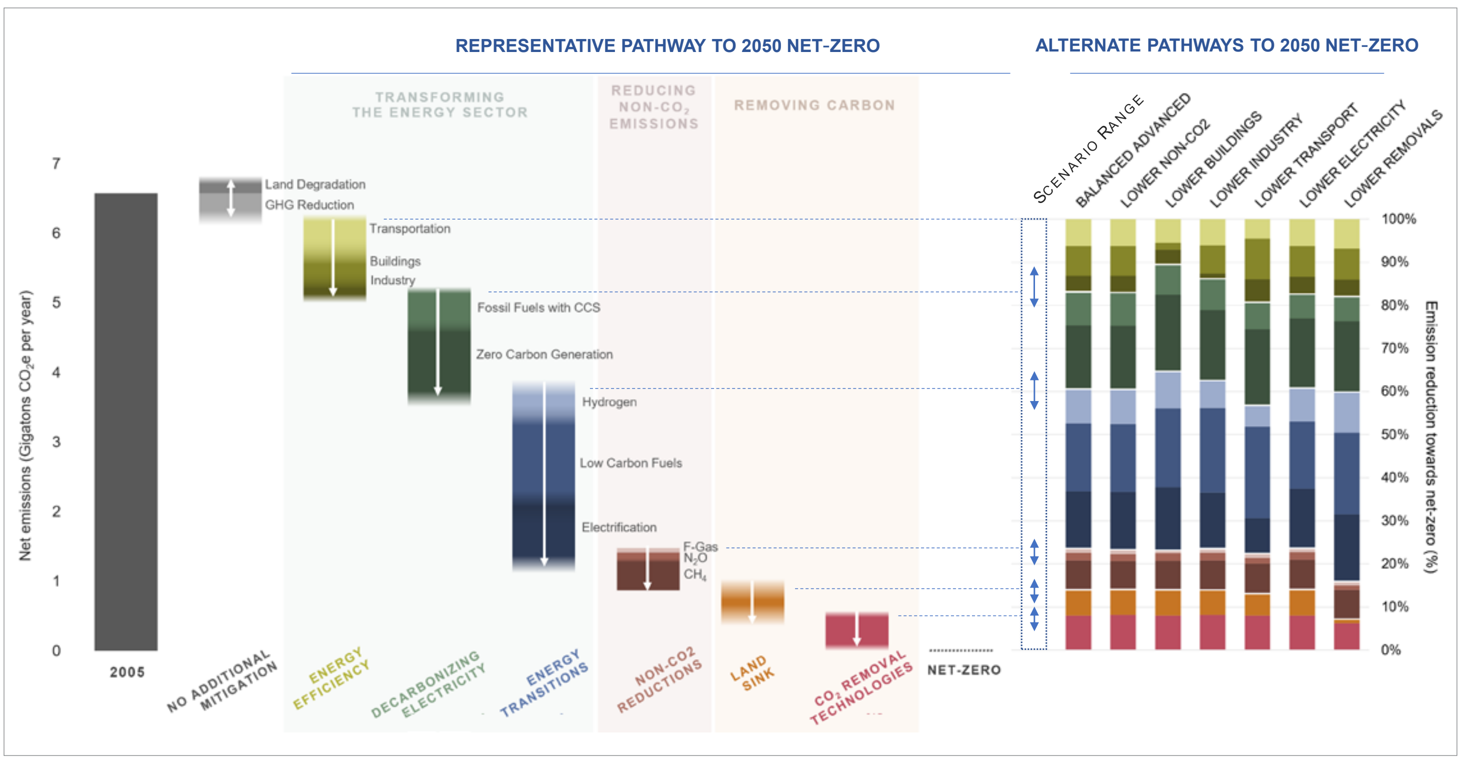


Figure 3: Emissions Reductions Pathways to Achieve 2050 Net-Zero in the United States. Achieving net-zero across the entire U.S. economy requires contributions from all sectors, including: efficiency, clean power, and electrification; reducing methane and other non-CO_2 gases; and enhancing natural and technological CO_2 removal. The left side of the figure shows a representative pathway with high levels of action across all sectors to achieve net-zero by 2050. The right side shows a set of alternative pathways depending on variations in uncertain factors such as trends in relative technology costs and the strength of the land sector carbon sink.

electricity by shifting to renewables and other emissions-free power. This shift could lead to over 1 Gt of annual reduction by 2050. A second pillar of energy transformation is simply to use energy more efficiently to provide the same services. Solutions like better insulation, advanced heat pumps for space and water heating, and efficient computers and electronics can save consumers billions on their annual energy bills. Cutting energy waste also reduces the rate of investment needed for new clean energy generation as demand grows. This pillar alone could contribute roughly 1 Gt of annual reductions by 2050. A third pillar of energy transformation is to switch as many uses as possible to clean energy—including clean electricity, but also including low-carbon fuels and clean hydrogen. Efficient electrification of transportation, buildings, and other end uses can also transform the energy sector by reducing overall energy demand. Electric motors in vehicles, for example, are approximately three times more efficient than internal combustion engines, and electric heat pumps are up to three times more efficient than heating with natural gas or electric resistance. These activities would lead to nearly 2 Gt of annual reductions by 2050.

Third, other non-CO_2 GHG emissions represent a critical component of the overall reduction strategy, collectively representing roughly 0.5 Gt of reductions by 2050. These gases have sources across many sectors and include methane emissions from agriculture, waste management, and fossil fuel use, HFCs used in refrigeration, and N_2O from agriculture and industry. Such gases often offer low cost and high impact reductions. For example, globally, methane accounts for half of the net 1.0°C of warming already occurring. Because of its relatively short lifetime in the atmosphere, compared to CO_2, rapidly reducing methane emissions is the single most effective strategy to reduce warming over the next 30 years and is crucial in keeping to the 1.5°C limit. The United States co-leads with the EU the Global Methane Pledge that aims to eliminate over 0.2°C of potential warming by 2050 by cutting global methane pollution at least 30% by 2030 relative to 2020 levels. As of October 2021, over 30 countries representing about 30% of global emissions and 60% of the global economy had joined the Pledge **(See Box in Chapter 5)**. As detailed in the NCS, the United States is implementing comprehensive actions to drive down methane in this decade, including new standards for landfills and oil and gas operations as well as major investments to remediate abandoned coal, oil, and gas mines and wells. The United States is also committed to incentives and innovations to reduce agricultural methane and agricultural N_2O emissions. Finally, a global HFC phasedown is expected to avoid up to 0.5°C of global warming by 2100.

Fourth, removing CO_2 from the atmosphere is a necessary component for reaching net-zero. Although most emissions across the economy can be eliminated through the above strategies, a few processes or activities that lead to emissions are currently difficult or costly to eliminate or have no viable existing substitutes, and despite many available cost-effective mitigation opportunities, non-CO_2 GHG emissions cannot be fully reduced to zero. This means that reaching net-zero will require additional contributions from removals until viable zero-emission solutions are developed and deployed. Overall, these removals would come from two broad categories of activities. One is through nature-based approaches that rely on natural carbon sinks—land and ocean—by expanding or enhancing conservation, restoration, sustainable management and other activities that would enhance natural removal of carbon as well as protect our vital natural ecosystems and related services and biodiversity. A second set of approaches is through various technologies and processes that directly capture CO_2 from the atmosphere and store it (such as direct air or ocean capture, bioenergy with CCS, or enhanced mineralization). Technologies capable of carbon dioxide removal are available today, but at nascent stages and therefore will require additional research, development, and deployment now through 2050 (more discussion of CDR technologies can be found in **section 6.4**).

CHAPTER 4:

TRANSFORMING THE ENERGY SYSTEM THROUGH 2050

The energy sector is pivotal for achieving net-zero emissions by 2050. Achieving net-zero is possible through a range of pathways, which depend on how technologies and policies evolve over the three-decade period. Nevertheless, by modelling a range of pathways with plausible assumptions for this evolution **(see Figure 4)**, we can distinguish broad trends and important drivers of the energy sector transformation.

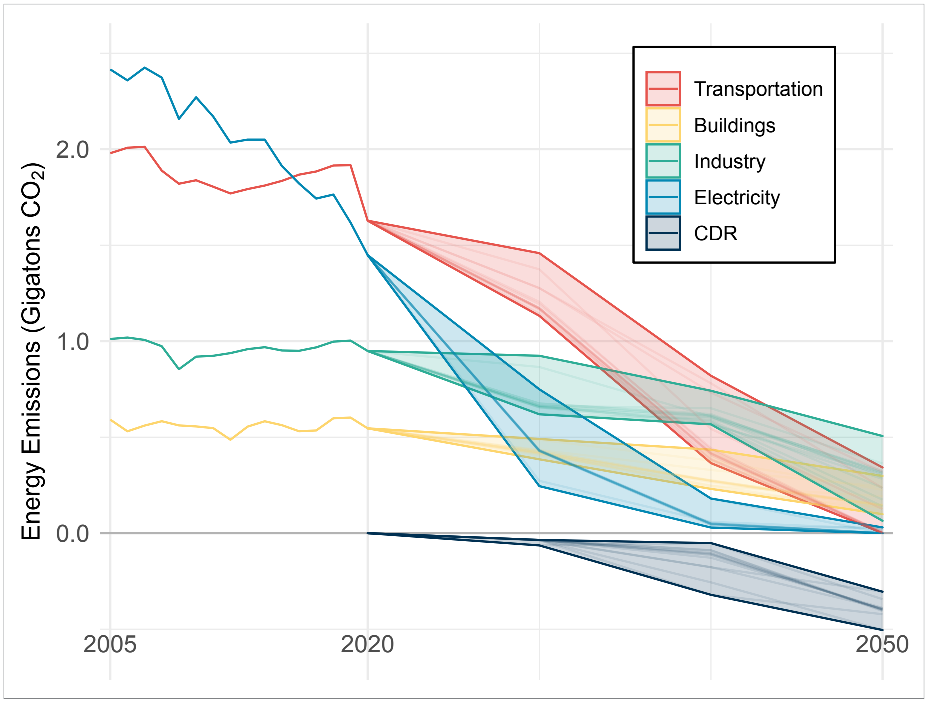


Figure 4: U.S. Energy CO_2 Emissions to 2050 by Economic Sector. Electricity CO_2 emissions and direct CO_2 emissions from the transportation, buildings, and industry fall dramatically in all scenarios, with the greatest reductions coming from electricity, followed by transportation, and non-land sink carbon dioxide removals (CDR) increase. Notes: Historical data are from EIA Monthly Energy Reviews, projections include data from all LTS scenarios using both GCAM and OP-NEMS, projections are shown in ten-year time steps.

4.1 ELECTRICITY

The United States has set a goal for 100% carbon pollution-free electricity by 2035, and this goal will provide an important foundation for the Long-Term Strategy of the United States. Electricity is used in every economic sector, and all 2050 net-zero pathways depend on rapidly decarbonizing electricity and expanding the use of this decarbonized electricity into as many uses as possible to displace polluting fuels. The electricity sector, which contributes about a quarter of all U.S. GHG emissions, has been reducing CO_2 emissions for years, with major shifts caused in part by increases in renewables and decreases in coal-fired generation **(see Figure 5)**. Continued cost reductions in generation and storage are expected to enable even more rapid reductions of emissions from this sector. New policies, incentives, market reforms, and other actions will be needed to ensure that electricity sector emissions continue to decrease as total electricity demand increases.

The electricity sector will continue to evolve rapidly as it decarbonizes. Expected continued cost reductions in renewable generation as well as battery and other storage technologies could see emissions decreases of

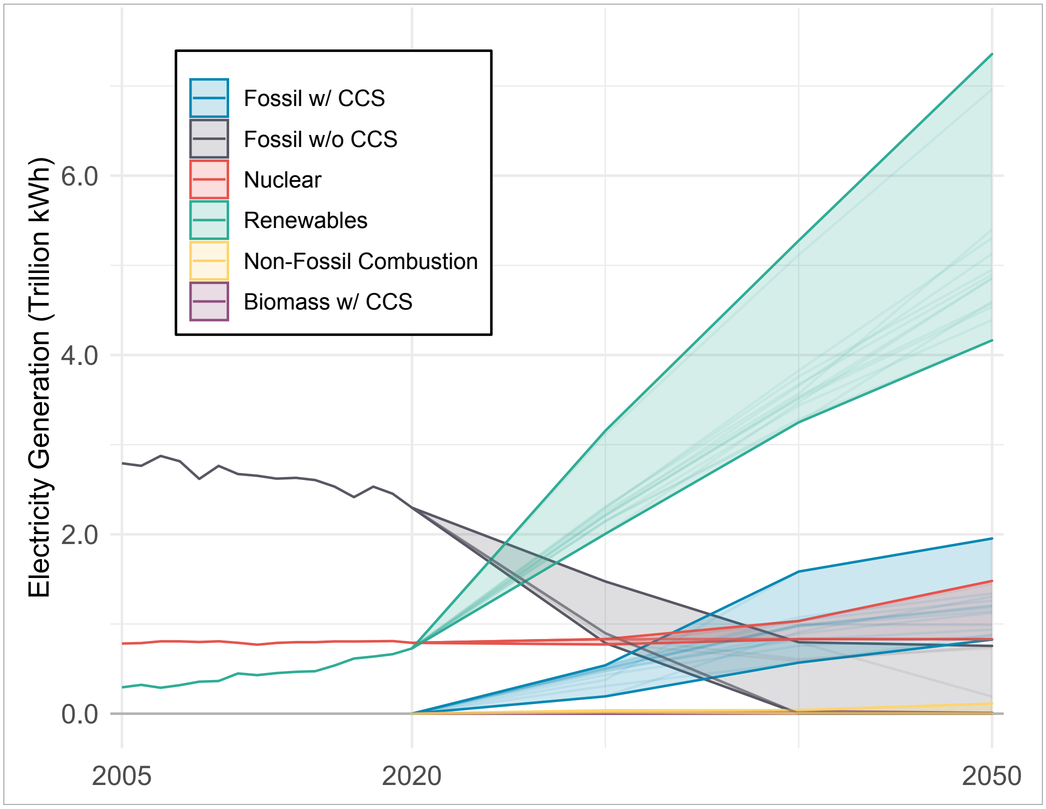


Figure 5: U.S. Electricity Generation 2005-2050. Generation by source in trillion kilowatt-hours. Total generation expands to 2050 due to increased use of clean electricity in new applications in transportation, industry, and buildings. Renewable generation increases rapidly to keep pace with growing electricity demand and ensure that the share of renewables continues to expand to 2050. Note: Historical data are from EIA Monthly Energy Reviews, projections include data from all LTS scenarios using both GCAM and OP-NEMS, projections are shown in ten-year time steps.

roughly 70-90% by 2030 on a path toward the 2035 100% clean electricity goal. As shown in **Figure 5**, solar and wind generation continues to increase substantially through 2050, while existing nuclear generation remains in operation and could see growth in the 2030s and 2040s. Unabated fossil generation (coal or gas generation without CCS technology) declines, and existing fossil fueled plants start to be fitted with carbon capture. By 2050, clean generation provides zero emission electricity to the rest of the economy, with all electricity providing 15-42% of primary energy.

Recent analyses suggest that wholesale electricity prices, on average, are unlikely to change significantly as we shift to a cleaner grid by 2030, with price impact estimates ranging from a 4% *decrease* to a 3% increase **[39].** Additionally, the transition to clean electricity is expected to reduce exposure of U.S. consumers to fuel supply shocks **[40]**.

Investment in clean energy generation must continue through mid-century as overall electricity generation increases to meet demand growth from other sectors. Average annual total capacity additions without storage from 2021 to 2030 range from 58 gigawatts per year (GW/yr.) to 115 GW/yr.; in 2031 to 2040 they range from 54 GW/yr. to 167 GW/yr.; and in 2041 to 2050 they range from 67 GW/yr. to 123 GW/yr. Storage capacity additions from 2021 to 2030 average 0.4 GW/yr. to 2.7 GW/yr.; in 2031 to 2040, they range from 3 GW/yr. to 40 GW/yr.; and in 2041 to 2050 they range from 11 GW/yr. to 64 GW/yr.

This rapid evolution and scale of change in the electricity sector is ambitious, with high and sustained deployment of new technologies through mid-century. Many significant challenges and barriers exist **[14] [22]**. The electricity transition will require adding significant amounts of new zero-carbon electricity capacity at a sufficient pace to replace uncontrolled fossil fuel-fired generation while also providing ample clean supply for a growing economy with increased electrification. New transmission, distribution, and storage infrastructure will be needed to maintain and improve grid reliability, including adapting the electric grid to be flexible to changing supply and demand over all increments of time. In particular, longer-duration storage solutions and appropriate incentive mechanisms will be critical. Absent new action, supply chains may become stressed by limited availability of raw materials (such as rare earth elements), manufacturing capacity, and skilled workforce. Some pathways may also require significant expansion of carbon capture and storage technologies during the overall transition, which bring specific challenges around technology development and siting.

These challenges are substantial but can be addressed through an integrated strategy of investment, innovation, and new technology deployment. Large-scale deployment of renewables can be accelerated by investments in grid infrastructure and advanced technologies. Grid infrastructure investments, including the buildout of new long-distance, high-voltage transmission projects, can enhance resilience, improve reliability, better integrate variable generation resources, lower electricity costs, and unlock the best clean energy resources by connecting them to demand centers. Significant deployment of energy efficiency can also help reduce the scale of investment required by lowering the total energy demand that must be met. Analyses show that as the sector becomes increasingly decarbonized, advanced technologies will be brought online to meet peak load and adjust to seasonal changes in demand. Advanced technologies—which could include clean hydrogen combustion or fuel cells, enhanced geothermal systems, long-duration energy storage, advanced nuclear, and fossil generation with CCS—can provide clean firm resources that can balance increased variable generation. However, these technologies require a rapid, sustained acceleration in research, development, and deployment. The significant investments in generation and transmission will underpin job growth across the nation, creating opportunities in cities and rural areas alike, particularly when paired with workforce training. Expansion of the transmission system, stronger interregional coordination, and distributed generation also provide resilience to natural disasters, saving lives and protecting businesses.

RAPID DECARBONIZATION IN THE U.S. ELECTRICITY SECTOR IS UNDERWAY

The electricity sector in the United States has been decarbonizing rapidly, with significant increases in renewable deployment in recent years.

The shift to lower-emissions sources has been under way for decades, with early contributions from nuclear and then fossil gas. More recently, since around 2010, federal investment policies, tax credits, and regulatory actions, as well as state policies, research and development, and market trends, drove significant renewable deployment. At the same time, between 2010 and 2019, more than 546 coal-fired power units retired, totaling 102 GW of capacity, with another 17 GW of capacity planned for retirement by 2025 [41]. This has led to a dramatic shift in the sources of U.S. electricity, with renewables now accounting for more generation than coal (Figure 6). In addition, the sum of coal and natural gas generation has also declined in the last decade, pointing to the important role of renewable energy.

One of the challenges to reach the 2050 net-zero goal (as well as the 2035 100% clean electricity goal) is the large amount of new zero-emission capacity (primarily renewables) that will need to be deployed annually to enable an increasingly large share of clean electricity generation. Figure 7 shows some indicative estimates of the magnitude of the annual capacity additions needed to remain on pace toward our goals, in comparison to recent historical levels of capacity additions. Recent trends in renewable deployment are encouraging. Solar and wind capacity additions were about 32 GW in 2020, the highest on record, and are expected to be about 28 GW in 2021. Acceleration will be needed but the deployment rate has been growing quickly.

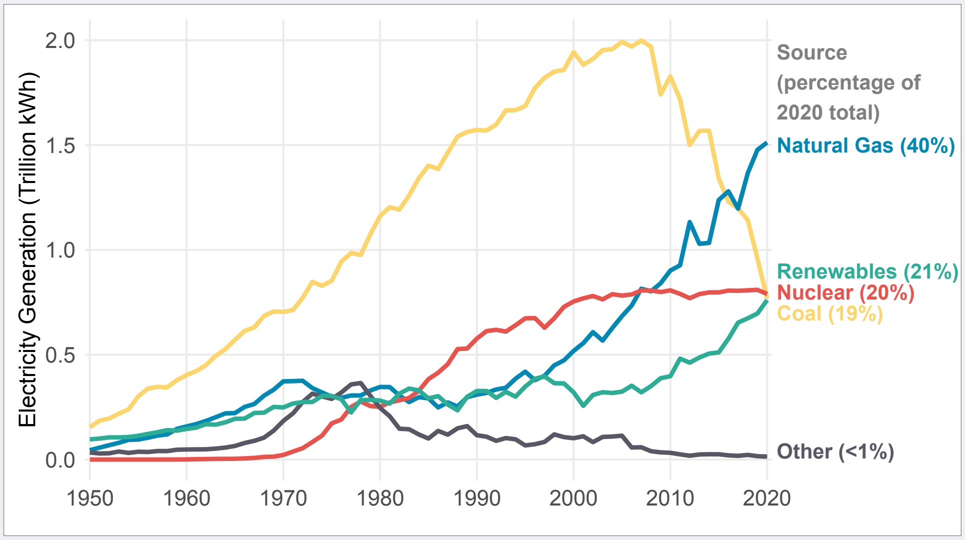


Figure 6: Annual U.S. Electricity Generation from All Sectors 1950-2020 (trillion kilowatt-hours). The electricity sector has been rapidly decarbonizing since 2008. This figure shows electricity net generation in all sectors (electric power, industrial, commercial, and residential) and includes both utility-scale and small-scale solar. Rapid increases in solar, wind, and other renewable generation means that in 2020, for the first time, renewable generation surpassed coal generation. Coal generation has declined rapidly, replaced by natural gas and renewables. Source: EIA **[42]**.

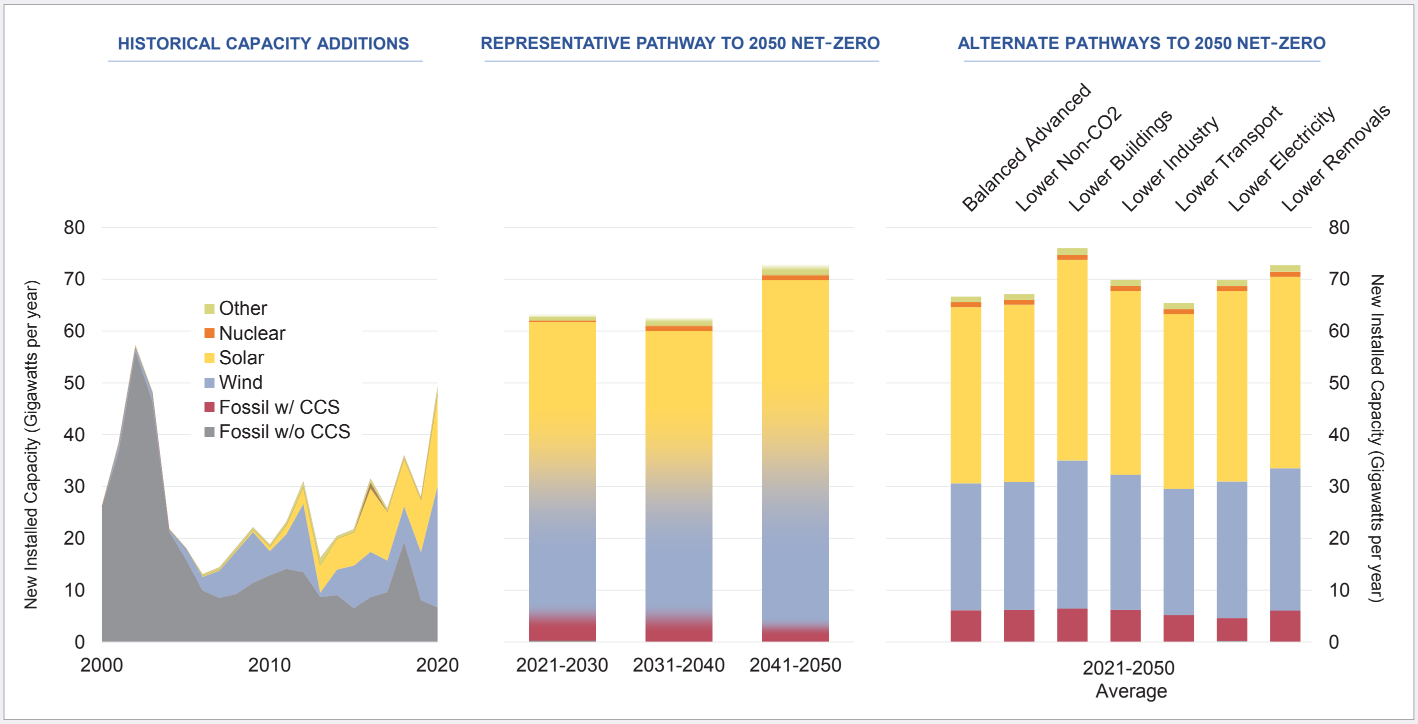


Figure 7: Electric Generation Capacity Additions 2000-2050. Renewable capacity additions have been growing rapidly in the past decade (left) and are more closely approaching levels that will be needed to sustain the overall decarbonization trend in electricity needed to reach the 2050 goal. A representative pathway (center) shows deployment of total zero-carbon technologies roughly on the order of 60–70 GW per year. Diverse scenarios in this analysis show a range of potential pathways to achieve net zero (right). Note: Historical data are from EIA Monthly Energy Reviews, projections include data from all LTS scenarios using GCAM. Other scenarios not shown in the figure have cumulative nuclear capacity additions ranging up to 90–100 GW through 2050.

4.2 TRANSPORTATION

The transportation sector provides vital mobility services for people and goods with on-road vehicles, planes, trains, ships, public transportation, and a wide variety of other modes. It is currently the highest emitting sector, representing 29% of all U.S. emissions **[27]**. To reduce emissions to net-zero by 2050 we will need to ensure that zero-emission vehicles dominate new sales for most types of vehicles by the early 2030s, as well as infrastructure to support alternate modes of transportation, such as trains, bikes, and public transit.

The United States will continue to increase the use of electricity and sustainably produced low-carbon fuels in the transportation sector while shifting away from fossil sources **(Figure 8)**. Over time, electricity, carbon beneficial biofuels, and hydrogen will become increasingly clean. The availability and adoption of these low-carbon fuels in the coming decades will largely depend on the economics of production and/or procurement, the competitiveness of bioenergy and hydrogen compared to alternative low-carbon technologies across sectors, policy support, private

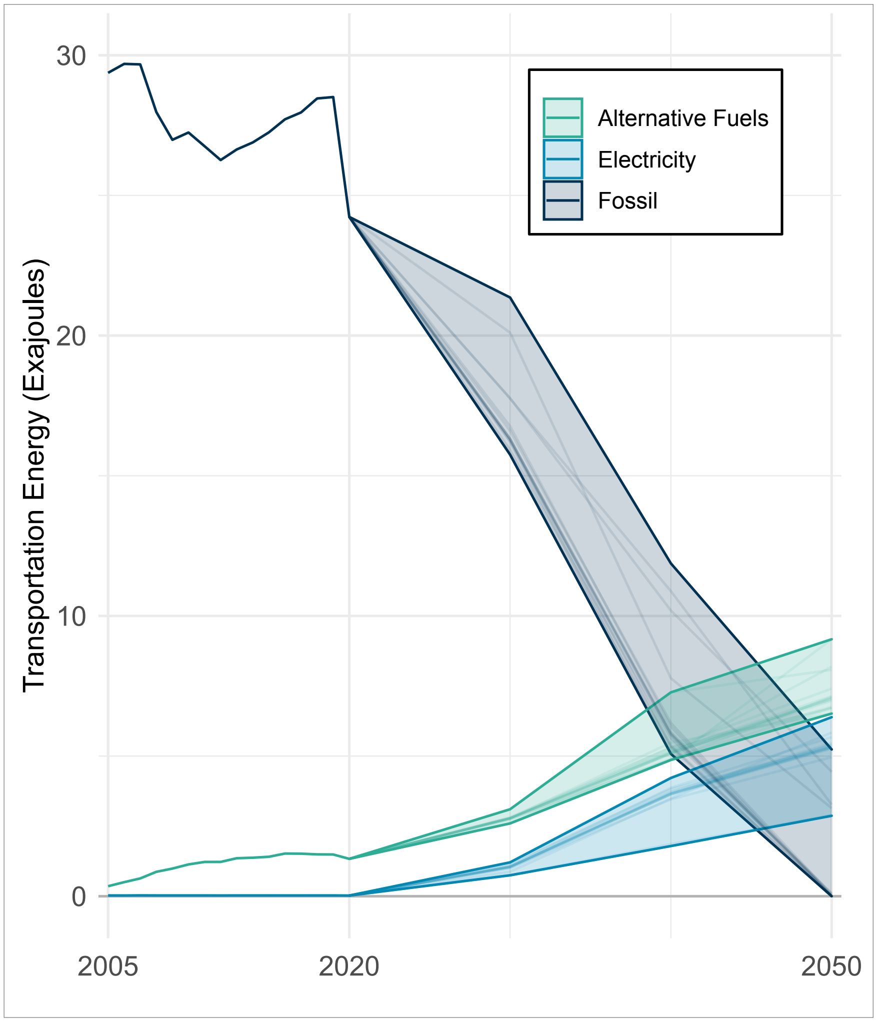


Figure 8: U.S. Transportation Final Energy Use 2005-2050. Overall transportation energy in exajoules (EJ) decreases while the use of electricity and alternative fuels, including biomass-derived fuels and hydrogen, increases to power nearly the full U.S. transport system by 2050. While light-duty vehicles are almost all electric by 2050 in most scenarios, there is uncertainty in other transportation sectors. Uncertainties in the future share of low-carbon bioenergy vs. hydrogen makes can affect the potential for electrification in the sector. These results show end use consumption instead of service demand (e.g., per mile travelled), so electricity demand appears smaller than alternative fuels demand due to the major inherent efficiency advantages of electric vehicles. Note: Historical data are from EIA Monthly Energy Reviews, projections include data from all LTS scenarios using both GCAM and OP-NEMS, projections are shown in ten-year time steps.

investment and, in the case of bio-based energy, the ability to minimize potential negative land carbon outcomes and other environmental impacts of biomass production. Although demand for transportation services increases through mid-century, the total energy consumed in this sector declines due to a combination of regulations and technological advances which drive efficiency improvements and deliver societal and consumer benefits.

A central component of the U.S. Long-Term Strategy in transportation is the expanded use of new transportation technologies—including a rapid expansion of zero-emission vehicles—in as many applications as possible across light-, medium-, and heavy-duty applications. Already, the growing popularity of electric vehicles (EVs), supported by incentives and continued advances in battery technology, is spurring greater EV adoption and industry goals for even higher EV sales. Other technologies can serve as important complements to EVs. The President's goal and associated policies to ensure half of all new vehicles sold in 2030 zero-emissions vehicles (including battery electric, plug-in hybrid electric, or fuel cell electric vehicles) will continue to spur growth across all zero-emission vehicle types.

This rapid deployment of zero-emissions vehicles is ambitious and will need to occur at a large scale across all vehicle types. Many challenges and barriers exist **[14] [22] [25]**. For example, costs for electric technologies, fueling, and charging infrastructure remain high in some applications. Some transportation segments, such as aviation, will likely remain difficult to electrify and some legacy vehicles will continue to be necessary in the near term, both of which would require alternate sources of low-carbon fuels that have yet to be deployed at the necessary scale. The existing built environment creates also high dependency on owner-occupied vehicles and presents numerous obstacles to alternate mobility options and shifting between modes such as transit, biking, or walking.

An integrated strategy to address these substantial challenges can help accelerate the development and rapid expansion of new transportation technologies. An expanded network of public transit options and infrastructure will increase urban mobility, helping to reduce emissions and increase equity in mobility. Electrifying segments of the rail system will decarbonize the existing rail system with the added benefit of enabling a more robust electric grid along railroad "right of way." Additionally, "vehicle to grid" innovations may provide support for grid services. Accelerated research, development, demonstration, and deployment of lower-carbon fuels, such as clean hydrogen and sustainable biofuels, will contribute to the decarbonization of applications that may be more difficult to electrify including aviation and marine transportation and some medium- and heavy-duty trucking segments.

4.3 BUILDINGS

Buildings house our population and provide a working environment for commercial sectors including offices, colleges and K-12 schools, restaurants, grocery stores, and retail shops. Homes and commercial buildings are responsible for over one-third of CO_2 emissions from the U.S. energy system. Of this, roughly two-thirds of buildings sector emissions currently come from electricity, with the remainder coming from direct combustion of gas, oil, and other fuels for space heating, water heating, cooking, and other services, and buildings currently account for about three quarters of U.S. electricity sales **[43]**. Electricity is used in buildings for lighting, space heating and cooling, water heating, electronics and appliances, and other services. CO_2 emissions from buildings have been falling since 2005, due to increases in energy efficiency, the decarbonization of the electricity sector, and a modest trend towards the electrification of end uses. These emissions reductions have been achieved even as commercial building square footage has increased by more than 25% and the population has grown by more than 10% since 2005. All buildings need to be decarbonized with an emphasis on strategies that deliver for overburdened and underserved communities. For example, in the residential sector, households with an annual income below

$60,000 account for nearly 50% of all household energy consumption, making it essential that efforts to decarbonize buildings are accessible to all households **[44]**.

The key driver of reducing building emissions is efficient use of electricity for end uses (such as heating, hot water, cooking, and others). Alongside the decarbonization of electricity, these changes can bring building sector emissions to near-zero by 2050. Across multiple possible pathways, building efficiency improvements also reduce the overall demand for energy by the sector, despite the substantial growth in the number of buildings, floorspace, and population expected through 2050 **(Figure 9)**. Within this overall decrease in energy demand, the share of electricity in final energy demand grows as end uses are electrified, from about 50% in 2020 to 90% or more by 2050 because the on-site combustion of gas, oil, and other fuels decreases substantially; however, the growth is also limited through energy efficiency and efficient electrification. Heat pumps and other electric heaters and electric cooking account for more than 60% of sales by 2030 and nearly 100% of sales by 2050. Energy demand in buildings is reduced by 9% in 2030 and 30% in 2050.

While recent trends are encouraging, the building sector presents some unique challenges to rapid decarbonization. Foremost is the often-long lifetime of buildings. Many buildings built today will still be in active use by 2050, which means that even immediate actions to improve new buildings take years before making a significant impact in the overall building stock. These factors affect all aspects of buildings including the outer shell; heating, ventilation, and air conditioning systems; and appliances and lighting—although some of these are more amenable to retrofitting than others. In addition, energy efficiency and efficient electrification have barriers relating to their upfront cost structure, financing, competing landlord and tenant incentives. These issues can be particularly difficult in underserved

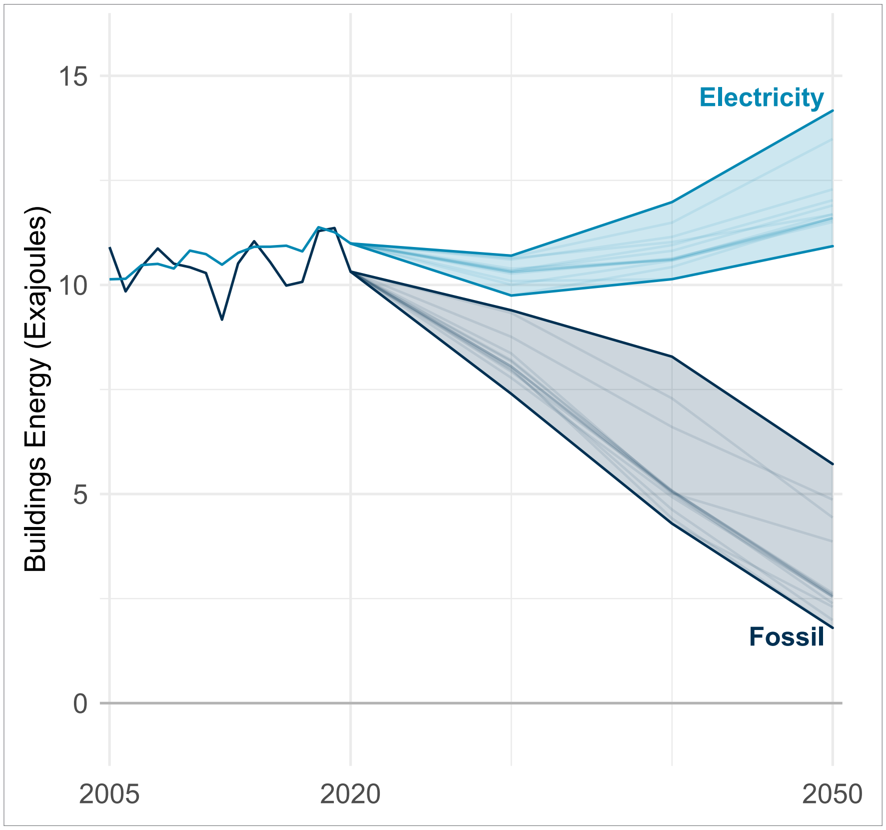


Figure 9: U.S. Buildings Site Energy 2005-2050. Overall building site energy use in exajoules (EJ) decreases at the same time as certain applications (e.g., heating) switch from fossil fuels (and some biomass) to clean electricity. Note: Historical data are from EIA Monthly Energy Reviews, projections include data from all LTS scenarios using both GCAM and OP-NEMS.

communities, which will also need widespread access to retrofits and new building technologies, though innovative financing tools such as inclusive investment programs can deliver substantial benefits to these communities while reducing or eliminating financing barriers and ensuring consumer protections.

To address these challenges, pursuing multiple options effectively help achieve the necessary rapid emissions reductions in buildings while also reducing the energy cost burden for families and businesses and improving the health and resilience of communities. There are three important sources of emissions reductions: technological advances including from envelope improvements (e.g., attic and wall insulation, sealing leaks, and efficient windows), improved efficiency of electric end uses (e.g., lighting, refrigeration, appliances, and electronics), and the efficient electrification of space and water heating, cooking, and clothes drying in both existing and new buildings. The rapid deployment of heat pumps for space heating and cooling and water heating is the central strategy for the efficient, flexible electrification of buildings. By increasing the amount of demand-responsive heating, cooling, and water heating on the grid, these technologies can respond to shifts in renewable generation levels on short notice and reduce the overall cost of a low- or zero-carbon generation mix.

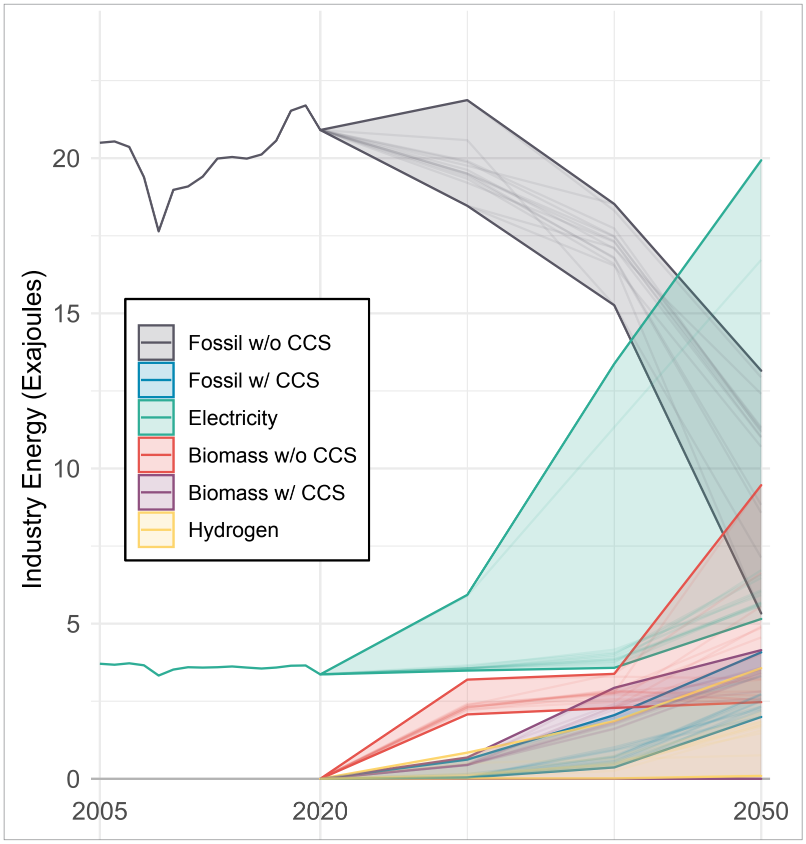
Efficient and electrified buildings provide substantial consumer benefits. The most important benefit is reduced utility bills for households and businesses which are both direct (through lower energy usage) and indirect (through lower energy prices). More efficient buildings significantly reduces electricity demand and lessen winter peaking loads as the sector electrifies, reducing the cost of new generation, transmission, and distribution, which in turn reduces energy prices for American families and businesses. These bill savings would be most beneficial to low-income households, which typically face the greatest energy burden. Buildings can also support electric vehicle charging infrastructure and rooftop solar installations, key elements of the broader energy transition. More efficient buildings also retain indoor temperature for longer during power outages under extreme weather conditions, improving health and safety. The role of state utility regulators will be especially important, as approval of new rate structures and consumer incentive programs will be vital in realizing the full potential of consumer benefits. Finally, building improvements will come from manufacturing, construction, and installation performed by skilled, well-paid American workers in communities across the country.

4.4. INDUSTRY

The U.S. industrial sector, currently produces roughly 23% of U.S. GHG emissions and 30% of emissions from the energy system **[45]**. It is heterogeneous, producing a wide range of products with diverse and sometimes specialized processes. The energy-intensive and emissions-intensive industries include mining, steel manufacturing, cement production, and chemical production, and collectively produce nearly half of overall industrial emissions. In addition to the CO_2 emissions resulting from industrial demand for electricity, the industrial sector emits GHGs directly from many operations and processes including the use of fossil fuels for onsite energy use and as feedstocks, direct process emissions of CO_2 from cement production and other industries, and emission of non-CO_2 GHGs such as N_2O from nitric and adipic acid production.

Although there are many hard-to-decarbonize elements of industrial activities, investments in technologies for advanced non-carbon fuels, energy efficiency, and electrification can reduce overall industrial sector CO_2 emissions by 69-95% by 2050. A large range of potential pathways for the industrial sector are shown in **Figure 10**. Overall energy use drops in most scenarios through energy efficiency and materials efficiency investments. In these scenarios, overall electricity use in the sector grows only slightly due to electrification. However, in scenarios that rely on a large quantity of hydrogen, electricity use increases dramatically to produce the hydrogen through electrolysis. In all scenarios, low-carbon fuels (including electricity) grow as a percentage of total energy use.

Figure 10: Industry Final Energy Use 2005-2050. Overall industrial energy use in exajoules (EJ) decreases to 2050 while certain applications switch from fossil fuels to clean electricity, hydrogen, or biofuels. Electricity use increases further in scenarios with larger hydrogen production due to the high electricity demand for that pro-cess. In this analysis, CCS in deployed in industry for process emissions, but there is limited representation of CCS on industrial energy in the models we use. Accordingly, it is likely that a greater share of industrial fossil energy emissions could be captured by 2050 than is shown here. Note: Historical data are from EIA Monthly Energy Reviews, projections include data from all LTS scenarios using both GCAM and OP-NEMS, projections are shown in ten-year time steps.



Reducing energy-related GHG emissions from industry presents a set of unique challenges **[14] [22] [26]**. A primary feature of this sector is that it is diverse: unlike electricity or buildings, for example, whose emissions come from a relatively small set of activities, industrial activities and infrastructure are designed around a large set of processes. Some of these processes might have relatively straightforward substitutes, but in other cases either those substitutes may not exist yet or might be higher cost. In some cases, alternate sources of process heating may need to be identified. In other cases, CCS applications may be needed but these may be expensive or infeasible at existing production facilities. At the same time, scaling up of material efficiency could be challenging because of product design limitations or consumer demand. Many of these challenges also affect the non-CO_2 emissions from industry, which are discussed further in **Chapter 5**.

In response to these challenges, the industrial energy transition can be enabled to decarbonize at a sufficiently rapid pace through a diverse set of approaches tailored to the specific needs of each subsector. Key strategies include energy efficiency, material efficiency, electrification, adoption of low-carbon fuels and feedstocks, and CCS. Energy efficiency, waste heat recovery, and accelerated adoption of advanced technologies such as additive manufacturing, can significantly reduce energy demand and lower costs to businesses. Material efficiency incorporates structural changes in manufacturing that include product recycling and reuse, material substitution, and demand reduction. Electrification of heated, fuel-consuming industrial processes and equipment is a viable pathway for some subsectors, such as light industry. Low-carbon fuels and feedstocks, including clean hydrogen and low-carbon biofuels, can reduce emissions from processes that are difficult to electrify. Finally, CCS can be used for emissions that are hard to abate through other means, particularly in the cement, chemicals, and iron and steel industries. Increased investments in research, development, demonstration, and deployment will advance technologies in production of iron and steel, cement, chemicals, and other industries, enabling these sectors to adopt low-carbon production.

CHAPTER 5:

REDUCING NON-CO_2 EMISSIONS THROUGH 2050

5.1 INTRODUCTION

Non-CO_2 GHGs make up 20% of the U.S. contributions to global warming **[27]**. Non-CO_2 GHGs are highly potent heat trapping gases, many of which have greater near-term climate impacts than CO_2 **[36]**. As shown in **Figure 11**, three gases make up the majority of non-CO_2 GHG emissions in the United States: methane (CH_4), nitrous oxides (N_2O), and fluorinated gases (including HFCs) **[27]**. The three sources that produce the largest proportion of emissions are soil management (i.e. agriculture and land use), livestock, and energy. While mitigation opportunities exist for many sources of non-CO_2 GHG emissions, costs and applicability vary. Because it is challenging to eliminate all of these sources, some remaining non-CO_2 emissions will need to be offset in 2050 by net-negative CO_2 emissions.

This analysis estimates that the total technical potential for non-CO_2 GHG mitigation across all sectors is approximately 35% without reducing the underlying activities **[36]**. Reducing the use of fossil fuels through efficiency and fuel switching also has the potential to further drive down non-CO_2 GHG emissions by 19% given the relationship between fugitive methane

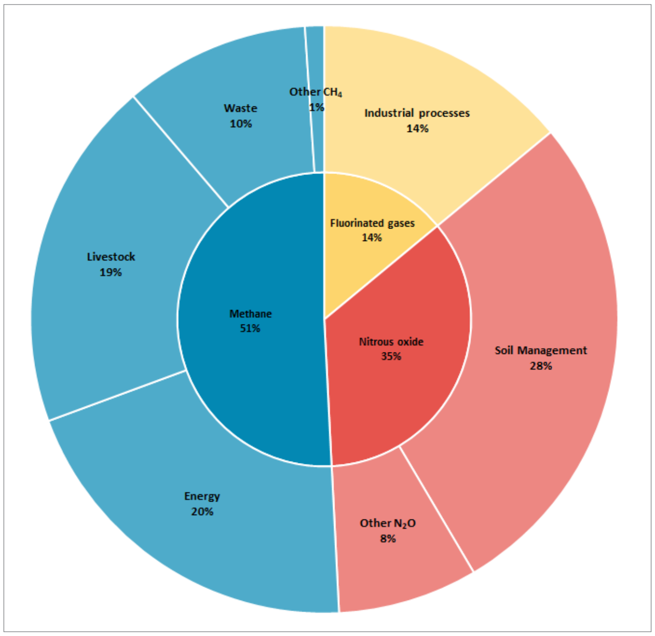


Figure 11: Sources of U.S. Non-CO_2 GHG Emissions, 2019. Contribution to 2019 U.S. GHG emissions from non-CO_2 sources partitioned by type and sector. The contributions are shown in CO_2 equivalent, meaning that they are represented in proportion to their global warming contribution 100 years after emission. Approximately half of the global warming contribution of non-CO_2 gases in 2019 came from methane, with nitrous oxide contributing the second most, followed by fluorinated gases.

emissions from the extraction, processing, and end-use of fossil fuels. These reflect multiple technological options that United States can use to achieve the necessary reductions in non-CO_2 GHG emissions to reach net-zero total emissions by 2050 **(Figure 12)**. Under these scenario assumptions, there remain non-CO_2 GHG emissions in the 2030 and 2050 timeframes, which must be offset by carbon dioxide removal.

Reductions in non-CO_2 emissions face several challenges. First is an underdeveloped set of mitigation strategies in certain subsectors. In part because of a lack of historical focus on non-CO_2 reductions, the set of available mitigation approaches for these gases is still relatively small and, in many cases, in earlier stages of technological development. This means that through 2050, overall non-CO_2 emissions can be held roughly constant by deploying currently available mitigation technologies. Achieving long-term reductions of non-CO_2 emissions below current levels requires development of new or more effective mitigation technologies and approaches. In addition, in a way that is similar to the industrial energy emissions described in **Chapter 4**, the sources of non-CO_2 emissions are diverse. This means that individual strategies must be developed for each sub-sector and gas.

In light of these challenges, this LTS analysis of non-CO_2 GHG mitigation potential assumes only modest technological and cost improvements over time. Because these assumptions may be conservative, additional, lower-cost, and more rapid reductions could be realized, and this will remain an area of active inquiry. Achieving more significant long-term reductions of non-CO_2 GHG emissions will require major technological advances and new, or more effective, backstop mitigation options. In sectors with less developed current approaches, this could include new research and development into identifying and commercializing new technologies to reduce non-CO_2 emissions. In other sectors, new

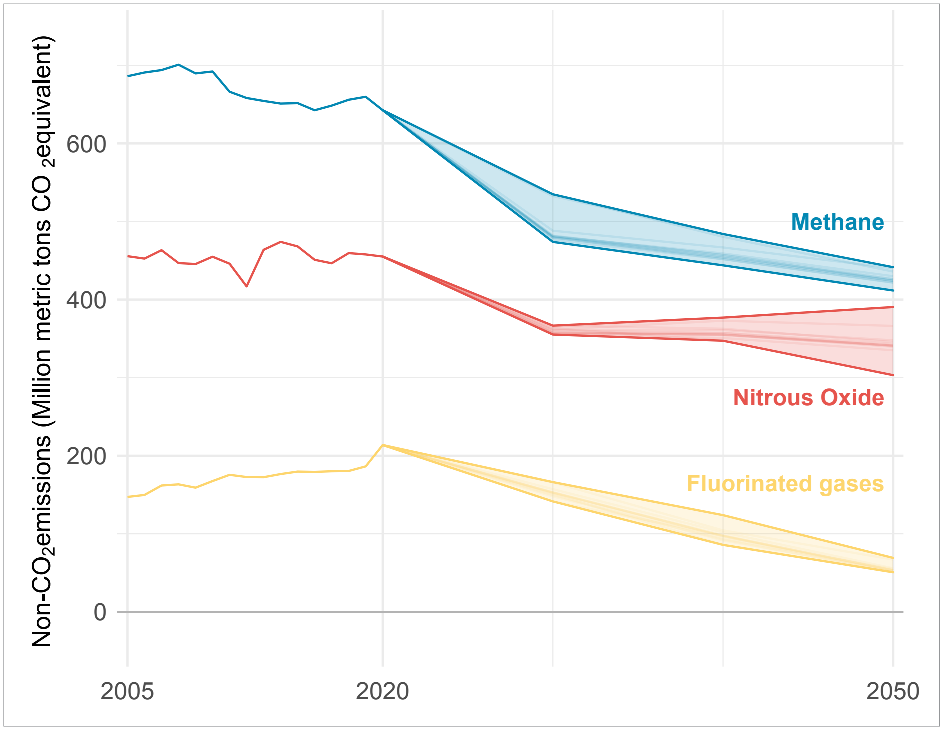


Figure 12: Pathways for Non-CO_2 Reductions from 2020 to 2050.
This figure shows the range of pathways available for non-CO_2 mitigation from today to 2050 across all modeled scenarios. In all scenarios there is significant reduction from the 2020 reference, highlighting the importance of non-CO_2 abatement.

mitigation options are under development and nearing commercialization that could result in large volumes of non-CO_2 mitigation and further reduce non-CO_2 emissions **(see Box 4)**.

5.2 KEY ABATEMENT OPPORTUNITIES

Potential reductions in non-CO_2 gases can come from a diverse set of actions, and these actions together aggregate to significant levels **(Figure 13)**. Technical potential includes technologies like anaerobic digestion of manure in the agricultural sector and leakage detection and mitigation in the oil and gas sector. As discussed above, some portion of each non-CO_2 gas, such as some of the methane and N_2O from the agriculture sector, cannot be abated in the 2050 timeframe even after applying all available mitigation technologies, and will have to be offset by negative CO_2 emissions.

5.2.1 METHANE

Methane is a potent GHG and accounts for about half of the current observed warming[5] of 1.0°C, according to the latest report of the Intergovernmental Panel on Climate

[5] Greenhouse gas emissions in total have contributed 150% of the observed warming of 1.0°C, but emissions of cooling aerosols have counter-acted some of that warming.

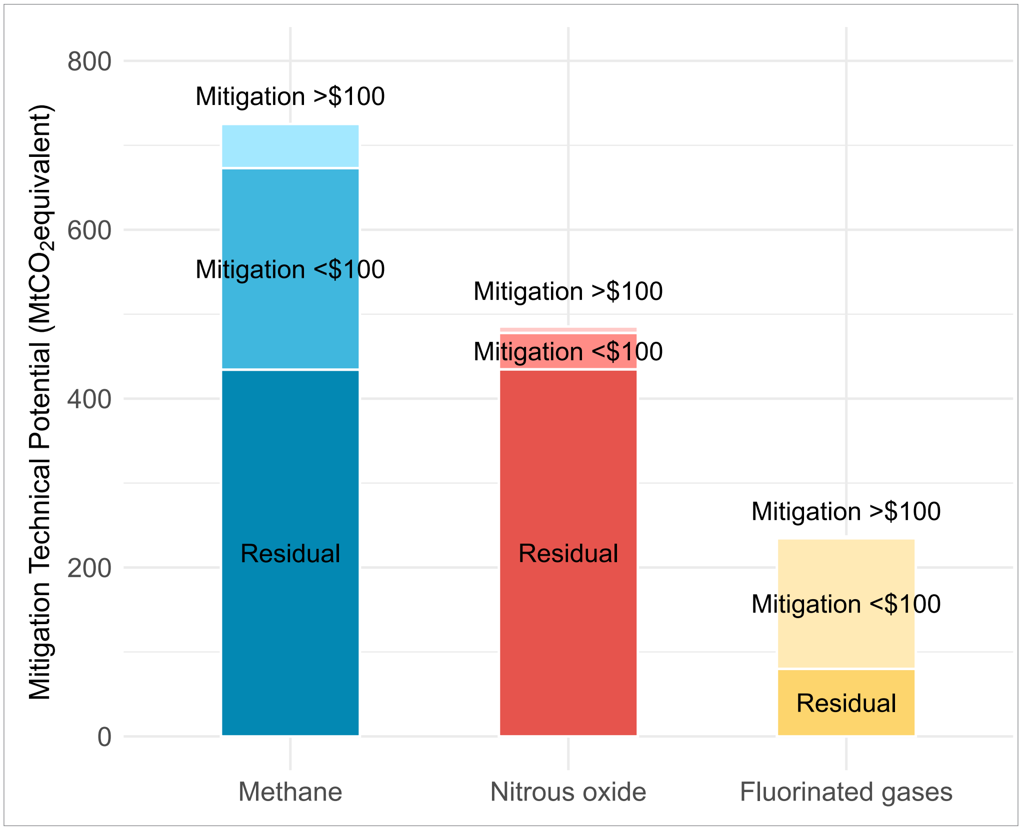


Figure 13: Non-CO_2 Mitigation Technical Potential by Gas ($MtCO_2e$) in 2050.
This figure shows potential reductions in 2050 from non-CO_2 emissions in methane, nitrous oxide, and fluorinated GHGs. It is constructed from abatement cost curves using technologies like anaerobic digestion of manure in the agricultural sector and leakage detection and mitigation in the oil and gas sector. Some abatement technologies are negative cost and many cost less than $100 per metric ton of CO_2e. Technical abatement potential is most significant for methane and fluorinated gases.

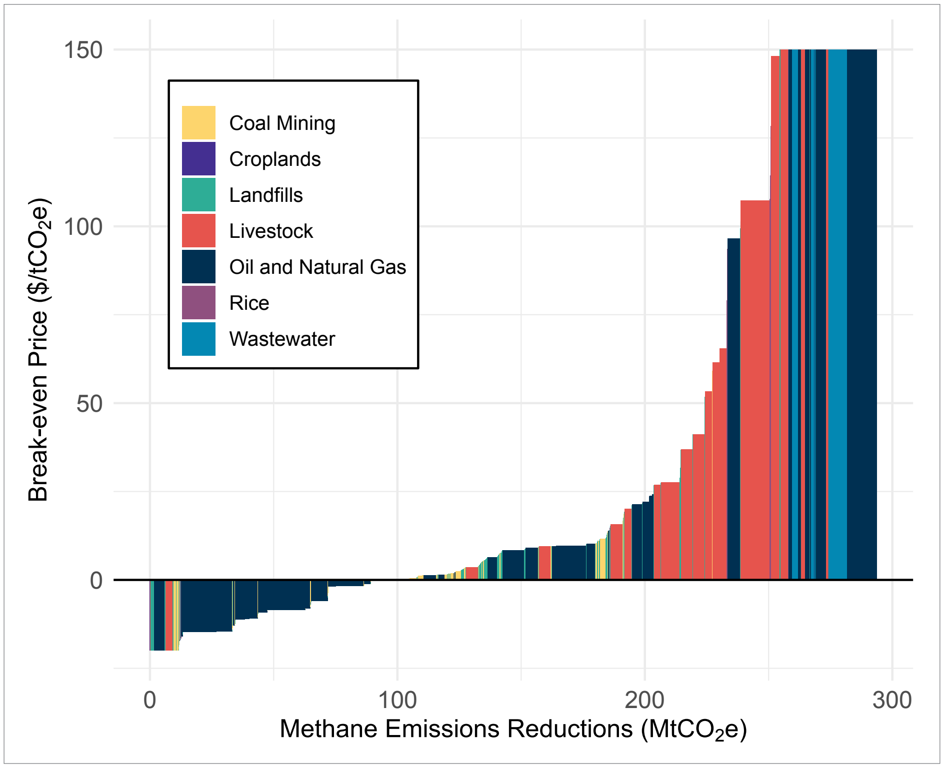


Figure 14: 2050 Methane Abatement Potential in the United States.
This figure shows sources of methane abatement potential in 2030 in the United States **[36]**. This marginal abatement cost curve indicates the price at which methane mitigation from various sources of methane are cost-effective. This figure does not include additional abatement that can be achieved by reducing the underlying activities that drive emissions. These additional reductions from activity driver changes are included in the GCAM modeling and reflected in **Figure 12**.

Change **[1]**. Methane is primarily generated by fossil fuel energy operations (oil, gas, and coal), waste operations, and livestock and agricultural operations. There are cost effective methane abatement options across all these sectors **[36]**. **Figure 14** shows 2050 methane abatement potential by source.

Methane mitigation opportunities by sector include:

- **ENERGY SECTOR METHANE.** Energy sector fugitive methane emissions result from operations in the oil and natural gas sector and the coal mining sector. In some cases, a large proportion of oil and gas methane emissions come from a small number of sources. Methane mitigation measures in oil and natural gas typically fall into three categories: equipment modifications or upgrades; changes in operational practices, including directed inspection, repair and maintenance (DI&M); and installation of new equipment **[35]**. Abatement measures are available to mitigate emissions associated with a variety of system components, including compressors, engines, dehydrators, pneumatic controls, pipelines, storage tanks, wells, and others. Commercially-available mitigation technologies can also recover and reduce CH_4 emissions from coal mining operations. These reduction technologies consist of one or more of the following primary components: a drainage and recovery system to remove CH_4 from the underground coal seam, an end use application for the gas recovered from the drainage system, and/or a ventilation air methane (VAM) recovery or mitigation system **[35]**. The CH_4 mitigation potential from the energy sector at $100/t$CO_2$e is 144 million metric tons of carbon dioxide equivalent (MtCO_2e) or approximately 43% of 2030 energy sector non-CO_2 GHG emissions and remains an important source of potential mitigation through 2050.

- **WASTE METHANE.** Landfills produce CH_4 and other landfill gases through the natural process of bacterial decomposition of organic waste under anaerobic conditions. Landfill gases are generated over a period of several decades, with flows usually beginning within 2 years of disposal. Abatement options to control landfill emissions are grouped into three categories: (1) collection and flaring, (2) landfill gas (LFG) utilization systems, and (3) enhanced waste diversion practices (e.g., recycling and reuse programs) **[35]**. Within the waste category, wastewater treatment is the second most important source of non-CO_2 GHGs. Methane emissions in wastewater treatment could be significantly reduced by 2050 through currently available mitigation options, such as anaerobic biomass digesters and centralized wastewater treatment facilities. Improved operational practices, such as controlling dissolved oxygen levels during treatment or limiting operating system upsets, can also help reduce N_2O emissions from wastewater treatment **[35]**. The CH_4 mitigation potential from the waste sector non-CO_2 GHG at $100/t is 8 Mt$CO_2$e or 6% of total 2030 waste sector emissions and remains an important source of potential mitigation through 2050.

- **LIVESTOCK METHANE.** Emissions from livestock include enteric fermentation and manure management. Enteric fermentation is a normal mammalian digestive process, where gut microbes produce CH_4. Livestock manure management produces CH_4 emissions during the anaerobic

GLOBAL METHANE PLEDGE

In September 2021 at the Major Economies Forum, the United States and European Union jointly announced the Global Methane Pledge. As of October 2021, over 30 supportive countries, representing well over 30% of global methane emissions and 60% of global GDP, had already joined—with many more expected. Countries joining the Global Methane Pledge commit to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030. They also commit to moving towards using highest-tier inventory methodologies to quantify methane emissions, with a particular focus on high emission sources.

Delivering on the Pledge would reduce warming by at least 0.2°C by 2050. In addition, it would prevent over 200,000 premature deaths, hundreds of thousands of asthma-related emergency room visits, and over 20 million tons of crop losses a year by 2030 by reducing ground-level ozone pollution caused in part by methane.

The United States is pursuing significant methane reductions on multiple fronts. The Long-Term Strategy analysis shows that the United States can do its part to meet the global goal of the Global Methane Pledge by reducing domestic methane emissions by over 30% below 2020 by 2030. This level of reduction would avoid 11,000 premature deaths, 1,600 asthma-related emergency room visits, and 4.1 million tons of agricultural losses per year in the United States.

decomposition of manure and N_2O emissions during the nitrification and denitrification of the organic nitrogen content in livestock manure and urine **[35]**. Without altering underlying demand, the mitigation potential of livestock methane at \$100/t is 70 $MtCO_2e$ or 27% of 2030 livestock non-CO_2 GHG emissions and remains an important source of potential mitigation through 2050.

- **CROPLAND AND RICE PRODUCTION METHANE.** The anaerobic decomposition of organic matter (i.e., decomposition in the absence of free oxygen) in flooded rice fields produces CH_4. GHG mitigation scenarios include several factors that influence the amount of CH_4 produced and carbon sequestration in soils, including water management practices and the quantity of organic material available to decompose **[35]**. The mitigation potential from the agriculture sector at \$100/t is 1.7 $MtCO_2e$ or 1% of 2030 agricultural CH_4 emissions **[36]**.

5.2.2 NITROUS OXIDE

Nitrous oxide (N_2O) is a potent GHG with 298 times more warming potential than carbon dioxide and a long atmospheric lifetime (approximately 114 years). N_2O comes from natural and anthropogenic sources and is removed from the atmosphere mainly by photolysis (i.e., breakdown by sunlight) in the stratosphere. In the United States, the main anthropogenic sources of N_2O are agricultural soil management, livestock waste management, mobile and stationary fossil fuel combustion, adipic acid production, and nitric acid production. N_2O is also produced naturally from a variety of biological sources in soil and water, although this report only covers man-made sources only. **Figure 15** shows 2050 nitrous oxide abatement potential by source.

Nitrous oxide mitigation opportunities by sector include:

- **AGRICULTURAL NITROUS OXIDE.** Agriculture is the source of over 82% of nitrous oxide emissions. Most N_2O is produced in soils by bacteria through the processes of nitrification and denitrification which occur with fertilizer application. It is also emitted in lesser amounts from livestock waste, rice production, and soil management such as draining, irrigation, and land use change. Nitrous oxide emissions can be mitigated by changing fertilizer management practices to increase the efficiency of plant uptake of nitrogen **[35]**. Practices include precision agriculture, using nitrification inhibitors, and splitting annual applications into seasonal applications. The mitigation potential from the agriculture sector at \$100/t is 8.8 $MtCO_2e$, which is 2.5% of 2030 nitrous oxide emissions from agriculture **[36]** and remains a small source of mitigation through 2050.

- **NITRIC AND ADIPIC ACID PRODUCTION.** Nitric acid is an inorganic compound used primarily to make synthetic commercial fertilizer. Adipic acid is a white crystalline solid used as a feedstock in the manufacture of synthetic fibers, coatings, plastics, urethane foams, elastomers, and synthetic lubricants. The production of these acids results in nitrous oxide emissions as a by-product. By 2030, about two-thirds of nitrous oxide emissions from this source category are projected to be from adipic acid production driven by high demand growth compared with about one-third from nitric acid production. Abatement measures applicable to nitric acid are characterized by the point in the production process they are implemented, but generally involve catalytic decomposition of the nitrous oxide by-products **[35]**. Thermal destruction is the abatement option applied to the adipic acid production process. The mitigation potential from nitric and adipic acid production at \$100/t is 17.7 $MtCO_2e$ or 62% of total sectoral 2030 nitrous oxide emissions **[36]** and remains an important source of mitigation through 2050.

5.2.3 FLUORINATED GASES

Fluorinated gases (F-GHGs) are anthropogenically-generated and used in a range of applications. Sometimes referred to as “climate superpollutants,” they are highly potent GHGs, capable of trapping hundreds to thousands of times more heat per molecule than carbon dioxide. According to the 2021 Inventory of U.S. Greenhouse Gas Emissions and Sinks **[27]**, most fluorinated gases emitted are hydrofluorocarbons (HFCs). A substitute for ozone-depleting substances, HFCs were initially developed to replace ozone-depleting substances (ODS) in refrigeration, air conditioning, aerosols, fire suppression, and as foam blowing agents. HFC emissions reductions are achievable by preventing or reducing leaks and transitioning to the use of alternatives with low global warming potential (GWP). **Figure 16** shows 2050 fluorinated GHG abatement potential by source.

Under the American Innovation and Manufacturing (AIM) Act of 2020, in September 2021 the EPA finalized a rule that phases down HFCs through an allowance allocation and trading program. The AIM

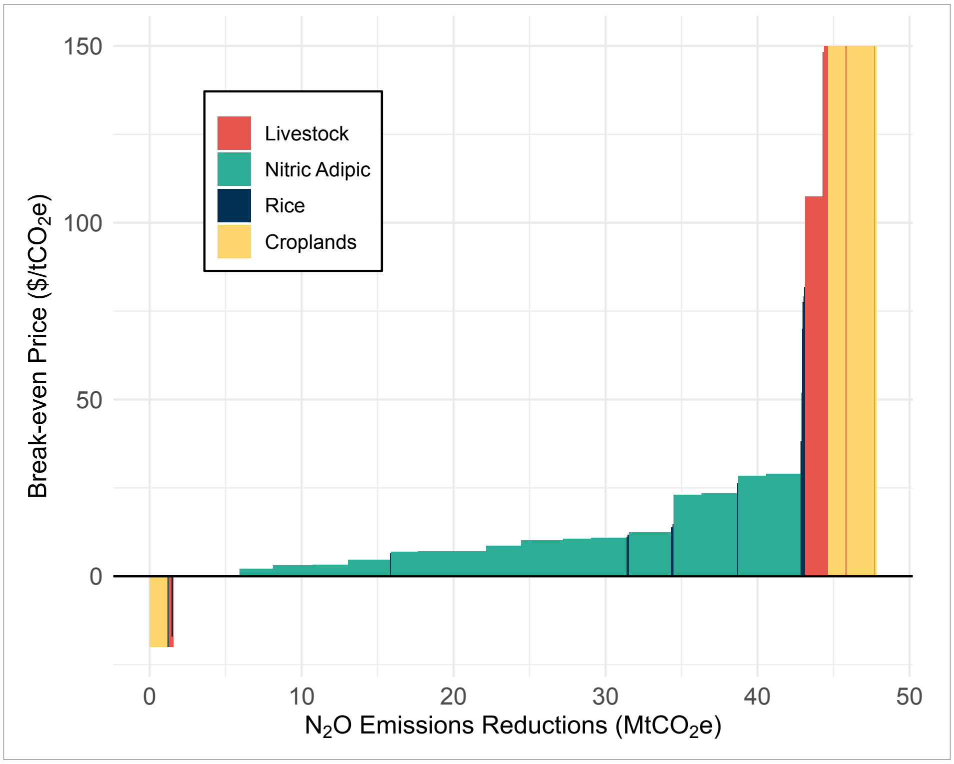


Figure 15: 2050 Nitrous Oxide Abatement Potential in the United States. This figure shows sources of nitrous oxide abatement potential in 2050 in the United States. This marginal abatement cost curve indicates the price at which nitrous oxide mitigation from various sources of are cost-effective. This figure does not include abatement associated with a reduction of the underlying activities that drive emissions. These additional reductions from activity driver changes are included in the GCAM modeling and reflected in **Figure 11**.

Act, along with this rule, provides the domestic legal framework to implement the phasedown of HFCs outlined in the Kigali Amendment to the Montreal Protocol, which 124 countries have joined to date. The phasedown will effectively decrease the production and import of HFCs in the United States by 85% by 2036 on the same step-down schedule as laid out in the Kigali Amendment and is expected to result in reductions of more than 4.5 billion metric tons of carbon dioxide-equivalent by 2050.

Achieving significant HFC reductions by 2050 will rely on a three-pronged approach. First, phase down the production and import of HFCs. Second, address the existing stock of refrigerators and air conditioners, which already contain HFCs and have potential to leak into the atmosphere over the coming decades. Third, deploy the next generation of low-GWP alternatives to existing HFCs. Additional RD&D support to ensure new alternatives to HFCs continue to enter the market may also be important, including both new molecules and new uses for existing alternatives. Combining these approaches, the mitigation potential of HFCs at less than $100/t is 84 $MtCO_2e$ which is 39% of total 2030 sectoral emissions and remains an important source of mitigation through 2050.

5.2.4 BLACK CARBON

Black carbon (soot) is not a GHG, but a powerful climate-warming aerosol [1] that is a component of fine particulate matter ($PM_{2.5}$) that enters the atmosphere through the incomplete combustion of fossil fuels, biofuels, and biomass [46]. The Arctic is particularly vulnerable to warming from black carbon. Black carbon is also a local air pollutant, contributing to major health impacts that disproportionately affect low-income and marginalized communities [47]. Transitioning from fossil fuel combustion for electricity and transport (on-road and off-road) to cleaner alternatives is key to reducing black carbon emissions in the United States. Flaring in the oil and gas sector is an additional source of black carbon. The EPA estimates that U.S. black carbon emissions have been reduced significantly since 2013 primarily due to reductions in the road and off-road transport sectors, largely through policies and strategies to reduce the emissions from mobile diesel engines. Strengthening particulate matter standards and addressing legacy diesel vehicles and emissions associated with ports, including from ships, port equipment, and trucks, would further contribute to meeting national climate, health, and climate justice goals.

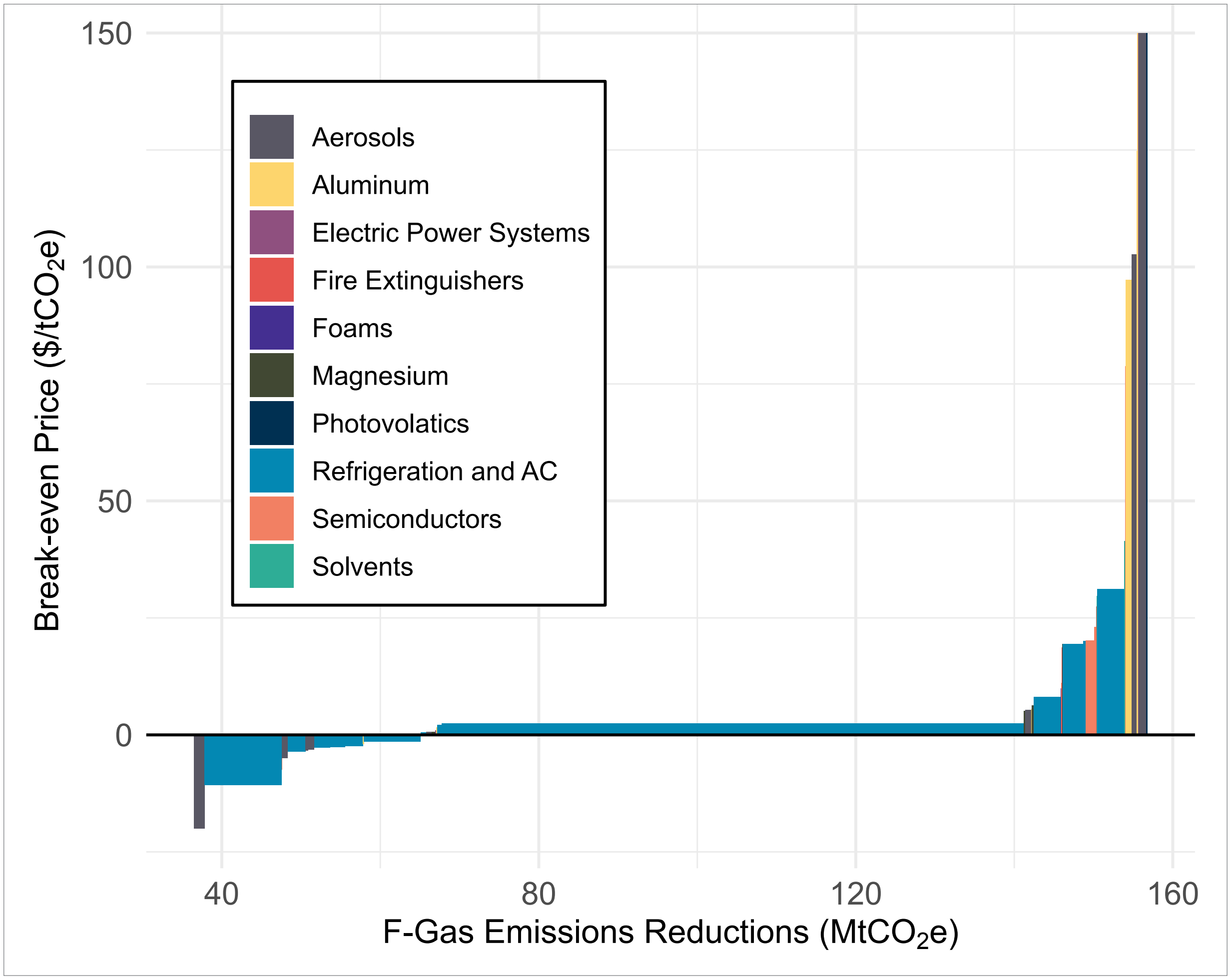
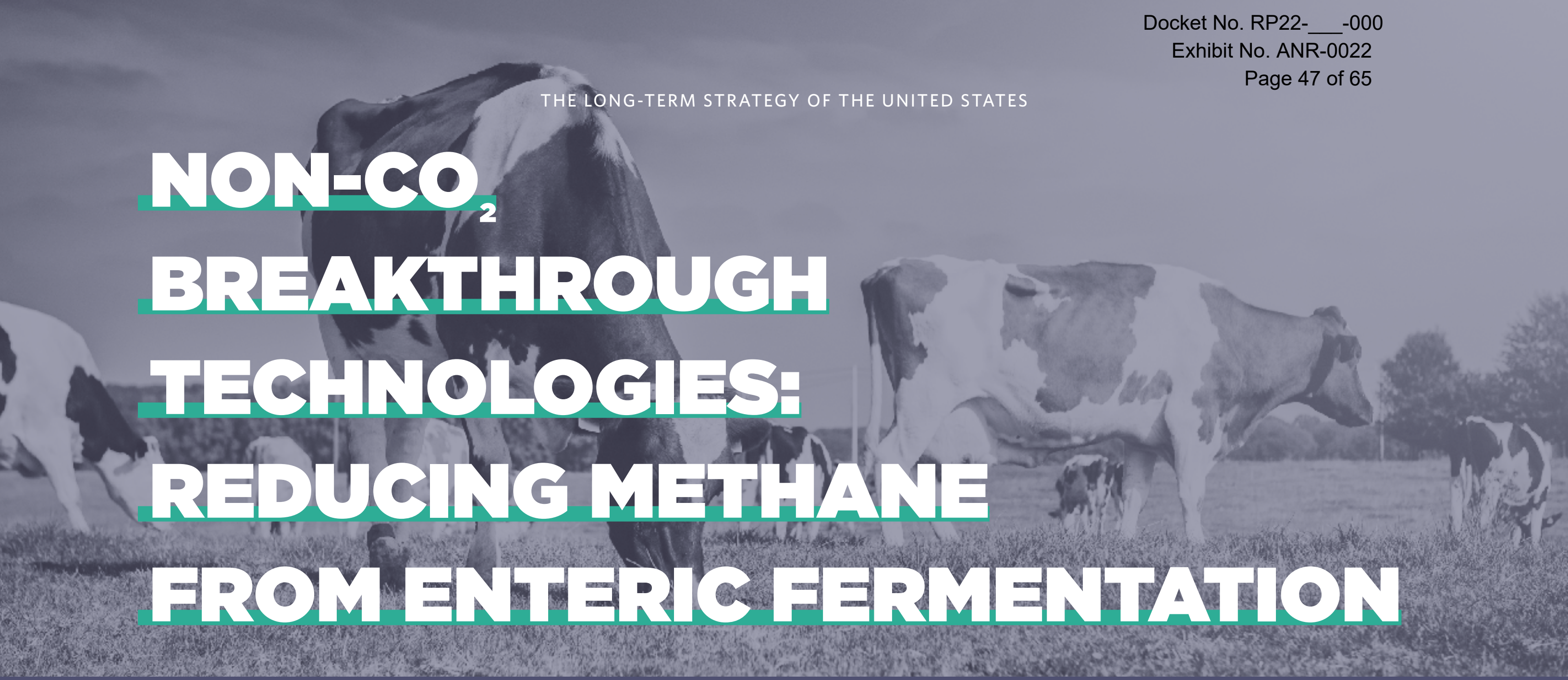


Figure 16: 2050 Fluorinated GHG Abatement Potential in the United States:
This figure shows sources of fluorinated GHG abatement potential in 2050 in the United States. This marginal abatement cost curve indicates the price at which F-GHG miti-gation from sources of are cost-effective. This figure does not include additional abatement that can be achieved by reducing the underlying activities that drive emissions. These additional reductions from activity driver changes are included in the GCAM modeling and reflected in **Figure 11**.



NON-CO_2 BREAKTHROUGH TECHNOLOGIES: REDUCING METHANE FROM ENTERIC FERMENTATION

While many low-cost abatement opportunities exist today for non-CO_2 emissions—and are reflected in this analysis—some specific applications do not have current, low-cost mitigation opportunities.

A renewed focus on research and development for these remaining non-CO_2 emission processes could potentially provide significant benefits as well as dramatically lower the costs of reductions. While not required to achieve our 2050 net-zero goal, such advances could provide valuable additional flexibility in how that goal could be achieved.

One example of this kind of positive breakthrough may be emerging. Without a technological advance, there is limited methane abatement potential from enteric sources—cattle, sheep, and goats—which produce methane as part of their digestive process. While improving productivity can, to a limited extent, help reduce methane emissions per pound of beef or gallon of milk, it does not provide a route to major reductions. However, recent research suggests that new technologies might be able to offer greatly increased effectiveness. New discoveries of low-cost feed additives indicate the possibility that these would unlock large additional potential emissions reductions. Examples of these additives include red algae *(Asparagopsis)* and a compound, 3-Nitrooxypropanol (3-NOP).

EPA and other researchers are collecting information to assess these technologies. *Asparagopsis*, 3-NOP, and other technologies that may increase non-CO_2 GHG mitigation. The science and economics of *Asparagopsis* is far from settled, with important remaining questions surrounding the costs to grow, harvest, and process *Asparagopsis* into feed, to assess scalability to produce marketable quantities (or directly synthesize bromoform); and to assess the long-term tolerance of cattle and the applicability to different production and regulatory systems. If national-scale developments prove technically and economically feasible, *Asparagopsis* could potentially decrease livestock emissions by as much as 160 $MtCO_2e$ (60%) in 2030. 3-NOP has shown strong potential for methane reduction across multiple trials, with over 45 peer-reviewed papers examining numerous aspects of the potential impacts of this additive. 3-NOP has been shown to be effective in reducing enteric emissions by about one-third in dairy cows and up to 70% in beef finishing trials without unacceptable side-effects. More innovation and testing are needed to further develop these solutions and bring them to market.

CHAPTER 6:

REMOVING CARBON THROUGH 2050 AND BEYOND

6.1 THE NECESSITY OF CO_2 REMOVAL TO REACH NET-ZERO

Efficiency, electrification of end uses, decarbonization of the electricity sector, and reduction in non-CO_2 emissions are the most important levers for decarbonizing the U.S. economy and will be the emphasis of the overall strategy to reach net-zero by 2050.

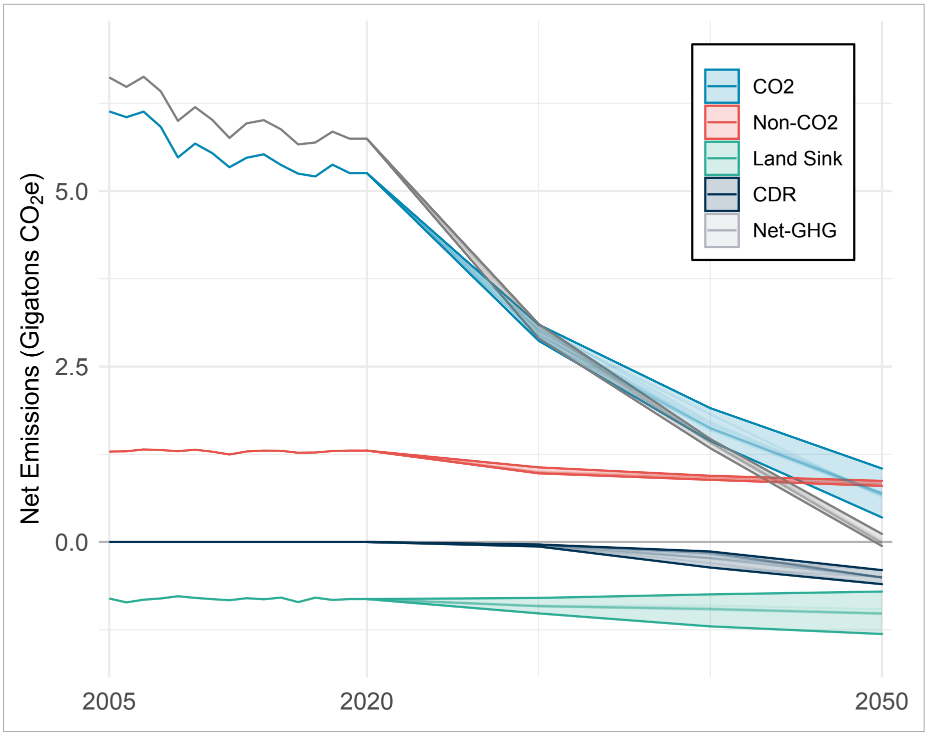


Figure 17: Balancing Emissions Reductions and Removals to Reach 2050 Net-Zero. This figure shows the range of outcomes for mitigation pathways as well as removals pathways to achieve net-zero by 2050. Some sources of non-CO_2 emissions, and potentially some CO_2 emissions, cannot be reduced to zero, and these must be balanced by CO_2 removals. CO_2 removals can happen through land sinks, such as forest growth and soil carbon sequestration, or through carbon dioxide removal technologies such as direct air capture or carbon capture and sequestration in industry or electricity generation. Note: Historical data in this figure are from the U.S. GHG Inventory (2021).

However, as mentioned in previous sections, some activities will be difficult to decarbonize completely by 2050. Because of this, removals of CO_2 from the atmosphere will be critical to enable the United States to reach net-zero by 2050 and to achieve net negative emissions thereafter. This implies an important role for the land sector, which can increase natural carbon dioxide removal and storage from the atmosphere, as well as a role for technologies including advanced carbon dioxide removal (CDR) technologies. Carbon dioxide removal technologies will only deliver desired societal and environmental benefits if their deployment is well-designed and well-governed. **Figure 17** shows the range of outcomes for mitigation pathways as well as removals pathways to achieve net-zero by 2050.

6.2 MAINTAINING AND ENHANCING CO_2 REMOVAL THROUGH THE U.S. LAND CARBON SINK

U.S. lands provide myriad social, economic, and environmental benefits. The United States has 8% of the world's forests (310 million ha) and 8% of global agricultural lands (400 million ha) **[48]**. These lands provide essential ecological, economic, and non-monetary social services, and will also be critical in supporting economy-wide decarbonization over the next 30 years and beyond.

Our lands, and human activities on those lands, emit CO_2 to the atmosphere through land conversion, soil degradation, and forest loss and degradation, but also remove it via photosynthesis and store it as carbon in trees, other vegetation, soils, and products. For the last several decades, U.S. lands have been a net carbon sink, meaning more CO_2 is sequestered than emitted annually from the land sector. This historic trend was due in part to millions of acres shifting into forest from other uses and the conservation and continued regrowth of trees on already forested lands, much of which had been deforested before the early 1900s **[49]**. Today's forest sink is still increasing but at a decreasing rate **[27]**. In 2019, the U.S. land carbon sink yielded net CO_2 removals of 813 $MtCO_2e$, offsetting approximately 12.4% of economy-wide GHG emissions **[27]**.

Though the overall U.S. lands net carbon sink has been relatively stable for recent decades, the future of that sink is uncertain **[50]**, and several challenges exist to bolstering it and expanding it significantly. Substantial forested lands, including large portions of our Western public lands, now have older forests which sequester less CO_2 and are more vulnerable to natural disturbances **[51]**. Moreover, increased levels of disturbances—fires, insects, diseases, droughts, and storms—are expected in the future, along with other potential ecosystem changes such as CO_2 fertilization, due to climate change. These changing environmental conditions will also dictate the future degree of mitigation and adaptation capabilities and opportunities **[53]**. These factors are already having an impact: total carbon removal in the land use, land use change, and forestry (LULUCF) sector has decreased by approximately 11% since 1990 **[27]**. In addition, U.S. lands include diverse ecosystems which complicates efforts at comprehensive and timely data collection, as well as monitoring and verification of baseline emissions, sequestration, and GHG outcomes of mitigation activities. In addition, the land base is finite in terms of its ability to continue to provide food, fiber, and essential ecosystem and biodiversity services while also supporting potentially increased levels of carbon-beneficial biomass for energy production and carbon removal strategies through bioenergy and CCS. In addition, CO_2 removals via natural systems can be more variable than those in other sectors or technologies, as they are subject to reversals, e.g., from natural disturbances like fires, storms, and pests or from individual landowners changing land management practices. Also, with respect to policies, U.S. lands are held and managed for different objectives by a range of different stake-holders that operate under different legal, social, and environmental norms. Achieving land sector goals necessitates coordination and cooperation with millions of private landowners, private sector corporations, and non-governmental organizations, as well as Tribal, local, state, and federal government agencies.

These challenges may be counterbalanced, at least in part, by changes in the economy, policy actions, and investments. Achieving significant land carbon benefits by 2050 and beyond requires targeted, science-based action in the near term and over the next several decades. These actions must not only work to enhance our land carbon sink but also ensure our lands continue to provide a host of other benefits, including provision of goods, jobs, ecosystem services, recreational and spiritual spaces, and biodiversity preservation. For example, public and private investments in natural climate solutions (e.g., augmented federal programs, private entities' involvement in land conservation and offset markets) can increase acreage, productivity, and overall health of U.S. forested lands **[52] [54]**. Strengthening existing and supporting new emerging timber markets, especially in the fast-growing climes of Southeast United States, can also help maintain and expand forested lands **[55]**. Policies, incentives, and investments that can support an enhanced sink through activities such as reforestation and soil carbon retention will be central. Low- or zero-carbon biomass for bioenergy and BECCS applications can also contribute to emissions reductions. These policies and programs must include safeguards to minimize issues such as potential reversals and leakage to the extent possible, and include efforts to bolster our ability to monitor, track, and verify emissions reductions at different scales.

Specific areas of focus include:

- **FORESTS.** GHG benefits in the relative near term can come from activities such as avoided forest land conversion to other uses. Some forest sector actions, such as longer harvest rotations or increased carbon storage in harvested wood products and substitution of more fossil-intensive construction materials with wood products, can yield both near- and long-term benefits **[56]**. There are considerable opportunities for reforestation in the United States **[57]**, potentially up to 133 million acres **[58]**. Other activities like afforestation, improved forest management and reduced natural disturbances (e.g., avoided forest fires via fuel treatments such as thinning and prescribed fires) can offer incremental near-term net carbon benefits and may yield substantial benefits in the long term **[59]**.
- **AGRICULTURAL LANDS.** There are potential substantial GHG mitigation and increased removal opportunities on U.S. croplands and grasslands via activities that conserve and/or increase soil carbon and employ innovative lands management approaches such as agroforestry, rotational grazing, reduced tillage, residue management, and more.
- **BIOENERGY.** Biomass is a key component of efforts to decarbonize the energy sector, as studies have shown that higher levels of biomass availability and use can offer lower-cost mitigation than decarbonization strategies without biomass (e.g., **[60] [61]**). Bioenergy can be particularly useful in deep decarbonization scenarios, as it can be used to decarbonize energy use in multiple sectors through a range of different energy pathways (e.g., liquid fuel, biogas, electricity, and hydrogen production) and it can be used in combination with CCS to further reduce GHG emissions **[9]**. Efforts aimed at employing biomass use for energy should include safeguards to ensure actual emissions reductions to the atmosphere and reflect consideration of the many non-carbon consequences of large-scale biomass production and use (e.g., competition with food production and biodiversity and broader ecosystem impacts).

6.3 ASSESSING POTENTIAL LAND SECTOR PATHWAYS

The LTS pathways explored for this study include varying degrees of private and public investment in natural climate solutions in both forestry and agriculture, such as improved forest management, fire reduction activities, afforestation, and improved agricultural soil management. To better reflect the uncertainties associated with estimating the complex carbon dynamics of different terrestrial ecosystems and related market interactions, and the potential extent of land use change between sectors, the U.S. LULUCF projections through 2050 are presented as a range, as seen in **Figure 18**. This range was developed via a collaborative multi-agency effort using different models reflecting alternate modeling techniques.

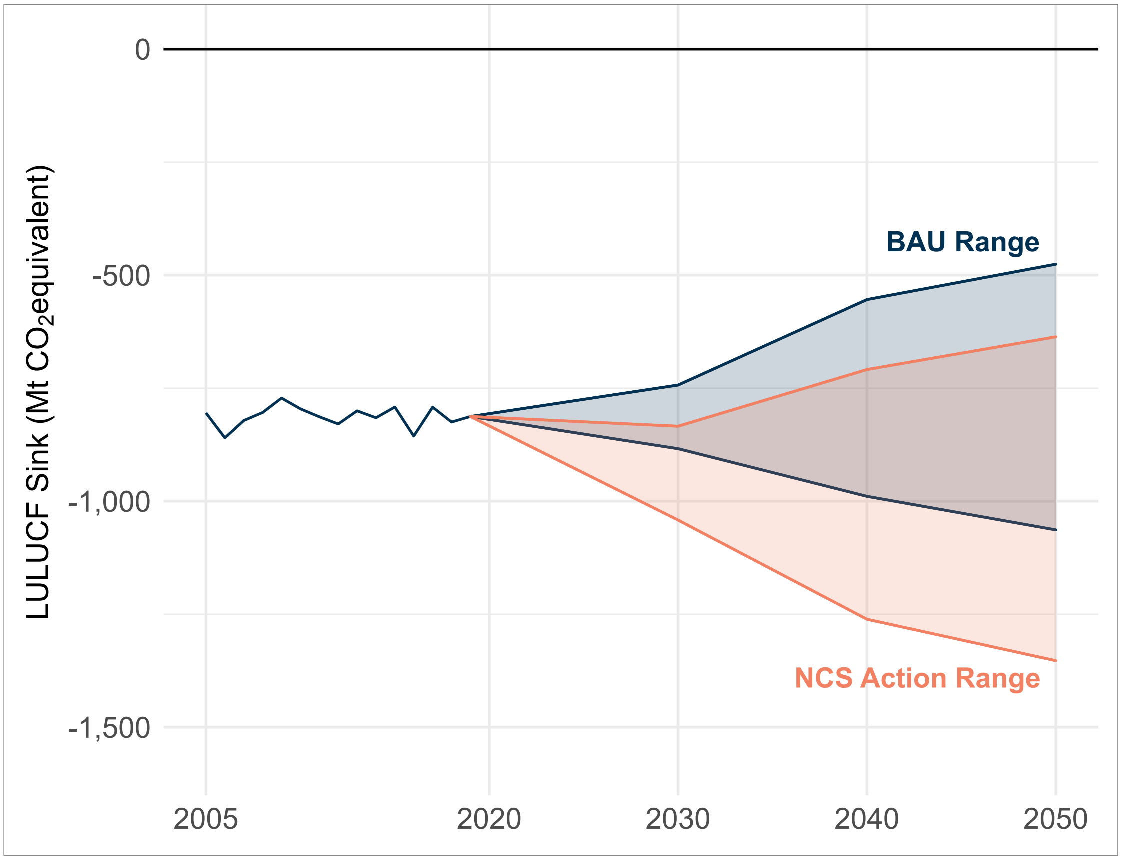


Figure 18: Land Use, Land Use Change, and Forestry CO_2 Business as Usual and LTS Action Projections with Uncertainty Ranges. There is a range of possible CO_2 outcomes for both the reference case and the Long-Term Strategy action case. Historic values are from the U.S. GHG Inventory **[27]** and projected values are derived from a range of land sector models. Estimates include forest ecosystem carbon pools, harvested wood products carbon storage, and land use and land use conversion fluxes across land types.

The analysis is based on several sectoral lands models including the Global Timber Model (GTM), the Forestry and Agriculture Sectoral Optimization Model with Greenhouse Gases (FASOM-GHG), three U.S. Forest Service models (the Resources Planning Act (RPA) Forest Dynamics model, the RPA Land Use Change model, and the Forest Resource Outlook model), and USDA agricultural soil carbon projections, to provide a range of potential land sink projections in 2050. As shown in **Figure 18**, there is a significant range of possible land sector pathways which could enable the United States to meet its net-zero goal by 2050.

6.4 CO_2 REMOVAL THROUGH ENGINEERED APPROACHES

In addition to the land sector CO_2 reduction potential, technological CO_2 removal options could be deployed over coming decades to support the net-zero emissions goal. While some technologies for such activities do exist, advanced CDR technologies are today in various stages of development.

At this early stage, it is difficult to estimate exactly which combinations of technologies might be most achievable and appropriate in terms of deployment, but potential strategies include:

- **BIOMASS CARBON REMOVAL AND STORAGE.**
This is a carbon dioxide removal approach where CO_2 is produced from the combustion, gasification, or other conversion of low- or zero-carbon biomass, for example to generate electricity or produce hydrogen, and the resulting CO_2 emissions are captured and then stored in a manner that prevents it from reentering the atmosphere. Specifically, the captured CO_2 emissions are compressed into a fluid and transported to a specified site, where they are injected into deep, underground geological formations, such as former oil and gas reservoirs or deep saline formations for long-term storage. CDR efforts using biomass as an input, such as biomass use for energy with CCS, should include safeguards to ensure actual emissions reductions to the atmosphere (e.g., including, to the extent possible, robust GHG accounting), and reflect consideration of the many non-carbon consequences of large-scale biomass production and use (e.g., competition with food production and biodiversity and broader ecosystem impacts) **[61]**.

- **DIRECT AIR CAPTURE AND STORAGE (DACS).**
This is a technology that captures CO_2 emissions directly from ambient air (instead of from point sources, such as power plants or industrial facilities), via solvent, solid sorbent, or mineral processes. The captured CO_2 is then either compressed and sequestered permanently in a geological setting or converted into a usable material such as a synthetic aggregate in concrete production.

- **ENHANCED MINERALIZATION.**
This is a CDR approach that accelerates natural geologic processes around mineral reactions with CO_2 from the ambient air, leading to permanent carbon storage through carbonate rock. There are several types of mineralization processes: in situ (e.g., CO_2 reactions in geologic formations underground), ex situ (e.g., CO_2 reactions that involve extraction, transport, and grinding of minerals), and surficial (e.g., ambient weathering using CO_2-enriched fluids and on-site minerals like mine tailings). Research and development for enhanced mineralization is still early, but the potential capacity of CO_2 mineralization could be quite high **[62].**

- **OCEAN-BASED CDR.**
This is a CDR approach that removes dissolved CO_2 from the ocean. Ocean-based approaches include nature-based approaches (e.g., kelp afforestation), engineered approaches (e.g., electrochemical CO_2 capture from seawater), or a combination of the two (e.g., growing macroalgae and sinking it to the sea floor). Ocean-based CDR is in early stages of research and development and merits closer study.

The early stages of these potential removal strategies present some visible challenges to large scale deployment by 2050. For example, there is currently no large-scale proof of concept for DAC technology or bioenergy with carbon capture and storage, making it difficult to determine how well the technology can scale up and what the true cost and adverse impacts of the technology are at large scale. In parallel, some technical obstacles remain. Research to date indicates that DAC requires high energy use for each metric ton of CO_2 removed. Other technologies, such as enhanced mineralization, are still in nascent stages of research and development, so the potential magnitude of reductions and the timeframes over which these technologies might deliver reductions is unknown. Other uncertainties associated with large-scale deployment of some technologies like BECCS could have broader upstream GHG and other environmental implications (e.g., life-cycle GHG outcomes of biomass production).

Addressing these challenges and uncertainties will require a substantial and integrated research, development, and deployment strategy. As one step towards the development and deployment of new approaches to CDR, Congress recently created the Carbon Dioxide Removal Task Force to "establish a research, development, and demonstration program…to test, validate, or improve technologies and strategies to remove carbon dioxide from the atmosphere on a large scale" **[63]**. However, additional actions will be needed to understand and innovate on CDR options, to reduce uncertainties, and to ensure sustainable outcomes.

CHAPTER 7:

BENEFITS OF CLIMATE ACTION THROUGH 2050

7.1 THE BENEFITS FROM A TRANSFORMED, NET-ZERO ECONOMY

Bold and timely climate action towards net-zero will help the United States and the world avoid the worst impacts of climate change—and provide a transformative boost to the U.S. economy and the health and well-being of all Americans. Reductions in fossil fuel combustion and reductions in non-CO_2 emissions will improve air quality and reduce the dangerous risks of climate change. The expansion of new industries will create high-quality jobs, maintain economic competitiveness, and enable sustainable, broad-based economic growth. The benefits from this transformation are not constrained by political borders: U.S. action and ambitious action from other countries will have positive spillover effects including driving down the cost of carbon-free technologies and reducing the costs of climate induced disasters and conflicts around the world, particularly for lowest-income nations that are least able to adapt.

In addition to the economic gains, action to meet the net-zero goal will, combined with global efforts, allow the United States to avoid the worst impacts of climate change, which are already being felt. For example, air pollution kills thousands of people in the United States annually **[64]** and millions worldwide, particularly in the lowest-income countries, and ongoing international conflicts are exacerbated by climate change **[65]**. The longer action is delayed, the faster the transition must be, potentially causing severe disruption **[66]**. Moreover, delay incurs more severe consequences such as changed weather regimes (including new extremes **[67]**), higher sea level rise, greater ocean acidification **[68]**, and a higher likelihood of reaching catastrophic damages or "tipping points" and potentially irreversible ecological impacts. These impacts have health and economic costs for all, but they are borne unequally, with greater consequences for low-income countries globally and communities of color, low-income communities, and indigenous communities within the United States **[69]**. For example, Black children are 34-41% more likely to live in areas with the highest projected increases in asthma diagnoses due to climate-driven changes in particulate air pollution **[68]**. These impacts are addressed more completely in the National Climate Strategy **[2]**.

7.2 IMPROVEMENTS IN PUBLIC HEALTH

Climate-driven changes in weather, human activity, and natural emissions are all expected to impact future air quality across the United States **[70]**. Acting now on climate change and decarbonizing our energy sector will result in vastly cleaner air, immediate and long-term improvements in public health, and ecological benefits throughout the United States. These benefits arise from several sources.

REDUCING GHGS CAUSES REDUCTION IN POLLUTANTS HARMFUL TO HEALTH, WELL-BEING, AND PRODUCTIVITY. Reducing GHGs to net-zero by 2050 will simultaneously reduce other pollutants, including particulate matter (PM), ozone and PM precursors, nitrous oxides (NO_x), sulfur dioxide (SO_2), and other air toxics. These benefits will be more significant in communities overburdened by air pollution. Ozone and PM are air pollutants that adversely affect human health and are monitored and regulated with national standards **[71]**. Human exposures to these pollutants have been associated with premature death, hospital admissions, and respiratory ailments, among others. A total of 60,600 deaths in the United States in 2019 alone were attributable to PM and ozone exposure **[73]**. The energy sector accounts for 80% of emissions of NO_x and 96% of SO_2 **[70]**. As the economy transitions to carbon-free energy, reductions in air pollution are also expected to increase productivity of the workforce due to health improvements. Beyond the traditional focus on mortality impacts, there is emerging evidence that minor health impacts from air pollutants can also adversely affect educational attainment and reduce labor productivity, e.g., fewer tasks completed and fewer hours worked **[74]**. Such improvements would be important because climate projections show a direct impact of future extreme temperatures reducing hours worked in the economy **[75]**.

REDUCING CLIMATE CHANGE SEVERITY SAVES LIVES AND IMPROVES HEALTH. Climate change threatens the health and well-being of Americans through catastrophic events; increases in heat-related illnesses and deaths; increases in vector-, food-, and water-borne disease; and reduced food and water quality. In addition to immediate fatalities associated with the events themselves, extreme weather events can exacerbate underlying medical conditions and disrupt critical health care, resulting in potentially lasting consequences. Furthermore, temperature increases have been linked to increases in premature death due to exposures to both cold and heat extremes; additionally heat exposure has led to increases in emergency room visits and hospital admissions for heat-related illnesses such as cardiovascular and respiratory conditions, kidney failure, and preterm birth, among others **[77]**. There are large disparities in urban heat environments in many U.S. cities that put lower-income people and people of color at higher risk of heat exposure **[79]**. Changes in temperature and rainfall patterns have been implicated in the spread of some infectious diseases in some areas, including mosquito-borne Zika and West Nile viruses, by creating conditions that promote the expansion, abundance, and activity of certain disease vectors **[76] [78]**. Waterborne diseases have been associated with excessive rainfall as well as drought conditions. Water temperature increases have contributed to the growth of toxic algal blooms and harmful pathogens (e.g., *Salmonella and Campylobacter*), the presence of which can adversely affect food security and availability **[77]**. As for air pollution, the benefits of action to reduce impacts will be strongest in communities that are historically disadvantaged, low-income, and/or lack access to health services and prevention and are therefore most vulnerable to climate change **[68]**. For example, Hispanic and Latino individuals are 25-43% more likely to currently live in areas with the highest projected labor hour losses in weather-exposed industries due to increases in high-temperature days.

7.3 AVOIDING COSTLY CLIMATE IMPACTS

Avoiding climate change will provide immediate and sustained benefits to the economy across several categories. Global emissions reductions can substantially reduce the damages of climate change in the United States **[80]**. One estimate shows reduced monetary damages from a subset of climate change impacts of $49 billion/year in 2050 and up to $388 billion/year in

2090 to the U.S. economy in 1.5°C-compatible scenarios compared to a reference scenario, from factors such as fewer deaths, less damage to infrastructure, and fewer lost wages.[6] Similarly, **Figure 19** shows the large and increasing benefits that accrue over time to the overall economy from a low-emissions pathway.[7] This analysis is only a lower bound estimate as it does not include a comprehensive accounting of all potential impacts such as other health effects, effects on managed and unmanaged ecosystems, some indirect effects, and social impacts.

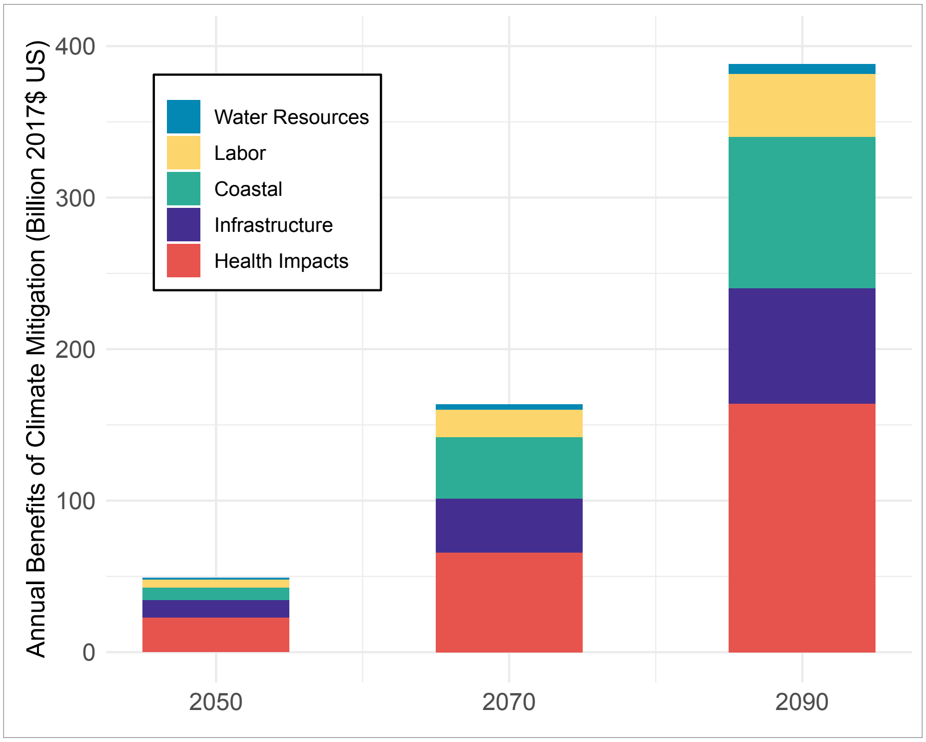


Figure 19: Projected Annual Benefits of Climate Mitigation for Select Years. Benefits from keeping to a 1.5⁰C trajectory grow significantly over time. U.S. annual economic impacts for a subset of sectors for the Reference minus 1.5°C scenario[8]. Impacts presented in billions of $2017.

[6] The temperature and radiative forcing for the two scenarios are calculated from the median over an ensemble of 600 MAGICC v7.5.1 runs selected to match assessed proxy ranges **[112]**. For the 1.5°C scenario, global mean temperature reaches 1.5°C in 2100 with a corresponding radiative forcing of 2.45 Wm^{-2} and 3.8°C in 2100 with a corresponding radiative forcing of 7.60 Wm^{-2} for the Reference scenario. Descriptions of future population, GDP, the transformation of global temperature change to continental U.S. temperature change, estimation of sea level rise, and other parameters and assumptions can be found in **[111]**. This framework includes impact estimates that employ a variety of assumptions regarding adaptive responses to climate impacts. The general adaptation scenarios considered in the analyses do not capture the complex issues that drive adaptation decision-making at regional and local scales. Adaptation and scenario assumptions used in this analysis: High Tide Flooding and Traffic impacts assume reasonably anticipated adaptation measures; Rail, Roads, Electricity Transmission and Distribution Infrastructure, and Coastal Properties assume reactive adaptation; Extreme Temperature Mortality assumes cities in cooler climates will adapt and become more resilient similar to present day cities in warm climates; and Ozone and $PM_{2.5}$ Mortality uses 2011 emissions of co-emitted pollutants. The rest of the sectors do not explicitly model adaptation.

[7] Damages, and therefore avoided damages, increase over time due to the increasing divergence in global mean temperature change between the two scenarios along with growing populations; more valuable potentially vulnerable infrastructure; and higher valuation of avoided mortality.

[8] 17 U.S. sectors are represented in this figure. Health impacts consist of the following sectors: extreme temperature mortality, ozone and $PM_{2.5}$ mortality, valley fever, wildfire health effects, and suppression and southwest dust health effects. Coastal impacts consist of the following sectors: coastal property, hightide flooding and traffic, and tropical storm wind damages. Infrastructure consists of the following sectors: rail and road infrastructure, electricity demand and supply, electricity transmission and distribution, and urban drainage. Water resources consist of the following sectors: water quality, winter recreation, and inland flooding. Lastly, the labor sector represents lost wages.

7.4 ENHANCED CLIMATE SECURITY

There is a growing body of evidence that climate change can exacerbate conflict and reduce global security. Climate change is a national security threat because it is globally destabilizing, changes military operating conditions, and demands new missions **[81]**. This means that mitigating the risk of climate change not only delivers ecological, public health, and economic benefits, but also enhances national and global security. By acting early and leading by example, the United States can build confidence in global efforts to reduce the risk of climate change **[82]**. The risks of a changing climate can make existing conflict more violent, lead to instability, and, through more erratic weather, affect the ability of the military to respond to security concerns. The U.S. National Intelligence Estimate assessment is that "climate change will increasingly exacerbate risks to U.S. national security interests as the physical impacts increase and geopolitical tensions mount about how to respond to the challenge" **[83].**

Extreme weather and conditions increasingly attributed to climate change already impact U.S. infrastructure, through the effects of sea level rise, storms, and wildfire. The U.S. Department of Defense calls climate change a "top management challenge" because of the threat to operational security and to the physical infrastructure of installations **[84]**, and finds that climate change is reshaping the geostrategic, operational, and tactical environments with significant implications for U.S. national security and defense **[6]**. It can also impact military readiness by diverting military assets and personnel to assist with disaster recovery, storms, and wildfire impact **[85]**.

Experts agree that climate-related events (droughts, storms, wildfires, and flooding) are already contributing to conflict **[86]**. While the main conflict drivers have been related to low socioeconomic development, low state capability, intergroup inequality, and a history of conflict, these drivers can be exacerbated by disruption related to climate change **[87]**. Clear causal relationships between climate change and specific conflicts are the subject of ongoing research, but drought, floods, and other disasters related to climate change have been associated with large-scale displacement of people and, in some cases, this has led to political instability and conflict.

Climate change is related to both short-term phenomena such as extreme weather events and long-term impacts such as rising sea levels and persistent drought. All of these can affect the lives and potentially the movements of large numbers of people in a way that can increase stresses within and between countries. Tropical storms, which are expected to become more severe as climate continues to change (and have already become more severe in the Atlantic Basin), already can displace large populations. Hurricane Katrina, for example, traumatically displaced tens of thousands of people from the city of New Orleans. In a country with lower capacity to address such crises, a similar event could create climate refugees and cause instability. Continued, more frequent, or more severe drought is also an expected result of climate change. In agricultural societies, severe drought can exacerbate stresses. Drought contributed to the current civil war in Syria, causing internal destabilization as well as political stresses in neighboring countries due to the resulting refugee crisis **[88]**. The impacts of long-term changing sea level have already led to climate refugees, including in parishes in southern Louisiana **[89]**—and this can be disruptive across the world. For example, a further sea level rise of six inches (15 cm) could displace millions from the Nile Delta in Egypt **[90]**. Instability in strategically important regions, even far from the United States, is a national security concern.

Societies can respond to crises like drought and water stress by strengthening political relationships that can benefit mutual security **[91]**, but, in particular for vulnerable societies, the impacts of climate change may result in increased conflict. Actively working to mitigate climate change along with helping communities to build resilience and adapt may reduce the risks of these conflicts.

7.5 BUILDING A STRONGER U.S. ECONOMY

The revolution in climate solutions has already begun. The fastest-growing power generation technologies are solar and wind, with a record-setting 35 GW of deployment in 2020, accounting for about 80% of new capacity [92]. Globally, the zero-emissions vehicle share of new car sales is expected to rise from 2% today to nearly 30% by 2030 [93], with significantly higher numbers in the United States in line with reaching 50% new car sales. In these and many other sectors, the transition to carbon neutrality will accelerate for compatibility with international climate targets [94], representing rapidly expanding new markets in the United States and globally.

The economic opportunity of decarbonization is immense. The United States is well-positioned to incubate new innovators and firms, with a well-trained workforce and institutions that have enabled global leaders in information technology, biotechnology, pharmaceuticals, and other industries [95]. Moreover, a unique endowment of natural resources makes geographic regions of the country well-suited to be hubs of a wide range of carbon-free activities [40]. The United States can lead in the clean technologies for the 21st century, manufacturing crucial technologies like batteries, electric vehicles, and heat pumps, without sacrificing critical worker protections or a fair distribution of benefits of economic activity.

Because innovation is cumulative and because many environmental technologies have returns to scale, investing early in the development of new technologies [96] will boost innovation in climate solutions and make the pathway to carbon neutrality more economically and politically feasible [97] [98]. Smart public investments in innovation stimulate private investment and economic growth and can help establish new (and often unforeseen) productive industries in the process [99] [100] [101]. One recent study finds social returns from investments in research and development are as much as four times larger than private returns [102], and an analysis of data on 16 advanced countries between 1980 and 1998 found that a 1% increase in public research and development investment generated an extra 0.17% in long-run output [103]. The benefits of accelerating innovation will spill over to our international partners, including to developing countries which will be hit hardest by climate damages and can least afford to take actions in response.

Although the overall economy will benefit from the transition to carbon neutrality, certain fossil fuel-dependent sectors and regions will have a more difficult transition. Some communities are already experiencing economic challenges from the declines in fossil fuel-related employment [104], while others (predominantly low-income communities, communities of color, and indigenous communities) are experiencing disproportionate impacts of climate disasters and air pollution. A comprehensive policy strategy can support American workers and firms through the transition, creating high-quality jobs throughout the country, including in historically marginalized communities and in regions that have lost major employers and taxpayers.

The United States can lead in clean technologies and jobs for the 21st century and is well-positioned to incubate new and innovative firms.

CHAPTER 8:

ACCELERATING GLOBAL CLIMATE PROGRESS

With our ambitious NDC target to cut emissions in half or more by 2030, and our goal for net-zero emissions no later than 2050, the United States has committed to sustained investment in a vibrant clean economy that will propel global climate action while improving social, economic, and health equity at home.

This report has presented the U.S. Long-Term Strategy to achieve these ambitious goals. The road ahead to 2050 contains opportunities, uncertainties, and challenges. The opportunities are clear and broad ranging, and collectively offer a pathway to reinventing and reinvigorating the American economy to be equitable, globally competitive, and supportive of global climate and sustainability goals. It will rely on American innovation and partnerships across all of society, including Tribal and subnational governments; private sector businesses, industry, and investors; non-governmental organizations and cultural institutions; universities, research organizations, and educational institutions; and our people. Together, we can meet the challenges in developing and deploying new clean technologies at scale. We can discover new and creative ways to provide better services and products with lower climate footprints. And we can develop, train, and educate workers for productive and healthier work in new and fast-growing industries. Undoubtedly, the U.S. roadmap will evolve as we learn more about the potential for new technologies in diverse applications, and as new policy platforms are developed over time. The United States intends to regularly review and update this Long-Term Strategy as needed to consider such developments and the latest science.

Given the rapid pace of action in the United States and other leading countries, if other major economies adopt similar levels of ambition, the world can keep a safer 1.5°C future within reach. For its part, the United States currently emits 11% of annual global GHGs (second to China, which emits 27% of the global total), so eliminating U.S. emissions by 2050 will make an important direct contribution to reaching our shared global climate goals. However, others must step up with both long-term and short-term ambition, and many are already doing so. To date, at least 63 countries representing over half current global emissions have committed to net-zero GHG emissions targets. Many more, representing over 70% of global emissions, are in diverse stages of identifying and committing to similar net-zero targets by mid-century **[105] [106] [107].** These commitments matter: achieving near-net-zero emissions globally by 2050 will dramatically improve our chances of limiting global warming to near 1.5°C.

However, while the rapid expansion of 2050 targets and long-term strategies is encouraging, commitments to act by 2030 are also critical. Countries representing well over half of the global economy, including nearly all the G7 countries, have already put forward strong 2030 NDCs. Leadership and action by these countries will support development of new and more affordable climate technologies and support enhanced diplomatic momentum to encourage global action toward reaching sufficient levels of near-term action.

But the United States, EU, UK, Japan, Canada, Republic of Korea, South Africa, and other ambitious major economies cannot do it alone. Strong 2030 NDCs will be required by all G20 economies to cut global emissions by at least 40% by 2030. Enhanced action by all G20 members to adopt high ambition 2030 NDCs and mid-century net-zero commitments could reduce warming by over 0.5°C and keep 1.5°C within reach **[108]**. Globally, this is the moment for all the world's major economies to act to rapidly reduce emissions to meet ambitious 2030 NDC targets and to develop and communicate strategies to achieve ambitious 2050 net-zero goals.

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