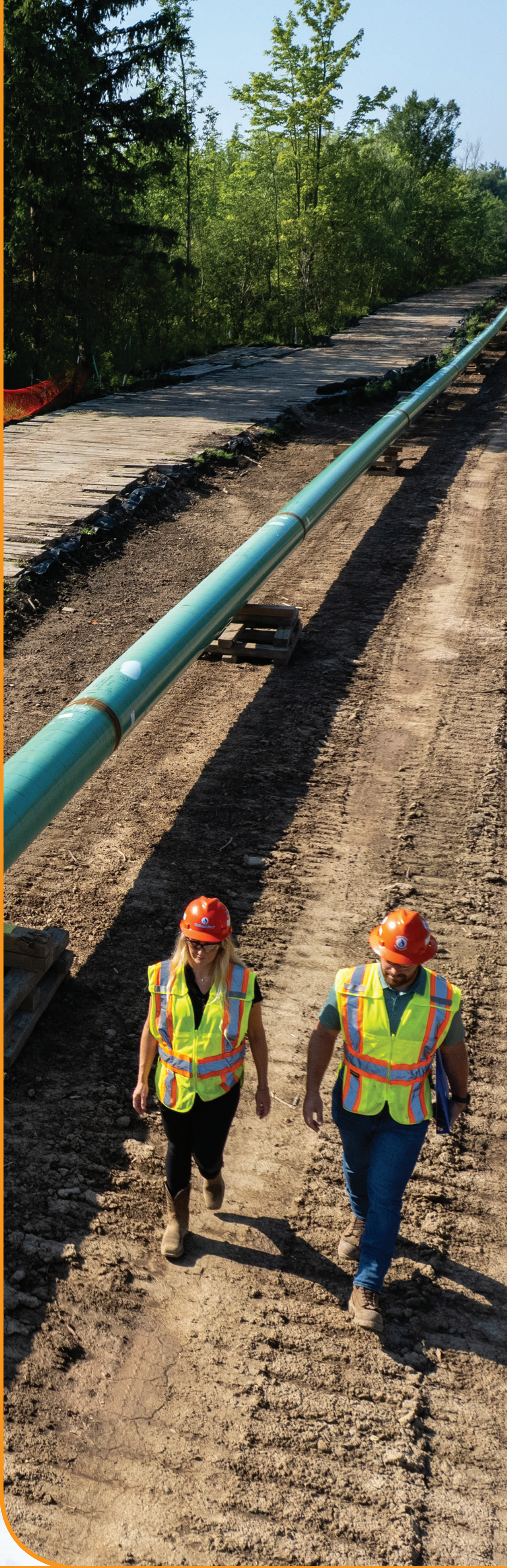
National Fuel®



# 2025 | Annual Report

“Fiscal 2025 was a terrific year, marked by significant milestones across our businesses. Our operational excellence and strong execution provide a solid platform for continued long-term growth. With natural gas increasingly recognized as a critical fuel for the future, the outlook for National Fuel has never been stronger.” – David P. Bauer

## Dear Fellow Shareholders,

Fiscal 2025 was an exceptional year for National Fuel. Thanks to the quality of our assets and the dedication of our employees, we delivered strong financial results and positioned the Company for even greater success in the years ahead.

## Significant Earnings Growth

Consolidated earnings per share grew substantially as a result of higher natural gas production and prices in our non-regulated operations, and the continuing revenue impact of our recent rate settlements at our regulated businesses. Our strong earnings performance allowed us to increase our dividend for the 55th consecutive year, which underscores our commitment to creating long-term value for shareholders.

## Driving Capital Efficiency and Expanding Our Drilling Inventory

With a 15% increase in natural gas production and a 12% reduction in capital investment (excluding acquisitions) since 2023, our Integrated Upstream and Gathering business continued its impressive trend in capital efficiency, with a nearly 25% improvement over that period. These results clearly highlight the strength of our assets and the talent of our workforce. And with our Tioga County development program still in its early stages, we expect additional opportunities to improve on this key metric in the coming years.

Further, this year we made significant progress in the delineation of the Upper Utica formation on the Tioga County acreage, which allowed us to add more than 200 highly economic locations to our drilling inventory. This gives us nearly 20 years of premium prospective well locations – a depth few can match. Importantly, we also secured substantial new pipeline capacity out of this key development area to ensure we have the takeaway needed to support our growing base of natural gas production that we expect in the years ahead.

## Strong Performance in Our Regulated Businesses

Our regulated businesses continued to deliver solid results, and recent rate settlements have strengthened our near-term outlook. In fiscal 2025, Pipeline and Storage revenues increased by $15 million, driven by the 2024 Supply Corporation rate case settlement. And in December 2024, we reached a three-year settlement in our Utility’s New York jurisdiction, providing clear visibility for growth through fiscal 2027.

Looking to the future, we continue to invest in the safety and reliability of our pipeline systems, replacing over 160 miles of our Utility’s distribution system in fiscal 2025, while also completing various system modernization projects at our interstate pipelines. These investments not only improve the quality of our service but also drive long-term value for shareholders.

**Cover Top Left:** Seneca Resources operates a drilling rig at a well pad in Tioga County, Pennsylvania. Over the past few years, Seneca has made notable strides in capital efficiency, reflecting the quality of its assets, a focused development strategy and strong operational performance.

**Cover Right:** The Line UNY Pipeline Project in Lancaster, New York, is a strategic infrastructure upgrade that replaced aging pipeline with high-strength, coated steel. This project is designed to enhance safety, reliability and operational efficiency.

**Cover Bottom Left:** National Fuel operations and customer service teams work through all weather, including the severe winter conditions of Western New York and Northwestern Pennsylvania. In winter 2025, Erie and Buffalo ranked among the snowiest cities in the country, facing multiple lake-effect storms. Our employees’ dedication keeps service reliable, even in the harshest conditions.

**Opposite Page:** Zoar Valley, located along the border of Erie and Cattaraugus Counties in New York, is the site of National Fuel’s first gas storage field.

## Executing on Pipeline Expansion Projects

Expansion opportunities in our Pipeline and Storage segment are accelerating. This summer, we received FERC approval for the Tioga Pathway Project, which will provide 190,000 dekatherms per day of takeaway capacity for the Company's Tioga County production. We also announced the Shippingport Lateral Project, which will provide 205,000 dekatherms per day of firm transportation capacity for a major power generation and data center facility in Western Pennsylvania. Together, these projects, both of which are targeted for late 2026 in-service, are expected to generate approximately $30 million in annual revenue.

As was evident at the July 2025 Pennsylvania Energy and Innovation Summit in Pittsburgh, the Commonwealth of Pennsylvania is committed to using its vast energy resources to attract new industry. Over $90 billion in new investments were announced at the Summit, many of which will be made in the vicinity of our existing pipeline systems. Against this backdrop, we are optimistic that the Shippingport project will be the first of many projects to come.

## Announced a Highly Strategic Ohio Utility Acquisition

In October, we executed an agreement to acquire CenterPoint Energy's Ohio natural gas utility business for $2.6 billion, the largest acquisition in the Company's history. With the closing of the transaction – expected in late 2026 – National Fuel will double its utility rate base, add significant customers in a state that is highly supportive of natural gas, and create another avenue for stable, long-term growth.

## Natural Gas: A Critical Part of the Energy Future

After years of commentary that rising energy demand could be met solely with wind and solar, policymakers (particularly in New York) are clearly shifting toward an "all-of-the-above" approach that prioritizes affordability and reliability. Natural gas is essential – whether for heating homes, meeting growing electricity demand from data centers, or supporting global LNG exports. The world needs more energy, and natural gas will be an important part of the solution. With integrated assets spanning the natural gas value chain, National Fuel is well positioned to serve this growing demand.

## Recognizing Leadership Transitions

This year marks the retirement of two outstanding leaders at the Company: Ron Kraemer and Donna DeCarolis. Ron and Donna have each made lasting contributions to National Fuel, guiding their teams with integrity, vision, and a deep commitment to our industry. Their leadership has been instrumental in shaping the success we celebrate today. On behalf of the entire organization, I want to thank them for their decades of service and wish them the very best in their well-deserved retirements.

The outlook for National Fuel has never been brighter. Backed by our talented workforce – our best asset – we are poised in the years ahead for meaningful growth across each of our business segments. I'm excited for the future and look forward to building on our legacy in the natural gas business and creating long-term value for our shareholders.

David P Bauer

**David P. Bauer**
President and Chief Executive Officer
January 6, 2026

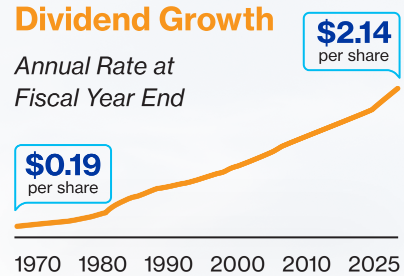
## Over a Half Century of Dividend Growth

**$1.6 billion returned** to shareholders over the last 10 years

**4% dividend increase** in fiscal 2025

**55 Years of Consecutive Dividend Growth**

*Annual Rate at Fiscal Year End*




**Top Left:** To support a growing residential complex in Amherst, New York, National Fuel successfully installed approximately 800 feet of 4-inch main and four 2-inch service lines, ensuring reliable energy delivery to more than 240 residences.

**Top Right:** National Fuel conducts informational tours of our operations for investors, students, public officials, emergency responders and other stakeholders to promote industry education and maintain transparency.

**Bottom Right:** At various locations, teams are now working in newly renovated office spaces designed to foster collaboration. A new Command Center was also recently constructed to strengthen our security and emergency response capabilities.

# Fiscal 2025 Highlights

## Integrated Upstream & Gathering Net Production *(Bcfe)*


## Utility Investment in Safety *($ millions)*


## Integrated Upstream & Gathering Capital Spend *($ millions)*


## Pipeline & Storage Revenues *($ millions)*


# Significant Progress on Emissions Reduction Program Through 2024

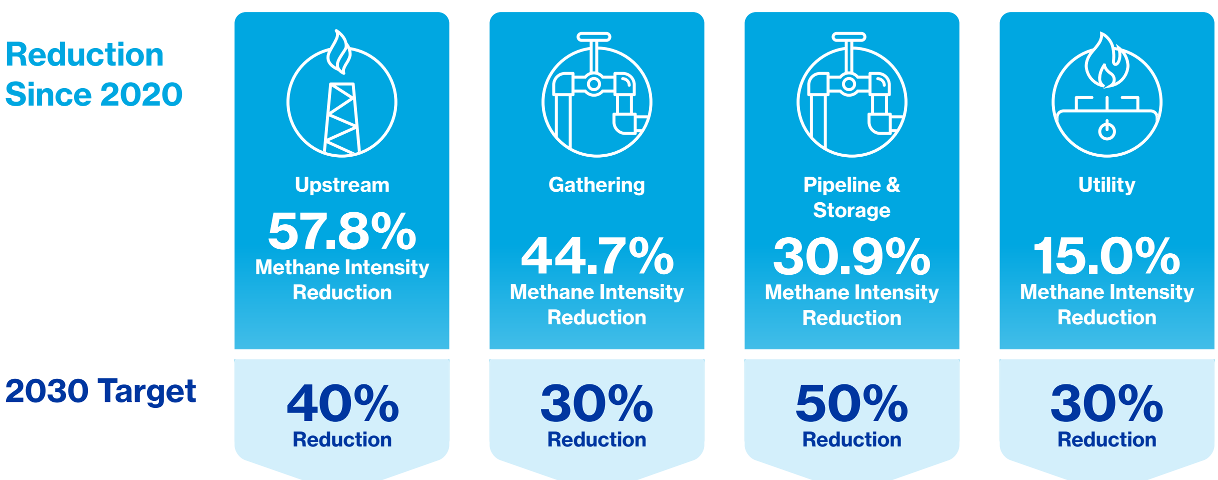


**Photo:** The Keeneyville Compressor Station in Tioga County, Pennsylvania, serves as a centralized facility where Seneca Resources' production gas is gathered, compressed and delivered into the transmission mainline. Leveraging state-of-the-art technology and automation, the station ensures safe, efficient and reliable operations.

National Fuel®

**National Fuel Gas Company** *(NYSE: NFG)*

6363 Main Street
Williamsville, New York 14221

716-857-7000 | www.nationalfuel.com

**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C. 20549**
# Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the Fiscal Year Ended September 30, 2025**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the Transition Period from to**
**Commission File Number 1-3880**

# National Fuel Gas Company

*(Exact name of registrant as specified in its charter)*

| New Jersey | 13-1086010 |
|---|---|
| *(State or other jurisdiction of incorporation or organization)* | *(I.R.S. Employer Identification No.)* |
| 6363 Main Street<br>Williamsville, New York | 14221 |
| *(Address of principal executive offices)* | *(Zip Code)* |

**(716) 857-7000**
*(Registrant's telephone number, including area code)*

**Securities registered pursuant to Section 12(b) of the Act:**

| Title of Each Class | Trading Symbol | Name of Each Exchange on Which Registered |
|---|---|---|
| Common Stock, par value $1.00 per share | NFG | New York Stock Exchange |

**Securities registered pursuant to Section 12(g) of the Act: None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

| | | | |
|---|---|---|---|
| Large accelerated filer | ☑ | Accelerated filer | ☐ |
| Non-accelerated filer | ☐ | Smaller reporting company | ☐ |
| | | Emerging growth company | ☐ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $7,009,145,000 as of March 31, 2025.

Common Stock, par value $1.00 per share, outstanding as of October 31, 2025: 90,386,463 shares.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the registrant's definitive Proxy Statement for its 2026 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days of September 30, 2025, are incorporated by reference into Part III of this report.

## Glossary of Terms

Frequently used abbreviations, acronyms, or terms used in this report:

***National Fuel Gas Companies***

**Company** The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure

**Distribution Corporation** National Fuel Gas Distribution Corporation

**Empire** Empire Pipeline, Inc.

**Midstream Company** National Fuel Gas Midstream Company, LLC

**National Fuel** National Fuel Gas Company

**Registrant** National Fuel Gas Company

**Seneca** Seneca Resources Company, LLC

**Supply Corporation** National Fuel Gas Supply Corporation

***Regulatory Agencies***

**CFTC** Commodity Futures Trading Commission

**EPA** United States Environmental Protection Agency

**FASB** Financial Accounting Standards Board

**FERC** Federal Energy Regulatory Commission

**IRS** Internal Revenue Service

**NYDEC** New York State Department of Environmental Conservation

**NYPSC** State of New York Public Service Commission

**PaPUC** Pennsylvania Public Utility Commission

**PHMSA** Pipeline and Hazardous Materials Safety Administration

**SEC** Securities and Exchange Commission

***Other***

**2017 Tax Reform Act** Tax legislation referred to as the "Tax Cuts and Jobs Act," enacted December 22, 2017.

**Bbl** Barrel (of oil)

**Bcf** Billion cubic feet (of natural gas)

**Bcfe (or Mcfe) — represents Bcf (or Mcf) Equivalent** The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. The Company uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.

**Btu** British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit.

**Capital expenditure** Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.

**Cashout revenues** A cash resolution of a gas imbalance whereby a customer pays Supply Corporation and/or Empire for gas the customer receives in excess of amounts delivered into Supply Corporation's and Empire's systems by the customer's shipper.

**CLCPA** Legislation referred to as the "Climate Leadership & Community Protection Act," enacted by the State of New York on July 18, 2019.

**Degree day** A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.

**Derivative** A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, options, no cost collars and swaps.

**Development costs** Costs incurred to obtain access to proved gas and oil reserves and to provide facilities for extracting, treating, gathering and storing the gas and oil.

**Development well** A well drilled to a known producing formation in a previously discovered field.

**Dth** Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.

**ESG** Environmental, social and governance

**Exchange Act** Securities Exchange Act of 1934, as amended

**Expenditures for long-lived assets** Includes capital expenditures, stock acquisitions and/or investments in partnerships.

**Exploitation** Development of a field, including the location, drilling, completion and equipment of wells necessary to produce the commercially recoverable oil and gas in the field.

**Exploration costs** Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.

**Exploratory well** A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial hydrocarbon deposit.

**Firm transportation and/or storage** The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.

**GAAP** Accounting principles generally accepted in the United States of America

**Goodwill** An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.

**Hedging** A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often through the use of derivative financial instruments.

**Hart-Scott-Rodino Act** The Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and the rules and regulations promulgated thereunder by the Federal Trade Commission.

**Hub** Location where pipelines intersect enabling the trading, transportation, storage, exchange, lending and borrowing of natural gas.

**ICE** Intercontinental Exchange. An exchange which maintains a futures market for crude oil and natural gas.

**Impact Fee** An annual fee imposed on unconventional wells spud in Pennsylvania. The fee is administered by the PaPUC and fees are distributed to counties and municipalities where the well is located.

**Interruptible transportation and/or storage** The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service, and for which the customer does not pay unless utilized.

**LDC** Local distribution company

**LIFO** Last-in, first-out

**Marcellus Shale** A Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York.

**Mbbl** Thousand barrels (of oil)

**Mcf** Thousand cubic feet (of natural gas)

**MD&A** Management's Discussion and Analysis of Financial Condition and Results of Operations

**MDth** Thousand decatherms (of natural gas)

**Methane** The primary component of natural gas. It is a compound made up of one carbon atom and four hydrogen atoms ($CH_4$).

**MMBtu** Million British thermal units (heating value of one decatherm of natural gas)
**MMcf** Million cubic feet (of natural gas)
**MMcfe** Million cubic feet equivalent
**Natural Gas** A naturally occurring mixture of gaseous hydrocarbons consisting primarily of methane and found in underground rock formations.
**NGA** The Natural Gas Act of 1938, as amended; the federal law regulating interstate natural gas pipeline and storage companies, among other things, codified beginning at 15 U.S.C. Section 717.
**NOAA** National Oceanic and Atmospheric Administration
**NYMEX** New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.
**OPEB** Other Post-Employment Benefit
**Open Season** A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.
**PCB** Polychlorinated Biphenyl
**Precedent Agreement** An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called "conditions precedent") happen, usually within a specified time.
**Proved developed reserves** Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
**Proved undeveloped (PUD) reserves** Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make those reserves productive.
**Reliable technology** Technology that a company may use to establish reserves estimates and categories that has been proven empirically to lead to correct conclusions.
**Reserves** The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
**Revenue decoupling mechanism** A rate mechanism which adjusts customer rates to render a utility financially indifferent to throughput decreases resulting from conservation.
**S&P** Standard & Poor's Ratings Service
**SAR** Stock appreciation right
**Section 7(b)/7(c) application** An application to the FERC under Section 7(b)/7(c) of the federal Natural Gas Act for authority to construct, operate (and provide services through) facilities to transport or store natural gas in interstate commerce.
**Service Agreement** The binding agreement by which the pipeline company agrees to provide service and the shipper agrees to pay for the service.
**SOFR** Secured Overnight Financing Rate
**Spot gas purchases** The purchase of natural gas on a short-term basis.
**Stock acquisitions** Investments in corporations.
**Unbundled service** A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.
**Utica Shale** A Middle Ordovician-age geological formation lying several thousand feet below the Marcellus Shale in the Appalachian region of the United States, including much of Ohio, Pennsylvania, West Virginia and southern New York.
**VEBA** Voluntary Employees' Beneficiary Association
**WNA** Weather normalization adjustment; an adjustment in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

**For the Fiscal Year Ended September 30, 2025**

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**Part III**



**Part IV**

## PART I

### Item 1 *Business*

### The Company and its Subsidiaries

National Fuel Gas Company (the Registrant), incorporated in 1902, is a holding company organized under the laws of the State of New Jersey. The Registrant owns directly or indirectly all of the outstanding securities of its subsidiaries. Reference to "the Company" in this report means the Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure. Also, all references to a certain year in this report relate to the Company's fiscal year ended September 30 of that year unless otherwise noted.

The Company is a diversified energy company engaged principally in the production, gathering, transportation, storage and distribution of natural gas. The Company operates an integrated business, with assets centered in western New York and Pennsylvania, being used for, and benefiting from, the production and transportation of natural gas from the Appalachian Basin. Current natural gas production development activities are focused in the Marcellus and Utica shales, geological formations that are present nearly a mile or more below the surface in the Appalachian region of the United States. Pipeline development activities are designed to transport natural gas production to both existing and new markets. The common geographic footprint of the Company's subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Appalachian Basin to markets in the eastern United States and Canada. The Company reports financial results for three business segments: Integrated Upstream and Gathering, Pipeline and Storage, and Utility.

1. The Integrated Upstream and Gathering segment is composed of the operations of Seneca Resources Company, LLC and National Fuel Gas Midstream Company, LLC, both Pennsylvania limited liability companies. Seneca is engaged in the exploration for, and development of, natural gas reserves in the Appalachian region of the United States. Midstream Company builds, owns and operates natural gas processing and pipeline gathering facilities in the Appalachian region, primarily providing gathering services to Seneca. At September 30, 2025, Seneca had proved developed and undeveloped reserves of 4,980,410 MMcf of natural gas and 180 Mbbl of oil.

2. The Pipeline and Storage segment operations are carried out by National Fuel Gas Supply Corporation, a Pennsylvania corporation, and Empire Pipeline, Inc., a New York corporation. Supply Corporation and Empire provide interstate natural gas transportation services for affiliated and nonaffiliated companies through integrated natural gas pipeline systems in Pennsylvania and New York. Supply Corporation also provides storage services through its underground natural gas storage fields, and Empire provides storage service (via lease with Supply Corporation) to a nonaffiliated company.

3. The Utility segment operations are carried out by National Fuel Gas Distribution Corporation, a New York corporation. Distribution Corporation provides natural gas utility services to approximately 756,000 customers through a local distribution system located in western New York and northwestern Pennsylvania. The principal metropolitan areas served by Distribution Corporation include Buffalo, Niagara Falls and Jamestown, New York and Erie and Sharon, Pennsylvania.

Financial information about each of the Company's business segments can be found in Item 7, MD&A and also in Item 8 at Note M — Business Segment Information.

Revenue from one customer of the Company's Integrated Upstream and Gathering segment, exclusive of hedging losses transacted with separate parties, represented approximately $258 million, or 11.3%, of the Company's consolidated revenue for the year ended September 30, 2025. This one customer was also a customer of the Company's Pipeline and Storage segment, accounting for an additional $16 million, or 0.7%, of the Company's consolidated revenue for the year ended September 30, 2025.

**Rates and Regulation**

The Company's businesses are subject to regulation under a wide variety of federal, state and local laws, regulations and policies. This includes federal and state agency regulations with respect to rate proceedings, project permitting and environmental requirements.

The Company is subject to the jurisdiction of the FERC with respect to Supply Corporation, Empire and some transactions performed by other Company subsidiaries. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. The operations of Distribution Corporation are subject to the jurisdiction of the NYPSC, the PaPUC and, with respect to certain transactions, the FERC. The NYPSC and the PaPUC, among other things, approve the rates that Distribution Corporation may charge to its utility customers. Those approved rates also impact the returns that Distribution Corporation may earn on the assets that are dedicated to those operations. If Supply Corporation, Empire or Distribution Corporation are unable to obtain approval from these regulators for the rates they are requesting to charge customers, particularly when necessary to cover increased costs, earnings may decrease. For additional discussion of the Pipeline and Storage and Utility segments' rates, see Item 7, MD&A under the heading "Rate Matters" and Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) and Note F — Regulatory Matters.

The discussion under Item 8 at Note F — Regulatory Matters includes a description of the regulatory assets and liabilities reflected on the Company's Consolidated Balance Sheets in accordance with applicable accounting standards. To the extent that the criteria set forth in such accounting standards are not met by the operations of the Utility segment or the Pipeline and Storage segment, as the case may be, the related regulatory assets and liabilities would be eliminated from the Company's Consolidated Balance Sheets and such accounting treatment would be discontinued.

The FERC also exercises jurisdiction over the construction and operation of interstate gas transmission and storage facilities and possesses significant penalty authority with respect to violations of the laws and regulations it administers. The Company is also subject to the jurisdiction of the PHMSA. PHMSA issues regulations and conducts evaluations, among other things, that set safety standards for pipelines and underground storage facilities. PHMSA may delegate this authority to a state, as it has in New York and Pennsylvania, and that state may choose to institute more stringent safety regulations for the construction, operation and maintenance of intrastate facilities. In addition to this state safety program, the NYPSC imposes additional requirements on the construction of certain utility facilities. Increased regulation by these agencies, and other regulators, or requested changes to construction projects, could lead to operational delays or restrictions and increase compliance costs that the Company may not be able to recover fully through rates or otherwise offset.

For additional discussion of the material effects of compliance with government environmental regulation, see Item 7, MD&A under the heading "Environmental Matters."

**The Integrated Upstream and Gathering Segment**

The Integrated Upstream and Gathering segment contributed net income of $324.7 million in 2025.

Additional discussion of the Integrated Upstream and Gathering segment appears below in this Item 1 under the headings "Sources and Availability of Raw Materials" and "Competition: The Integrated Upstream and Gathering Segment," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

**The Pipeline and Storage Segment**

The Pipeline and Storage segment contributed net income of $121.0 million in 2025.

The Pipeline and Storage segment generated approximately 35% of its revenues in 2025 from services provided to the Utility segment or Integrated Upstream and Gathering segment.

Additional discussion of the Pipeline and Storage segment appears below under the headings "Sources and Availability of Raw Materials," "Competition: The Pipeline and Storage Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

**The Utility Segment**

The Utility segment contributed net income of $83.2 million in 2025.

Additional discussion of the Utility segment appears below under the headings "Sources and Availability of Raw Materials," "Competition: The Utility Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

**All Other Category and Corporate Operations**

The All Other category and Corporate operations incurred a net loss of $10.4 million in 2025.

Additional discussion of the All Other category and Corporate operations appears below in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

**Sources and Availability of Raw Materials**

The Integrated Upstream and Gathering segment seeks to discover and produce raw materials (primarily natural gas). It also gathers, processes and transports natural gas largely produced by Seneca, as further described in this report in Item 7, MD&A and Item 8 at Note M — Business Segment Information and Note N — Supplementary Information for Exploration and Production Activities.

The Pipeline and Storage segment transports and stores natural gas owned by its customers, whose gas primarily originates in the Appalachian region of the United States, as well as other gas supply regions in the United States and Canada. Additional discussion of proposed pipeline projects appears in Item 7, MD&A.

Natural gas is the principal raw material for the Utility segment. In 2025, the Utility segment purchased 77.4 Bcf of gas (including 75.5 Bcf for delivery to retail customers and 1.9 Bcf used in operations) pursuant to its purchase contracts with firm delivery requirements. Gas purchased from producers and suppliers in the United States under multi-month contracts accounted for 46% of these purchases. Purchases of gas in the spot market (contracts of one month or less) accounted for 54% of the Utility segment's 2025 purchases. Purchases from DTE Energy Trading, Inc. (33%), Emera Energy Services, Inc. (11%), Chevron Natural Gas (10%), Shell Energy North America (7%), and NRG Business Marketing, LLC (6%) accounted for nearly 67% of the Utility segment's 2025 gas purchases. No other producer or supplier provided the Utility segment with more than 5% of its gas requirements in 2025. The Utility segment does not directly purchase gas from affiliates.

**Competition**

Competition in the natural gas industry exists among providers of natural gas, as well as between natural gas and other sources of energy, such as fuel oil, geothermal, and electrification technologies. Management believes that the reliability and affordability of natural gas support its competitive position relative to electrification and other energy sources.

The Company competes on the basis of price, service and reliability, product performance and other factors. Sources and providers of energy, other than those described under this "Competition" heading, do not compete with the Company to any significant extent.

**Competition: The Integrated Upstream and Gathering Segment**

The Integrated Upstream and Gathering Segment, composed of Seneca and Midstream Company, competes with major integrated and independent natural gas producers and marketers in the sale of natural gas, as well as in the acquisition, exploration, and development of mineral rights and leasehold interests.

Seneca serves as the primary operator on its properties and employs advanced technologies to support exploration and development activities. It maintains a robust portfolio of firm transportation and physical firm sales contracts and utilizes financial hedging strategies to mitigate commodity price volatility and protect cash flows.

Midstream Company provides gathering services primarily for Seneca, and to a lesser extent, for other producers in the Appalachian region. It competes with other natural gas gathering and processing companies and benefits from close operational alignment with Seneca, enabling cost-effective and timely delivery of production to market.

The integration of upstream and gathering operations is a key differentiator within the industry, enabling greater capital allocation efficiency and a low-cost structure that supports resilient margins across commodity cycles. Operating as a unified business enhances performance by streamlining development timelines, reducing third-party dependencies, and improving coordination between drilling and gathering activities. These synergies contribute to increased capital efficiency, with a focus on maximizing production and resource recovery per dollar invested.

**Competition: The Pipeline and Storage Segment**

Supply Corporation competes for growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and with other companies providing gas storage services. Supply Corporation has some unique characteristics which enhance its competitive position. Most of Supply Corporation's facilities are in or near areas overlying the Marcellus and Utica shale production areas in Pennsylvania, and it has established interconnections with producers and other pipelines that provide access to these supplies and to premium off-system markets. Its facilities are also located adjacent to the Canadian border at the Niagara River providing access to markets in Canada and the northeastern and midwestern United States via the TC Energy pipeline system. Supply Corporation is well positioned to support potential data center and power generation development in both New York and Pennsylvania through the expansion of its existing facilities, including via its Line N pipeline, which interconnects with multiple interstate pipelines and is proximate to significant in-basin natural gas production. Supply Corporation has developed and placed into service a number of pipeline expansion projects designed to transport natural gas to key markets in New York, Pennsylvania, the northeastern United States, Canada, and to long-haul pipelines with access to the U.S. Midwest, Mid-Atlantic and the Gulf Coast. For further discussion of Pipeline and Storage projects, refer to Item 7, MD&A under the heading "Investing Cash Flow."

Empire competes for natural gas market growth with other pipeline companies transporting gas in the northeast United States and upstate New York in particular. Empire is well situated to provide transportation of Appalachian shale gas as well as gas supplies available at Empire's interconnects with TC Energy at Chippawa and Millennium Pipeline at Corning. Empire's geographic location provides it the opportunity to compete for service to its on-system LDC markets, as well as for a share of the gas transportation markets into Canada (via Chippawa) and into the northeastern United States. Various expansion projects on Empire have expanded its footprint and capability, allowing Empire to serve new markets in New York and elsewhere in the Northeast, and to attach to prolific Marcellus and Utica supplies principally from Tioga and Bradford Counties in Pennsylvania. Like Supply Corporation, Empire's expanded system facilitates transportation of natural gas to key markets within New York State, the northeastern United States and Canada.

**Competition: The Utility Segment**

With respect to gas commodity service, in New York and Pennsylvania, both of which have implemented "unbundling" policies that allow customers to choose their gas commodity supplier, Distribution Corporation has retained a substantial majority of small sales customers. In both New York and Pennsylvania, approximately 8% of Distribution Corporation's small-volume residential and commercial customers purchase their supplies from unregulated marketers. In contrast, almost all large commercial and industrial customers are served by marketers. However, retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation, because in both jurisdictions, utility cost of service is recovered through rates and charges for gas delivery service, not gas commodity service.

Competition for transportation service to large-volume customers continues with local producers or pipeline companies attempting to sell or transport gas directly to end-users located within the Utility segment's service territories without use of the utility's facilities (i.e., bypass). In addition, while competition with fuel oil suppliers continues to exist and competition with electrification alternatives is growing, particularly in New York State, natural gas retains its competitive position from a reliability and affordability standpoint.

The Utility segment competes in its most vulnerable markets (the large commercial and industrial markets) by offering unbundled, flexible, high quality services. The Utility segment continues to advance programs promoting the efficient use of natural gas.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation in jurisdictions that impact the Utility segment. In addition to the federal Inflation Reduction Act, New York, for example, adopted the CLCPA in July 2019, which could ultimately result in increased competition from electric and geothermal forms of energy. However, given the extended time frames associated with the CLCPA's emission reduction mandates as discussed in Item 7, MD&A under the heading "Environmental Matters" and subheading "Environmental Regulation," any meaningful competition and/or business impacts resulting from the CLCPA cannot be determined.

**Seasonality**

Variations in weather conditions can materially affect the volume of natural gas delivered by the Utility segment, as virtually all of its residential and commercial customers use natural gas for space heating. The effect that this has on Utility segment margins is largely mitigated by a weather normalization adjustment (WNA). Prior to October 2023, the weather impact on cash flow in the Utility segment was mitigated by a WNA solely in its New York rate jurisdiction. However, effective October 2023, the weather impact on cash flow in the Utility segment is also mitigated by a WNA in its Pennsylvania rate jurisdiction. Refer to Item 8, Note A — Summary of Significant Accounting Policies under the heading "Regulatory Mechanisms" for additional discussion. Under the WNA, weather that is warmer than normal results in an upward adjustment to customers' current bills, while weather that is colder than normal results in a downward adjustment, so that in either case projected delivery revenues calculated at normal temperatures will be largely recovered.

Volumes transported and stored by Supply Corporation and Empire may vary significantly depending on weather, without materially affecting the revenues of those companies. Supply Corporation's and Empire's allowed rates are based on a straight fixed-variable rate design which allows recovery of fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover only the variable costs associated with actual transportation or storage of gas.

**Capital Expenditures**

A discussion of capital expenditures by business segment is included in Item 7, MD&A under the heading "Investing Cash Flow."

**Environmental Matters**

A discussion of material environmental matters involving the Company is included in Item 7, MD&A under the heading "Environmental Matters" and in Item 8, Note L — Commitments and Contingencies.

**Miscellaneous**

The Utility segment has numerous municipal franchises under which it uses public roads and certain other rights-of-way and public property for the location of facilities.

The Company makes its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports, available free of charge on the Company's website, www.nationalfuel.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. The information available at the Company's website is not part of this Form 10-K or any other report filed with or furnished to the SEC.

**Human Capital**

The Company aims to attract qualified employees, and to retain those employees through offering competitive benefits and compensation packages, and career development and training opportunities in a safe, inclusive and productive work environment. Human capital measures and objectives that the Company focuses on in managing its business are outlined below. Additional information regarding the Company's human capital measures and objectives is contained in the Company's recently published Corporate Responsibility Report, which is available on the Company's website, www.nationalfuel.com. The information on the Company's website is not, and will not be deemed to be, a part of this annual report on Form 10-K or incorporated into any of the Company's other filings with the SEC.

*Employees and Collective Bargaining Agreements*

The Company and its wholly-owned subsidiaries had a total of 2,322 full-time employees at September 30, 2025.

As of September 30, 2025, 47% of the Company's active workforce was covered under collective bargaining agreements. The Company has agreements in place with collective bargaining units in New York into February 2029. Additionally, the Company has agreements with collective bargaining units in Pennsylvania into April 2026 and will begin negotiations with the two bargaining units in Pennsylvania in late 2025.

*Company Culture*

The Company is committed to creating a safe and inclusive work environment for all employees. In managing the business, the Company focuses on the safety of its employees, contractors and communities and has implemented safety programs and management practices to promote a culture of safety. This includes required trainings for both field and office employees, as well as specific qualifications and certifications for field employees and applicable contractors. The Company also ties executive compensation and salaried variable pay programs to safety related goals to emphasize the importance of and focus on safety at the Company.

The Company has also implemented policies and training that reinforce the Company's commitment to inclusion in the workplace. The Company's policies prohibit discrimination or harassment against any employee or applicant on the basis of sex, race/ethnicity, and other protected categories. The Company communicates to employees its commitment to a harassment free workplace through the onboarding process, annual distribution and acknowledgement of the Company's Non-Discrimination and Anti-Harassment Policy, and training for all employees including management.

*Voluntary Attrition Rate*

The Company measures the voluntary attrition rate of its employees in assessing the Company's overall human capital. The Company's voluntary attrition rate was 4.7% (not including retirements), which is relatively the same as last year's attrition rate. The Company continues to actively monitor employee metrics, including attrition rate, as an indicator of management of and responsiveness to human capital matters.

*No Work Stoppages*

During fiscal 2025, the Company did not incur any work stoppages (strikes or lockouts) and therefore experienced zero idle days for the fiscal year.

*Employee Benefits, Compensation and Development*

To attract employees and meet the needs of the Company's workforce, the Company offers market-competitive benefits packages and compensation to employees of its subsidiaries. The Company's benefits package options and career development opportunities may vary depending on type of employee and date of hire. Benefits packages may include healthcare benefits, financial and retirement benefits, insurance benefits, and lifestyle benefits. Additionally, the Company periodically conducts employee surveys to provide additional insight into employee perspectives and interest in desired benefits.

The Company's compensation program for salaried employees is intended to align employee compensation with the market while providing greater incentive to the Company's employees to work toward the achievement of Company goals. This meaningful investment illustrates the Company's view that attracting, retaining and motivating our employees is integral to the Company's success.

The Company provides its employees with professional development and training resources to enhance their careers within the Company, which, depending on employee type, may include the following: (i) tuition aid program; (ii) sponsorship for professional licensing; (iii) corporate and technical training programs; (iv) continuous talent review and succession planning; (v) voluntary mentorship programs; and (vi) professional development and cross-training discussions encouraged through annual performance reviews and career development discussions.

**Executive Officers of the Company as of November 15, 2025(1)**

| Name and Age (as of November 15, 2025) | Current Company Positions and Other Material Business Experience During Past Five Years |
|---|---|
| David P. Bauer (56) | Chief Executive Officer of the Company since July 2019. |
| Michael D. Colpoys (61) | President of Distribution Corporation since July 2025. Mr. Colpoys previously served as Senior Vice President of Distribution Corporation from October 2021 through June 2025 and Vice President of Distribution Corporation from June 2016 through September 2021. |
| Joseph N. Del Vecchio (59) | President of Supply Corporation since February 2025. Mr. Del Vecchio previously served as Executive Vice President of Supply Corporation from January 2023 through January 2025 and Senior Vice President of Supply Corporation from October 2021 through December 2022. Mr. Del Vecchio also previously served as Vice President and Chief Regulatory Counsel of Distribution Corporation from April 2015 through September 2021. |
| Timothy J. Silverstein (42) | Treasurer and Chief Financial Officer of the Company since May 2023. Treasurer of Seneca Resources Company since May 2023. Mr. Silverstein previously served as Treasurer of Distribution Corporation, Supply Corporation, Empire and Midstream Company from July 2021 through February 2025, and as Assistant Treasurer of Distribution Corporation, Supply Corporation and Empire from April 2020 through June 2021. |
| Elena G. Mendel (59) | Controller and Chief Accounting Officer of the Company since July 2019. Controller of Distribution Corporation, Supply Corporation, Empire, and Midstream Company since July 2019. |
| Martin A. Krebs (55) | Chief Information Officer of the Company since December 2018 and Senior Vice President of Distribution Corporation since May 2023. |
| Lee E. Hartz (49) | General Counsel and Secretary of the Company and General Counsel and Secretary of Distribution Corporation since April 2025. Vice President of Distribution Corporation since July 2021. Mr. Hartz previously served as Assistant Vice President of Distribution Corporation from March 2021 through June 2021 and Assistant Vice President of Supply Corporation from October 2013 until March 2021. |
| Justin I. Loweth (47) | President of Midstream Company since April 2022 and President of Seneca Resources Company since May 2021. Mr. Loweth previously served as Senior Vice President of Seneca Resources Company from October 2017 through April 2021. |

(1) The executive officers serve at the pleasure of the Board of Directors. The information provided relates to the Company and its principal subsidiaries. Many of the executive officers also have served, or currently serve, as officers or directors of other subsidiaries of the Company.

## Item 1A *Risk Factors*

## STRATEGIC RISKS

***The Company is dependent on capital and credit markets to successfully execute its business strategies.***

The Company relies upon short-term bank borrowings, commercial paper markets and longer-term capital markets to finance capital requirements not satisfied by cash flow from operations. The Company is dependent on these capital sources to provide capital to its subsidiaries to fund operations, acquire, maintain and develop properties, and execute growth strategies. The availability and cost of credit sources may be cyclical and these capital sources may not remain available to the Company. Turmoil in credit markets may make it difficult for the Company to obtain financing on acceptable terms or at all for working capital, capital expenditures and other investments, or to refinance existing debt. These difficulties could adversely affect the Company's growth strategies, operations and financial performance.

The Company's ability to borrow under its credit facilities and commercial paper agreements, and its ability to issue long-term debt under its indenture, depend on the Company's compliance with its obligations under the facilities, agreements and indenture.

The Company's short-term bank loans, commercial paper, and borrowings under the Term Loan Agreement, entered into on February 14, 2024 with six lenders (the "Term Loan Agreement"), are in the form of floating rate debt or debt that may have rates fixed for short periods of time (up to six months), resulting in exposure to interest rate fluctuations in the absence of interest rate hedging transactions. The cost of long-term debt, the interest rates on the Company's short-term bank loans, commercial paper, and borrowings under its Term Loan Agreement, and the ability of the Company to issue commercial paper are affected by its credit ratings published by S&P, Moody's Investors Service, Inc. and Fitch Ratings, Inc. A downgrade in the Company's credit ratings could increase borrowing costs, restrict or eliminate access to commercial paper markets, negatively impact the availability of capital from uncommitted sources, and require the Company's subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. Additionally, $2.4 billion of the Company's outstanding long-term debt would be subject to an interest rate increase if certain fundamental changes occur that involve a material subsidiary and result in a downgrade of a credit rating assigned to the notes below investment grade.

In addition, we may be subject to financial risks related to our planned acquisition of all of the issued and outstanding equity interests of Vectren Energy Delivery of Ohio, LLC ("CenterPoint Ohio") from CenterPoint Energy Resources Corp. (the "Seller"). For discussion of these risks, refer to the risk factor under the heading "*The planned acquisition of CenterPoint Ohio may limit our financial flexibility.*"

***The regulatory, legislative, consumer behaviors and capital access developments related to climate change may adversely affect operations and financial results.***

The laws, regulations and other initiatives to address climate change may impact the Company's financial results. Federal, state and local legislative and regulatory initiatives proposed or adopted in an attempt to limit the effects of climate change, including greenhouse gas emissions, could have significant impacts on the energy industry including government-imposed limitations, prohibitions or moratoriums on the use and/or production of natural gas, establishment of a carbon tax and/or methane fee, lack of support for system modernization, as well as accelerated depreciation of assets and/or stranded assets.

Federal and state legislatures have from time to time considered bills that would establish a cap-and-trade program, cap-and-invest program, methane fee, carbon tax, or other similar mechanisms to provide incentive for the reduction of greenhouse gas emissions. A number of states have also adopted energy strategies or plans with goals that include the reduction of greenhouse gas emissions. For example, Pennsylvania has a methane reduction framework for the natural gas industry which has resulted in permitting changes with the stated goal of reducing methane emissions from well sites, compressor stations and pipelines. Furthermore, in 2019, the New York State legislature passed the CLCPA, which created emission reduction and electrification mandates, and could ultimately impact the Utility segment's customer base and business. Pursuant to the CLCPA, in December 2022, New York's Climate Action Council ("CAC") approved a final scoping plan that includes recommendations to strategically downsize and decarbonize the natural gas system and curtail use of natural gas and natural gas appliances, as well as recommendations to meet the CLCPA's emissions reduction targets in the transportation, buildings, electricity, industry, agriculture & forestry and waste sectors. The final scoping plan also recommends statewide and cross-sector policies relevant to gas system transition, economywide strategies, land use, local government, and adaptation and resilience. Additionally, the scoping plan recommends the implementation of a cap-and-invest program in New York. In January 2023, New York's Governor directed the NYDEC and the New York State Energy Research and Development Authority to advance an economywide cap-and-invest program that establishes a declining cap on greenhouse gas emissions, and invests in programs to drive emissions reductions. In addition, in October 2025, a New York State court directed NYDEC to promulgate rules and regulations to ensure compliance with emissions reductions limits outlined in the CLCPA by February 6, 2026, which may include such a cap-and-invest program. If this proposed program or a similar program becomes effective and the Company becomes subject to new or revised cap-and-trade programs, cap-and-invest programs, methane charges, fees for carbon-based fuels or other similar costs or charges, the Company may experience additional costs and incremental operating expenses, which would impact our future earnings and cash flows, and may also experience decreased revenue in the event that implementation of these policies leads to reduced demand for natural gas.

In addition to the CLCPA, legislation or regulation that aims to reduce greenhouse gas emissions could also include natural gas bans, greenhouse gas emissions limits and reporting requirements, carbon taxes and/or similar fees on carbon dioxide, methane or equivalent emissions, restrictive permitting, increased efficiency standards requiring system remediation and/or changes in operating practices, and incentives or mandates to conserve energy or use renewable energy sources. For example, in May 2023, New York State passed legislation that prohibits the installation of fossil fuel burning equipment and building systems in new buildings commencing on or after December 31, 2025, subject to various exemptions. While the Company does not currently expect that this legislation will have a substantial impact on its financial results or operations, future legislation or regulation that aims to reduce natural gas demand or to impose additional operations requirements or restrictions on natural gas facilities, if effectuated, could impact our future earnings and cash flows. In addition, in December 2024 (and later amended in February 2025), New York's Governor signed the Climate Change Superfund Act into law, which will require certain fossil fuel producers, refiners and related entities to pay into a state "climate superfund" an amount commensurate with the entity's past global greenhouse gas emissions over a specified period of time. The NYDEC has until June 2027 to develop implementing regulations. The Act is currently the subject of multiple federal court lawsuits challenging its constitutionality.

Additionally, the trend toward increased energy conservation, change in consumer behaviors, competition from renewable energy sources, and technological advances to address climate change may reduce the demand for natural gas, which could impact our future earnings and cash flows. For further discussion of the risks associated with environmental regulation to address climate change, refer to Part II, Item 7, MD&A under the heading "Environmental Matters."

Further, the trend toward a low-carbon economy could shift funding away from, or limit or restrict certain sources of funding for, companies focused on fossil fuel-related development or carbon-intensive investments. To the extent financial markets view climate change and greenhouse gas emissions as a financial risk, the Company's cost of and access to capital could be negatively impacted.

***Organized opposition to the natural gas industry could have an adverse effect on Company operations.***

Organized opposition to the natural gas industry, including exploration and production activity, pipeline expansion and replacement projects, and the extension and continued operation of natural gas distribution systems, may continue to increase as a result of, among other things, safety incidents involving natural gas facilities, and concerns raised by policymakers, financial institutions and advocacy groups about greenhouse gas emissions, hydraulic fracturing, or fossil fuels generally. This opposition may lead to increased regulatory and legislative initiatives that could place limitations, prohibitions or moratoriums on the use and development of natural gas, impose costs tied to carbon emissions, provide cost advantages to alternative energy sources, or impose mandates that increase operational costs associated with new or existing natural gas infrastructure and technology. There are also increasing litigation risks associated with climate change concerns and related disclosures. Increased litigation could cause operational delays or restrictions, and increase the Company's operating costs. In turn, these factors could impact the competitive position of natural gas, ultimately affecting the Company's results of operations and cash flows.

***Delays or changes in plans or costs with respect to Company projects, including regulatory delays or denials with respect to necessary approvals, permits or orders, could delay or prevent anticipated project completion, as well as the renewal or modification of key permits for ongoing operations, and may result in asset write-offs and reduced earnings.***

Construction of planned distribution, gathering, and transmission pipeline and storage facilities, as well as the expansion and replacement of existing facilities, and the development of new natural gas wells, is subject to various regulatory, environmental, political, legal, economic and other development risks, including the ability to obtain necessary approvals and permits from regulatory agencies on a timely basis and on acceptable terms, or at all. Existing or potential third-party opposition, such as opposition from landowner and environmental groups, which are beyond our control, could materially affect the anticipated construction of a project as well as the renewal or modification of key permits for ongoing operations. In addition, third parties could impede the Company's acquisition, expansion or renewal of rights-of-way or land rights on a timely basis and on acceptable terms. Any delay in project development or construction may prevent a planned project from going into service when anticipated, which could cause a delay in the receipt of revenues from those facilities, result in increased project costs due to extended construction timeframes and asset write-offs, and materially impact operating results or anticipated results. Additionally, delays in pipeline construction projects or gathering facility completion could impede Seneca's ability to transport its production, or to fulfill obligations to sell at contracted delivery points.

## FINANCIAL RISKS

***As a holding company, the Company depends on its operating subsidiaries to meet its financial obligations.***

The Company is a holding company with no significant assets other than the stock of its operating subsidiaries. In order to meet its financial needs, the Company relies exclusively on repayments of principal and interest on intercompany loans made by the Company to its operating subsidiaries and income from dividends. Such operating subsidiaries may not generate sufficient net income to pay dividends to the Company or generate sufficient cash flow to make payments of principal or interest on such intercompany loans.

***The Company may be adversely affected by economic conditions, including trade policies, and their impact on our suppliers and customers.***

Periods of slowed economic activity generally result in decreased energy consumption, particularly by industrial and large commercial companies. As a consequence, national or regional recessions or other downturns in economic activity could adversely affect the Company's revenues and cash flows or restrict its future growth. Additionally, current tariffs, as well as the imposition of additional tariffs on U.S. imports of various goods and related retaliatory tariffs, as well as supply chain disruptions, and the associated costs and inflation related thereto, could have an impact on the Company's operations. Economic conditions in the Company's utility service territories, along with legislative and regulatory prohibitions and/or limitations on terminations of service, also impact its collections of accounts receivable. Customers of the Company's Utility segment may have particular trouble paying their bills during periods of declining economic activity, high inflation, or high commodity prices, potentially resulting in increased bad debt expense and reduced earnings. Similarly, if reductions were to occur in funding of the federal Low Income Home Energy Assistance Program, or such funding was delayed or suspended for a prolonged period, bad debt expense could increase and earnings could decrease. In addition, exploration and production companies that are customers of the Company's Pipeline and Storage segment may decide not to renew contracts for the same transportation capacity. Certain customers of Seneca can represent a concentrated risk from time to time. Any of these events or circumstances could have or contribute to a material adverse effect on the Company's results of operations, financial condition and cash flows.

***Changes in interest rates may affect the Company's financing and its regulated businesses' rates of return.***

Rising interest rates may impair the Company's ability to cost-effectively finance capital expenditures and may increase the rates at which the Company can refinance maturing debt. In addition, the Company's authorized rate of return in its regulated businesses is based upon certain assumptions regarding interest rates. If interest rates are lower than assumed rates, the Company's authorized rate of return could be reduced. If interest rates are higher than assumed rates, the Company's ability to earn its authorized rate of return may be adversely impacted.

***Fluctuations in natural gas prices could adversely affect revenues, cash flows and profitability.***

Financial results in the Company's Integrated Upstream and Gathering segment are materially dependent on prices received for its natural gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, and gathering natural gas. Natural gas prices can be volatile and can be affected by various factors, including weather conditions, natural disasters, consumer demand, national and worldwide economic conditions, economic disruptions caused by terrorist activities, acts of war or major accidents, domestic and foreign political conditions and events, the price and availability of alternative fuels, the proximity to, and availability of, sufficient availability of and capacity on transportation and liquefaction facilities, regional and global levels of supply and demand, energy conservation measures, and government regulations. The Company sells the natural gas that it produces at a combination of current market prices, indexed prices or through fixed- price contracts. The Company hedges a substantial portion of future sales that are based on indexed prices utilizing the physical sale counterparty and/or the financial markets. The prices the Company receives depend upon factors beyond the Company's control, including the factors affecting price mentioned above. Any prolonged reduction in natural gas prices could result in the Company reducing the level of exploration and production activity the Company otherwise would pursue, which could have a material adverse effect on its future revenues, cash flows and results of operations.

In the Company's Pipeline and Storage segment, significant changes in the price differential between equivalent quantities of natural gas at different geographic locations or sustained high natural gas prices relative to other sources of energy could adversely impact the Company. For example, if the price of natural gas at a particular receipt point on the Company's pipeline system increases relative to the price of natural gas at other locations, then the volume of natural gas received by the Company at the relatively more expensive receipt point may decrease, or the Company may need to discount the approved tariff rate for that transportation path in the future in order to maintain the existing volumes on its system. Changes in price differentials can cause shippers to seek alternative lower priced natural gas supplies and, consequently, alternative transportation routes. In some cases, shippers may decide not to renew transportation contracts due to changes in price differentials. While much of the impact of lower volumes under existing contracts would be offset by the straight fixed-variable rate design, this rate design does not protect Supply Corporation or Empire where shippers do not contract for expiring capacity at the same quantity and rate. If contract renewals were to decrease, revenues and earnings in this segment may decrease. Significant changes in the price differential between futures contracts for natural gas having different delivery dates could also adversely impact the Company. For example, if the prices of natural gas futures contracts for winter deliveries to locations served by the Pipeline and Storage segment decline relative to the prices of such contracts for summer deliveries (as a result, for instance, of increased production of natural gas within the segment's geographic area or other factors), then demand for the Company's natural gas storage services driven by that price differential could decrease. These changes could adversely affect future revenues, cash flows and results of operations.

In the Company's Utility segment, during periods when natural gas prices are significantly higher than historical levels, customer demand could be reduced, thereby decreasing delivery revenues, particularly in the Company's Pennsylvania service territory where delivery revenues are not protected by a revenue decoupling mechanism. Customers may also have trouble paying the resulting higher bills when gas prices are higher or in periods of economic uncertainty, which could increase bad debt expenses and could ultimately reduce earnings. Additionally, increases in the cost of purchased gas affect cash flows and can therefore impact the amount or availability of the Company's capital resources.

***The Company has significant transactions involving price hedging of its natural gas production, fixed price natural gas sale commitments, as well as its foreign exchange transactions.***

To protect itself to some extent against price volatility and to lock in fixed pricing on natural gas production for certain periods of time, Seneca regularly enters into commodity price derivatives contracts (hedging arrangements) with respect to a portion of its expected production. These contracts may extend over multiple years, covering a substantial majority of the Company's expected natural gas production over the course of the current fiscal year, and lesser percentages of subsequent years' expected production. These contracts reduce exposure to subsequent price drops but can also limit the Company's ability to benefit from increases in natural gas prices.

The nature of these hedging contracts could lead to potential liquidity impacts in scenarios of significantly increased natural gas prices if the Company has hedged its current production at prices below the current market price. Hedging collateral deposits represent the cash, letters of credit, or other eligible instruments held in Company funded margin accounts to serve as collateral for hedging positions used at Seneca. A significant increase in natural gas prices may cause certain of the Company's outstanding derivative instrument contracts to be in a liability position creating margin calls on the Company's hedging arrangements, which could require the Company to temporarily post significant amounts of cash collateral with our hedge counterparties. That collateral could be in excess of the Company's available short-term liquidity under its committed credit facility and other uncommitted sources of capital, leading to potential default under certain of its hedging arrangements. That interest-bearing cash collateral is returned to us in whole or in part upon a reduction in forward market prices, depending on the amount of such reduction, or in whole upon settlement of the related derivative contract.

Use of price hedges, including natural gas hedges and foreign exchange hedges, also exposes the Company to the risk of nonperformance by a contract counterparty. These parties might not be able to perform their obligations under the hedge arrangements.

Under the Company's hedging guidelines, natural gas derivatives contracts must be confined to the price hedging of existing and forecasted production. The Company maintains a system of internal controls to monitor compliance with its guidelines. However, unauthorized speculative trades, if they were to occur, could expose the Company to substantial losses to cover positions in its derivatives contracts. In addition, in the event the Company's actual production of natural gas falls short of hedged volumes, the Company may incur substantial losses to cover its hedges to the extent the hedges are in a loss position.

We may be subject to risks related to increased federal oversight and regulation of the over-the-counter derivatives markets and certain entities that participate in those markets. For discussion of these risks, refer to Item 7, MD&A under the heading "Market Risk Sensitive Instruments."

***You should not place undue reliance on reserve information because such information represents estimates.***

This Form 10-K contains estimates of the Company's proved natural gas reserves and the future net cash flows from those reserves, which the Company's petroleum engineers prepared and independent petroleum engineers audited. Petroleum engineers consider many factors and make assumptions in estimating natural gas reserves and future net cash flows. These factors include: historical production from the area compared with production from other producing areas; the assumed effect of governmental regulation; and assumptions concerning natural gas prices, production and development costs, severance and excise taxes, and capital expenditures. Changes in natural gas prices impact the quantity of economic natural gas reserves. Estimates of reserves and expected future cash flows prepared by different engineers, or by the same engineers at different times, may differ substantially. Ultimately, actual production, revenues and expenditures relating to the Company's reserves will vary from any estimates, and these variations may be material. Accordingly, the accuracy of the Company's reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment.

If conditions remain constant, then the Company is reasonably certain that its reserve estimates represent economically recoverable natural gas reserves and future net cash flows. If conditions change in the future, then subsequent reserve estimates may be revised accordingly. You should not assume that the present value of future net cash flows from the Company's proved reserves is the current market value of the Company's estimated natural gas reserves. In accordance with SEC requirements, the Company bases the estimated discounted future net cash flows from its proved reserves on a 12-month average of historical prices for natural gas (based on first day of the month prices and adjusted for hedging) and on costs as of the date of the estimate, which are all discounted at the SEC mandated discount rate. Actual future prices and costs may differ materially from those used in the net present value estimate. Any significant price changes will have a material effect on the present value of the Company's reserves.

Petroleum engineering is a subjective process of estimating underground accumulations of natural gas and other hydrocarbons that cannot be measured in an exact manner. The process of estimating natural gas reserves is complex. The process involves significant assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Future economic and operating conditions are uncertain, and changes in those conditions could cause a revision to the Company's reserve estimates in the future. Estimates of economically recoverable natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including historical production from the area compared with production from other comparable producing areas, and the assumed effects of regulations by governmental agencies. Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves: the quantities of natural gas that are ultimately recovered, the timing of the recovery of natural gas reserves, the production and operating costs to be incurred, the amount and timing of future development and abandonment expenditures, and the price received for the production.

***Financial accounting requirements regarding exploration and production activities may affect the Company's profitability.***

The Company accounts for its exploration and production activities under the full cost method of accounting. Each quarter, the Company must perform a "ceiling test" calculation, comparing the level of its unamortized investment in exploration and production properties to the present value of the future net revenue projected to be recovered from those properties according to methods prescribed by the SEC. In determining present value, the Company uses a 12-month historical average price for commodity pricing (based on first day of the month prices and adjusted for hedging) as well as the SEC mandated discount rate. If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be "impaired," and the full cost authoritative accounting and reporting guidance require that the investment must be written down to the calculated net present value. Such an instance would require the Company to recognize an immediate expense in that quarter, and its earnings would be reduced. Depending on the magnitude of any decrease in average prices, that charge could be material. In addition, because an impairment results in a charge to retained earnings, it lowers the Company's total capitalization, all other things being equal, and increases the Company's debt to capitalization ratio. Although the Company's committed credit facility's debt to capitalization covenant excludes 50% of aggregate ceiling test impairments occurring on or after July 1, 2018, up to a total of $400 million, impairments in excess of such amounts can impact the Company's ability to maintain compliance with this debt to capitalization covenant. For the fiscal year ended September 30, 2024 and the quarter ended December 31, 2024, the Company recorded pre-tax impairments under the ceiling test of $463.7 million and $108.3 million, respectively. Depending on a number of factors, including fluctuations in or subtractions from proved reserves, increases in development costs for undeveloped reserves, and significant fluctuations in natural gas prices, the Company may record additional ceiling test impairments in future periods.

## OPERATIONAL RISKS

***The nature of the Company's operations presents inherent risks of loss that could adversely affect its results of operations, financial condition and cash flows.***

The Company's operations in its various reporting segments are subject to inherent hazards and risks such as: fires; natural disasters; explosions; blowouts during well drilling; collapses of wellbore casing or other tubulars; pipeline ruptures; spills; and other hazards and risks that may cause personal injury, death, property damage, environmental damage or business interruption losses. Additionally, the Company's facilities, machinery, equipment, and technology/software systems may be subject to sabotage. These events, in turn, could lead to governmental investigations, recommendations, claims, fines or penalties. As protection against operational hazards, the Company maintains insurance coverage against some, but not all, potential losses. The Company also seeks, but may be unable, to secure written indemnification agreements with contractors that adequately protect the Company against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, the imposition of fines, penalties or mandated programs by governmental authorities, the failure of a contractor to meet its indemnification obligations, or the failure of an insurance company to pay valid claims could result in substantial losses to the Company. In addition, insurance may not be available, or if available may not be adequate, to cover any or all of these risks. It is also possible that insurance premiums or other costs may rise significantly in the future, so as to make such insurance prohibitively expensive.

Hazards and risks faced by the Company, and insurance and indemnification obtained or provided by the Company, may subject the Company to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines or penalties against the Company or be resolved on unfavorable terms, the result of which could have a material adverse effect on the Company's results of operations, financial condition and cash flows.

***Our businesses depend on natural gas gathering, storage, and transmission facilities, which, if unavailable, could adversely affect the Company's results of operations, financial condition, and cash flows.***

Our businesses depend on natural gas gathering, storage, and transmission facilities, including third-party midstream facilities that are not within our control. Seneca, as well as our Utility segment, have entered into long-term agreements with midstream providers for natural gas gathering, storage, and/or transportation services. The disruption or unavailability of the midstream facilities required to provide these services, due to maintenance, mechanical failures, accidents, weather, regulatory requirements and/or other operational hazards, could negatively impact our ability to market and/or deliver our products, especially if such disruption were to last for an extended period of time. In addition, any substantial disruptions to the services provided by our midstream providers could cause us to curtail a significant amount of our production or could impair our ability to deliver natural gas to our utility customers and could have a material adverse effect on the Company's results of operations, financial condition, and cash flows. Furthermore, as substantially all of our production is transported from the well pad to interconnections with various FERC-regulated pipelines through our affiliated gathering facilities, such a production curtailment could result in significantly reduced throughput on those facilities, adversely affecting revenues and cash flows of our Integrated Upstream and Gathering segment.

***Attacks on or disruption of the Company's information technology and operational technology systems, including third party attempts to breach the Company's network security, or other cybersecurity threats and incidents could adversely affect the Company's operations and financial results.***

The Company relies on information technology and operational technology systems to process, transmit, and store information, to manage and support a variety of business processes and activities, and to comply with regulatory, legal, and tax requirements. The Company's information technology and operational technology systems, some of which are dependent on third party business partners, may be vulnerable to damage, interruption, or shutdown due to any number of causes outside of our control such as catastrophic events, natural disasters, fires, power outages, systems failures, telecommunications failures, and employee error or malfeasance. In addition, the Company's information technology and operational technology systems and those of our third-party business partners are subject to cybersecurity threats and attacks, including attempts by others to gain unauthorized access, or to otherwise introduce malicious software or software vulnerabilities. These attempts might be the result of industrial or other espionage, or actions by hackers seeking to harm the Company, its services or customers. These more sophisticated cyber-related attacks, as well as cybersecurity failures resulting from human error, pose a risk to the security and accessibility of the Company's systems and networks and the confidentiality, availability and integrity of the Company's and its customers' data. That data may be considered sensitive, confidential, or personal information that is subject to privacy and security laws, regulations and directives. While the Company employs controls to maintain and protect its information technology and operational technology systems, the Company may be vulnerable to disruptions, cybersecurity incidents, lost or corrupted data, programming errors and employee errors and/or malfeasance that could lead to interruptions to the Company's business operations or the unauthorized access, use, disclosure, modification or destruction of sensitive, confidential or personal information. Cybersecurity threats or attempts to breach the Company's network security may result in disruption of the Company's business operations and services, delays in production, theft of sensitive and valuable data, damage to our physical systems, malicious alteration or corruption of data or systems, costs related to remediation or the payment of ransom, and litigation including individual claims or consumer class actions, commercial litigation, administrative, and civil or criminal investigations or actions, regulatory intervention and sanctions or fines, investigation and remediation costs and reputational harm. Significant expenditures may be required to remedy system disruptions, cybersecurity incidents, or breaches or address cybersecurity threats, including restoration of customer service and enhancement of information technology and operational technology systems. We have invested in the protection of data and information technology, and actively work to enhance our business continuity and disaster recovery capabilities; however, there can be no assurance that our efforts will be successful.

The Company seeks to prevent, detect and investigate cybersecurity incidents, but in some cases the Company might be unaware of an incident or its magnitude and effects. In addition to existing risks and cybersecurity threats, the adoption of new technologies, including generative artificial intelligence tools, may increase the Company's exposure to data breaches and cybersecurity incidents or the Company's ability to detect and remediate effects of breaches and cybersecurity incidents. The Company has experienced attempts to breach its network security and cybersecurity threats and has received notifications from third-party service providers who have experienced disruptions to services or data breaches where Company data was potentially impacted. Although the scope of such occurrences and incidents is sometimes unknown, they could prove to be material to the Company. Even though insurance coverage is in place for cyber-related risks, if a material disruption or breach were to occur, the Company's operations, earnings, cash flows and financial condition could be adversely affected to the extent not fully covered by such insurance.

***The amount and timing of actual future natural gas production and the costs of our natural gas production operations are difficult to predict and may vary significantly from estimates, which may reduce the Company's earnings.***

There are many risks in developing natural gas, including numerous uncertainties inherent in estimating quantities of proved natural gas reserves and in projecting future rates of production and timing of development expenditures. The future success of the Company's Integrated Upstream and Gathering segment depends on its ability to develop additional natural gas reserves that are economically recoverable, and its failure to do so may negatively impact the Company's financial outlook for this segment. The total and timing of actual future production may vary significantly from reserves and production estimates. The Company's drilling of development wells can involve significant risks, including those related to timing, success rates, and cost overruns, and these risks can be affected by lease and rig availability, completion crew and related equipment availability, geology, and other factors. Drilling for natural gas and related investments in supporting facilities can be unprofitable, not only from non-productive wells, but from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, competition and cost to acquire mineral rights, weather conditions, governmental requirements, including completion of environmental impact analyses and compliance with other environmental laws and regulations, and shortages or delays in the delivery of equipment and services can delay drilling operations or result in their cancellation. The cost of drilling, completing, and operating wells, as well as the development of related exploration and production assets, is significant and often uncertain. New wells and related assets may not be successful or the Company may not recover all or any portion of its investment. Production can also be delayed or made uneconomic if there is insufficient gathering and transportation capacity available at an economic price to get that production to a location where it can be profitably sold. Without continued successful exploration or acquisition activities, the Company's reserves and revenues will decline as a result of its current reserves being depleted by production. The Company cannot make assurances that it will be able to find or acquire additional reserves at acceptable costs.

***The Company's ability to access water and opportunities for disposal or recycling produced water can impact drilling and completion operations.***

The drilling and hydraulic fracturing process requires significant volumes of water and an ability to recycle or dispose of water produced as a by-product of gas production. Limitations or restrictions on the Company's ability to secure sufficient amounts of water, including disruptions from natural causes (such as drought) or issues with transportation availability and costs, could impact its operations. If the Company is unable to secure adequate water volumes, drilling and completions can be delayed, or it would have to obtain new sources of water at increased costs. Similarly, if the Company experiences limitations or restrictions on its ability to recycle or dispose of its produced water, whether due to environmental regulations, permit requirements, transportation issues or other factors, producing wells may need to be shut-in and new wells may be delayed until such time as adequate recycling or disposal capacity is obtained, which can require significant lead times for permitting and could result in increased costs, delays in the Company's operations and adverse impacts on its cash flow and results of operations.

***The physical risks associated with climate change may adversely affect the Company's operations and financial results.***

Climate change could create acute and/or chronic physical risks to the Company's operations, which may adversely affect financial results. Acute physical risks include more frequent and severe weather events, which may result in adverse physical effects on portions of natural gas infrastructure, and may disrupt the Company's supply chain, workforce, and ultimately its operations. Disruption of production activities, as well as natural gas transportation and distribution systems, could result in reduced operational efficiency, and customer service interruption. Severe weather events could also cause physical damage to facilities, which could lead to reduced revenues, increased insurance premiums or increased operational costs. To the extent the Company's regulated businesses are unable to recover those costs, or if the recovery of those costs results in higher rates and reduced demand for Company services, the Company's future financial results could be adversely impacted. Chronic physical risks include long-term shifts in climate patterns resulting in new storm patterns or chronic increased temperatures, which could impact natural gas demand, and adversely impact the Company's future financial results.

***Disputes with collective bargaining units representing the Company's workforce, and work stoppage (e.g. strike or lockout), could adversely affect the Company's operations as well as its financial results.***

Approximately half of the Company's active workforce is represented by collective bargaining units in New York and Pennsylvania. These labor agreements are negotiated periodically, and therefore, the Company is subject to the risk that such agreements may not be able to be renewed on reasonably satisfactory terms, on anticipated timelines, or at all. In connection with the negotiation of such collective bargaining agreements, or in other matters involving collective bargaining units representing the Company's workforce, the Company could experience, among other things, strikes, work stoppages, slowdowns or lockouts, which could cause a disruption of the Company's operations, impact the Company's ability to fully execute operational plans, and have a material adverse effect on the Company's results of operations and financial condition.

## REGULATORY RISKS

***The Company's need to comply with comprehensive, complex, and the sometimes unpredictable enforcement of government regulations may increase its costs and limit its revenue growth, which may result in reduced earnings.***

The Company's businesses are subject to regulation under a wide variety of federal and state laws, regulations and policies. Existing statutes and regulations, including current tax rates and state prevailing wage rate schedules, may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Company or its contractors, which may increase the Company's costs, require refunds to customers or affect its business in ways that the Company cannot predict. Administrative agencies may apply existing laws and regulations in unanticipated, inconsistent or legally unsupportable ways, making it difficult to develop and complete projects, and harming the economic climate generally. In addition, judicial decisions limiting the authority of regulatory agencies, or decisions impacting current regulations and policies implemented by such agencies, could create uncertainty regarding the regulatory landscape and impact the Company's ability to plan for future investments.

Various aspects of the Company's operations are subject to regulation by a variety of federal and state agencies with respect to permitting and environmental requirements. In some areas, the Company's operations may also be subject to locally adopted ordinances. Administrative proceedings or increased regulation by these agencies could lead to operational delays or restrictions and increased expense for one or more of the Company's subsidiaries.

The Company is subject to the jurisdiction of the PHMSA. The PHMSA issues regulations and conducts evaluations, among other things, that set safety standards for pipelines and underground storage facilities. If as a result of these or similar new laws or regulations the Company incurs material compliance costs that it is unable to recover fully through rates or otherwise offset, the Company's financial condition, results of operations, and cash flows could be adversely affected.

The Company is subject to the jurisdiction of the FERC with respect to Supply Corporation, Empire and some transactions performed by other Company subsidiaries. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. Pursuant to the petition of a customer or state commission, or on the FERC's own initiative, the FERC has the authority to investigate whether Supply Corporation's and Empire's rates are still "just and reasonable" as required by the NGA, and if not, to adjust those rates prospectively. If Supply Corporation or Empire is required in a rate proceeding to adjust the rates it charges its gas transportation and/or storage customers, or if either Supply Corporation or Empire is unable to obtain approval for rate increases, particularly when necessary to cover increased costs, Supply Corporation's or Empire's earnings may decrease. In addition, the FERC exercises jurisdiction over the construction and operation of interstate natural gas transmission and storage facilities and also possesses significant penalty authority with respect to violations of the laws and regulations it administers.

The operations of Distribution Corporation are subject to the jurisdiction of the NYPSC, the PaPUC and, with respect to certain transactions, the FERC. The NYPSC and the PaPUC, among other things, approve the rates that Distribution Corporation may charge to its utility customers. Those approved rates also impact the returns that Distribution Corporation may earn on the assets that are dedicated to those operations. If Distribution Corporation is unable to obtain approval from these regulators for the rates it is requesting to charge utility customers, particularly when necessary to cover increased costs, earnings and/or cash flows may decrease.

***Environmental regulation significantly affects the Company's business.***

The Company's business operations are subject to federal, state, and local laws, regulations and agency policies relating to environmental protection including obtaining and complying with permits, leases, approvals, consents and certifications from various governmental and permit authorities. These laws, regulations and policies concern the generation, storage, transportation, disposal, emission or discharge of pollutants, contaminants, hazardous substances and greenhouse gases into the environment, the reporting of such matters, and the general protection of public health, natural resources, wildlife and the environment. For example, currently applicable environmental laws and regulations restrict the types, quantities and concentrations of materials that can be released into the environment in connection with regulated activities, limit or prohibit activities in certain protected areas, and may require the Company to investigate and/or remediate contamination at certain current and former properties regardless of whether such contamination resulted from the Company's actions or whether such actions were in compliance with applicable laws and regulations at the time they were taken. Moreover, spills or releases of regulated substances or the discovery of currently unknown contamination could expose the Company to material losses, expenditures and environmental, health and safety liabilities. Such liabilities could include penalties, sanctions or claims for damages to persons, property or natural resources brought on behalf of the government or private litigants that could cause the Company to incur substantial costs or uninsured losses. In addition, estimates of the Company's potential liabilities relating to current or former natural gas and oil properties, including the costs associated with plugging and abandoning wells, may be incorrect, and actual plugging and abandonment expenses may vary substantially from the Company's estimates.

Costs of compliance and liabilities could negatively affect the Company's results of operations, financial condition and cash flows. In addition, compliance with environmental laws, regulations or permit conditions could require unexpected capital expenditures at the Company's facilities, temporarily shut down the Company's facilities or delay or cause the cancellation of expansion projects or natural gas drilling activities. Because the costs of such compliance are significant, additional regulation could negatively affect the Company's business.

***Increased regulation of exploration and production activities, including hydraulic fracturing, could adversely impact the Company.***

Various state legislative and regulatory initiatives regarding the exploration and production business have been proposed or adopted in the northeast United States affecting the Marcellus and Utica Shale gas plays. These initiatives include potential new or updated statutes and regulations governing the drilling, casing, cementing, testing, monitoring and abandonment of wells, the protection of water supplies and restrictions on water use and water rights, hydraulic fracturing operations, increased setback requirements, surface owners' rights and damage compensation, the spacing of wells, use and disposal of potentially hazardous materials, and environmental and safety issues regarding natural gas pipelines. New permitting fees and/or severance taxes for natural gas production are also possible. Additionally, legislative initiatives and environmental and health studies, proceedings or rule-making initiatives at federal, state or local agencies focused on the hydraulic fracturing process, the use of underground injection control wells for produced water disposal, and related operations could result in operational delays or prohibitions and/or additional permitting, compliance, reporting and disclosure requirements, which could lead to increased operating costs and increased risks of litigation for the Company.

***The Company could be adversely affected by the delayed recovery or disallowance of purchased gas costs incurred by the Utility segment.***

Tariff rate schedules in each of the Utility segment's service territories contain purchased natural gas adjustment clauses which permit Distribution Corporation to file with state regulators for rate adjustments to recover increases in the cost of purchased natural gas. Assuming those rate adjustments are granted, increases in the cost of purchased natural gas have no direct impact on profit margins. Distribution Corporation is required to file an accounting reconciliation with the regulators in each of the Utility segment's service territories regarding the costs of purchased natural gas. Extreme weather events, variations in seasonal weather, and other events disrupting supply and/or demand could cause the Company to experience unforeseeable and unprecedented increases in the costs of purchased natural gas. Prudently incurred natural gas costs could be subject to deferred recovery if regulators determine such costs are detrimental to customers in the short-term. Furthermore, there is a risk of disallowance of full recovery of these costs if regulators determine that Distribution Corporation was imprudent in making its natural gas purchases. Any material delayed recovery or disallowance of purchased natural gas costs could have a material adverse effect on cash flow and earnings.

## RISKS RELATED TO OUR PLANNED ACQUISITION OF CENTERPOINT OHIO

***Our planned acquisition of CenterPoint Ohio may not occur at all or may not occur in the expected time frame, which may negatively affect the trading price of our stock and our future business and financial results.***

Completion of the planned acquisition of CenterPoint Ohio is subject to the satisfaction or waiver of customary and other closing conditions. The acquisition is not assured and is subject to risks and uncertainties, including the risk that the necessary regulatory approvals will not be obtained or that other closing conditions will not be satisfied. We cannot predict whether and when such approvals will be received, or such conditions will be satisfied. The Securities Purchase Agreement includes customary termination rights for both the Company and the Seller, including the right of either party to terminate the agreement if the planned acquisition of CenterPoint Ohio has not been consummated within eighteen months following the execution date of the Securities Purchase Agreement (the "Outside Date"). The Outside Date may be extended by either party for up to two additional three-month periods under certain conditions. Additionally, if the Securities Purchase Agreement is terminated under certain circumstances, including relating to the failure to obtain regulatory approvals in a timely manner, the Company may be required to pay a significant termination fee. If the planned acquisition of CenterPoint Ohio is not completed, or if there are significant delays in completing the planned acquisition, it may negatively affect the trading price of our stock and our future business and financial results.

***The planned acquisition of CenterPoint Ohio may limit our financial flexibility.***

We expect to acquire CenterPoint Ohio for total consideration of $2.62 billion, inclusive of the amount to repay a $1.2 billion promissory note. Although we have obtained committed financing for the entirety of the purchase price, we expect to obtain permanent financing for the planned acquisition by accessing the capital markets, which may include the issuance of long-term debt and equity. If we are not able to obtain permanent financing on favorable terms, we may be required to finance a portion of the purchase price of the planned acquisition at interest rates higher than currently expected, which could limit our financial flexibility. In addition, our ability to make payments on our debt, fund our other liquidity needs, and make planned capital expenditures following the planned acquisition of CenterPoint Ohio will depend on our ability to generate cash in the future. Our ability to generate cash, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory, and other factors that are beyond our control. The degree to which we will be leveraged following the completion of the planned acquisition could require us to dedicate a substantial portion of our cash flow from operations to the payment of debt service, reducing the availability of our cash flow to fund working capital, capital expenditures, acquisitions, and other general corporate purposes.

***We may not realize the benefits, including growth opportunities, that are anticipated from the planned acquisition of CenterPoint Ohio.***

The benefits that are expected to result from the planned acquisition of CenterPoint Ohio will depend, in part, on our ability to realize the anticipated growth opportunities of the acquired business. Our success in realizing these growth opportunities, and the timing of this realization, depend on our ability to deploy capital and to obtain timely recovery of capital investments under mechanisms currently supported by Ohio utility regulators and state policymakers. In addition, realization of these benefits may depend on the successful integration of CenterPoint Ohio with the Company's current operations. There can be no assurance that we will successfully or cost-effectively integrate this business, and the Company may incur substantial and unanticipated expenses in connection with the integration of CenterPoint Ohio. Such expenses are difficult to estimate accurately and may exceed current estimates. Accordingly, we may not realize the anticipated benefits from the planned acquisition, including growth opportunities, and these benefits may be offset by costs incurred to integrate, or delays in integrating, the businesses. These items could have a material adverse effect on the Company's results of operations, financial condition and cash flows.

## GENERAL RISKS

***The Company's credit ratings may not reflect all the risks of an investment in its securities.***

The Company's credit ratings are an independent assessment of its ability to pay its obligations. Consequently, real or anticipated changes in the Company's credit ratings will generally affect the market value of the specific debt instruments that are rated, as well as the market value of the Company's common stock. The Company's credit ratings, however, may not reflect the potential impact on the value of its common stock of risks related to structural, market or other factors discussed in this Form 10-K.

***The increasing costs of certain employee and retiree benefits, and the regulatory treatment of certain benefit plan activity, could adversely affect the Company's results.***

The Company's earnings and cash flow may be impacted by the amount of income or expense it expends or records for employee benefit plans. This is particularly true for pension and other post-retirement benefit plans, which are dependent on actual plan asset returns and factors used to determine the value and current costs of plan benefit obligations. In addition, if medical costs rise at a rate faster than the general inflation rate, the Company might not be able to mitigate the rising costs of medical benefits. Increases to the costs of pension, other post-retirement and medical benefits could have an adverse effect on the Company's financial results.

The Company's earnings and cash flows may also be impacted by the rate treatment of certain income and expense activity, including the crediting of employee benefit plan trust income to ratepayers by reducing delivery rates and customer revenues, and the refund of regulatory liability balances. The application of current rate treatment is subject to change in a future rate proceeding.

***Significant shareholders or potential shareholders may attempt to effect changes at the Company or acquire control over the Company, which could adversely affect the Company's results of operations and financial condition.***

Shareholders of the Company may from time to time engage in proxy solicitations, advance shareholder proposals or otherwise attempt to effect changes or acquire control over the Company. Campaigns by shareholders to effect changes at publicly traded companies are sometimes led by investors seeking to increase short-term shareholder value through actions such as financial restructuring, increased debt, special dividends, stock repurchases or sales of assets or the entire company. Additionally, activist shareholders may submit proposals to promote an environmental, social, and/or governance position. Responding to proxy contests and other actions by activist shareholders can be costly and time-consuming, disrupting the Company's operations and diverting the attention of the Company's Board of Directors and senior management from the pursuit of business strategies. As a result, shareholder campaigns could adversely affect the Company's results of operations and financial condition.

**Item 1B** ***Unresolved Staff Comments***

None.

**Item 1C** ***Cybersecurity***

**Overview**

The Company, as an owner and operator of critical energy infrastructure, is subject to evolving risks from cybersecurity threats. The Company increasingly relies on technology to optimize its business functions. The Company maintains a cybersecurity program that is designed to assess, identify and manage material risks from cybersecurity threats and includes internal and external controls, risk assessments, incident simulations, employee trainings and corporate policies.

**Governance**

The Board of Directors retains risk oversight of significant risks from cybersecurity threats that might arise from the Company's operations. An important aspect of the Board's oversight role is the enterprise risk management process, under which enterprise-wide risks have been identified and assessed, which the Board is briefed on quarterly at the Audit Committee meetings. Information security risks are identified and assessed as part of the Company's enterprise risk management process.

The Corporate Information Security Steering Committee ("CISSC") is responsible for assessing and managing the Company's material risks from cybersecurity threats. The CISSC meets quarterly to discuss emerging information security risks and the Company's corresponding mitigation and defense efforts. Led by the Company's Chief Information Officer ("CIO") and Chief Information Security Officer ("CISO"), the CISSC is composed of Information Security ("InfoSec") professionals, leadership from key departments and the Company's senior management. The Company's CIO has over 30 years of experience in the field of information systems and cybersecurity and the CISO has over 20 years of experience in cyber and physical security and leads an experienced security and networking team. The CISO regularly provides information security updates to the Board.

The InfoSec team promotes security awareness through personnel training and regularly reviewing internal information security policies, monitoring for anomalous behavior, investigating potential security events, attempting to mitigate security vulnerabilities, and assisting business partners on cybersecurity matters. The InfoSec team meets regularly with key Information Technology and Operation Technology leadership to discuss potential cybersecurity threats and review alerts.

The Company's Incident Response Team, made up primarily of the General Counsel, CIO, CISO, Legal, and InfoSec directors, reviews the Company's Information Security Incident Response Plan ("ISIRP") annually. As part of the ISIRP, the Company has also established a cybersecurity incident escalation process whereby potential cybersecurity incidents are identified, monitored, assessed, and escalated to our Disclosure Committee, as appropriate.

**Risk Management and Strategy**

The Company has established an information security program (the "Information Security Program") that is designed to assess, identify and manage material risks from cybersecurity threats. The Information Security Program is designed to align to the Cybersecurity Framework published by the National Institute of Standards and Technology ("NIST"). However, this does not mean that the Company's Information Security Program meets any particular technical standards, specifications or requirements, but rather that the Company uses NIST and other cybersecurity standards as a guide to help us identify, assess and manage cybersecurity risks relevant to its business. The Information Security Program is centralized under the CISO, who reports to the CIO. The Company periodically reevaluates its Information Security Program to assess whether planned initiatives are appropriate and to assess risk mitigation and defense efforts. The Company maintains cybersecurity insurance coverage.

The Company conducts regular cybersecurity vulnerability assessments that are designed to identify potential risks and opportunities for cybersecurity improvement. The Company also conducts cybersecurity incident simulations annually and undergoes internal and external audits of our processes. The Company participates in industry organizations, engages third-party service providers, and maintains close working relationships with law enforcement agencies to help us identify and address risks from cybersecurity threats.

The Company provides employees with least privilege access, and contractors with independent access to Company systems, which is audited regularly. Employees and contractors receive regular information security training, including malicious email testing, "phishing" awareness training and targeted cybersecurity training.

The Company engages multiple independent cybersecurity consultants throughout the year to conduct assessments of the Company's technology and risks from cybersecurity threats. On occasion, the Company voluntarily participates in separate assessments focused on different information security issues performed by various U.S. federal agencies, including the Cybersecurity and Infrastructure Security Agency, the Transportation Security Administration, the Department of Homeland Security and the FERC. The Company also annually performs the NYPSC review of third-party attestation as it relates to Case 13-M-0178 (protection of personally identifiable customer information).

To date, the Company does not believe risks from cybersecurity threats, including those threats resulting from previous cybersecurity incidents, have materially affected or are reasonably likely to materially affect the Company's business strategy, results of operations or financial condition. However, because the Company operates in the area of critical infrastructure, as defined under federal law and by the Transportation Security Administration, the Company has been and will continue to be the target of cybersecurity attacks from time to time. As such, the Company cannot guarantee that future cybersecurity incidents will not materially affect the Company's business strategy, results of operations and financial condition. For further discussion regarding cybersecurity risks and their impact on our business strategy, results of operations and financial condition, see the risk factor entitled "Attacks on or disruption of the Company's information technology and operational technology systems, including third party attempts to breach the Company's network security, or other cybersecurity threats and incidents could adversely affect the Company's operations and financial results" under the heading "Risk Factors" in Item 1A of this Annual Report.

**Item 2** ***Properties***

**General Information on Facilities**

The net investment of the Company in property, plant and equipment was $7.7 billion at September 30, 2025. The Integrated Upstream and Gathering segment constitutes 46.0% of this investment, and is primarily located in the Appalachian region of the United States. Approximately 53.9% of the Company's investment in net property, plant and equipment was in the Utility and Pipeline and Storage segments, whose operations are located primarily in western and central New York and western Pennsylvania. The remaining 0.1% of the Company's net investment in property, plant and equipment falls within All Other and Corporate operations. During the past five years, the Company has made significant additions to property, plant and equipment in order to expand its integrated upstream and gathering operations in the Appalachian region of the United States and to expand and modernize transmission, storage, and distribution facilities for customers in New York and Pennsylvania. Net property, plant and equipment has increased $1.7 billion, or 28.6%, since September 30, 2020. The five-year increase is net of impairments of assets recorded in 2021, 2024 and 2025 (pre-tax amounts of $76 million, $519 million and $142 million, respectively).

The Integrated Upstream and Gathering segment had a net investment in property, plant and equipment of $3.5 billion at September 30, 2025. Capitalized costs relating to exploration and production activities, the components of which are disclosed in Item 8, Note N — Supplementary Information for Exploration and Production Activities, represent 69% of this segments total net investment. Gathering lines and related compressor stations represent 23% of this segment's total net investment and includes 401 miles of pipelines utilized to move Appalachian production (including Marcellus and Utica shales) to various transmission pipeline receipt points as well as 24 compressor stations with 128,286 installed horsepower.

The Pipeline and Storage segment had a net investment of $2.2 billion in property, plant and equipment at September 30, 2025. Transmission pipeline represents 35% of this segment's total net investment and includes 2,233 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 15% of this segment's total net investment and consist of 382 miles of pipeline, as well as 28 storage fields operating at a combined working gas level of 77.2 Bcf, three of which are jointly owned and operated with other interstate gas pipeline companies. Net investment in storage facilities includes $80.7 million of gas stored underground, representing the cost of base gas utilized to maintain pressure levels for normal operating purposes as well as gas maintained for system balancing and other purposes, including that needed for no-notice transportation service. The Pipeline and Storage segment has 30 compressor stations with 259,038 installed horsepower that represent 31% of this segment's total net investment in property, plant and equipment.

The Pipeline and Storage segment's facilities provided the capacity to meet Supply Corporation's 2025 peak day sendout for transportation service of 2,371 MMcf, which occurred on January 21, 2025. Withdrawals from storage of 563 MMcf provided approximately 24% of the requirements on that day.

The Utility segment had a net investment in property, plant and equipment of $2.0 billion at September 30, 2025. The net investment in its gas distribution network (including 15,112 miles of distribution pipeline) and its service connections to customers represent approximately 51% and 31%, respectively, of the Utility segment's net investment in property, plant and equipment at September 30, 2025.

Company maps are included in Exhibit 99.2 of this Form 10-K and are incorporated herein by reference.

**Exploration and Production Activities**

Seneca, which is part of the Company's Integrated Upstream and Gathering segment, is engaged in the exploration for and the development of natural gas reserves in the Appalachian region of the United States. Seneca's development activities in the Appalachian region are focused primarily in the Marcellus and Utica shales. Further discussion of exploration and production activities is included in Item 8, Note N — Supplementary Information for Exploration and Production Activities. Note N sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2025, 2024 and 2023 reserves shown in Note N are valued using an unweighted arithmetic average of first day of the month commodity price for each month within the twelve-month period prior to the end of the reporting period. The reserves were estimated by Seneca's petroleum engineers and were audited by independent petroleum engineers from Netherland, Sewell & Associates, Inc. Note N discusses the qualifications of Seneca's petroleum engineers, internal controls over the reserve estimation process and audit of the reserve estimates and changes in proved developed and undeveloped gas reserves year over year.

Seneca's proved developed and undeveloped natural gas reserves increased from 4,752 Bcf at September 30, 2024 to 4,980 Bcf at September 30, 2025. This increase is attributed to extensions and discoveries of 632

Bcf and revisions of previous estimates of 22 Bcf, partially offset by production of 426 Bcf. Upward revisions of 69 Bcf are mainly attributed to positive performance improvements and price revisions. The additions and upward revisions were partially offset by downward revisions of 47 Bcf from changes to development layout, the removal of one PUD location and operating expense-related revisions. The Company has no near term plans to develop the reserves at this PUD location.

Seneca's proved developed and undeveloped natural gas reserves increased from 4,535 Bcf at September 30, 2023 to 4,752 Bcf at September 30, 2024. This increase is attributed to extensions and discoveries of 602 Bcf and revisions of previous estimates of 7 Bcf, partially offset by production of 392 Bcf. Upward revisions of 145 Bcf are mainly attributed to positive performance improvements, changes to the booked lateral length and optimized development layout. The additions and upward revisions were partially offset by downward revisions of 138 Bcf from the removal of nine PUD locations related to schedule changes and price-related revisions. The Company has no near term plans to develop the reserves at these PUD locations.

At September 30, 2025, Seneca had delivery commitments for natural gas production of 2,055 Bcf. The Company expects to meet those commitments through the future production of reserves that are currently classified as proved reserves and future extensions and discoveries.

The following is a summary of certain oil and gas information taken from Seneca's records.

**Production**

| | For The Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| **United States** | | | |
| Appalachian Region | | | |
| Average Sales Price per Mcf of Gas | $ 2.59 (1) | $ 1.88 (1) | $ 2.78 (1) |
| Average Sales Price per Mcf of Gas (after hedging) | $ 2.70 | $ 2.44 | $ 2.55 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 0.67 (1) | $ 0.69 (1) | $ 0.68 (1) |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 1,169 (1) | 1,072 (1) | 1,020 (1) |

(1) Average sales prices per Mcf of gas reflect sales of gas in the Marcellus and Utica Shale fields. The Marcellus Shale fields (which exceed 15% of total reserves at September 30, 2025, 2024 and 2023) contributed 574 MMcfe, 645 MMcfe and 521 MMcfe of daily production in 2025, 2024 and 2023, respectively. The average lifting costs (per Mcfe) were $0.72 in 2025, $0.72 in 2024 and $0.73 in 2023. The Utica Shale fields (which exceed 15% of total reserves at September 30, 2025, 2024 and 2023) contributed 591 MMcfe, 423 MMcfe and 495 MMcfe of daily production in 2025, 2024 and 2023, respectively. The average lifting costs (per Mcfe) were $0.61 in 2025, $0.64 in 2024 and $0.62 in 2023.

**Productive Wells**

| | Appalachian Region |
|---|---|
| **At September 30, 2025** | **Gas** |
| Productive Wells — Gross | 1,084 |
| Productive Wells — Net | 964 |

**Developed and Undeveloped Acreage**

| At September 30, 2025 | Appalachian Region | |
|---|---|---|
| Developed Acreage | | |
| — Gross | 671,791 | |
| — Net | 659,913 | |
| Undeveloped Acreage | | |
| — Gross | 688,591 | |
| — Net | 641,455 | |
| Total Developed and Undeveloped Acreage | | |
| — Gross | 1,360,382 | |
| — Net | 1,301,368 | (1) |

(1) Of the 1,301,368 Total Developed and Undeveloped Net Acreage in the Appalachian region as of September 30, 2025, there are a total of 1,229,682 net acres in Pennsylvania. Of the 1,229,682 total net acres in Pennsylvania, shale development in the Marcellus, Utica or Geneseo shales has occurred on approximately 153,105 net acres, or 12% of Seneca's total net acres in Pennsylvania. Developed Acreage in the table reflects previous development activities in the Upper Devonian formation, but does not include the potential for development beneath this formation in areas of previous development, which includes the Marcellus, Utica and Geneseo shales.

As of September 30, 2025, the aggregate amounts of gross undeveloped acreage expiring under lease in the next three years and thereafter are as follows: 18,458 acres in 2026 (16,150 net acres), 14,698 acres in 2027 (12,679 net acres), 7,248 acres in 2028 (6,558 net acres) and 177,270 acres thereafter (169,102 net acres). The remaining 470,917 gross acres (436,966 net acres) represent non-expiring oil and gas rights owned by the Company. Of the acreage that is currently scheduled to expire in 2026, 2027 and 2028, Seneca has 814.7 Bcf of associated proved undeveloped gas reserves. As a part of its management approved development plan, Seneca generally commences development of these reserves prior to the expiration of the leases and/or proactively extends/renews these leases.

**Drilling Activity**

| | Productive | | | Dry | | |
|---|---|---|---|---|---|---|
| For the Year Ended September 30 | 2025 | 2024 | 2023 | 2025 | 2024 | 2023 |
| **United States** | | | | | | |
| Appalachian Region | | | | | | |
| Net Wells Completed | | | | | | |
| — Exploratory | — | — | — | — | — | — |
| — Development(1) | 31.25 | 34.00 | 34.25 | 1.50 | — | 0.50 |

(1) Fiscal 2025 and 2023 Appalachian region dry wells include 1.5 and 0.5 net wells, respectively, drilled prior to 2013 that were never completed under a joint venture in which Seneca was the nonoperator. Seneca became the operator of the properties in 2017 and plugged and abandoned the wells in 2025 and 2023 after Seneca determined it would not continue development activities.

**Present Activities**

| At September 30, 2025 | Appalachian Region |
|---|---|
| Wells in Process of Drilling(1) | |
| — Gross | 52.00 |
| — Net | 51.50 |

(1) Includes wells awaiting completion.

**Item 3** ***Legal Proceedings***

For a discussion of various environmental and other matters, refer to Part II, Item 7, MD&A and Item 8 at Note L — Commitments and Contingencies.

For a discussion of certain rate matters involving the NYPSC, refer to Part II, Item 7, MD&A of this report under the heading "Other Matters - Rate Matters."

**Item 4** ***Mine Safety Disclosures***

Not Applicable.

## PART II

**Item 5** ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

At September 30, 2025, there were 7,821 registered shareholders of Company common stock. The common stock is listed and traded on the New York Stock Exchange under the trading symbol "NFG". Information regarding the market for the Company's common equity and related stockholder matters appears under Item 12 at Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters and Item 8 at Note H — Capitalization and Short-Term Borrowings.

On July 1, 2025, the Company issued a total of 5,180 unregistered shares of Company common stock to non-employee directors of the Company then serving on the Board of Directors of the Company (or, in the case of non-employee directors who elected to defer receipt of such shares pursuant to the Company's Deferred Compensation Plan for Directors and Officers (the "DCP"), to the DCP trustee), consisting of 518 shares per director. All of these unregistered shares were issued under the Company's 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors' services during the quarter ended September 30, 2025. The Company issued an additional 587 unregistered shares in the aggregate on July 15, 2025 pursuant to the dividend reinvestment feature of the DCP, to the six non-employee directors who participate in the DCP. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

**Issuer Purchases of Equity Securities**

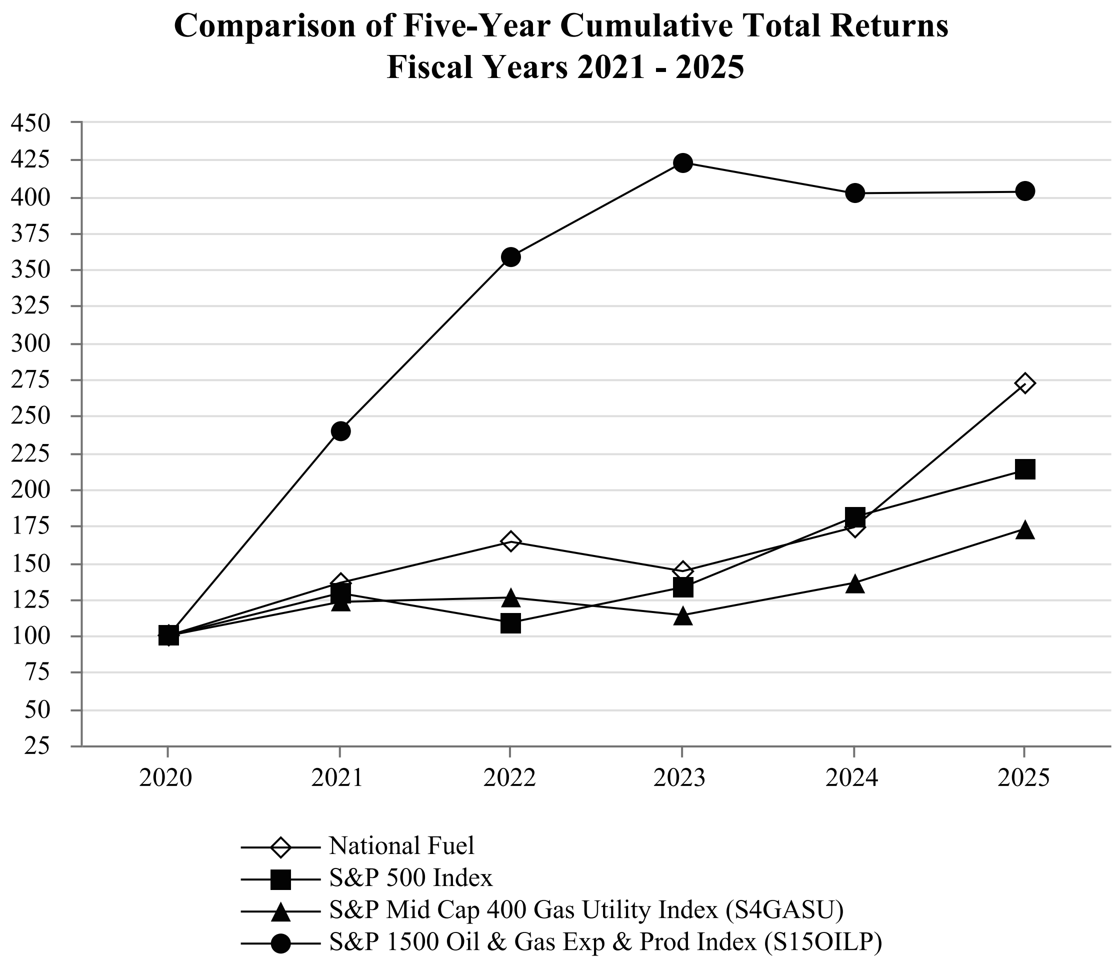
| Period | Total Number of Shares Purchased(a) | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs | Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs(b) |
|---|---|---|---|---|
| July 1-31, 2025 | 9,923 | $ 84.21 | — | $ 82,094,302 |
| Aug. 1-31, 2025 | 9,733 | $ 86.76 | — | $ 82,094,302 |
| Sept. 1-30, 2025 | 15,996 | $ 86.96 | — | $ 82,094,302 |
| Total | 35,652 | $ 86.14 | — | $ 82,094,302 |

(a) Represents (i) shares of common stock of the Company purchased with Company "matching contributions" for the accounts of participants in the Company's 401(k) plans, (ii) shares of common stock of the Company, if any, tendered to the Company by holders of stock-based compensation awards for the payment of applicable withholding taxes, and (iii) shares of common stock of the Company purchased on the open market pursuant to the Company's share repurchase program. Of the 35,652 shares purchased other than through a publicly announced share repurchase program, 29,645 were purchased for the Company's 401(k) plans and 6,007 were purchased as a result of shares tendered to the Company by holders of stock-based compensation awards.

(b) On March 8, 2024, the Company's Board of Directors authorized the repurchase of up to $200 million of shares of the Company's common stock. The calculation of the dollar value of shares remaining available for purchase excludes excise taxes and brokerage fees paid by the Company in connection with the repurchase program which in the aggregate totaled $1.07 million from the beginning of the program to September 30, 2025. Repurchases may be made from time to time in the open market or through privately negotiated transactions, including through the use of trading plans intended to qualify under SEC Rule 10b5-1, in accordance with applicable securities laws and other restrictions. In light of the Company's agreement to acquire CenterPoint Ohio's natural gas utility, repurchases under the program have been suspended. The repurchase program has no expiration date.

**Performance Graph**

The following graph compares the Company's common stock performance with the performance of the S&P 500 Index, the S&P Mid Cap 400 Gas Utility Index and the S&P 1500 Oil & Gas Exploration & Production Index for the period September 30, 2020 through September 30, 2025. The graph assumes that the value of the investment in the Company's common stock and in each index was $100 on September 30, 2020 and that all dividends were reinvested.




| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| National Fuel | $100 | $136 | $164 | $144 | $174 | $272 |
| S&P 500 Index | $100 | $129 | $109 | $133 | $181 | $213 |
| S&P Mid Cap 400 Gas Utility Index (S4GASU) | $100 | $123 | $126 | $114 | $136 | $173 |
| S&P 1500 Oil & Gas Exp & Prod Index (S15OILP) | $100 | $240 | $359 | $423 | $402 | $403 |

Source: Bloomberg

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

**Item 6** ***(Reserved)***

## Item 7 *Management's Discussion and Analysis of Financial Condition and Results of Operations*

### OVERVIEW

The Company is a diversified energy company engaged principally in the production, gathering, transportation, storage and distribution of natural gas. The Company operates an integrated business, with assets centered in western New York and Pennsylvania, being utilized for, and benefiting from, the production and transportation of natural gas from the Appalachian Basin. The common geographic footprint of the Company's subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Appalachian Basin to markets in the eastern United States and Canada. The Company's efforts in this regard are not limited to affiliated projects. The Company has also been designing and building pipeline projects for the transportation of natural gas for non-affiliated natural gas customers in the Appalachian Basin. In addition to expansion projects, the Company continues to focus on the ongoing modernization of its regulated Pipeline and Storage and Utility assets.

In the Company's 2024 Form 10-K and its Form 10-Qs for the first three quarters of 2025, the Company previously reported financial results for four business segments: Exploration and Production, Pipeline and Storage, Gathering, and Utility. The division of the Company's operations into reportable segments is based upon a combination of factors including differences in products and services as well as regulatory environment. During the quarter ended September 30, 2025, the president and chief executive officer determined that the Exploration and Production segment and Gathering segment should be treated as one operating segment in order to provide more clarity for management and investors as to the interdependence of both Seneca and Midstream Company in bringing Appalachian natural gas to market. As a result, the Company is now reporting financial results for three business segments: Integrated Upstream and Gathering, Pipeline and Storage, and Utility. Prior year segment information shown below has been recast to reflect this change in presentation. Refer to Item 1, Business, for a more detailed description of each of the segments.

**Fiscal 2025 Highlights**

This Item 7, MD&A, provides information concerning:

1. The critical accounting estimates of the Company;
2. Changes in revenues and earnings of the Company under the heading, "Results of Operations;"
3. Operating, investing and financing cash flows under the heading "Capital Resources and Liquidity" and;
4. Other Matters, including: (a) 2025 and projected 2026 funding for the Company's pension and other post-retirement benefits; (b) disclosures and tables concerning market risk sensitive instruments; (c) rate matters in the Company's New York, Pennsylvania and FERC-regulated jurisdictions; (d) environmental matters; (e) new authoritative accounting and financial reporting guidance; and (f) effects of inflation.

The information in MD&A should be read in conjunction with the Company's financial statements in Item 8 of this report, which includes a comparison of our Results of Operations and Capital Resources and Liquidity for fiscal 2025 and fiscal 2024. For a discussion of the Company's earnings, refer to the Results of Operations section below. A discussion of changes in the Company's results of operations from fiscal 2023 to fiscal 2024 for the Utility segment, the Pipeline and Storage segment, and All Other and Corporate operations has been omitted from this Form 10-K, but may be found in Item 7, MD&A, of the Company's Form 10-K for the fiscal year ended September 30, 2024, filed with the SEC on November 22, 2024. Changes in the Integrated Upstream and Gathering segment's results of operations from fiscal 2023 to fiscal 2024 have been included in this Form 10-K, which has been recast to reflect the treatment of the previously reported Exploration and Production segment and Gathering segment as one operating segment as a result of the Company's change in segment reporting discussed above.

The Company's Integrated Upstream and Gathering segment continues to grow, as evidenced by a 5% growth in proved reserves from the prior year to a total of 4,981 Bcfe at September 30, 2025. Production increased 34 Bcfe, or 9%, during the year ended September 30, 2025 to a total of 427 Bcfe, and is expected to increase again in fiscal 2026.

The Company has continued to pursue development projects to expand its Pipeline and Storage segment. One project on Supply Corporation's system, referred to as the Tioga Pathway Project, is an expansion and modernization project that would allow for the transportation of 190,000 Dth per day of shale gas supplies from a new interconnection in northwest Tioga County, Pennsylvania to an existing Supply Corporation interconnection with Tennessee Gas Pipeline Company, LLC at Ellisburg and a new virtual delivery point into an existing Transcontinental Gas Pipe Line Company, LLC ("Transco") capacity lease, providing access to Mid-Atlantic markets. On May 5, 2025, FERC issued the Section 7(b)/7(c) certificate for the project. Construction on the Tioga Pathway Project is expected to commence in early calendar 2026. This project has a target in-service date in late calendar 2026 and a preliminary cost estimate of approximately $101 million.

Supply Corporation has also announced that it expects to serve as the transporter for 205,000 Dth/day of natural gas supplies to the Shippingport Power Station, a natural gas power generation facility under development in Beaver County, Pennsylvania. In order to provide this new natural gas transportation capacity, Supply Corporation expects to construct an approximately 7.5 mile pipeline lateral from its existing Line N pipeline system to a direct interconnection with the facility (the "Shippingport Lateral Project"), with the incremental capacity expected to come online as early as Fall 2026 and a preliminary cost estimate of approximately $57 million. The project obtained FERC authorization under the Commission's prior notice regulations on November 7, 2025. The Tioga Pathway Project and the Shippingport Lateral Project are both discussed in more detail in the Capital Resources and Liquidity section that follows.

From a rate perspective, Distribution Corporation, in its New York jurisdiction, reached a settlement with the parties to its rate case proceeding. On December 19, 2024, the NYPSC issued an order approving the settlement. The settlement, effective January 1, 2025, established a three-year rate plan that reflects a return on equity of 9.7% and authorized a revenue requirement increase of $57.3 million in fiscal 2025, an additional revenue requirement increase of $15.8 million in fiscal 2026, and an additional revenue requirement increase of $12.7 million in fiscal 2027. The settlement also included standard make-whole language allowing full recovery of revenues that would have been billed at the new rates between October 1, 2024 and December 31, 2024. In addition, on March 17, 2025, FERC approved an amendment to Empire's 2019 rate case settlement. This settlement amendment is estimated to decrease Empire's revenues on a yearly basis by approximately $0.5 million. For further discussion of these and other rate matters, refer to the Rate Matters section below.

On October 20, 2025, the Company entered into a Securities Purchase Agreement (the "Purchase Agreement") with CenterPoint Energy Resources Corp. (the "Seller"), pursuant to which, among other things, the Company agreed to acquire from the Seller all of the issued and outstanding equity interests of Vectren Energy Delivery of Ohio, LLC for an aggregate purchase price of $2.62 billion, subject to customary adjustments, as provided in the Purchase Agreement. Closing is expected to occur in the fourth quarter of calendar 2026, pending completion of a notice filing and review with the Public Utilities Commission of Ohio, Hart-Scott-Rodino review, and other customary closing conditions. The purchase price will include a combination of $1.42 billion in cash and a $1.2 billion promissory note to be issued by the Company to the Seller. The promissory note, which was part of the Seller's desired transaction structure and was incorporated into the Company's business valuation, will have a maturity date of 364 days post-closing and will carry an interest rate of 6.5%. The Company intends to execute permanent financing, inclusive of the amount to repay the promissory note, using the issuance of long-term debt and common equity, along with expected future free cash flow. This acquisition will add significant regulated scale for the Company, doubling the size of the Company's gas utility rate base, while expanding its operations beyond New York and Pennsylvania into the neighboring state of Ohio, a state with a constructive regulatory and political environment that is supportive of natural gas.

In connection with its entry into the Purchase Agreement, the Company entered into a senior unsecured bridge loan facility commitment letter supported by The Toronto-Dominion Bank, New York Branch ("TD Bank") and Wells Fargo Bank, National Association (together with TD Bank, the "Commitment Parties") and additional banks, as well as a 364-day term loan facility commitment letter supported by the Commitment

Parties and additional banks, all of which are lenders under the Company's primary credit facility. The combination of both facilities fully supports the purchase price of $2.62 billion.

As discussed in the following Critical Accounting Estimates section, the Company uses the full cost method of accounting for determining the book value of its exploration and production properties and that book value is subject to a quarterly ceiling test. In addition to the non-cash impairment charges under the ceiling test that the Company recorded during fiscal 2024, the Company recorded a non-cash impairment charge under the ceiling test during the quarter ended December 31, 2024 of $108.3 million ($79.1 million after-tax). At September 30, 2025, June 30, 2025 and March 31, 2025, the ceiling exceeded the book value of the exploration and production properties, and thus, did not result in an impairment charge in any of these quarters. Please refer to the Critical Accounting Estimates section below for more details on this matter and a sensitivity analysis concerning commodity price changes.

From a financing perspective, on February 19, 2025, the Company issued $500.0 million of 5.50% notes due March 15, 2030 and $500.0 million of 5.95% notes due March 15, 2035. The proceeds of these debt issuances were used for general corporate purposes, including the March 2025 redemptions of $450.0 million of the Company's 5.20% notes that were scheduled to mature in July 2025 and $500.0 million of the Company's 5.50% notes that were scheduled to mature in January 2026. The Company redeemed those notes for $450.8 million and $503.3 million, respectively, plus accrued interest. The remaining proceeds of the debt issuances were used in conjunction with funding a defeasance trust associated with the June 2025 redemption of $50.0 million of 7.38% notes, the last of the notes under the Company's 1974 indenture. For details of these matters, refer to the Capital Resources and Liquidity section below.

The Company is a party to a syndicated Credit Agreement that provides a $1.0 billion unsecured committed revolving credit facility. In January 2025, the Company and the syndicate of banks under the Credit Agreement consented to a second one-year extension on the maturity date of the Credit Agreement, such that the Company has aggregate commitments available in the full amount of $1.0 billion through February 23, 2029. In May 2025, the number of lenders under the Credit Agreement increased to twelve as a new lender joined the syndicate, assuming a portion of an existing lender's commitment.

The Company began repurchasing outstanding shares of its common stock during the quarter ended March 31, 2024 under a share repurchase program authorized by the Company's Board of Directors. The program authorizes the Company to repurchase up to an aggregate amount of $200 million of its outstanding common stock in the open market or through privately negotiated transactions. During fiscal 2025, the Company executed transactions to repurchase 828,720 shares at an average price of $64.37 per share, for a total cost of $53.8 million (including broker fees and excise taxes). From inception to September 30, 2025, the Company has repurchased 1,974,979 shares under the share repurchase program at an average price of $59.70, for a total cost of $119.0 million (including broker fees and excise taxes). In light of the Company's agreement to acquire CenterPoint Ohio's natural gas utility, repurchases under the program have been suspended. The program has no fixed expiration date. These matters are discussed further in the Capital Resources and Liquidity section that follows.

The Company expects to use cash from operations, short-term and/or long-term borrowings, and equity financing as needed to meet its financing needs for fiscal 2026, including the repayment of a $300.0 million delayed draw term loan that matures in February 2026 and any potential funding for the CenterPoint Ohio acquisition. The Company continues to evaluate these financing needs and options to meet them. Given the current economic conditions, which include continued inflationary pressures, volatile interest rates and the ongoing impacts of federal policy changes, the cost and/or availability of capital may be impacted, but the Company continues to expect to meet its financing needs.

## CRITICAL ACCOUNTING ESTIMATES

The Company has prepared its consolidated financial statements in conformity with GAAP. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. In the event estimates or assumptions prove to be different from actual results, adjustments are made in subsequent periods to reflect more current information. The following is a summary of the Company's most critical accounting estimates, which are defined as those estimates whereby judgments or uncertainties could affect the application of accounting policies and materially different amounts could be reported under different conditions or using different assumptions. For a complete discussion of the Company's significant accounting policies, refer to Item 8 at Note A — Summary of Significant Accounting Policies.

*Exploration and Development Costs.* In the Company's Integrated Upstream and Gathering segment, upstream property acquisition, exploration and development costs are accounted for under the full cost method of accounting. Under this accounting methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves attributable to a cost center.

Proved reserves are estimated quantities of reserves that, based on geologic and engineering data, appear with reasonable certainty to be producible under existing economic and operating conditions. Such estimates of proved reserves are inherently imprecise and may be subject to substantial revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The estimates involved in determining proved reserves are critical accounting estimates because they serve as the basis over which capitalized costs are depleted under the full cost method of accounting (on a units-of-production basis). Unproved properties are excluded from the depletion calculation until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

In addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying an unweighted arithmetic average of the first day of the month commodity prices for each month within the twelve-month period prior to the end of the reporting period (as adjusted for hedging) to estimated future production of proved reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unproved properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures, which are based on current costs, associated with future production. The amount of the ceiling can fluctuate significantly from period to period because of additions to or subtractions from proved reserves and significant fluctuations in natural gas prices. The ceiling is then compared to the capitalized cost of exploration and production properties less accumulated depletion and related deferred income taxes. If the capitalized costs of exploration and production properties less accumulated depletion and related deferred taxes exceeds the ceiling at the end of any fiscal quarter, a non-cash impairment charge must be recorded to write down the book value of the reserves to their present value. This non-cash impairment cannot be reversed at a later date if the ceiling increases. It should also be noted that a non-cash impairment to write down the book value of the reserves to their present value in any given period causes a reduction in future depletion expense. At September 30, 2025, the ceiling exceeded the book value of the exploration and production properties by approximately $1.1 billion (after-tax). The 12-month average of the first day of the month price for natural gas for each month during 2025, based on the quoted Henry Hub spot price for natural gas, was $3.10 per MMBtu. (Note: Because actual pricing of the Company's producing properties varies depending on their location and hedging, the prices used to calculate the ceiling may differ from the Henry Hub price, which is only indicative of 12-month average prices for 2025. Actual realized pricing includes adjustments for regional market differentials, transportation fees and contractual arrangements.) In regard to the sensitivity of the ceiling test calculation to commodity price changes, if natural gas prices were $0.25 per MMBtu lower than the average prices in the twelve-month period used at September 30, 2025 in the ceiling test calculation, the ceiling would have exceeded the book value of the Company's exploration and production properties by approximately $677.2 million (after-tax), which would not have resulted in an impairment charge. This calculated amount is based solely on price changes and does not take into account any other changes to the ceiling test calculation, including, among others, changes in reserve quantities and future cost estimates.

It is difficult to predict what factors could lead to future non-cash impairments under the SEC's full cost ceiling test. Fluctuations in or subtractions from proved reserves, increases in development costs for undeveloped reserves and significant fluctuations in natural gas prices have an impact on the amount of the ceiling at any point in time.

As discussed above, the full cost method of accounting provides a ceiling to the amount of costs that can be capitalized in the full cost pool. In accordance with current authoritative guidance, the future cash outflows associated with plugging and abandoning wells are excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation.

*Regulation.* The Company is subject to regulation by certain state and federal authorities. The Company, in its Utility and Pipeline and Storage segments, has accounting policies which conform to the FASB authoritative guidance regarding accounting for certain types of regulations, and which are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting principles for certain types of rate-regulated activities provides that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the balance sheet and included in the Consolidated Statement of Income for the period in which the discontinuance of regulatory accounting treatment occurs. Such amounts would be classified as an extraordinary item. For further discussion of the Company's regulatory assets and liabilities, refer to Item 8 at Note F — Regulatory Matters.

## RESULTS OF OPERATIONS

### EARNINGS

### 2025 Compared with 2024

The Company's earnings were $518.5 million in 2025 compared to earnings of $77.5 million in 2024. The increase in earnings of $441.0 million was primarily the result of current year earnings recognized in the Integrated Upstream and Gathering segment compared to a prior year loss combined with higher earnings in the Pipeline and Storage, and Utility segments. A higher loss in the Corporate category partially offset these increases. In the discussion that follows, all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted. Earnings were impacted by the following events in 2025 and 2024:

*2025 Event*

- Non-cash impairment charges of $141.8 million ($103.6 million after-tax) recorded during 2025 in the Integrated Upstream and Gathering segment, consisting mostly of a ceiling test impairment charge of $108.3 million ($79.1 million after-tax). The remaining charges are related to an impairment of certain water disposal assets.

*2024 Events*

- Non-cash impairment charges of $473.1 million ($343.2 million after-tax) recorded during 2024 in the Integrated Upstream and Gathering segment, consisting mostly of ceiling test impairment charges of $463.7 million ($336.4 million after-tax). The remaining charges are related to impairments of certain water disposal assets.
- Non-cash impairment charge of $46.1 million ($33.8 million after-tax) recorded during the quarter ended September 30, 2024 in the Pipeline and Storage segment associated with the Northern Access project.

**Earnings (Loss) by Segment**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | | (Thousands) | |
| Integrated Upstream and Gathering | $ 324,698 | $ (57,041) | $ 331,999 |
| Pipeline and Storage | 120,957 | 79,670 | 100,501 |
| Utility | 83,249 | 57,089 | 48,395 |
| Total Reported Segments | 528,904 | 79,718 | 480,895 |
| All Other | (814) | (617) | (531) |
| Corporate | (9,586) | (1,588) | (3,498) |
| Total Consolidated | $ 518,504 | $ 77,513 | $ 476,866 |

**INTEGRATED UPSTREAM AND GATHERING**

**Revenues**

**Integrated Upstream and Gathering Operating Revenues**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | | (Thousands) | |
| Gas Produced in Appalachia (after Hedging) | $ 1,151,240 | $ 955,790 | $ 948,484 |
| Gathering | 11,813 | 15,537 | 13,891 |
| Other | 21,083 | 5,288 | 9,971 |
| Operating Revenues | $ 1,184,136 | $ 976,615 | $ 972,346 |

**Production**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| Gas Production (MMcf) | 426,357 | 392,047 | 372,271 |

**Average Prices**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| **Average Gas Price/Mcf** | | | |
| Weighted Average | $ 2.59 | $ 1.88 | $ 2.78 |
| Weighted Average After Hedging(1) | $ 2.70 | $ 2.44 | $ 2.55 |

(1) Refer to further discussion of hedging activities below under "Market Risk Sensitive Instruments" and in Note J — Financial Instruments in Item 8 of this report.

**2025 Compared with 2024**

Operating revenues for the Integrated Upstream and Gathering segment increased $207.5 million in 2025 as compared with 2024. Gas production revenue after hedging increased $195.5 million due to the impact of a $0.26 per Mcf increase in the weighted average price of natural gas after hedging, combined with a 34.3 Bcf increase in natural gas production. The increase in natural gas production in 2025 as compared with 2024 was largely due to pads recently turned in line. In addition, other revenue increased $15.8 million primarily due to a change in segment reporting combined with a gain recognized on the sale of certain fixed assets. These increases in operating revenues were partially offset by a decrease of $3.7 million in gathering revenue driven primarily by a decrease in gathered volume. The decrease in gathered volume was largely the result of natural production declines by producers connected to the Trout Run gathering system, partially offset by the impact of new wells brought online by producers connected to the Tioga gathering system.

**2024 Compared with 2023**

Operating revenues for the Integrated Upstream and Gathering segment increased $4.3 million in 2024 as compared with 2023. Gas production revenue after hedging increased $7.3 million primarily due to a 19.8 Bcf increase in gas production offset by a $0.11 per Mcf decrease in the weighted average realized price of gas after hedging. The increase in gas production was largely due to new Marcellus and Utica wells in the Appalachian region. Gathering revenue increased $1.6 million driven primarily by an increase in gathered volume in this segment's eastern development areas (Trout Run and Tioga). The increase in gathered volume can be attributed to an increase in gross natural gas production by producers connected to the gathering systems. Partially offsetting this increase, other revenue decreased $4.7 million due to the non-recurrence of temporary capacity release revenue for a portion of this segment's transportation capacity in 2023.

Refer to further discussion of derivative financial instruments in the "Market Risk Sensitive Instruments" section that follows. Refer to the tables above for production and price information.

**Earnings**

**2025 Compared with 2024**

The Integrated Upstream and Gathering segment's earnings in 2025 were $324.7 million, an increase of $381.7 million when compared with a net loss of $57.0 million in 2024. The $381.7 million increase was primarily attributed to the following factors:

| | (Millions) | |
|---|---|---|
| Lower non-cash impairments of assets | $ 239.6 | (1) |
| Higher natural gas prices after hedging | 88.3 | |
| Higher natural gas production | 66.1 | |
| Higher other revenue | 12.5 | |
| Lower earnings reduction associated with remeasurement of state deferred income taxes due to ceiling test impairments | 4.8 | |
| Lower depreciation / depletion expense | 3.9 | (2) |
| Lower lease operating expenses | 1.1 | (3) |
| Change in mark to market adjustment on contingent consideration | 0.8 | (4) |
| Higher other operating expenses | (13.5) | (5) |
| Higher income tax expense | (10.6) | (6) |
| Higher other tax expense | (3.3) | (7) |
| Lower other income | (3.1) | (8) |
| Lower gathering revenues | (2.9) | |
| Premiums paid on early redemption of debt | (1.7) | (9) |
| Other items | (0.3) | |
| | $ 381.7 | |

(1) Includes a ceiling test impairment of $79.1 million and a $24.5 million impairment of certain water disposal assets recorded during the quarter ended December 31, 2024, offset by ceiling test impairments of $336.4 million and a $6.8 million impairment of certain water disposal assets both recorded during the year ended September 30, 2024.

(2) The decrease in depreciation / depletion expense is primarily the result of a $7.5 million decrease in depletion expense due to ceiling test impairments recorded in fiscal 2024 and 2025, which lowered the segment's full cost pool depletable base. This decrease was partially offset by a $3.6 million increase in depreciation expense largely due to additional plant in-service associated with the Tioga gathering system.

(3) The decrease in lease operating expenses was primarily the result of lower workover and salt water disposal costs.

(4) Includes a decrease in unrealized losses in 2025 as compared to 2024 related to contingent consideration received as part of the sale of this segment's California oil properties in 2022, net of tax effects. The fair value of the contingent consideration was zero at September 30, 2025.

(5) The increase in other operating expenses is mainly attributed to a change in segment reporting, as well as higher personnel costs, higher abandonment accretion expense, and higher environmental remediation costs in fiscal 2025, partially offset by higher abandonment costs recognized in fiscal 2024.

(6) The increase in income tax expense was primarily driven by an increase in state income tax expense due to higher pre-tax income.

(7) The increase in other tax expense was primarily attributable to higher Impact Fees in the Appalachian region as the Company moved into a higher rate tier due to higher NYMEX pricing combined with additional wells drilled in the current year.

(8) The decrease in other income is mainly attributable to the non-recurrence of business interruption insurance proceeds received during the quarter ended December 31, 2023 related to a pipeline outage impacting Seneca's ability to market gas, combined with lower interest income due to the reimbursement of security deposits related to the terminated Northern Access project.

(9) Represents the Integrated Upstream and Gathering segment's share of the premiums paid by the Company to redeem long-term debt. Refer to Note H — Capitalization and Short-Term Borrowings for further discussion.

**2024 Compared with 2023**

The Integrated Upstream and Gathering segment experienced a loss of $57.0 million in 2024, a decrease of $389.0 million from earnings of $332.0 million in 2023. The $389.0 million decrease was primarily attributed to the following factors:

| | (Millions) | |
|---|---|---|
| Non-cash impairments of assets | $ (343.2) | (1) |
| Lower natural gas prices after hedging | (34.0) | |
| Higher depreciation / depletion expense | (31.5) | (2) |
| Higher other operating expenses | (10.9) | (3) |
| Earnings reduction associated with remeasurement of state deferred income taxes due to ceiling test impairments | (5.8) | |
| Change in mark to market adjustment on contingent consideration related to the sale of California oil properties in 2022 | (4.1) | |
| Lower other revenue | (3.7) | |
| Higher interest expense | (3.7) | (4) |
| Higher lease operating expenses | (3.3) | (5) |
| Higher natural gas production | 39.8 | |
| Lower income tax expense | 7.2 | (6) |
| Lower other tax expense | 2.9 | (7) |
| Higher gathering revenue | 1.3 | |
| | $ (389.0) | |

(1) Includes aggregate ceiling test impairments of $336.4 million recorded during the quarters ended June 30, 2024 and September 30, 2024 and a $6.8 million impairment of certain water disposal assets recorded during the quarter ended September 30, 2024.

(2) The increase in depreciation / depletion expense was primarily due to an increase in depletion expense of $29.1 million largely due to the net increase in production combined with a $0.06 per Mcf increase in the depletion rate. An increase in depreciation expense of $2.4 million, primarily due to additional plant in-service associated with the Tioga and Clermont gathering systems, also contributed to the increase.

(3) The increase in other operating expenses was primarily attributable to recognizing an accrual of plugging and abandonment costs related to certain offshore Gulf of Mexico wells and certain California wells that were sold by Seneca to operators that are now defunct or unable to cover the cost of the abandonment activities. As a result, a portion of the cost of abandoning the wells was expected to revert back to Seneca. Higher personnel and material costs also contributed to the increase in other operating expenses.

(4) The increase in interest expense was largely attributable to higher average interest rates on intercompany short-term and long-term borrowings, partially offset by lower intercompany long-term debt balances.

(5) The increase in lease operating expenses was primarily the result of higher workover and repairs and maintenance expenses, partially offset by lower salt water disposal costs.

(6) The reduction in income tax expense was primarily driven by a decrease in pre-tax income and lower state income tax expense. The lower state income taxes were a result of a decrease in Pennsylvania's state income tax rate from 9.99% in the prior year to 8.99% in the current year, as well as a change in the mix of revenues between state jurisdictions.

(7) The decrease in other tax expense was primarily attributable to lower Impact Fees in the Appalachian region as the Company moved into a lower rate tier due to lower NYMEX pricing.

## PIPELINE AND STORAGE

### Revenues

### Pipeline and Storage Operating Revenues

| | Year Ended September 30 | |
|---|---|---|
| | 2025 | 2024 |
| | (Thousands) | |
| Firm Transportation | $ 323,470 | $ 311,247 |
| Interruptible Transportation | 709 | 653 |
| | 324,179 | 311,900 |
| Firm Storage Service | 100,292 | 95,931 |
| Interruptible Storage Service | — | 2 |
| | 100,292 | 95,933 |
| Other | 3,130 | 4,560 |
| | $ 427,601 | $ 412,393 |

### Pipeline and Storage Throughput — (MMcf)

| | Year Ended September 30 | |
|---|---|---|
| | 2025 | 2024 |
| Firm Transportation | 785,147 | 757,407 |
| Interruptible Transportation | 984 | 1,791 |
| | 786,131 | 759,198 |

### 2025 Compared with 2024

Operating revenues for the Pipeline and Storage segment increased $15.2 million in 2025 as compared with 2024. For the twelve months ended September 30, 2025, the $12.3 million increase in transportation revenues and $4.4 million increase in storage revenues were primarily attributable to an increase in Supply Corporation's transportation and storage rates effective February 1, 2024 in accordance with Supply Corporation's rate case settlement. The settlement was approved by FERC on June 11, 2024. This increase was partially offset by the impact of a final true-up adjustment recorded during the year ended September 30, 2024 to the surcharge for pipeline safety and greenhouse gas costs that ended effective February 1, 2024. The increase in transportation revenues was also partially offset by a decline in revenues associated with miscellaneous contract terminations and revisions. The $1.4 million decrease in other revenues primarily reflects lower cashout revenues, which are completely offset by purchased gas expense, and an adjustment to match electric surcharge revenues to electric power costs recorded in operation and maintenance expense.

Transportation volume increased by 26.9 Bcf in 2025 as compared with 2024, primarily due to an increase in volume from colder weather. This increase was partially offset by lower capacity utilization with certain contract shippers and certain contract expirations and revisions. Volume fluctuations, other than those caused by the addition or termination of contracts, generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

The majority of Supply Corporation's and Empire's transportation and storage contracts allow either party to terminate the contract upon six or twelve months' notice effective at the end of the primary term and include "evergreen" language that allows for annual term extension(s). The Pipeline and Storage segment's contracted transportation and storage capacity with both affiliated and unaffiliated shippers is expected to remain relatively constant in fiscal 2026.

**Earnings**

**2025 Compared with 2024**

The Pipeline and Storage segment's earnings in 2025 were $121.0 million, an increase of $41.3 million when compared with earnings of $79.7 million in 2024. The $41.3 million increase can be attributed to the following factors:

| | (Millions) |
|---|---|
| Non-cash impairment of assets | $ 33.8 [1] |
| Higher operating revenues | 13.2 |
| Lower interest expense | 1.5 [2] |
| Higher operating expenses | (4.8) [3] |
| Lower other income | (3.1) [4] |
| Other items | 0.7 |
| | $ 41.3 |

[1] An impairment charge recognized during the year ended September 30, 2024 wrote down the carrying value of certain assets associated with Supply Corporation and Empire's Northern Access project.

[2] The decrease in interest expense was primarily driven by a decrease in intercompany short-term borrowings, partially offset by an increase in interest on additional intercompany long-term borrowings associated with the Company's February 2025 debt issuance.

[3] The increase in operating expenses was primarily due to an increase in personnel costs, as well as an increase in outside service expenses, largely related to system integrity and maintenance spending, and higher power costs related to Empire's electric motor drive compressor station. The increase in electric power costs is offset by an equal increase in revenue.

[4] The decrease in other income was primarily due to a lower average amount outstanding on intercompany short-term notes receivables and a lower weighted average interest rate on those receivables, as well as a decline in non-service pension and post-retirement benefit income.

**UTILITY**

**Revenues**

**Utility Operating Revenues**

| | **Year Ended September 30** | |
|---|---|---|
| | **2025** | **2024** |
| | **(Thousands)** | |
| Retail Revenues: | | |
| Residential | $ 610,370 | $ 514,607 |
| Commercial | 82,364 | 69,834 |
| Industrial | 4,417 | 3,146 |
| | 697,151 | 587,587 |
| Transportation | 111,692 | 111,031 |
| Other | 8,786 | (1,256) |
| | $ 817,629 | $ 697,362 |

**Utility Throughput — million cubic feet (MMcf)**

| | Year Ended September 30 | |
|---|---|---|
| | **2025** | **2024** |
| Retail Sales: | | |
| Residential | 64,267 | 56,758 |
| Commercial | 10,614 | 8,989 |
| Industrial | 635 | 444 |
| | 75,516 | 66,191 |
| Transportation | 66,202 | 62,297 |
| | 141,718 | 128,488 |

**Degree Days**

| Year Ended September 30 | | Normal | Actual | Percent (Warmer) Colder Than Normal(1) | Percent (Warmer) Colder Than Prior Year(1) |
|---|---|---|---|---|---|
| 2025 | Buffalo, NY(2) | 6,307 | 5,885 | (6.7)% | 14.0 % |
| | Erie, PA | 5,771 | 5,597 | (3.0)% | 17.0 % |
| 2024 | Buffalo, NY | 6,653 | 5,162 | (22.4)% | (9.7)% |
| | Erie, PA | 5,805 | 4,782 | (17.6)% | (12.9)% |

(1) Percents compare actual degree days to normal degree days and actual degree days to actual prior year degree days.

(2) Normal degree days changed from NOAA 30-year degree days to NOAA 15-year degree days with the implementation of new base rates in New York effective October 2024.

**2025 Compared with 2024**

Operating revenues for the Utility segment increased $120.3 million in 2025 compared with 2024. The increase resulted from a $109.6 million increase in retail gas sales revenue, a $0.7 million increase in transportation revenue and a $10.0 million increase in other revenue. The increases in retail gas sales and transportation revenues reflect the impact of new base delivery rates in Distribution Corporation's New York jurisdiction pursuant to a settlement approved by the NYPSC on December 19, 2024. Additional details regarding the base rate regulatory proceeding can be found in the Rate Matters section below. The increase in retail gas sales revenue also reflects higher revenues collected from customers for purchased gas costs resulting from a 9.3 Bcf increase in throughput mainly due to colder weather combined with an increase in the cost of gas sold (per Mcf). The increase in transportation revenue also reflects a 3.9 Bcf increase in throughput due primarily to colder weather, partially offset by the amortization of certain regulatory assets in accordance with the New York rate settlement. The increase in other revenue was largely due to the elimination of the refund provision that required the Utility segment to defer and return the income tax benefits resulting from the 2017 Tax Reform Act to customers ($12.0 million). The refund provision is no longer necessary because Distribution Corporation's new base delivery rates now reflect the current federal income tax rate of 21%. This increase in other revenue was partially offset by decreases in other gas revenues ($0.8 million), capacity release revenues ($0.8 million), and late payment charges billed to customers ($0.4 million).

**Purchased Gas**

The cost of purchased gas is one of the Company's largest operating expenses. Annual variations in purchased gas costs are attributed directly to changes in gas sales volume, the price of gas purchased and the operation of purchased gas adjustment clauses. Distribution Corporation recorded $358.5 million and $283.2 million of Purchased Gas expense during 2025 and 2024, respectively. Under its purchased gas adjustment clauses in New York and Pennsylvania, Distribution Corporation does not profit from fluctuations in gas costs. Purchased Gas expense recorded on the consolidated income statement matches the revenues collected from customers, a component of Operating Revenues on the consolidated income statement. Under mechanisms approved by the NYPSC in New York and the PaPUC in Pennsylvania, any difference between actual purchased gas costs and what has been collected from the customer is deferred on the consolidated balance sheet as either an asset, Unrecovered Purchased Gas Costs, or a liability, Amounts Payable to Customers. These deferrals are subsequently collected from the customer or passed back to the customer, subject to review by the NYPSC and the PaPUC. Absent disallowance of full recovery of Distribution Corporation's purchased gas costs, such costs do not impact the profitability of the Company. Purchased gas costs impact cash flow from operations due to the timing of recovery of such costs versus the actual purchased gas costs incurred during a particular period. Distribution Corporation's purchased gas adjustment clauses seek to mitigate this impact by adjusting revenues on either a quarterly or monthly basis.

Distribution Corporation contracts for firm long-term transportation and storage capacity services with rights-of-first-refusal from ten upstream pipeline companies including Supply Corporation for transportation and storage services and Empire, for transportation services. Distribution Corporation contracts for firm spot and term gas supplies with various producers, marketers and two local distribution companies to meet its gas purchase requirements. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

**Earnings**

**2025 Compared with 2024**

The Utility segment's earnings in 2025 were $83.2 million, an increase of $26.1 million when compared with earnings of $57.1 million in 2024. The increase can be attributed to the following factors:

| | (Millions) | |
|---|---|---|
| Impact of new base rates in New York | $ 31.8 | |
| Higher other income | 15.3 | (1) |
| Impact of higher customer usage | 2.4 | |
| Higher operating expenses | (9.7) | (2) |
| Higher interest expense | (6.5) | (3) |
| Higher income tax expense | (3.8) | (4) |
| Higher depreciation expense | (3.5) | (5) |
| Other items | 0.1 | |
| | $ 26.1 | |

(1) The increase in other income was primarily due to the New York rate settlement, which required the recognition of non-service pension and post-retirement benefit income and a corresponding reduction in new base rates.

(2) The increase in operating expenses is largely attributable to higher personnel costs partially offset by a reduction in amortizations of certain regulatory assets and lower uncollectible expenses mainly as a result of a tracker implemented, both of which were associated with the New York rate settlement.

(3) The increase in interest expense is mainly attributed to an increase in both short-term and long-term intercompany debt balances.

(4) The increase in income tax expense was primarily driven by a smaller tax deduction in 2025 as compared to 2024 in the Utility's Pennsylvania jurisdiction for certain repairs and maintenance expenditures, lower benefit from the amortization of excess deferred income taxes in accordance with the New York rate settlement, and higher state income tax expense due to higher pre-tax income.

(5) The increase in depreciation expense is attributable to higher average property, plant and equipment balances.

The impact of weather variations on earnings in the Utility segment is mitigated by a WNA. The WNA, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the

Utility segment. In addition, in periods of colder than normal weather, the WNA benefits the Utility segment's customers. For 2025, the WNA preserved earnings of approximately $3.9 million and $1.7 million, respectively, in the Utility segment's New York and Pennsylvania rate jurisdictions as the weather was warmer than normal on a cycle-bill basis in both jurisdictions. For 2024, the WNA preserved earnings of approximately $8.1 million and $5.5 million, respectively, in the Utility segment's New York and Pennsylvania rate jurisdictions as the weather was warmer than normal on a cycle-bill basis in both jurisdictions.

**ALL OTHER AND CORPORATE OPERATIONS**

**Earnings**

**2025 Compared with 2024**

All Other and Corporate operations had a net loss of $10.4 million in 2025, an increase in loss of $8.2 million when compared with a net loss of $2.2 million in 2024. The increase in loss was attributable to the following factors: (1) the Company recorded unrealized losses on equity securities of $0.9 million in 2025 compared to unrealized gains on equity securities of $2.4 million in 2024; (2) higher interest expense ($2.1 million) due mainly to higher average long-term borrowings; (3) higher operating expense ($2.9 million) due mainly to higher legal, consulting, and outside service costs; and (4) higher income tax expense ($1.0 million) due primarily to the impact of less favorable consolidated tax sharing provisions in fiscal 2025. These changes were partially offset by realized gains from investment securities sold during 2025 ($1.2 million).

**OTHER INCOME (DEDUCTIONS)**

Although most of the variances in Other Income (Deductions) are discussed in the earnings discussion by segment above, the following is a summary on a consolidated basis (amounts below are pre-tax amounts):

Net other income on the Consolidated Statements of Income was $36.4 million in 2025 compared to net other income of $16.2 million in 2024, for a net increase of $20.2 million. This increase can be attributed primarily to a $22.4 million increase in non-service pension and post-retirement benefit income combined with a $5.8 million change in the year-over-year revaluation of the contingent consideration received as part of the sale of the Company's California oil properties in 2022. These increases were partially offset by year-over-year changes in the value of investment securities. During the year ended September 30, 2025, there were net gains of $0.5 million on investment securities, compared to net gains of $3.5 million on investment securities during the year ended September 30, 2024. Also offsetting these increases, was a decrease in interest income of $2.7 million, and the non-recurrence of $2.0 million of business interruption insurance proceeds received during the year ended September 30, 2024 related to a pipeline outage that impacted Seneca's ability to market its gas.

**INTEREST CHARGES**

Although most of the variances in Interest Charges are discussed in the earnings discussion by segment above, the following is a summary on a consolidated basis (amounts below are pre-tax amounts):

Interest on long-term debt increased $18.1 million in 2025 as compared to 2024. These increases are primarily due to higher average balances and a higher weighted average interest rate on long-term debt. On February 19, 2025, the Company issued $500.0 million of 5.50% notes and $500.0 million of 5.95% notes. On March 6, 2025, the Company redeemed $450.0 million of 5.20% notes due July 2025 and $500.0 million of 5.50% notes due January 2026 and paid early redemption premiums totaling $2.4 million that were recorded as interest expense on long-term debt in the Integrated Upstream and Gathering segment. The Company also redeemed $50.0 million of 7.38% notes on June 13, 2025. In addition, in April 2024, the Company elected to draw a total of $300.0 million under a delayed draw term loan credit facility. These borrowings had a locked-in weighted average interest rate of 5.97% for 2025.

Other interest expense decreased $0.9 million in 2025 as compared to 2024. The decrease was primarily due to lower weighted average interest rates on short-term debt for 2025 and lower average short-term debt balances in 2025 compared to 2024.

## CAPITAL RESOURCES AND LIQUIDITY

The primary sources and uses of cash during the last two years are summarized in the following condensed statement of cash flows:

| | Year Ended September 30 | |
|---|---|---|
| | 2025 | 2024 |
| | (Millions) | |
| Provided by Operating Activities | $ 1,100.0 | $ 1,066.0 |
| Capital Expenditures | (912.8) | (931.2) |
| Sale of Fixed Income Mutual Fund Shares in Grantor Trust | 7.0 | — |
| Other Investing Activities | 14.1 | (2.7) |
| Net Change in Other Short-Term Notes Payable to Banks and Commercial Paper | 59.5 | (196.8) |
| Net Proceeds from Issuance of Long-Term Debt | 988.7 | 299.4 |
| Shares Repurchased Under Repurchase Plan | (54.4) | (64.1) |
| Reduction of Long-Term Debt | (1,004.1) | — |
| Net Repurchases of Common Stock Under Stock and Benefit Plans | (4.7) | (4.0) |
| Dividends Paid on Common Stock | (188.4) | (183.8) |
| Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash | $ 4.9 | $ (17.2) |

The Company expects to have adequate amounts of cash available to meet both its short-term and long-term cash requirements for at least the next twelve months and for the foreseeable future thereafter. During 2026, based on current commodity prices, cash provided by operating activities is expected to exceed capital expenditures. The Company has a delayed draw term loan that matures in February 2026, which the Company anticipates repaying with cash from operations as well as short-term or long-term borrowings. Looking forward to 2027, based on current commodity prices, cash provided by operating activities is again expected to exceed capital expenditures. These cash flow projections include the impact of the CenterPoint Ohio acquisition but do not reflect the impact of other acquisitions or divestitures that may arise in the future.

### OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income, gains and losses associated with investing and financing activities, and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, impairment of assets, deferred income taxes and stock-based compensation.

Cash provided by operating activities in the Utility and Pipeline and Storage segments may vary substantially from year to year because of the impact of rate cases. In the Utility segment, supplier refunds, over- or under-recovered purchased gas costs, weather and regulatory lag may also significantly impact cash flow. The impact of weather on cash flow is tempered in the Pipeline and Storage segment by the straight fixed-variable rate design used by Supply Corporation and Empire. The weather impact on cash flow in the Utility segment is mitigated by a WNA in both its New York and Pennsylvania rate jurisdictions. Refer also to Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) for additional discussion.

Cash provided by operating activities in the Integrated Upstream and Gathering segment may vary from year to year as a result of changes in the commodity prices of natural gas as well as changes in production. The Company uses various derivative financial instruments, including price swap agreements and no cost collars, in an attempt to manage this energy commodity price risk. The pricing protection obtained from derivative financial instruments will fluctuate over time as instruments expire and are replaced with new instruments reflecting current commodity prices of natural gas.

The Company, in its Utility segment and Integrated Upstream and Gathering segment, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. Refer to Item 8 at Note L — Commitments and Contingencies under the heading "Other" for additional discussion concerning these contractual commitments as well as the amounts of future gas purchase, transportation and storage contract commitments expected to be incurred during the next five years and thereafter. Also refer to Item 8 at Note D — Leases for a discussion of the Company's operating lease arrangements and a schedule of lease payments during the next five years and thereafter.

Net cash provided by operating activities totaled $1,100.0 million in 2025, an increase of $34.0 million compared with the $1,066.0 million provided by operating activities in 2024. The increase in cash provided by operating activities primarily reflects higher cash provided by operating activities in the Integrated Upstream and Gathering segment, partially offset by lower cash provided by activities in the Utility segment. The increase in the Integrated Upstream and Gathering segment is primarily due to the timing of cash receipts and hedge settlements from natural gas production. The decrease in the Utility segment is primarily due to the timing of gas cost recovery, partially offset by the impact of higher revenues resulting from the base rate increase in Distribution Corporation's New York rate jurisdiction.

Net cash provided by operating activities totaled $1,066.0 million in 2024, a decrease of $171.1 million compared with the $1,237.1 million provided by operating activities in 2023. The decrease in cash provided by operating activities primarily reflects lower cash provided by operating activities in the Integrated Upstream and Gathering segment and Utility segment. The decrease in the Integrated Upstream and Gathering segment is primarily due to lower cash receipts from natural gas production. The decrease in the Utility segment is primarily due to the timing of gas cost recovery.

## INVESTING CASH FLOW

### Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets, including non-cash capital expenditures, totaled $918.1 million, $942.0 million and $1,123.6 billion in 2025, 2024 and 2023, respectively. The table below presents these expenditures:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | | (Millions) | |
| Integrated Upstream and Gathering: | | | |
| Capital Expenditures (1) | $ 605.4 (2) | $ 645.6 (3) | $ 841.0 (4) |
| Pipeline and Storage: | | | |
| Capital Expenditures | 121.8 (2) | 110.8 (3) | 141.9 (4) |
| Utility: | | | |
| Capital Expenditures | 190.0 (2) | 184.6 (3) | 139.9 (4) |
| All Other and Corporate: | | | |
| Capital Expenditures | 0.9 | 1.0 | 0.8 |
| Total Expenditures | $ 918.1 | $ 942.0 | $1,123.6 |

(1) The year ended September 30, 2023 includes $124.8 million related to the acquisition of upstream assets acquired from SWN Production Company, LLC ("SWN"). The acquisition cost is reported as a component of Acquisition of Upstream Assets on the Consolidated Statement of Cash Flows.

(2) 2025 capital expenditures for the Integrated Upstream and Gathering segment, the Pipeline and Storage segment and the Utility segment include $87.9 million, $19.4 million and $18.0 million, respectively, of non-cash capital expenditures.

(3) 2024 capital expenditures for the Integrated Upstream and Gathering segment, the Pipeline and Storage segment and the Utility segment include $85.0 million, $14.4 million and $20.6 million, respectively, of non-cash capital expenditures.

(4) 2023 capital expenditures for the Integrated Upstream and Gathering segment, the Pipeline and Storage segment and the Utility segment include $63.8 million, $31.8 million and $13.6 million, respectively, of non-cash capital expenditures.

***Integrated Upstream and Gathering***

In 2025, the Integrated Upstream and Gathering segment capital expenditures were primarily upstream well drilling and completion expenditures in the Appalachian region, including $141.8 million spent in the Marcellus Shale area and $351.2 million spent in the Utica Shale area. These amounts included approximately $246.3 million spent to develop proved undeveloped reserves. Integrated Upstream and Gathering segment capital expenditures also included expenditures related to the continued expansion of Midstream Company's Tioga, Clermont and Trout Run gathering systems. These expenditures were largely attributable to the installation of new in-field gathering pipelines related to bringing new development online and system optimization, as well as the continued development of centralized station facilities, including increased dehydration capacity and compression horsepower.

In 2024, the Integrated Upstream and Gathering segment capital expenditures were primarily upstream well drilling and completion expenditures in the Appalachian region, including $76.3 million spent in the Marcellus Shale area and $439.9 million spent in the Utica Shale area. These amounts included approximately $305.6 million spent to develop proved undeveloped reserves. The Company also completed the acquisition of certain undeveloped acreage in Tioga County, Pennsylvania for $6.2 million in 2024. The acquisition included 2,083 net acres and was accounted for as an asset acquisition with the purchase price allocated to property, plant and equipment. The cost of this acquisition is reported as a component of Capital Expenditures on the Consolidated Statement of Cash Flows. Integrated Upstream and Gathering segment capital expenditures also included expenditures related to the continued expansion of Midstream Company's Clermont, Tioga and Trout Run gathering systems. These expenditures were largely attributable to the installation of new in-field gathering pipelines related to bringing new development online, as well as the continued development of centralized station facilities, including increased dehydration capacity and compression horsepower.

In 2023, the Integrated Upstream and Gathering segment capital expenditures were primarily upstream well drilling and completion expenditures in the Appalachian region, including $292.6 million spent in the Marcellus Shale area and $430.7 million spent in the Utica Shale area. These amounts included approximately $342.0 million spent to develop proved undeveloped reserves. Integrated Upstream and Gathering segment capital expenditures also included expenditures related to the continued expansion of Midstream Company's Clermont, Tioga and Trout Run gathering systems. These expenditures were largely attributable to the installation of new in-field gathering pipelines related to bringing new development online, as well as the continued development of centralized station facilities, including increased dehydration capacity and compression horsepower.

On June 1, 2023, the Company completed its acquisition of certain upstream assets located primarily in Tioga County, Pennsylvania from SWN for total consideration of $124.8 million. As part of the transaction, the Company acquired approximately 34,000 net acres in an area that is contiguous with existing Company-owned upstream assets. This transaction was accounted for as an asset acquisition and, as such, the purchase price was allocated to property, plant and equipment.

Other 2023 acquisitions included the acquisition of certain upstream assets located in Lycoming County in Northeast Pennsylvania for total consideration of $11.5 million as well as the acquisition of undeveloped acreage in Tioga County, Pennsylvania for $13.6 million. The acquisition in Lycoming County included 1,145 net acres and the acquisition in Tioga County included 4,222 net acres. Both transactions were accounted for as asset acquisitions and, as such, the purchase price for each transaction was allocated to property, plant and equipment. The cost of these acquisitions is reported as a component of Capital Expenditures on the Consolidated Statement of Cash Flows.

***Pipeline and Storage***

The Pipeline and Storage segment's capital expenditures for 2025 and 2024 were primarily for additions, improvements and replacements to this segment's transmission and gas storage systems, which included system modernization expenditures that enhance the reliability and safety of the systems and reduce emissions.

***Utility***

The majority of the Utility segment's capital expenditures for 2025 and 2024 were made for main and service line improvements and replacements that enhance the reliability and safety of the system and reduce emissions. Expenditures were also made for main extensions.

***Other Investing Activities***

In September 2025, the Company sold $7.0 million of fixed income mutual fund shares held in a grantor trust that was established for the benefit of Pennsylvania ratepayers. The proceeds are being used in the Utility segment's Pennsylvania service territory to fund the final installment of a 5-year pass back of overcollected OPEB expenses, as well as to diversify a portion of grantor trust investments into lower risk money market mutual fund shares.

**Estimated Capital Expenditures**

The Company's estimated capital expenditures for the next three years are:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2026 | 2027 | 2028 |
| | | (Millions) | |
| Integrated Upstream and Gathering(1) | $ 585 | $ 575 | $ 565 |
| Pipeline and Storage | 230 | 145 | 125 |
| Utility(2) | 195 | 200 | 205 |
| All Other | — | — | — |
| | $ 1,010 | $ 920 | $ 895 |

(1) Includes estimated expenditures for the years ended September 30, 2026, 2027 and 2028 of approximately $295 million, $245 million and $145 million, respectively, to develop proved undeveloped reserves. The Company is committed to developing its proved undeveloped reserves within five years as required by the SEC's final rule on Modernization of Oil and Gas Reporting.

(2) Includes estimated expenditures for the years ended September 30, 2026, 2027, and 2028 of approximately $170 million, $180 million and $185 million, respectively, for system modernization and safety to enhance the reliability and safety of the system and reduce emissions.

***Integrated Upstream and Gathering***

Capital expenditures for the Integrated Upstream and Gathering segment in 2026 through 2028 are expected to be primarily upstream well drilling and completion expenditures, combined with related infrastructure, in the Appalachian region, as well as additional pipeline and compression infrastructure related to gathering systems.

***Pipeline and Storage***

Capital expenditures for the Pipeline and Storage segment in 2026 through 2028 are expected to include: the replacement and modernization of transmission and storage facilities, the reconditioning of storage wells, improvements of compressor stations and emissions reduction initiatives, as well as capital expenditures related to system expansion.

In addition, due to the continuing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia, specifically in the Marcellus and Utica Shale producing areas, Supply Corporation and Empire have completed and continue to pursue expansion projects designed to move anticipated Marcellus and Utica production gas to other interstate pipelines, on-system markets, and markets beyond the Supply Corporation and Empire pipeline systems, including projects to support regional demand for power generation to support the electric grid and data center development. Expansion and modernization projects where the Company has forecasted a significant amount of investment in preliminary survey and investigation costs and/or capital expenditures in 2026 through 2028, and where a precedent agreement has been executed, are discussed below.

Supply Corporation has designed a project that would allow for the transportation of 190,000 Dth per day of shale gas supplies from a new interconnection in northwest Tioga County, Pennsylvania to an existing Supply Corporation interconnection with Tennessee Gas Pipeline Company, LLC at Ellisburg and a new virtual delivery point into an existing Transcontinental Gas Pipe Line Company, LLC ("Transco") capacity lease, providing access to Mid-Atlantic markets ("Tioga Pathway Project"). The Tioga Pathway Project involves the construction of approximately 19 miles of new pipeline and the replacement of approximately four miles of existing pipeline on the Supply Corporation system. Supply Corporation has executed a Precedent Agreement with Seneca for 190,000 Dth per day of transportation capacity and filed a Section 7(b)/7(c) application with the FERC on August 21, 2024. FERC issued the Section 7(b)/7(c) certificate on May 5, 2025. Construction on the Tioga Pathway Project is expected to commence in early calendar 2026. This project has a projected in-service date of late calendar 2026 and an estimated capital cost of approximately $101 million. The majority of these expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2025, approximately $10.0 million has been spent on this project, including $5.0 million spent to study the project that is included in Deferred Charges on the Consolidated Balance Sheet. The remaining $5.0 million spent on the project has been capitalized as Construction Work in Progress.

Additionally, Supply Corporation concluded an open season on February 26, 2025, and based on interest in that open season, designed a project that would allow for the transportation of 205,000 Dth per day of natural gas supplies from its existing Line N pipeline system to a new interconnection with the Shippingport Power Station, a natural gas power generation facility under development in Beaver County, Pennsylvania, which is expected to support a co-located data center (the "Shippingport Lateral Project"). In order to provide this new natural gas transportation capacity, Supply Corporation expects to construct an approximately 7.5 mile pipeline lateral from its existing Line N pipeline system to a direct interconnection with the facility with the incremental capacity expected to come online as early as Fall 2026 and an estimated capital cost of approximately $57 million. Supply Corporation has executed a Precedent Agreement with Shippingport Power Station, LLC, the facility developer, for 100% of the capacity for the Shippingport Lateral Project and filed an application with FERC under the Commission's prior notice regulations on August 29, 2025. The project obtained FERC authorization on November 7, 2025. As of September 30, 2025, approximately $1.8 million has been spent on this project, including $1.7 million spent to study the project that is included in Deferred Charges on the Consolidated Balance Sheet. The remaining $0.1 million spent on the project has been capitalized as Construction Work in Progress. The remaining expenditures expected to be spent on the project are included in Pipeline and Storage estimated capital expenditures in the table above.

***Utility***

Capital expenditures for the Utility segment in 2026 through 2028 are expected to be concentrated in the areas of main and service line improvements and replacements that will enhance the reliability and safety of the system, emission reduction initiatives and, to a lesser extent, the purchase of new equipment.

***Project Funding***

During fiscal 2025 and 2024, capital expenditures were funded with cash from operations and short-term debt. Going forward, the Company expects to use cash from operations and short-term or long-term borrowings, as needed, to finance capital expenditures. The level of short-term and/or long-term borrowings will depend upon the amount of cash provided by operations, which, in turn, will likely be most impacted by natural gas production and the associated commodity price realizations in the Integrated Upstream and Gathering segment. It will also likely depend on the timing of gas cost and base rate recovery in the Utility segment as well as the timing of base rate recovery in the Pipeline and Storage segment.

In the Integrated Upstream and Gathering segment, the Company has entered into contractual obligations to support its development activities and operations in Pennsylvania, including hydraulic fracturing and other well completion services, well tending services, well workover activities, tubing and casing purchases, production equipment purchases, water hauling services and contracts for drilling rig services. Refer to Item 8 at Note L — Commitments and Contingencies under the heading "Other" for the amounts of contractual obligations expected to be incurred during the next five years and thereafter to support the Company's exploration and development activities. These amounts are largely a subset of the estimated capital expenditures for the Integrated Upstream and Gathering segment shown above.

The Company, in its Pipeline and Storage segment, Integrated Upstream and Gathering segment and Utility segment, has entered into several contractual commitments associated with various pipeline, compressor and gathering system modernization and expansion projects. Refer to Item 8 at Note L — Commitments and Contingencies under the heading "Other" for the amounts of contractual commitments expected to be incurred during the next five years and thereafter associated with the Company's pipeline, compressor and gathering system modernization and expansion projects. These amounts are a subset of the estimated capital expenditures for the Pipeline and Storage segment, Integrated Upstream and Gathering segment and Utility segment that are shown above.

The Company continuously evaluates capital expenditures and potential investments in corporations, partnerships, and other business entities. The amounts are subject to modification for opportunities such as the acquisition of attractive natural gas properties, accelerated development of existing natural gas properties, natural gas storage and transmission facilities, natural gas generation facilities, natural gas gathering and compression facilities and the expansion of natural gas transmission line capacities, regulated utility assets and other opportunities as they may arise. The amounts are also subject to modification for opportunities involving emission reductions and/or energy transition including investments directly related to low- and no-carbon fuels. While the majority of capital expenditures in the Utility segment are necessitated by the continued need for replacement and upgrading of mains and service lines, the magnitude of future capital expenditures or other investments in the Company's business segments depends, to a large degree, upon market and regulatory conditions as well as legislative actions.

**FINANCING CASH FLOW**

Consolidated short-term debt increased $59.5 million, to a total of $150.2 million, when comparing the balance sheet at September 30, 2025 to the balance sheet at September 30, 2024. The maximum amount of short-term debt outstanding during the year ended September 30, 2025 was $330.0 million. In addition to cash provided by operating activities, the Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing items such as capital expenditures, asset purchases, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. As of September 30, 2025, the Company had outstanding commercial paper of $150.2 million and did not have any outstanding short-term notes payable to banks.

On October 20, 2025, the Company entered into a Securities Purchase Agreement (the "Purchase Agreement") with CenterPoint Energy Resources Corp. (the "Seller"), pursuant to which, among other things, the Company agreed to acquire from the Seller all of the issued and outstanding equity interests of Vectren Energy Delivery of Ohio, LLC (the "Acquired Company"), the Seller's Ohio natural gas local distribution company, for an aggregate purchase price of $2.62 billion, subject to customary adjustments (the "Purchase Price"), as provided in the Purchase Agreement (the "Transaction"). The Purchase Price will be paid through a combination of cash and a promissory note to be issued by the Company to the Seller pursuant to a Seller Note Agreement (the "Seller Note Agreement") between the Company, as borrower, and the Seller, as lender. The Seller Note Agreement, which was part of the Seller's desired transaction structure and was incorporated into the Company's business valuation, will provide a $1.2 billion unsecured term loan credit facility (the "Seller Note Facility") that matures on the last business day that is not more than 364 days from the closing of the Transaction.

The borrowings under the Seller Note Facility will bear interest at a rate of 6.5% per annum. The Seller Note Agreement will contain customary representations and affirmative, negative and financial covenants, consistent with the Company's existing term loan agreement. The Seller Note Agreement will also include covenants restricting certain actions with respect to the Acquired Company. The Seller Note Agreement will contain certain specified events of default, and should an event of default occur, the lender is entitled to exercise certain remedies, including acceleration of the loan and related obligations.

The Seller Note Agreement will contain a covenant defeasance provision that permits the Company to relieve itself from its obligations to comply with covenants under the Seller Note Agreement upon deposit of an amount with a paying agent sufficient to pay the principal of and interest due on the loan on each applicable interest payment date and the maturity date.

In connection with its entry into the Purchase Agreement, the Company entered into a bridge facility commitment letter (the "Bridge Commitment Letter"), pursuant to which The Toronto-Dominion Bank, New York Branch ("TD Bank") and Wells Fargo Bank, National Association ("Wells Fargo Bank" and, together with TD Bank, the "Commitment Parties"), agreed to provide to the Company loans under a senior unsecured bridge loan facility (the "Bridge Facility") composed of a $1.42 billion 364-day tranche (the "Acquisition Tranche"), the proceeds of which will be used, if needed, to finance the Transaction, and a $1.2 billion 364-day tranche (the "Seller Note Tranche"), the proceeds of which will be used, if needed, to refinance the Seller Note Facility at its scheduled maturity.

On November 6, 2025, the Company entered into a 364-day term loan facility commitment letter (the "Term Loan Commitment Letter"), pursuant to which the Commitment Parties and ten additional banks, all of which are lenders under our primary credit facility, agreed to provide to the Company loans under a 364-day senior unsecured term loan facility (the "Term Loan Facility") in the amount of $1.42 billion, the proceeds of which will be used, if needed, to finance the Transaction. Entering into the Term Loan Commitment Letter enabled the Company to terminate the commitments under the Bridge Commitment Letter in respect of the Acquisition Tranche. Also on November 6, 2025, the same ten additional banks joined the Commitment Parties as parties to the Bridge Commitment Letter in respect of the Seller Note Tranche.

Subject to the conditions in the respective commitment letters, the commitments under the Term Loan Facility and the Bridge Facility (together, the "Commitments") may be reduced by proceeds of certain additional indebtedness that may be incurred by the Company and certain equity offerings of the Company to finance the Transaction. The Company expects to reduce the Commitments through such financings or offerings, possibly to zero, prior to the closing date of the Transaction or the scheduled maturity of the Seller Note Facility, as applicable, but there can be no assurance such financings or offerings will occur and any such expectation is subject to market conditions.

The Company is subject to certain customary fees with respect to the Term Loan Facility and the Bridge Facility. Interest on borrowings under the Term Loan Facility or the Bridge Facility would accrue at one of two rates, at the option of the Company: Term SOFR plus an applicable margin of 1.125% to 1.750%, or a base rate (at least as great as one-month Term SOFR plus 1.0%) plus an applicable margin of 0.125% to 0.750%. In each case, the applicable margin would depend on the Company's credit ratings (at current ratings, the applicable margin would be 1.500% for Term SOFR loans and 0.500% for base rate loans). With respect to the Term Loan Facility, the Company will pay a fee on the 270th day after the funding date in an amount equal to 0.025% of the principal amount of any loans outstanding under such facility at the close of business on that date. With respect to the Bridge Facility, the applicable margin would increase by an additional 0.25% on each of the 90th, 180th and 270th day after the funding date for any loans outstanding under the Bridge Facility. Any borrowings under the Term Loan Facility or the Bridge Facility would mature 364 days from the funding date, which, for the Term Loan Facility, would be on or around the closing date of the Transaction and, for the Bridge Facility, would be on or around the scheduled maturity of the Seller Note Facility.

The availability of borrowings under the Term Loan Facility and the Bridge Facility is subject to the satisfaction of certain customary conditions for transactions of these types. Any definitive financing documentation for the Term Loan Facility or the Bridge Facility will contain customary representations and warranties, covenants and events of defaults for transactions of these types. The Company expects to execute permanent financing prior to the respective funding dates of the Term Loan Facility and the Bridge Facility, such that borrowings under the facilities would not be incurred. There can be no assurance, however, such permanent financing will occur and any such expectation is subject to market conditions.

The Company is a party to a syndicated Credit Agreement (as amended from time to time, the "Credit Agreement") that provides a $1.0 billion unsecured committed revolving credit facility. In January 2025, the Company and the banks in the syndicate consented to a second one-year extension of the maturity date of the

Credit Agreement, such that the Company has aggregate commitments available in the full amount of $1.0 billion through February 23, 2029. In May 2025, the number of lenders under the Credit Agreement increased to twelve as a new lender joined the syndicate, assuming a portion of an existing lender's commitment.

The total amount available to be issued under the Company's commercial paper program is $500.0 million. The commercial paper program is backed by the Credit Agreement. The Company also has uncommitted lines of credit with financial institutions for general corporate purposes. Borrowings under these uncommitted lines of credit would be made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institution and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines. Other financial institutions may also provide the Company with uncommitted or discretionary lines of credit in the future.

The Company entered into its existing term loan agreement (the "Term Loan Agreement") on February 14, 2024, with six of the 12 banks that are lenders under the Credit Agreement. The Term Loan Agreement provides a $300.0 million unsecured committed delayed draw term loan facility with a maturity date of February 14, 2026, and the Company has the ability to select interest periods of one, three or six months for borrowings. In April 2024, pursuant to the delayed draw mechanism, the Company elected to draw a total of $300.0 million under the facility. After deducting debt issuance costs, the net proceeds to the Company amounted to $299.4 million. The Company used the proceeds for general corporate purposes, which included the redemption of outstanding commercial paper. Borrowings under the Term Loan Agreement currently bear interest at a rate equal to SOFR for the applicable interest period, plus an adjustment of 0.10%, plus a spread of 1.375%. The current weighted average locked-in interest rate is 5.43% until mid-December 2025.

Both the Credit Agreement and the Term Loan Agreement provide that the Company's debt to capitalization ratio will not exceed 0.65 at the last day of any fiscal quarter. For purposes of calculating the debt to capitalization ratio, the Company's total capitalization will be increased by adding back 50% of the aggregate after-tax amount of non-cash charges directly arising from any ceiling test impairment occurring on or after July 1, 2018, not to exceed $400 million. Since that date, the Company recorded non-cash, after-tax ceiling test impairments totaling $797.0 million. As a result, at September 30, 2025, $398.5 million was added back to the Company's total capitalization for purposes of calculating the debt to capitalization ratio under the Credit Agreement and the Term Loan Agreement. In addition, for purposes of calculating the debt to capitalization ratio, the following amounts included in Accumulated Other Comprehensive Income (Loss) on the Company's consolidated balance sheet will be excluded from the determination of comprehensive shareholders' equity: all unrealized gains or losses on commodity-related derivative financial instruments, and up to $10 million in unrealized gains or losses on other derivative financial instruments. As a result of these exclusions, such unrealized gains or losses will not positively or negatively affect the calculation of the debt to capitalization ratio. Finally, pursuant to amendments to the Credit Agreement and Term Loan Agreement entered into as of November 6, 2025, for purposes of calculating the debt to capitalization ratio, the Company's $1.2 billion obligation under the Seller Note Facility, which is to be incurred at the closing of the Transaction, will be excluded from the definition of consolidated indebtedness upon such time and to the extent that the Company, in accordance with the Seller Note Agreement, deposits with a paying agent funds for defeasance of the Seller Note Facility.

At September 30, 2025, the Company's debt to capitalization ratio, as calculated under the agreements, was 0.45. The constraints specified in the Credit Agreement and the Term Loan Agreement would have permitted an additional $3.61 billion in short-term and/or long-term debt to be outstanding at September 30, 2025 before the Company's debt to capitalization ratio exceeded 0.65.

A downgrade in the Company's credit ratings could increase borrowing costs, negatively impact the availability of capital from banks, commercial paper purchasers and other sources, and require the Company's subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. If the Company is not able to maintain investment-grade credit ratings, it may not be able to access commercial paper markets. However, the Company expects that it could borrow under its credit facilities or rely upon other liquidity sources.

The Credit Agreement and the Term Loan Agreement each contain a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the Credit Agreement or Term Loan Agreement, as applicable. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity.

On February 19, 2025, the Company issued $500.0 million of 5.50% notes due March 15, 2030 and $500.0 million of 5.95% notes due March 15, 2035. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $495.2 million and $493.5 million, respectively. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. Additionally, the interest rate payable on the notes will be subject to adjustment from time to time, with a maximum adjustment of 2.00%, such that the coupon will not exceed 7.50% on the 5.50% notes and 7.95% on the 5.95% notes, if certain change of control events involving a material subsidiary result in a downgrade of the credit rating assigned to the notes to a rating below investment grade. A downgrade with a resulting increase to the coupon does not preclude the coupon from returning to its original rate if the Company's credit rating is subsequently upgraded.

The proceeds of the February 19, 2025 debt issuances were used for general corporate purposes, including the March 6, 2025 redemptions of $450.0 million of the Company's 5.20% notes that were scheduled to mature in July 2025 and $500.0 million of the Company's 5.50% notes that were scheduled to mature in January 2026. The Company redeemed those notes for $450.8 million and $503.3 million, respectively, plus accrued interest. The remaining proceeds of the debt issuances were used to repay a portion of short-term borrowings the Company incurred to fund a trust for the benefit of holders of $50.0 million of 7.38% notes under the Company's 1974 indenture prior to the June 13, 2025 maturity date of these notes. Placing these funds in trust enabled the Company to cancel and discharge the 1974 indenture. This relieved the Company from its obligations to comply with the 1974 indenture's covenants. The funds were paid out of the trust on June 13, 2025 for the redemption of the $50.0 million of 7.38% notes, leaving no notes outstanding under the 1974 indenture.

The Current Portion of Long-Term Debt at September 30, 2025 consisted of a $300.0 million long-term delayed draw term loan that matures in February 2026. The Current Portion of Long-Term Debt at September 30, 2024 consisted of the $50.0 million of 7.38% notes and $450.0 million of 5.20% notes discussed above, with maturity dates in June 2025 and July 2025, respectively. As of September 30, 2025, the future contractual obligations related to aggregate principal amounts of long-term debt, including interest expense, maturing during the next five years and thereafter are as follows: $420.9 million in 2026, $697.7 million in 2027, $385.1 million in 2028, $72.0 million in 2029, $557.0 million in 2030, and $1,138.7 million thereafter. Refer to Item 8 at Note H — Capitalization and Short-Term Borrowings, as well as the table under Interest Rate Risk in the Market Risk Sensitive Instruments section below, for the amounts excluding interest expense. Principal payments of long-term debt are a component of cash used in financing activities while interest payments on long-term debt are a component of cash used in operating activities. The Company's present liquidity position is believed to be adequate to satisfy known demands.

The Company's embedded cost of long-term debt was 4.90% at September 30, 2025 and 4.91% at September 30, 2024. Refer to "Interest Rate Risk" in this Item for a more detailed breakdown of the Company's embedded cost of long-term debt.

On March 8, 2024, the Company's Board of Directors authorized the Company to implement a share repurchase program, whereby the Company may repurchase outstanding shares of common stock, up to an aggregate amount of $200 million in the open market or through privately negotiated transactions, including through the use of trading plans intended to qualify under SEC Rule 10b5-1, in accordance with applicable securities laws and other restrictions.

During the year ended September 30, 2025, the Company executed transactions to repurchase 828,720 shares at an average price of $64.37 per share, for a total cost of $53.8 million (including broker fees and excise taxes). Share repurchases that settled during the year ended September 30, 2025 were funded with cash provided by operating activities and/or short-term borrowings. From inception to September 30, 2025, the Company has repurchased 1,974,979 shares under the share repurchase program at an average price of $59.70, for a total cost of $119.0 million (including broker fees and excise taxes). In light of the Company's agreement to acquire CenterPoint Ohio's natural gas utility, repurchases under the program have been suspended. The program has no fixed expiration date.

## OTHER MATTERS

In addition to the environmental and other matters discussed in this Item 7 and in Item 8 at Note L — Commitments and Contingencies, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

The Company has a tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan). During 2025, the Company did not make any contributions to the Retirement Plan. The Company does not expect to make any contributions to the Retirement Plan in 2026. For further discussion of the Company's Retirement Plan, including actuarial assumptions, refer to Item 8 at Note K — Retirement Plan and Other Post-Retirement Benefits. As noted in that footnote, the Retirement Plan has been closed to new participants since 2003. In that regard, the average remaining service life of active participants in the Retirement Plan is approximately 5 years.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The Company has established VEBA trusts and 401(h) accounts for its other post-retirement benefits. The Company did not make any contributions to its VEBA trusts or 401(h) accounts in 2025, and does not anticipate making contributions to these accounts in 2026. The Company made direct payments of $0.6 million to retirees not covered by the VEBA trusts and 401(h) accounts during 2025. For further discussion of the Company's other post-retirement benefits, including actuarial assumptions, refer to Item 8 at Note K — Retirement Plan and Other Post-Retirement Benefits. As noted in that footnote, the other post-retirement benefits provided by the Company have been closed to new participants since 2003. In that regard, the average remaining service life of active participants is approximately 4 years for those eligible for other post-retirement benefits.

The Company has made certain guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the Consolidated Balance Sheets in accordance with the authoritative guidance (see Item 8 at Note J — Financial Instruments); and (ii) other obligations which are reflected on the Consolidated Balance Sheets. The Company believes that the likelihood it would be required to make payments under the guarantees is remote.

## MARKET RISK SENSITIVE INSTRUMENTS

### Energy Commodity Price Risk

The Company uses various derivative financial instruments (derivatives), including price swap agreements and no cost collars, as part of the Company's overall energy commodity price risk management strategy in its Integrated Upstream and Gathering segment. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas, thereby attempting to provide more stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company's risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from, or pay to, the respective counterparties at September 30, 2025 to terminate the derivatives. However, the tables below and the fair value that is disclosed do not consider the physical side of the natural gas transactions that are related to the financial instruments.

Rules adopted by the CFTC and other regulators could adversely impact the Company. While many of those rules place specific conditions on the operations of swap dealers rather than directly on the Company, concern remains that swap dealers with whom the Company may transact will pass along their increased costs stemming from final rules through higher transaction costs and prices or other direct or indirect costs. Some of those rules also may apply directly to the Company and adversely impact its ability to trade swaps and over-the-counter derivatives, whether due to increased costs, limitations on trading capacity or for other reasons. Additionally, given the enforcement authority granted to the CFTC on anti-market manipulation, anti-fraud and anti-disruptive trading practices, it is difficult to predict how the evolving enforcement priorities of the CFTC will impact our business. Should the Company violate any laws or regulations applicable to our hedging activities, it could be subject to CFTC enforcement action and material penalties and sanctions.

The authoritative guidance for fair value measurements and disclosures requires consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2025, the Company determined that nonperformance risk associated with its natural gas price swap agreements, natural gas no cost collars and foreign currency contracts would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company's (assuming the derivative is in a loss position) credit default swaps rates.

The following tables disclose natural gas price swap information by expected maturity dates for agreements in which the Company receives a fixed price in exchange for paying a variable price as quoted in various national natural gas publications or on the NYMEX. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2025. At September 30, 2025, the Company had not entered into any natural gas price swap agreements extending beyond 2029.

***Natural Gas Price Swap Agreements***

| | Expected Maturity Dates | | | | |
|---|---|---|---|---|---|
| | **2026** | **2027** | **2028** | **2029** | **Total** |
| Notional Quantities (Equivalent Bcf) | 119.6 | 93.9 | 45.7 | 4.3 | 263.5 |
| Weighted Average Fixed Rate (per Mcf) | $ 4.07 | $ 4.06 | $ 3.91 | $ 3.83 | $ 4.03 |
| Weighted Average Variable Rate (per Mcf) | $ 3.76 | $ 4.12 | $ 3.98 | $ 3.88 | $ 3.93 |

At September 30, 2025, the Company would have received an aggregate of approximately $28.0 million to terminate the natural gas price swap agreements outstanding at that date.

At September 30, 2024, the Company had natural gas price swap agreements covering 220.7 Bcf at a weighted average fixed rate of $3.74 per Mcf.

***No Cost Collars***

The following table discloses the notional quantities, the weighted average ceiling price and the weighted average floor price for the no cost collars used by the Company to manage natural gas price risk. The no cost collars provide for the Company to receive monthly payments from (or make payments to) other parties when a variable price falls below an established floor price (the Company receives payment from the counterparty) or exceeds an established ceiling price (the Company pays the counterparty). At September 30, 2025, the Company had not entered into any natural gas no cost collars extending beyond 2028.

| | Expected Maturity Dates | | | |
|---|---|---|---|---|
| | 2026 | 2027 | 2028 | Total |
| Natural Gas | | | | |
| Notional Quantities (Equivalent Bcf) | 100.7 | 43.6 | 6.5 | 150.8 |
| Weighted Average Ceiling Price (per Mcf) | $ 4.92 | $ 4.53 | $ 4.39 | $ 4.78 |
| Weighted Average Floor Price (per Mcf) | $ 3.67 | $ 3.57 | $ 3.45 | $ 3.63 |

At September 30, 2025, the Company would have received an aggregate of approximately $6.1 million to terminate the natural gas no cost collars outstanding at that date.

At September 30, 2024, the Company had no cost collars agreements covering 128.7 Bcf at a weighted average ceiling price of $4.65 per Mcf and a weighted average floor price of $3.52 per Mcf.

**Foreign Exchange Risk**

The Company uses foreign exchange forward contracts to manage the risk of currency fluctuations associated with transportation costs denominated in Canadian currency in the Integrated Upstream and Gathering segment. All of these transactions are forecasted.

The following table discloses foreign exchange contract information by expected maturity dates. The Company receives a fixed price in exchange for paying a variable price as noted in the Canadian to U.S. dollar forward exchange rates. Notional amounts (Canadian dollars) are used to calculate the contractual payments to be exchanged under contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2025. At September 30, 2025, the Company had not entered into any foreign currency exchange contracts extending beyond 2030.

| | Expected Maturity Dates | | | | | |
|---|---|---|---|---|---|---|
| | 2026 | 2027 | 2028 | 2029 | 2030 | Total |
| Notional Quantities (Canadian Dollar in millions) | $10.4 | $ 9.8 | $ 8.7 | $ 8.6 | $ 6.6 | $44.1 |
| Weighted Average Fixed Rate ($Cdn/$US) | $1.34 | $1.34 | $1.32 | $1.32 | $1.31 | $1.33 |
| Weighted Average Variable Rate ($Cdn/$US) | $1.36 | $1.35 | $1.34 | $1.33 | $1.32 | $1.34 |

At September 30, 2025, absent other positions with the same counterparties, the Company would have paid to its respective counterparties an aggregate of $0.7 million to terminate these foreign exchange contracts.

Refer to Item 8 at Note J — Financial Instruments for a discussion of the Company's exposure to credit risk related to its derivative financial instruments.

**Interest Rate Risk**

The fair value of long-term debt is $2.7 billion at September 30, 2025. This fair value amount is not intended to reflect principal amounts that the Company will ultimately be required to pay. The following table presents the principal cash repayments and related weighted average interest rates by expected maturity date for the Company's long-term fixed rate debt:

| | Principal Amounts by Expected Maturity Dates | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2026 | 2027 | 2028 | 2029 | 2030 | Thereafter | Total |
| | (Dollars in millions) | | | | | | |
| Long-Term Fixed Rate Debt | $ — | $ 600.0 | $ 300.0 | $ — | $ 500.0 | $1,000.0 | $2,400.0 |
| Weighted Average Interest Rate Paid | — | 4.7% | 4.8% | — | 5.5% | 4.5% | 4.8% |
| Long-Term Variable Rate Debt | $ 300.0 | $ — | $ — | $ — | $ — | $ — | $ 300.0 |
| Weighted Average Interest Rate Paid (1) | 5.6% | — | — | — | — | — | 5.6% |

(1) Interest rate is based on a weighted average SOFR interest rate and was 5.62% as of September 30, 2025. The current weighted average locked-in interest rate is 5.43% until mid-December 2025.

## RATE MATTERS

### Utility Operation

Delivery rates for both the New York and Pennsylvania divisions are regulated by the states' respective public utility commissions and typically are changed only when approved through a procedure known as a "rate case." In both jurisdictions, delivery rates do not reflect the recovery of purchased gas costs. Prudently-incurred gas costs are recovered through operation of automatic adjustment clauses, and are collected primarily through a separately-stated "supply charge" on the customer bill.

### New York Jurisdiction

Distribution Corporation's current delivery rates in its New York jurisdiction were approved by the NYPSC in an order issued on December 19, 2024 with rates effective January 1, 2025 ("2024 Rate Order"). The 2024 Rate Order authorizes a three-year rate plan effective October 1, 2024, with a make-whole provision allowing full recovery of revenues that would have been billed at the new rates between October 1, 2024 and December 31, 2024. It also reflects a return on equity of 9.7% and authorizes a revenue requirement increase of $57.3 million in fiscal 2025, an additional revenue requirement increase of $15.8 million in fiscal 2026, and an additional revenue requirement increase of $12.7 million in fiscal 2027. These revenue requirement increases are being reflected in customer bills on a levelized basis over the three-year rate plan. The revenue requirement for each year of the three-year plan has been reduced by $14 million for actuarial projections of income that is expected to be recognized for qualified pension and other post-retirement benefits. Qualified pension and other post-retirement benefit income or costs are matched with amounts included in revenue resulting in zero impact to earnings. The 2024 Rate Order approves the continuation of several ratemaking mechanisms, including revenue decoupling and WNA, and establishes a number of new cost trackers and regulatory deferrals. It also includes an earnings sharing mechanism, gas safety and customer service performance metrics (including maintaining the Company's leak prone pipe replacement program), and provisions that will facilitate achievement of the emissions reduction goals of the CLCPA.

### Pennsylvania Jurisdiction

Distribution Corporation's current delivery rates in its Pennsylvania jurisdiction were approved by the PaPUC in an order issued on June 15, 2023 with rates effective August 1, 2023 ("2023 Rate Order"). The 2023 Rate Order provided for, among other things, an increase in Distribution Corporation's annual base rate operating revenues of $23 million and authorized a new weather normalization adjustment mechanism.

On April 10, 2024, Distribution Corporation filed with the PaPUC a petition for approval of a distribution system improvement charge ("DSIC") to recover, between base rate cases, capital expenses related to eligible property constructed or installed to rehabilitate, improve and replace portions of the Company's natural gas distribution system. The DSIC petition was approved by the PaPUC on December 5, 2024, and on January 1, 2025, the Company initiated recovery of eligible costs on incremental rate base added after September 30, 2024. During the year ended September 30, 2025, Distribution Corporation recovered $0.9 million from customers.

### Pipeline and Storage

Supply Corporation's rate settlement was approved June 11, 2024 with rates effective February 1, 2024, and provides that Supply Corporation may make a rate filing for new rates to be effective at any time. As well, any party can make a filing under NGA Section 5. Supply Corporation has no rate case currently on file.

On March 17, 2025, FERC approved an amendment to Empire's 2019 rate case settlement, which provides for a modest reduction in Empire's transportation unit rates, effective November 1, 2025. This settlement amendment is estimated to decrease Empire's revenues on a yearly basis by approximately $0.5 million. Empire will not be able to file a new Section 4 rate case before April 30, 2027 and is required to file a Section 4 rate case by May 31, 2031.

## ENVIRONMENTAL MATTERS

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory requirements. In 2021, the Company set methane intensity reduction targets at each of its businesses, an absolute greenhouse gas emissions reduction target for the consolidated Company, and greenhouse gas reduction targets associated with the Company's utility delivery system. In 2022, the Company began measuring progress against these reduction targets. The Company's ability to estimate accurately the time, costs and resources necessary to meet emissions targets may be impacted as environmental exposures, technology and opportunities change and regulatory and policy updates are issued.

For further discussion of the Company's environmental exposures, refer to Item 8 at Note L — Commitments and Contingencies under the heading "Environmental Matters."

The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

**Environmental Regulation**

While the current federal administration has initiated efforts to roll-back and/or limit certain environmental initiatives, legislative and regulatory measures concerning climate change and greenhouse gas emissions are in various phases of discussion or implementation in the United States. These efforts include legislation, legislative proposals and new regulations at the state and federal level, and private party litigation related to greenhouse gas emissions. Legislation or regulation that aims to reduce greenhouse gas emissions could also include emissions limits, reporting requirements, carbon taxes, cap-and-invest and cap-and-trade programs, restrictive permitting, increased efficiency standards, and incentives or mandates to conserve energy or use renewable energy sources.

Additionally, a number of states have adopted energy strategies or plans with aggressive goals for the reduction of greenhouse gas emissions. Pennsylvania has a methane reduction framework with the stated goal of reducing methane emissions from well sites, compressor stations and pipelines. In New York, the CLCPA, which was passed in 2019, mandates reducing greenhouse gas emissions by 40% from 1990 levels by 2030, and by 85% from 1990 levels by 2050, with the remaining emission reduction achieved by controlled offsets. The CLCPA also requires electric generators to meet 70% of demand with renewable energy by 2030 and 100% with zero emissions generation by 2040. Statements from New York's Governor and other state authorities have acknowledged that the near term targets of the statute may not be achievable in the required timeframes. The NYPSC has initiated and/or modified various proceedings in an effort to help the State meet these emissions reduction targets. In May 2023, New York State passed legislation that prohibits the installation of fossil fuel burning equipment and building systems in new buildings commencing on or after December 31, 2025, subject to certain exemptions. This legislation is subject to ongoing litigation, with the parties agreeing, in November 2025, to suspend the requirements of the legislation pending resolution of appellate proceedings. In addition, the NYDEC, in conjunction with the New York State Energy Research and Development Authority, is developing a cap-and-invest program in the state, although issuance of certain key regulations necessary to implement the program has been delayed. The above-enumerated initiatives could impact the Company's customer base and assets, and could also increase the Company's cost of environmental compliance by increasing reporting requirements, requiring retrofitting of existing equipment, requiring installation of new equipment, and/or requiring the purchase of emission allowances. They could also reduce demand for natural gas and delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals. Changing market conditions and new regulatory requirements, as well as unanticipated or inconsistent application of existing laws and regulations by federal and state administrative agencies, make it difficult to predict a long-term business impact across twenty or more years. Federal, state or local governments may also provide tax advantages and other subsidies to support alternative energy sources, mandate the use of specific fuels or technologies, or promote research into new technologies to reduce the cost and increase the scalability of alternative energy sources.

## NEW AUTHORITATIVE ACCOUNTING AND FINANCIAL REPORTING GUIDANCE

For discussion of the recently issued authoritative accounting and financial reporting guidance, refer to Item 8 at Note A — Summary of Significant Accounting Policies under the heading "New Authoritative Accounting and Financial Reporting Guidance."

## EFFECTS OF INFLATION

The Company's operations are sensitive to increases in the rate of inflation because of its operational and capital spending requirements in both its regulated and non-regulated businesses. For the regulated businesses, recovery of increasing costs from customers can be delayed by the regulatory process of a rate case filing. For the non-regulated businesses, prices received for services performed or products produced are determined by market factors that are not necessarily correlated to the underlying costs required to provide the service or product.

## SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The Company is including the following cautionary statement in this Annual Report on Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new authoritative accounting and reporting guidance, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," "may," and similar expressions, are "forward-looking statements" as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. Changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing;
2. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design, retained natural gas and system modernization), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;
3. Changes in economic conditions, including the imposition of additional tariffs on U.S. imports and related retaliatory tariffs, inflationary pressures, supply chain issues, liquidity challenges, and global, national or regional recessions, and their effect on the demand for, and customers' ability to pay for, the Company's products and services;
4. The Company's ability to complete strategic transactions, such as the pending transaction with CenterPoint Energy Resources Corp., including receipt of required regulatory clearances and satisfaction of other conditions to closing, and to recognize the anticipated benefits of such transactions;

5. Governmental/regulatory actions and/or market pressures to reduce or eliminate reliance on natural gas;
6. The Company's ability to estimate accurately the time and resources necessary to meet emissions targets;
7. Changes in the price of natural gas;
8. Impairments under the SEC's full cost ceiling test for natural gas reserves;
9. The creditworthiness or performance of the Company's key suppliers, customers and counterparties;
10. Financial and economic conditions, including the availability of credit, and occurrences affecting the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures, other investments, and acquisitions, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions;
11. Negotiations with the collective bargaining units representing the Company's workforce, including potential work stoppages during negotiations;
12. Changes in price differentials between similar quantities of natural gas sold at different geographic locations, and the effect of such changes on commodity production, revenues and demand for pipeline transportation capacity to or from such locations;
13. The impact of information technology disruptions, cybersecurity or data security breaches, including the impact of issues that may arise from the use of artificial intelligence technologies;
14. Factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas reserves, including among others geology, lease availability and costs, title disputes, weather conditions, water availability and disposal or recycling opportunities of used water, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations;
15. Increased costs or delays or changes in plans with respect to Company projects or related projects of other companies, as well as difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;
16. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits;
17. Other changes in price differentials between similar quantities of natural gas having different quality, heating value, hydrocarbon mix or delivery date;
18. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
19. Uncertainty of natural gas reserve estimates;
20. Significant differences between the Company's projected and actual production levels for natural gas;
21. Changes in demographic patterns and weather conditions (including those related to climate change);
22. Changes in the availability, price or accounting treatment of derivative financial instruments;
23. Changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company's pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities;
24. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities or acts of war, as well as economic and operational disruptions due to third-party outages;
25. Significant differences between the Company's projected and actual capital expenditures and operating expenses; or

26. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Forward-looking and other statements in this Annual Report on Form 10-K regarding methane and greenhouse gas reduction plans and goals are not an indication that these statements are necessarily material to investors or required to be disclosed in our filings with the SEC. In addition, historical, current and forward-looking statements regarding methane and greenhouse gas emissions may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve and assumptions that are subject to change in the future.

**INDUSTRY AND MARKET DATA DISCLOSURE**

The market data and certain other statistical information used throughout this Form 10-K are based on independent industry publications, government publications or other published independent sources. Some data is also based on the Company's good faith estimates. Although the Company believes these third-party sources are reliable and that the information is accurate and complete, it has not independently verified the information.

## Item 7A *Quantitative and Qualitative Disclosures About Market Risk*

Refer to the "Market Risk Sensitive Instruments" section in Item 7, MD&A.

**Item 8** ***Financial Statements and Supplementary Data***

***Index to Financial Statements***

**Financial Statements:**



All schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

***Supplementary Data***

Supplementary data that is included in Note N — Supplementary Information for Exploration and Production Activities (unaudited), appears under this Item, and reference is made thereto.

## Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of National Fuel Gas Company

***Opinions on the Financial Statements and Internal Control over Financial Reporting***

We have audited the accompanying consolidated balance sheets of National Fuel Gas Company and its subsidiaries (the "Company") as of September 30, 2025 and 2024, and the related consolidated statements of income and earnings reinvested in the business, of comprehensive income, and of cash flows for each of the three years in the period ended September 30, 2025, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of September 30, 2025, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of September 30, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2025 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2025, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

***Basis for Opinions***

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

***Definition and Limitations of Internal Control over Financial Reporting***

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

***Critical Audit Matter***

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

*The Impact of Proved Natural Gas Reserves on Exploration and Production Properties, Net*

As described in Note A to the consolidated financial statements, the Company's capitalized costs relating to exploration and production activities, net of depreciation, depletion and amortization (DD&A) were $2.5 billion as of September 30, 2025. The Company follows the full cost method of accounting. Under this methodology, all costs associated with property acquisition, exploration and development activities are capitalized. For exploration and production properties, DD&A is computed based on quantities produced in relation to proved reserves using the units-of-production method. As disclosed by management, in addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. If capitalized costs, net of accumulated DD&A and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. For the year ended September 30, 2025, pre-tax impairment charges of $108.3 million were recognized. Estimates of the Company's proved natural gas reserves and the future net cash flows from those reserves were prepared by the Company's petroleum engineers and audited by independent petroleum engineers (together referred to as "management's specialists"). Petroleum engineering involves significant assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Estimates of economically recoverable natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including quantities of natural gas that are ultimately recovered, the timing of the recovery of natural gas reserves, the production and operating costs to be incurred, the amount and timing of future development and abandonment expenditures, and the price received for the production.

The principal considerations for our determination that performing procedures relating to the impact of proved natural gas reserves on exploration and production properties, net is a critical audit matter are (i) the significant judgment by management, including the use of management's specialists, when developing the estimates of proved natural gas reserves and (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the data, methods, and assumptions used by management and its specialists in developing the estimates of proved natural gas reserves.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved natural gas reserves. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of proved natural gas reserves. As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included (i) evaluating the methods and assumptions used by the specialists; (ii) testing the completeness and accuracy of the underlying data used by the specialists; and (iii) evaluating the specialists' findings.

/s/ PRICEWATERHOUSECOOPERS LLP
Buffalo, New York
November 21, 2025

We have served as the Company's auditor since 1941.

## NATIONAL FUEL GAS COMPANY

## CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS REINVESTED IN THE BUSINESS

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | (Thousands of dollars, except per common share amounts) | | |
| **INCOME** | | | |
| **Operating Revenues:** | | | |
| Utility Revenues | $ 817,274 | $ 696,807 | $ 941,779 |
| Integrated Upstream and Gathering and Other Revenues | 1,184,136 | 976,615 | 972,346 |
| Pipeline and Storage Revenues | 276,131 | 271,388 | 259,646 |
| | 2,277,541 | 1,944,810 | 2,173,771 |
| **Operating Expenses:** | | | |
| Purchased Gas | 213,441 | 150,062 | 437,595 |
| Operation and Maintenance: | | | |
| Utility | 230,639 | 218,393 | 205,239 |
| Integrated Upstream and Gathering and Other | 206,616 | 187,024 | 168,390 |
| Pipeline and Storage | 120,610 | 114,601 | 105,127 |
| Property, Franchise and Other Taxes | 94,380 | 88,851 | 92,700 |
| Depreciation, Depletion and Amortization | 456,594 | 457,026 | 409,573 |
| Impairment of Assets | 141,802 | 519,129 | — |
| | 1,464,082 | 1,735,086 | 1,418,624 |
| **Operating Income** | 813,459 | 209,724 | 755,147 |
| **Other Income (Expense):** | | | |
| Other Income (Deductions) | 36,428 | 16,226 | 18,138 |
| Interest Expense on Long-Term Debt | (140,870) | (122,799) | (111,948) |
| Other Interest Expense | (14,964) | (15,896) | (19,938) |
| **Income Before Income Taxes** | 694,053 | 87,255 | 641,399 |
| Income Tax Expense | 175,549 | 9,742 | 164,533 |
| **Net Income Available for Common Stock** | 518,504 | 77,513 | 476,866 |
| **EARNINGS REINVESTED IN THE BUSINESS** | | | |
| Balance at Beginning of Year | 1,727,326 | 1,885,856 | 1,587,085 |
| | 2,245,830 | 1,963,369 | 2,063,951 |
| Share Repurchases under Repurchase Plan | (43,382) | (50,823) | — |
| Dividends on Common Stock | (189,919) | (185,220) | (178,095) |
| **Balance at End of Year** | $ 2,012,529 | $ 1,727,326 | $ 1,885,856 |
| **Earnings Per Common Share:** | | | |
| Basic: | | | |
| **Net Income Available for Common Stock** | $ 5.73 | $ 0.84 | $ 5.20 |
| Diluted: | | | |
| **Net Income Available for Common Stock** | $ 5.68 | $ 0.84 | $ 5.17 |
| **Weighted Average Common Shares Outstanding:** | | | |
| Used in Basic Calculation | 90,500,916 | 91,791,167 | 91,748,890 |
| Used in Diluted Calculation | 91,227,473 | 92,344,511 | 92,285,918 |

See Notes to Consolidated Financial Statements

## NATIONAL FUEL GAS COMPANY

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | (Thousands of dollars) | | |
| Net Income Available for Common Stock | $ 518,504 | $ 77,513 | $ 476,866 |
| Other Comprehensive Income (Loss), Before Tax: | | | |
| Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans | (14,593) | (17,511) | (9,660) |
| Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans | 4,252 | 2,507 | 1,674 |
| Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period | (3,166) | 286,894 | 708,206 |
| Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income | (45,891) | (216,655) | 88,656 |
| Other Comprehensive Income (Loss), Before Tax | (59,398) | 55,235 | 788,876 |
| Income Tax Expense (Benefit) Related to the Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans | (3,445) | (3,996) | (2,284) |
| Reclassification Adjustment for Income Tax Benefit Related to the Amortization of the Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans | 1,001 | 584 | 411 |
| Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period | (858) | 81,197 | 214,270 |
| Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income | (12,350) | (62,134) | 5,806 |
| Income Taxes — Net | (15,652) | 15,651 | 218,203 |
| Other Comprehensive Income (Loss) | (43,746) | 39,584 | 570,673 |
| Comprehensive Income | $ 474,758 | $ 117,097 | $1,047,539 |

See Notes to Consolidated Financial Statements

# NATIONAL FUEL GAS COMPANY

# CONSOLIDATED BALANCE SHEETS

| | At September 30 2025 | At September 30 2024 |
|---|---|---|
| | (Thousands of dollars) | |
| **ASSETS** | | |
| **Property, Plant and Equipment** | $ 15,406,329 | $ 14,524,798 |
| Less — Accumulated Depreciation, Depletion and Amortization | 7,693,687 | 7,185,593 |
| | 7,712,642 | 7,339,205 |
| **Current Assets** | | |
| Cash and Temporary Cash Investments | 43,166 | 38,222 |
| Receivables — Net of Allowance for Uncollectible Accounts of $17,099 and $26,194, Respectively | 180,801 | 127,222 |
| Unbilled Revenue | 16,219 | 15,521 |
| Gas Stored Underground | 33,468 | 35,055 |
| Materials and Supplies - at average cost | 50,545 | 47,670 |
| Unrecovered Purchased Gas Costs | 5,769 | — |
| Other Current Assets | 80,759 | 92,229 |
| | 410,727 | 355,919 |
| **Other Assets** | | |
| Recoverable Future Taxes | 89,247 | 80,084 |
| Unamortized Debt Expense | 6,236 | 5,604 |
| Other Regulatory Assets | 135,486 | 108,022 |
| Deferred Charges | 73,941 | 69,662 |
| Other Investments | 68,346 | 81,705 |
| Goodwill | 5,476 | 5,476 |
| Prepaid Pension and Post-Retirement Benefit Costs | 169,228 | 180,230 |
| Fair Value of Derivative Financial Instruments | 39,388 | 87,905 |
| Other | 8,387 | 5,958 |
| | 595,735 | 624,646 |
| **Total Assets** | $ 8,719,104 | $ 8,319,770 |
| **CAPITALIZATION AND LIABILITIES** | | |
| **Capitalization:** | | |
| **Comprehensive Shareholders' Equity** | | |
| Common Stock, $1 Par Value; Authorized - 200,000,000 Shares; Issued and Outstanding - 90,379,095 Shares and 91,005,993 Shares, Respectively | $ 90,379 | $ 91,006 |
| Paid In Capital | 1,050,918 | 1,045,487 |
| Earnings Reinvested in the Business | 2,012,529 | 1,727,326 |
| Accumulated Other Comprehensive Loss | (59,222) | (15,476) |
| **Total Comprehensive Shareholders' Equity** | 3,094,604 | 2,848,343 |
| **Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs** | 2,382,861 | 2,188,243 |
| **Total Capitalization** | 5,477,465 | 5,036,586 |
| **Current and Accrued Liabilities** | | |
| Notes Payable to Banks and Commercial Paper | 150,200 | 90,700 |
| Current Portion of Long-Term Debt | 300,000 | 500,000 |
| Accounts Payable | 184,046 | 165,068 |
| Amounts Payable to Customers | 968 | 42,720 |
| Dividends Payable | 48,353 | 46,872 |
| Interest Payable on Long-Term Debt | 14,393 | 27,247 |
| Customer Advances | 17,188 | 19,373 |
| Customer Security Deposits | 29,853 | 36,265 |
| Other Accruals and Current Liabilities | 174,689 | 162,903 |
| Fair Value of Derivative Financial Instruments | 6,074 | 4,744 |
| | 925,764 | 1,095,892 |
| **Other Liabilities** | | |
| Deferred Income Taxes | 1,225,262 | 1,111,165 |
| Taxes Refundable to Customers | 306,335 | 305,645 |
| Cost of Removal Regulatory Liability | 307,659 | 292,477 |
| Other Regulatory Liabilities | 121,944 | 151,452 |
| Pension and Other Post-Retirement Liabilities | 5,252 | 3,511 |
| Asset Retirement Obligations | 236,787 | 203,006 |
| Other Liabilities | 112,636 | 120,036 |
| | 2,315,875 | 2,187,292 |
| **Commitments and Contingencies (Note L)** | — | — |
| **Total Capitalization and Liabilities** | $ 8,719,104 | $ 8,319,770 |

See Notes to Consolidated Financial Statements

## NATIONAL FUEL GAS COMPANY

## CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | (Thousands of dollars) | | |
| **Operating Activities** | | | |
| Net Income Available for Common Stock | $ 518,504 | $ 77,513 | $ 476,866 |
| Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities: | | | |
| Impairment of Assets | 141,802 | 519,129 | — |
| Depreciation, Depletion and Amortization | 456,594 | 457,026 | 409,573 |
| Deferred Income Taxes | 121,274 | (2,610) | 151,403 |
| Premium Paid on Early Redemption of Debt | 2,385 | — | — |
| Stock-Based Compensation | 19,754 | 22,080 | 20,630 |
| Other | 24,936 | 24,411 | 19,647 |
| Change in: | | | |
| Receivables and Unbilled Revenue | (54,521) | 34,369 | 213,579 |
| Gas Stored Underground and Materials and Supplies | (1,378) | 1,738 | (8,406) |
| Unrecovered Purchased Gas Costs | (5,769) | — | 99,342 |
| Other Current Assets | 11,387 | 8,144 | (41,077) |
| Accounts Payable | 12,785 | 5,616 | (37,095) |
| Amounts Payable to Customers | (41,752) | (16,299) | 58,600 |
| Customer Advances | (2,185) | (1,630) | (5,105) |
| Customer Security Deposits | (6,412) | 7,501 | 4,481 |
| Other Accruals and Current Liabilities | 489 | 2,637 | (67,664) |
| Other Assets | (29,106) | (48,183) | (26,564) |
| Other Liabilities | (68,760) | (25,481) | (31,135) |
| **Net Cash Provided by Operating Activities** | 1,100,027 | 1,065,961 | 1,237,075 |
| **Investing Activities** | | | |
| Capital Expenditures | (912,821) | (931,236) | (1,009,868) |
| Sale of Fixed Income Mutual Fund Shares in Grantor Trust | 7,000 | — | 10,000 |
| Acquisition of Upstream Assets | — | — | (124,758) |
| Other | 14,121 | (2,669) | 12,279 |
| **Net Cash Used in Investing Activities** | (891,700) | (933,905) | (1,112,347) |
| **Financing Activities** | | | |
| Proceeds from Issuance of Short-Term Note Payable to Bank | — | — | 250,000 |
| Repayment of Short-Term Note Payable to Bank | — | — | (250,000) |
| Net Change in Other Short-Term Notes Payable to Banks and Commercial Paper | 59,500 | (196,800) | 227,500 |
| Net Proceeds from Issuance of Long-Term Debt | 988,729 | 299,359 | 297,306 |
| Shares Repurchased Under Repurchase Plan | (54,430) | (64,086) | — |
| Reduction of Long-Term Debt | (1,004,086) | — | (549,000) |
| Net Repurchases of Common Stock Under Stock and Benefit Plans | (4,658) | (3,956) | (6,709) |
| Dividends Paid on Common Stock | (188,438) | (183,798) | (176,096) |
| **Net Cash Used in Financing Activities** | (203,383) | (149,281) | (206,999) |
| **Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash** | 4,944 | (17,225) | (82,271) |
| **Cash, Cash Equivalents and Restricted Cash At Beginning of Year** | 38,222 | 55,447 | 137,718 |
| **Cash, Cash Equivalents and Restricted Cash At End of Year** | $ 43,166 | $ 38,222 | $ 55,447 |
| **Supplemental Disclosure of Cash Flow Information** | | | |
| **Cash Paid For:** | | | |
| Interest | $ 159,362 | $ 125,130 | $ 124,441 |
| Income Taxes | $ 48,876 | $ 4,132 | $ 38,098 |
| **Non-Cash Investing Activities:** | | | |
| Non-Cash Capital Expenditures | $ 125,268 | $ 119,988 | $ 109,208 |

See Notes to Consolidated Financial Statements

## NATIONAL FUEL GAS COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### Note A — Summary of Significant Accounting Policies

***Principles of Consolidation***

The Company consolidates all entities in which it has a controlling financial interest. All significant intercompany balances and transactions are eliminated. The Company uses proportionate consolidation when accounting for drilling arrangements related to exploration and production properties accounted for under the full cost method of accounting.

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

***Reclassifications***

During the quarter ended September 30, 2025, the segment reporting structure was modified to merge the Exploration and Production segment and Gathering segment into one reportable segment. As a result, revenue and operation and maintenance expense line items on the consolidated statements of income in prior periods have been reclassified to conform to the current year presentation. Additional discussion is provided at Note M — Business Segment Information.

***Regulation***

The Company is subject to regulation by certain state and federal authorities. The Company has accounting policies which conform to GAAP, as applied to regulated enterprises, and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. Reference is made to Note F — Regulatory Matters for further discussion.

***Allowance for Uncollectible Accounts***

The allowance for uncollectible accounts is the Company's best estimate of the amount of probable credit losses in the existing accounts receivable. The allowance, the majority of which is in the Utility segment, is determined based on historical experience, the age of customer accounts, other specific information about customer accounts, and the economic and regulatory environment. Account balances have historically been written off against the allowance approximately twelve months after the account is final billed or when it is anticipated that the receivable will not be recovered. Starting in the quarter ended March 31, 2025, account balances are being written-off against the allowance approximately three months after the account is final billed or when it is anticipated that the receivable will not be recovered. This change in policy was initiated to better match the timing of write-offs with the recovery of uncollectible expense in rates and resulted in a one-time cumulative adjustment to the allowance during the quarter ended March 31, 2025.

Activity in the allowance for uncollectible accounts are as follows:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | | (Thousands) | |
| Balance at Beginning of Year | $ 26,194 | $ 36,295 | $ 40,228 |
| Additions Charged to Costs and Expenses | 19,195 | 13,180 | 14,482 |
| Add: Discounts on Purchased Receivables | 863 | 753 | 1,380 |
| Deduct: Net Accounts Receivable Written-Off | 29,153 | 24,034 | 19,795 |
| Balance at End of Year | $ 17,099 | $ 26,194 | $ 36,295 |

***Regulatory Mechanisms***

The Company's rate schedules in the Utility segment contain clauses that permit adjustment of revenues to reflect price changes from the cost of purchased gas included in base rates. Differences between amounts currently recoverable and actual adjustment clause revenues, as well as other price changes and pipeline and storage company refunds not yet includable in adjustment clause rates, are deferred and accounted for as either unrecovered purchased gas costs or amounts payable to customers. Such amounts are generally recovered from (or passed back to) customers during the following fiscal year.

Estimated refund liabilities to ratepayers represent management's current estimate of such refunds. Reference is made to Note F — Regulatory Matters for further discussion.

Prior to January 1, 2025, the Utility segment's tariff in its New York rate jurisdiction contained a system modernization/improvement tracker that was intended to provide recovery for leak prone pipe replacement. Amounts calculated under the tracker that were in excess of the annual amount that could be billed to the ratepayer were deferred as a regulatory asset per commission approval. After January 1, 2025, the mechanisms are no longer effective. The regulatory asset associated with the system modernization/improvement tracker is being amortized in accordance with the most recent rate settlement.

The impact of weather on revenues in the Utility segment's New York rate jurisdiction is tempered by a WNA, which covers the eight-month period from October through May. The WNA is designed to adjust the rates of retail customers to reflect the impact of deviations from normal weather. Weather that is warmer than normal results in a surcharge being added to customers' current bills, while weather that is colder than normal results in a refund being credited to customers' current bills.

On June 15, 2023, the PaPUC approved the Utility segment's Pennsylvania rate jurisdiction's use of a WNA as a five-year pilot program. The program became effective October 2023 and covers the eight-month period from October through May. Prior to October 2023, the Utility segment's Pennsylvania rate jurisdiction did not have a WNA, causing weather variations to have a direct impact on the Pennsylvania rate jurisdiction's revenues.

The impact of customer usage fluctuations in the Utility segment's New York rate jurisdiction is tempered by a revenue decoupling mechanism ("RDM"). The "revenue per class" RDM renders the Company financially indifferent to throughput changes for residential and small non-residential customers. Delivery revenues in excess of targets established in a base rate proceeding result in a refund being credited to customers' bills. Delivery revenues below the target result in a surcharge being added to customers' bills. The surcharge or credit is calculated over a twelve-month period ending September 30th, and applied to customer bills annually, beginning January 1st.

In the Pipeline and Storage segment, the allowed rates that Supply Corporation and Empire bill their customers are based on a straight fixed-variable rate design, which allows recovery of all fixed costs, including return on equity and income taxes, through fixed monthly reservation charges. Because of this rate design, changes in throughput due to weather variations do not have a significant impact on the revenues of Supply Corporation or Empire.

***Asset Acquisition and Business Combination Accounting***

In accordance with authoritative guidance issued by the FASB that clarifies the definition of a business, when the Company executes an acquisition, it will perform an initial screening test as of the acquisition date that, if met, results in the conclusion that the set of activities and assets is not a business. If the initial screening test is not met, the Company evaluates whether the set of activities is a business based on whether there are inputs and a substantive process in place. The definition of a business impacts whether the Company consolidates an acquisition under business combination guidance or asset acquisition guidance.

When the Company acquires assets and liabilities deemed to be an asset acquisition, the fair value of the purchase consideration, including the transaction costs of the asset acquisition, is assumed to be equal to the fair value of the net assets acquired. The purchase consideration, including the transaction costs, is allocated to the individual assets and liabilities assumed based on their relative fair values. Transaction costs associated with asset acquisitions are capitalized as part of the costs of the group of assets acquired.

When the Company acquires assets and liabilities deemed to be a business combination, the acquisition method is applied. Goodwill is measured as the fair value of the consideration transferred less the net recognized fair value of the identifiable assets acquired and the liabilities assumed, all measured at the acquisition date. Transaction costs that the Company incurs in connection with a business combination, such as finders' fees, legal fees, due diligence fees and other professional and consulting fees are expensed as incurred.

***Property, Plant and Equipment***

In the Company's Integrated Upstream and Gathering segment, upstream property acquisition, exploration and development costs are accounted for under the full cost method of accounting. Under this methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves attributable to a cost center. The Company's capitalized costs relating to exploration and production activities, net of accumulated depreciation, depletion and amortization, were $2.5 billion and $2.3 billion at September 30, 2025 and 2024, respectively. For further discussion of capitalized costs, refer to Note N — Supplementary Information for Exploration and Production Activities.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying commodity pricing (as adjusted for hedging) to estimated future production of proved reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unproved properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The commodity prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of first day of the month commodity price for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent non-cash impairment is required to be charged to earnings in that quarter. At September 30, 2025, the ceiling exceeded the book value of the exploration and production properties by approximately $1.1 billion. The book value of the exploration and production properties exceeded the ceiling at December 31, 2024. As such, the Company recognized a non-cash, pre-tax impairment charge of $108.3 million for the quarter ended December 31, 2024. A deferred income tax benefit of $29.2 million related to the non-cash impairment charge was also recognized for the quarter ended December 31, 2024. The book value of the exploration and production properties exceeded the ceiling at September 30, 2024, as well as at June 30, 2024. As such, the Company recognized non-cash, pre-tax ceiling test impairment charges in the Integrated Upstream and Gathering segment of $463.7 million for the year ended September 30, 2024. Deferred income tax benefits of $127.3 million related to the non-cash impairment charges were also recognized for the year ended September 30, 2024. In adjusting estimated future net cash flows for hedging under the ceiling test at September 30, 2025, 2024 and 2023, estimated future net cash flows were increased by $261.0 million, $428.5 million and $38.8 million, respectively.

The Integrated Upstream and Gathering segment also has items of property, plant and equipment that are accounted for outside of the provisions of the full cost method of accounting, including water disposal assets used in its upstream operations as well as gathering lines and compressor stations associated with its gathering operations, all of which are recorded at historical cost. As discussed in Note I — Fair Value Measurements, an impairment charge related to certain water disposal assets was recorded in the Integrated Upstream and Gathering segment at December 31, 2024 and September 30, 2024.

The principal assets of the Utility and Pipeline and Storage segments, consisting primarily of gas distribution pipelines, transmission pipelines, storage facilities and compressor stations, are recorded at historical cost. There were no indications of any impairments to property, plant and equipment in the Utility and Pipeline and Storage segments at September 30, 2025. An impairment charge related to the Northern Access Project, which is discussed at Note I — Fair Value Measurements, was recorded in the Pipeline and Storage segment at September 30, 2024. The impairment charge reduced the value of certain assets recorded in Property, Plant and Equipment and Deferred Charges on the Consolidated Balance Sheet.

Maintenance and repairs of property and replacements of minor items of property are charged directly to maintenance expense. The original cost of the regulated subsidiaries' property, plant and equipment retired, and the cost of removal less salvage, are charged to accumulated depreciation.

***Depreciation, Depletion and Amortization***

For exploration and production properties, depreciation, depletion and amortization is computed based on quantities produced in relation to proved reserves using the units of production method. The cost of unproved exploration and production properties is excluded from this computation. Depreciation, depletion and amortization expense for exploration and production properties was $261.7 million, $270.6 million and $235.7 million for the years ended September 30, 2025, 2024 and 2023, respectively. For all other property, plant and equipment, depreciation and amortization is computed using the straight-line method in amounts sufficient to recover costs over the estimated useful lives of property in service. The following is a summary of depreciable plant by segment:

| | As of September 30 | |
|---|---|---|
| | 2025 | 2024 |
| | (Thousands) | |
| Integrated Upstream and Gathering | $ 9,151,025 | $ 8,417,495 |
| Pipeline and Storage | 3,003,944 | 2,919,506 |
| Utility | 2,801,821 | 2,645,981 |
| All Other and Corporate | 16,650 | 15,915 |
| | $ 14,973,440 | $ 13,998,897 |

Average depreciation, depletion and amortization rates are as follows:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| Integrated Upstream and Gathering: | | | |
| Exploration and Production Operations, per Mcfe(1) | $ 0.61 | $ 0.69 | $ 0.63 |
| Integrated Upstream and Gathering Other Operations | 3.6 % | 3.6 % | 3.5 % |
| Pipeline and Storage | 2.6 % | 2.7 % | 2.6 % |
| Utility | 2.8 % | 2.8 % | 2.7 % |
| All Other and Corporate | 3.7 % | 3.0 % | 2.9 % |

(1) Amounts represents depletion of exploration and production properties.

***Goodwill***

The Company has recognized goodwill of $5.5 million as of September 30, 2025 and 2024 on its Consolidated Balance Sheets related to the Company's acquisition of Empire in 2003. The Company accounts for goodwill in accordance with the current authoritative guidance, which requires the Company to test goodwill for impairment annually. At September 30, 2025, 2024 and 2023, the fair value of Empire was greater than its book value. As such, the goodwill was not considered impaired at those dates. Going back to the origination of the goodwill in 2003, the Company has never recorded an impairment of its goodwill balance.

***Financial Instruments***

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and to manage a portion of the risk of currency fluctuations associated with transportation costs denominated in Canadian currency. These instruments include natural gas price swap agreements and no cost collars and foreign currency forward contracts. The Company accounts for these instruments as cash flow hedges for which the fair value of the instrument is recognized on the Consolidated Balance Sheets as either an asset or a liability labeled Fair Value of Derivative Financial Instruments. Reference is made to Note I — Fair Value Measurements for further discussion concerning the fair value of derivative financial instruments.

For cash flow hedges, the offset to the asset or liability that is recorded is a gain or loss recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets. The gain or loss recorded in accumulated other comprehensive income (loss) remains there until the hedged transaction occurs, at which point the gains or losses are reclassified to operating revenues on the Consolidated Statements of Income. Reference is made to Note J — Financial Instruments for further discussion concerning cash flow hedges.

***Accumulated Other Comprehensive Loss***

The components of Accumulated Other Comprehensive Loss and changes for the years ended September 30, 2025 and 2024, net of related tax effects, are as follows (amounts in parentheses indicate debits) (in thousands):

| | Gains and Losses on Derivative Financial Instruments | Funded Status of the Pension and Other Post-Retirement Benefit Plans | Total |
|---|---|---|---|
| **Year Ended September 30, 2025** | | | |
| Balance at October 1, 2024 | $ 55,799 | $ (71,275) | $ (15,476) |
| Other Comprehensive Gains and Losses Before Reclassifications | (2,308) | (11,148) | (13,456) |
| Amounts Reclassified From Other Comprehensive Loss | (33,541) | 3,251 | (30,290) |
| Balance at September 30, 2025 | $ 19,950 | $ (79,172) | $ (59,222) |
| **Year Ended September 30, 2024** | | | |
| Balance at October 1, 2023 | $ 4,623 | $ (59,683) | $ (55,060) |
| Other Comprehensive Gains and Losses Before Reclassifications | 205,697 | (13,515) | 192,182 |
| Amounts Reclassified From Other Comprehensive Loss | (154,521) | 1,923 | (152,598) |
| Balance at September 30, 2024 | $ 55,799 | $ (71,275) | $ (15,476) |

The amounts included in accumulated other comprehensive loss related to the funded status of the Company's pension and other post-retirement benefit plans consist of prior service costs and accumulated losses. The total amount for prior service cost was $0.4 million at both September 30, 2025 and 2024. The total amount for accumulated losses was $78.8 million and $70.9 million at September 30, 2025 and 2024, respectively.

***Reclassifications Out of Accumulated Other Comprehensive Loss***

The details about the reclassification adjustments out of accumulated other comprehensive loss for the years ended September 30, 2025 and 2024 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

| Details About Accumulated Other Comprehensive Loss Components | Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Loss for the Year Ended September 30, | | Affected Line Item in the Statement Where Net Income is Presented |
|---|---|---|---|
| | 2025 | 2024 | |
| Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges: | | | |
| Commodity Contracts | $ 46,957 | $ 217,012 | Operating Revenues |
| Foreign Currency Contracts | (1,066) | (357) | Operating Revenues |
| Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans: | | | |
| Prior Service Cost | (42) | (56) | (1) |
| Net Actuarial Loss | (4,210) | (2,451) | (1) |
| | 41,639 | 214,148 | Total Before Income Tax |
| | (11,349) | (61,550) | Income Tax Expense |
| | $ 30,290 | $ 152,598 | Net of Tax |

(1) These accumulated other comprehensive loss components are included in the computation of net periodic benefit cost. Refer to Note K — Retirement Plan and Other Post-Retirement Benefits for additional details.

***Gas Stored Underground***

In the Utility segment, gas stored underground in the amount of $33.5 million is carried at lower of cost or net realizable value, on a LIFO method. Based upon the average price of spot market gas purchased in September 2025, including transportation costs, the current cost of replacing this inventory of gas stored underground exceeded the amount stated on a LIFO basis by approximately $18.7 million at September 30, 2025.

***Unamortized Debt Expense***

Costs associated with the reacquisition of debt related to rate-regulated subsidiaries are deferred and amortized over the remaining life of the issue or the life of the replacement debt in order to match regulatory treatment. At September 30, 2025, the remaining weighted average amortization period for such costs was approximately 3 years.

***Income Taxes***

The Company and its subsidiaries file a consolidated federal income tax return. State tax returns are filed on a combined or separate basis depending on the applicable laws in the jurisdictions where tax returns are filed.

The Company follows the asset and liability approach in accounting for income taxes, which requires the recognition of deferred income taxes for the expected future tax consequences of net operating losses, credits and temporary differences between the financial statement carrying amounts and the tax basis of assets and liabilities. A valuation allowance is provided on deferred tax assets if it is determined, within each taxing jurisdiction, that it is more likely than not that the asset will not be realized.

The Company reports a liability or a reduction of deferred tax assets for unrecognized tax benefits resulting from uncertain tax positions taken or expected to be taken in a tax return. When applicable, the Company recognizes interest relating to uncertain tax positions in Other Interest Expense and penalties in Other Income (Deductions).

***Consolidated Statement of Cash Flows***

The components, as reported on the Company's Consolidated Balance Sheets, of the total cash, cash equivalents, and restricted cash presented on the Statement of Cash Flows are as follows (in thousands):

| | Year Ended September 30 | | | |
|---|---|---|---|---|
| | **2025** | **2024** | **2023** | **2022** |
| Cash and Temporary Cash Investments | $ 43,166 | $ 38,222 | $ 55,447 | $ 46,048 |
| Hedging Collateral Deposits | — | — | — | 91,670 |
| Cash, Cash Equivalents, and Restricted Cash | $ 43,166 | $ 38,222 | $ 55,447 | $137,718 |

The Company considers all highly liquid debt instruments purchased with a maturity date of generally three months or less to be cash equivalents. The Company's restricted cash is composed entirely of amounts reported as Hedging Collateral Deposits on the Consolidated Balance Sheets. Hedging Collateral Deposits is an account title for cash held in margin accounts funded by the Company to serve as collateral for derivative financial instruments in an unrealized loss position. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instruments liability or asset balances.

***Other Current Assets***

The components of the Company's Other Current Assets are as follows:

| | Year Ended September 30 | |
|---|---|---|
| | **2025** | **2024** |
| | **(Thousands)** | |
| Prepayments | $ 16,477 | $ 18,463 |
| Prepaid Property and Other Taxes | 13,920 | 14,187 |
| Federal Income Taxes Receivable | 14,511 | 8,154 |
| State Income Taxes Receivable | 489 | 13,161 |
| Regulatory Assets | 35,362 | 38,264 |
| | $ 80,759 | $ 92,229 |

***Other Accruals and Current Liabilities***

The components of the Company's Other Accruals and Current Liabilities are as follows:

| | Year Ended September 30 | |
|---|---|---|
| | 2025 | 2024 |
| | (Thousands) | |
| Accrued Capital Expenditures | $ 45,932 | $ 47,344 |
| Regulatory Liabilities | 20,624 | 29,352 |
| Liability for Royalty and Working Interests | 28,076 | 15,007 |
| Pennsylvania Impact Fee | 14,923 | 9,972 |
| Non-Qualified Benefit Plan Liability | 11,567 | 14,135 |
| Other | 53,567 | 47,093 |
| | $ 174,689 | $ 162,903 |

***Customer Advances***

The Company, primarily in its Utility segment, has balanced billing programs whereby customers pay their estimated annual usage in equal installments over a twelve-month period. Monthly payments under the balanced billing programs are typically higher than current month usage during the summer months. During the winter months, monthly payments under the balanced billing programs are typically lower than current month usage. At September 30, 2025 and 2024, customers in the balanced billing programs had advanced excess funds of $17.2 million and $19.4 million, respectively.

***Customer Security Deposits***

The Company, primarily in its Utility and Pipeline and Storage segments, oftentimes requires security deposits from marketers, producers, pipeline companies, and commercial and industrial customers before providing services to such customers. At September 30, 2025 and 2024, the Company had received customer security deposits amounting to $29.9 million and $36.3 million, respectively.

***Earnings Per Common Share***

Basic earnings per common share is computed by dividing income or loss by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the potentially dilutive securities the Company had outstanding during fiscal 2025, 2024 and/or 2023 were restricted stock units and performance shares. For fiscal 2025, 2024 and 2023, the diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these securities as determined using the Treasury Stock Method. Restricted stock units and performance shares that are antidilutive are excluded from the calculation of diluted earnings per common share. There were 3,228 securities, 569 securities and 3,888 securities excluded as being antidilutive for the years ended September 30, 2025, 2024 and 2023, respectively.

***Share Repurchases***

The Company considers all shares repurchased as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law. The repurchases are accounted for on the date the share repurchase is traded as an adjustment to common stock (at par value) with the excess repurchase price allocated between paid in capital and retained earnings. Refer to Note H — Capitalization and Short-Term Borrowings for further discussion of the Company's share repurchase program.

***Stock-Based Compensation***

The Company has various stock award plans which provide or provided for the issuance of one or more of the following to key employees: SARs, incentive stock options, nonqualified stock options, restricted stock, restricted stock units, performance units or performance shares. The Company follows authoritative guidance which requires the measurement and recognition of compensation cost at fair value for all share-based payments. For all Company stock awards, forfeitures are recognized as they occur.

Restricted stock units are subject to restrictions on vesting and transferability. Restricted stock units represent the right to receive shares of common stock of the Company (or the equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company) at the end of a specified time period. The restricted stock units do not entitle the participants to dividend and voting rights. The fair value at the date of grant of the restricted stock units (represented by the market value of Company common stock on the date of the award) must be reduced by the present value of forgone dividends over the vesting term of the award. The fair value of restricted stock units on the date of award is recorded as compensation expense over the vesting period.

Performance shares are an award constituting units denominated in common stock of the Company, the number of which may be adjusted over a performance cycle based upon the extent to which performance goals have been satisfied. Earned performance shares may be distributed in the form of shares of common stock of the Company, an equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company. The performance shares do not entitle the participant to receive dividends during the vesting period. For performance shares based on a return on capital goal and greenhouse gas emissions reductions goal, the fair value at the date of grant of the performance shares is determined by multiplying the expected number of performance shares to be issued by the market value of Company common stock on the date of grant reduced by the present value of forgone dividends. For performance shares based on a total shareholder return goal, the Company uses the Monte Carlo simulation technique to estimate the fair value price at the date of grant.

Refer to Note H — Capitalization and Short-Term Borrowings under the heading “Stock Award Plans” for additional disclosures related to stock-based compensation awards for all plans.

***New Authoritative Accounting and Financial Reporting Guidance***

In November 2023, the FASB issued authoritative guidance which improves reportable segment disclosure requirements, primarily through enhanced disclosures for significant segment expenses. The guidance was effective retrospectively for the Company as of September 30, 2025. As a result, the Company has enhanced its segment disclosures to include the presentation of significant costs and expenses by segment. The adoption of this authoritative guidance only affects the Company’s disclosures, with no impact to its financial condition and results of operations. All applicable disclosures have been included in Note M — Business Segment Information.

**Note B — Acquisitions**

On October 20, 2025, the Company entered into a Securities Purchase Agreement (the “Purchase Agreement”) with CenterPoint Energy Resources Corp. (the “Seller”), pursuant to which, among other things, the Company agreed to acquire from the Seller all of the issued and outstanding equity interests of Vectren Energy Delivery of Ohio, LLC for an aggregate purchase price of $2.62 billion, subject to customary adjustments, as provided in the Purchase Agreement. Closing is expected to occur in the fourth quarter of calendar 2026, pending completion of a notice filing and review with the Public Utilities Commission of Ohio, Hart-Scott-Rodino review, and other customary closing conditions. The purchase price will include a combination of $1.42 billion in cash and a $1.2 billion promissory note to be issued by the Company to the Seller. The promissory note, which was part of the Seller’s desired transaction structure and was incorporated into the Company's business valuation, will have a maturity date of 364 days post-closing and will carry an interest rate of 6.5%. The Company intends to execute permanent financing, inclusive of the amount to repay the promissory note, using the issuance of long-term debt and common equity, along with expected future free cash flow. This acquisition will add significant regulated scale for the Company, doubling the size of the Company's gas utility rate base, while expanding its operations beyond New York and Pennsylvania into the neighboring state of Ohio, a state with a constructive regulatory and political environment that is supportive of natural gas.

In connection with its entry into the Purchase Agreement, the Company entered into a senior unsecured bridge loan facility commitment letter supported by The Toronto-Dominion Bank ("TD Bank"), New York Branch and Wells Fargo Bank, National Association (together with TD Bank, the "Commitment Parties") and additional banks, as well as a 364-day term loan facility commitment letter supported by the Commitment Parties and additional banks, all of which are lenders under the Company's primary credit facility. The combination of both facilities fully supports the purchase price of $2.62 billion.

On June 1, 2023, the Company completed its acquisition of certain upstream assets located primarily in Tioga County, Pennsylvania from SWN Production Company, LLC ("SWN") for total consideration of $124.8 million. The purchase price, which reflects an effective date of January 1, 2023, was reduced for production revenues less expenses that were retained by SWN from the effective date to the closing date. As part of the transaction, the Company acquired approximately 34,000 net acres in an area that is contiguous with existing Company-owned upstream assets. This transaction was accounted for as an asset acquisition, and, as such, the purchase price was allocated to property, plant and equipment. The following is a summary of the asset acquisition in thousands:

| | |
|---|---|
| Purchase Price | $ 124,178 |
| Transaction Costs | 580 |
| Total Consideration | $ 124,758 |

## Note C — Revenue from Contracts with Customers

The following tables provide a disaggregation of the Company's revenues for the years ended September 30, 2025, 2024 and 2023, presented by type of service from each reportable segment.

| | Year Ended September 30, 2025 | | | | | | |
|---|---|---|---|---|---|---|---|
| Revenues by Type of Service | Integrated Upstream and Gathering | Pipeline and Storage | Utility | Total Reportable Segments | All Other | Corporate and Intersegment Eliminations | Total Consolidated |
| | | | | (Thousands) | | | |
| Production of Natural Gas | $ 1,104,283 | $ — | $ — | $ 1,104,283 | $ — | $ — | $ 1,104,283 |
| Production of Crude Oil | 1,837 | — | — | 1,837 | — | — | 1,837 |
| Natural Gas Processing | 1,196 | — | — | 1,196 | — | — | 1,196 |
| Natural Gas Gathering Service | 11,813 | — | — | 11,813 | — | — | 11,813 |
| Natural Gas Transportation Service | — | 324,179 | 109,443 | 433,622 | — | (108,351) | 325,271 |
| Natural Gas Storage Service | — | 100,292 | — | 100,292 | — | (42,485) | 57,807 |
| Natural Gas Residential Sales | — | — | 596,988 | 596,988 | — | — | 596,988 |
| Natural Gas Commercial Sales | — | — | 84,515 | 84,515 | — | — | 84,515 |
| Natural Gas Industrial Sales | — | — | 4,403 | 4,403 | — | (4) | 4,399 |
| Other | 18,050 | 3,130 | 10,813 | 31,993 | — | (985) | 31,008 |
| Total Revenues from Contracts with Customers | 1,137,179 | 427,601 | 806,162 | 2,370,942 | — | (151,825) | 2,219,117 |
| Alternative Revenue Programs | — | — | 11,467 | 11,467 | — | — | 11,467 |
| Derivative Financial Instruments | 46,957 | — | — | 46,957 | — | — | 46,957 |
| Total Revenues | $ 1,184,136 | $ 427,601 | $ 817,629 | $ 2,429,366 | $ — | $ (151,825) | $ 2,277,541 |

| | Year Ended September 30, 2024 | | | | | | |
|---|---|---|---|---|---|---|---|
| **Revenues by Type of Service** | **Integrated Upstream and Gathering** | **Pipeline and Storage** | **Utility** | **Total Reportable Segments** | **All Other** | **Corporate and Intersegment Eliminations** | **Total Consolidated** |
| | | | | (Thousands) | | | |
| Production of Natural Gas | $ 738,778 | $ — | $ — | $ 738,778 | $ — | $ — | $ 738,778 |
| Production of Crude Oil | 2,298 | — | — | 2,298 | — | — | 2,298 |
| Natural Gas Processing | 1,053 | — | — | 1,053 | — | — | 1,053 |
| Natural Gas Gathering Service | 15,537 | — | — | 15,537 | — | — | 15,537 |
| Natural Gas Transportation Service | — | 311,900 | 103,866 | 415,766 | — | (99,658) | 316,108 |
| Natural Gas Storage Service | — | 95,933 | — | 95,933 | — | (40,995) | 54,938 |
| Natural Gas Residential Sales | — | — | 502,744 | 502,744 | — | — | 502,744 |
| Natural Gas Commercial Sales | — | — | 68,466 | 68,466 | — | — | 68,466 |
| Natural Gas Industrial Sales | — | — | 3,103 | 3,103 | — | (5) | 3,098 |
| Other | 1,937 | 4,560 | (1,256) | 5,241 | — | (902) | 4,339 |
| Total Revenues from Contracts with Customers | 759,603 | 412,393 | 676,923 | 1,848,919 | — | (141,560) | 1,707,359 |
| Alternative Revenue Programs | — | — | 20,439 | 20,439 | — | — | 20,439 |
| Derivative Financial Instruments | 217,012 | — | — | 217,012 | — | — | 217,012 |
| Total Revenues | $ 976,615 | $ 412,393 | $ 697,362 | $ 2,086,370 | $ — | $ (141,560) | $ 1,944,810 |

| | Year Ended September 30, 2023 | | | | | | |
|---|---|---|---|---|---|---|---|
| **Revenues by Type of Service** | **Integrated Upstream and Gathering** | **Pipeline and Storage** | **Utility** | **Total Reportable Segments** | **All Other** | **Corporate and Intersegment Eliminations** | **Total Consolidated** |
| | | | | (Thousands) | | | |
| Production of Natural Gas | $ 1,036,499 | $ — | $ — | $ 1,036,499 | $ — | $ — | $ 1,036,499 |
| Production of Crude Oil | 2,261 | — | — | 2,261 | — | — | 2,261 |
| Natural Gas Processing | 1,203 | — | — | 1,203 | — | — | 1,203 |
| Natural Gas Gathering Service | 13,891 | — | — | 13,891 | — | — | 13,891 |
| Natural Gas Transportation Service | — | 291,225 | 98,304 | 389,529 | — | (82,889) | 306,640 |
| Natural Gas Storage Service | — | 84,962 | — | 84,962 | — | (36,283) | 48,679 |
| Natural Gas Residential Sales | — | — | 727,728 | 727,728 | — | — | 727,728 |
| Natural Gas Commercial Sales | — | — | 103,270 | 103,270 | — | — | 103,270 |
| Natural Gas Industrial Sales | — | — | 5,658 | 5,658 | — | (7) | 5,651 |
| Other | 6,507 | 3,004 | 508 | 10,019 | — | (947) | 9,072 |
| Total Revenues from Contracts with Customers | 1,060,361 | 379,191 | 935,468 | 2,375,020 | — | (120,126) | 2,254,894 |
| Alternative Revenue Programs | — | — | 6,892 | 6,892 | — | — | 6,892 |
| Derivative Financial Instruments | (88,015) | — | — | (88,015) | — | — | (88,015) |
| Total Revenues | $ 972,346 | $ 379,191 | $ 942,360 | $ 2,293,897 | $ — | $ (120,126) | $ 2,173,771 |

The Company records revenue related to its derivative financial instruments in the Integrated Upstream and Gathering segment. The Company also records revenue related to alternative revenue programs in its Utility segment. Revenue related to derivative financial instruments and alternative revenue programs are excluded from the scope of the authoritative guidance regarding revenue recognition since they are accounted for under other existing accounting guidance.

***Integrated Upstream and Gathering Segment Revenue***

The Company's Integrated Upstream and Gathering segment records revenue from the sale of the natural gas and oil that it produces, which means that revenue is recorded based on the actual amount of natural gas or oil that is delivered to a pipeline, or upon pick-up in the case of oil, netted down for the Company's ownership interest. Substantially all Integrated Upstream and Gathering segment production consists of natural gas production from the Appalachian region of the United States. If a production imbalance occurs between what was supposed to be delivered to a pipeline and what was actually produced and delivered, the Company accrues the difference as an imbalance. The sales contracts generally require the Company to deliver a specific quantity of a commodity per day for a specific number of days at a price that is either fixed or variable and considers the delivery of each unit (MMBtu or Bbl) to be a separate performance obligation that is satisfied upon delivery.

The transaction price for the sale of natural gas and oil is contractually agreed upon based on prevailing market pricing (primarily tied to a market index with certain adjustments based on factors such as delivery location and prevailing supply and demand conditions) or fixed pricing. The Company allocates the transaction price to each performance obligation on the basis of the relative standalone selling price of each distinct unit sold. Revenue is recognized at a point in time when the transfer of the commodity occurs at the delivery point per the contract. The amount billable, as determined by the contracted quantity and price, indicates the value to the customer, and is used for revenue recognition purposes by the Integrated Upstream and Gathering segment as specified by the "invoice practical expedient" (the amount that the Integrated Upstream and Gathering segment has the right to invoice) under the authoritative guidance for revenue recognition. The contracts typically require payment within 30 days of the end of the calendar month in which the natural gas and oil is delivered.

The Company's Integrated Upstream and Gathering segment also provides gathering and processing services in the Appalachian region of Pennsylvania. The primary performance obligation associated with the Integrated Upstream and Gathering segment's gathering and processing services is to deliver gathered natural gas volumes from producers' wells, into interstate pipelines at contractually agreed upon per unit rates. This obligation is satisfied over time. The performance obligation is satisfied based on the passage of time and meter reads, which correlates to the period for which the charges are eligible to be invoiced. The amount billable, as determined by the meter read and the contracted volumetric rate, indicates the value to the customer, and is used for revenue recognition purposes by the Integrated Upstream and Gathering segment as specified by the "invoice practical expedient" (the amount that the Integrated Upstream and Gathering segment has the right to invoice) under the authoritative guidance for revenue recognition. Customers are billed after the end of each calendar month, with payment typically due by the 10th day after the invoice is received.

The Company uses derivative financial instruments to manage commodity price risk in the Integrated Upstream and Gathering segment related to sales of the natural gas that it produces. Gains or losses on such derivative financial instruments are recorded as adjustments to revenue; however, they are not considered to be revenue from contracts with customers.

***Pipeline and Storage Segment Revenue***

The Company's Pipeline and Storage segment records revenue for natural gas transportation and storage services in New York and Pennsylvania at tariff-based rates regulated by the FERC. Customers secure their own gas supply and the Pipeline and Storage segment provides transportation and/or storage services to move the customer-supplied gas to the intended location, including injections into or withdrawals from the storage field. This performance obligation is satisfied over time. The rate design for the Pipeline and Storage segment's customers generally includes a combination of volumetric or commodity charges as well as monthly "fixed" charges (including charges commonly referred to as capacity charges, demand charges, or reservation charges). These types of fixed charges represent compensation for standing ready over the period of the month to deliver quantities of gas, regardless of whether the customer takes delivery of any quantity of gas. The performance obligation under these circumstances is satisfied based on the passage of time and meter reads, if applicable, which correlates to the period for which the charges are eligible to be invoiced. The amount billable, as determined by the meter read and the "fixed" monthly charge, indicates the value to the customer, and is used for revenue recognition purposes by the Pipeline and Storage segment as specified by the "invoice practical expedient" (the amount that the Pipeline and Storage segment has the right to invoice) under the authoritative guidance for revenue recognition. Customers are billed after the end of each calendar month, with payment typically due by the 25th day of the month in which the invoice is received.

The Company's Pipeline and Storage segment expects to recognize the following revenue amounts in future periods related to "fixed" charges associated with remaining performance obligations for transportation and storage contracts: $228.0 million for fiscal 2026; $214.1 million for fiscal 2027; $162.7 million for fiscal 2028; $129.7 million for fiscal 2029; $122.7 million for fiscal 2030; and $529.1 million thereafter.

***Utility Segment Revenue***

The Company's Utility segment records revenue for natural gas sales and natural gas transportation services in western New York and northwestern Pennsylvania at tariff-based rates regulated by the NYPSC and the PaPUC, respectively. Natural gas sales and transportation services are provided largely to residential, commercial and industrial customers. The Utility segment's performance obligation to its customers is to deliver natural gas, an obligation which is satisfied over time. This obligation generally remains in effect as long as the customer consumes the natural gas provided by the Utility segment. The Utility segment recognizes revenue when it satisfies its performance obligation by delivering natural gas to the customer. Natural gas is delivered and consumed by the customer simultaneously. The satisfaction of the performance obligation is measured by the turn of the meter dial. The amount billable, as determined by the meter read and the tariff-based rate, indicates the value to the customer, and is used for revenue recognition purposes by the Utility segment as specified by the "invoice practical expedient" (the amount that the Utility segment has the right to invoice) under the authoritative guidance for revenue recognition. Since the Utility segment bills its customers in cycles having billing dates that do not generally coincide with the end of a calendar month, a receivable is recorded for natural gas delivered but not yet billed to customers based on an estimate of the amount of natural gas delivered between the last meter reading date and the end of the accounting period. Such receivables are a component of Unbilled Revenue on the Consolidated Balance Sheets. The Utility segment's tariffs allow customers to utilize budget billing. In this situation, since the amount billed may differ from the amount of natural gas delivered to the customer in any given month, revenue is recognized monthly based on the amount of natural gas consumed. The differential between the amount billed and the amount consumed is recorded as a component of Receivables or Customer Advances on the Consolidated Balance Sheets. All receivables or advances related to budget billing are settled within one year.

***Utility Segment Alternative Revenue Programs***

As indicated in the revenue table shown above, the Company's Utility segment has alternative revenue programs that are excluded from the scope of the authoritative guidance regarding revenue recognition. The NYPSC has authorized alternative revenue programs that are designed to mitigate the impact that weather and conservation have on margin. The NYPSC and PaPUC have also authorized additional alternative revenue programs that adjust billings for the effects of broad external factors or to compensate the Company for demand-side management initiatives. These alternative revenue programs primarily allow the Company and customer to share in variances from imputed margins due to migration of transportation customers, allow for adjustments to the gas cost recovery mechanism for fluctuations in uncollectible expenses associated with gas costs, and allow the Company to pass on to customers costs associated with customer energy efficiency programs. In general, revenue is adjusted monthly for these programs and is collected from or passed back to customers within 24 months of the annual reconciliation period.

**Note D — Leases**

The Company follows authoritative guidance regarding lease accounting, which requires entities that lease the use of property, plant and equipment to recognize on the balance sheet the assets and liabilities for the rights and obligations created by all leases, including leases classified as operating leases. The Company has elected to apply the following practical expedients provided in the authoritative guidance:

1. An election not to apply the recognition requirements in the authoritative guidance to short-term leases (a lease that at commencement date has a lease term of one year or less);

2. A practical expedient that permits combining lease and non-lease components in a contract and accounting for the combination as a lease (elected by asset-class).

***Nature of Leases***

The Company primarily leases building space and drilling rigs, and on a limited basis, compressor equipment and other miscellaneous assets. The Company determines if an arrangement is a lease at the inception of the arrangement. To the extent that an arrangement represents a lease, the Company classifies that lease as an operating or a finance lease in accordance with the authoritative guidance. The Company did not have any material finance leases as of September 30, 2025 or September 30, 2024. The Company also does not have any material arrangements where the Company is the lessor.

*Buildings and Property*

The Company enters into building and property rental agreements with third parties for office space, certain field locations and other properties used in the Company's operations. Building and property leases include the Company's corporate headquarters in Williamsville, New York, and Integrated Upstream and Gathering segment offices in Houston, Texas, and Pittsburgh, Pennsylvania. The primary non-cancelable terms of the Company's building and property leases range from one month to fourteen years. Most building leases include one or more options to renew, generally at the Company's sole discretion, with renewal terms that can extend the lease terms from one year to sixteen years. Renewal options are included in the lease term if they are reasonably certain to be exercised. The agreements do not contain any material restrictive covenants.

*Drilling Rigs*

The Company enters into contracts for drilling rig services with third party contractors to support Seneca's development activities in Pennsylvania. Seneca's drilling rig arrangements are structured with a non-cancelable primary term of one year or less. Upon mutual agreement with the contractor, Seneca has the option to extend contracts with amended terms and conditions, including a renegotiated day rate fee.

Drilling rig lease costs are capitalized as part of natural gas properties on the Consolidated Balance Sheet when incurred.

*Compressor Equipment*

The Company enters into contracts for compressor services with third parties primarily to support its gathering system in Pennsylvania. The primary non-cancelable terms of the Company's compressor equipment leases range from 3 months to 5 years. Most compressor equipment leases include one or more options to renew or to continue past the primary term on a month-to-month basis, generally at the Company's sole discretion. Renewal options are included in the lease term if they are reasonably certain to be exercised.

***Significant Judgments***

*Lease Identification*

The Company uses judgment when determining whether or not an arrangement is or contains a lease. A contract is or contains a lease if the contract conveys the right to use an explicitly or implicitly identified asset that is physically distinct and the Company has the right to control the use of the identified asset for a period of time. When determining right of control, the Company evaluates whether it directs the use of the asset and obtains substantially all of the economic benefits from the use of the asset.

*Discount Rate*

The Company uses a discount rate to calculate the present value of lease payments in order to determine lease classification and measurement of the lease asset and liability. In the absence of a rate of interest that is readily determinable in the contract, the Company estimates the incremental borrowing rate (IBR) for each lease. The IBR reflects the rate of interest that the Company would pay on the lease commencement date to borrow an amount equal to the lease payments on a collateralized basis over a similar term in similar economic environments.

*Firm Transportation and Storage Contracts*

The Company's subsidiaries enter into long-term arrangements to both reserve firm transportation capacity on third party pipelines and provide firm transportation and storage services to third party shippers. The Company's firm capacity contracts with third party shippers do not provide rights to use substantially all of the underlying pipeline or storage asset. As such, the Company has concluded that these arrangements are not leases under the authoritative guidance.

*Gas Leases*

The authoritative guidance does not apply to leases to explore for or use natural gas resources, including the right to explore for those resources and rights to use the land in which those resources are contained. As such, the Company has concluded that its gas exploration and production leases and gas storage leases are not leases under the authoritative guidance.

***Amounts Recognized in the Financial Statements***

Operating lease costs, excluding those relating to drilling rig leases that are capitalized as part of exploration and production properties under the full cost method of accounting as well as certain equipment leases related to construction projects, are presented in Operations and Maintenance expense on the Consolidated Statement of Income. The following table summarizes the components of the Company's total operating lease costs (in thousands):

| | Year Ended September 30 | |
|---|---|---|
| | **2025** | **2024** |
| Operating Lease Expense | $ 12,723 | $ 11,827 |
| Variable Lease Expense(1) | 581 | 601 |
| Short-Term Lease Expense(2) | 719 | 299 |
| Total Lease Expense | $ 14,023 | $ 12,727 |
| Lease Costs Recorded to Property, Plant and Equipment(3) | $ 20,878 | $ 20,143 |

(1) Variable lease payments that are not dependent on an index or rate are not included in the lease liability.
(2) Short-term lease costs exclude expenses related to leases with a lease term of one month or less.
(3) Lease costs relating to drilling rig leases that are capitalized as part of exploration and production properties under full cost pool accounting as well as certain equipment leases used on construction projects.

Right-of-use assets and lease liabilities are recognized at the commencement date of a leasing arrangement based on the present value of lease payments over the lease term. The weighted average remaining lease term was 5.0 years and 5.7 years as of September 30, 2025 and 2024, respectively. The weighted average discount rate was 5.65% and 5.68% as of September 30, 2025 and 2024, respectively.

The Company's right-of-use operating lease assets are reflected as Deferred Charges on the Consolidated Balance Sheet. The corresponding operating lease liabilities are reflected in Other Accruals and Current Liabilities (current) and Other Liabilities (noncurrent). Short-term leases that have a lease term of one year or less are not recorded on the Consolidated Balance Sheet.

The following amounts related to operating leases were recorded on the Company's Consolidated Balance Sheet (in thousands):

| | Year Ended September 30 | |
|---|---|---|
| | 2025 | 2024 |
| Assets: | | |
| Deferred Charges | $ 41,317 | $ 44,206 |
| Liabilities: | | |
| Other Accruals and Current Liabilities | $ 11,479 | $ 11,518 |
| Other Liabilities | $ 29,683 | $ 32,616 |

Cash paid for lease liabilities, reported in cash provided by operating activities on the Company's Consolidated Statement of Cash Flows, was $14.0 million and $12.7 million for the years ended September 30, 2025 and 2024, respectively. The Company did not record any right-of-use assets in exchange for new lease liabilities during the years ended September 30, 2025 or 2024.

The following schedule of operating lease liability maturities summarizes the undiscounted lease payments owed by the Company to lessors pursuant to contractual agreements in effect as of September 30, 2025 (in thousands):

| | At September 30, 2025 |
|---|---|
| 2026 | $ 11,773 |
| 2027 | 10,779 |
| 2028 | 9,282 |
| 2029 | 5,774 |
| 2030 | 3,306 |
| Thereafter | 6,408 |
| Total Lease Payments | 47,322 |
| Less: Interest | (6,160) |
| Total Lease Liability | $ 41,162 |

**Note E — Asset Retirement Obligations**

The Company accounts for asset retirement obligations in accordance with the authoritative guidance that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. An asset retirement obligation is defined as a legal obligation associated with the retirement of a tangible long-lived asset in which the timing and/or method of settlement may or may not be conditional on a future event that may or may not be within the control of the Company. When the liability is initially recorded, the entity capitalizes the estimated cost of retiring the asset as part of the carrying amount of the related long-lived asset. Over time, the liability is adjusted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. The Company estimates the fair value of its asset retirement obligations based on the discounting of expected cash flows using various estimates, assumptions and judgments regarding certain factors such as the existence of a legal obligation for an asset retirement obligation; estimated amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. Asset retirement obligations incurred in the current period were Level 3 fair value measurements as the inputs used to measure the fair value are unobservable.

The Company has recorded an asset retirement obligation representing plugging and abandonment costs associated with the Integrated Upstream and Gathering segment's natural gas production wells and has capitalized such costs in property, plant and equipment (i.e. the full cost pool). Asset retirement obligation costs have also been recorded in the Integrated Upstream and Gathering segment for certain costs connected with the retirement of the gathering lines and other components of the gathering system, including storage tanks. These costs are primarily related to the capping and purging of pipe, which are generally abandoned in place when retired.

In addition to the asset retirement obligation recorded in the Integrated Upstream and Gathering segment, the Company has recorded future asset retirement obligations associated with the plugging and abandonment of natural gas storage wells in the Pipeline and Storage segment and the removal of asbestos and asbestos-containing material in various facilities in the Utility and Pipeline and Storage segments. Asset retirement obligation costs related to storage tanks have been recorded in the Utility and Pipeline and Storage segments. The Company has also recorded asset retirement obligations for certain costs connected with the retirement of the distribution mains, services and other components of the pipeline system in the Utility segment and the transmission mains and other components in the pipeline system in the Pipeline and Storage segment. The retirement costs within the distribution and transmission systems are primarily for the capping and purging of pipe, which are generally abandoned in place when retired, as well as for the clean-up of PCB contamination associated with the removal of certain pipe.

During fiscal 2024 and fiscal 2025, the Company experienced an increase in plugging and abandonment costs associated with the Integrated Upstream and Gathering segment's natural gas production wells and the Pipeline and Storage segment's natural gas storage wells, which contributed to an increase in the asset retirement obligation in both years. The increase in plugging and abandonment costs is the primary component of the Revisions of Estimates amount for fiscal 2024 and fiscal 2025 shown in the table below.

The following is a reconciliation of the change in the Company's asset retirement obligations:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | | (Thousands) | |
| Balance at Beginning of Year | $ 203,006 | $ 165,492 | $ 161,545 |
| Liabilities Incurred | 5,210 | 2,367 | 3,313 |
| Revisions of Estimates | 56,570 | 51,967 | 6,728 |
| Liabilities Settled | (38,862) | (25,556) | (14,448) |
| Accretion Expense | 10,863 | 8,736 | 8,354 |
| Balance at End of Year | $ 236,787 | $ 203,006 | $ 165,492 |

## Note F — Regulatory Matters

### *Regulatory Assets and Liabilities*

The Company has recorded the following regulatory assets and liabilities:

| | At September 30 | |
|---|---|---|
| | 2025 | 2024 |
| | (Thousands) | |
| **Regulatory Assets:** | | |
| Recoverable Future Taxes (Note G) | $ 89,247 | $ 80,084 |
| Unamortized Debt Expense (Note A) | 6,236 | 5,604 |
| Other Regulatory Assets: | | |
| Pension Costs (Note K) | 42,602 | 30,259 |
| NY Rate Case Levelization and Tracking Mechanisms(1) | 28,688 | — |
| Asset Retirement Obligations (Note E) | 24,634 | 21,951 |
| Post-Retirement Benefit Costs (Note K) | 13,306 | 7,932 |
| System Modernization / Improvement Tracker (See Regulatory Mechanisms in Note A) | 12,625 | 31,362 |
| Other | 13,631 | 16,518 |
| Total Long-Term Regulatory Assets | $ 230,969 | $ 193,710 |
| Current Regulatory Assets: | | |
| Unrecovered Purchased Gas Costs (See Regulatory Mechanisms in Note A) | 5,769 | — |
| Other Current Assets: | | |
| System Modernization / Improvement Tracker (See Regulatory Mechanisms in Note A) | 14,481 | 15,681 |
| Other | 20,881 | 22,583 |
| Total Regulatory Assets | $ 272,100 | $ 231,974 |

(1) New York Rate Case Levelization and Tracking Mechanisms were approved in accordance with Distribution Corporation's New York rate settlement on December 19, 2024, as discussed below. The mechanisms include: (a) levelization deferral of $17.8 million which relates to a volumetric surcredit within the Company's delivery adjustment charge that minimizes customer bill impacts, (b) uncollectible expense tracker of $9.8 million, which tracks and reconciles the actual uncollectible expense to the amounts recovered in base rates and, (c) property tax tracker of $1.1 million, which represents the amount deferred between actual property taxes incurred and the level included in customer rates.

| | At September 30 | |
|---|---|---|
| | 2025 | 2024 |
| | (Thousands) | |
| **Regulatory Liabilities:** | | |
| Taxes Refundable to Customers (Note G) | $ 306,335 | $ 305,645 |
| Cost of Removal Regulatory Liability | 307,659 | 292,477 |
| Other Regulatory Liabilities: | | |
| Post-Retirement Benefit Costs (Note K) | 108,714 | 135,399 |
| Environmental Site Remediation Costs (Note L) | 1,800 | 5,390 |
| Other | 11,430 | 10,663 |
| Total Long-Term Regulatory Liabilities | $ 735,938 | $ 749,574 |
| Current Regulatory Liabilities: | | |
| Amounts Payable to Customers (See Regulatory Mechanisms in Note A) | 968 | 42,720 |
| Other Current and Accrued Liabilities: | | |
| Post-Retirement Benefit Costs (Note K) | 5,800 | 5,800 |
| Other | 14,824 | 23,552 |
| Total Regulatory Liabilities | $ 757,530 | $ 821,646 |

If for any reason the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the Consolidated Balance Sheets and included in income of the period in which the discontinuance of regulatory accounting treatment occurs.

***Cost of Removal Regulatory Liability***

In the Company's Utility and Pipeline and Storage segments, costs of removing assets (i.e. asset retirement costs) are collected from customers through depreciation expense. These amounts are not a legal retirement obligation as discussed in Note E — Asset Retirement Obligations. Rather, they are classified as a regulatory liability in recognition of the fact that the Company has collected dollars from customers that will be used in the future to fund asset retirement costs.

***New York Jurisdiction***

Distribution Corporation's current delivery rates in its New York jurisdiction were approved by the NYPSC in an order issued on December 19, 2024 with rates effective January 1, 2025 ("2024 Rate Order"). The 2024 Rate Order authorizes a three-year rate plan effective October 1, 2024, with a make-whole provision allowing full recovery of revenues that would have been billed at the new rates between October 1, 2024 and December 31, 2024. It also reflects a return on equity of 9.7% and authorizes a revenue requirement increase of $57.3 million in fiscal 2025, an additional revenue requirement increase of $15.8 million in fiscal 2026, and an additional revenue requirement increase of $12.7 million in fiscal 2027. These revenue requirement increases are being reflected in customer bills on a levelized basis over the three-year rate plan. The revenue requirement for each year of the three-year plan has been reduced by $14 million for actuarial projections of income that is expected to be recognized for qualified pension and other post-retirement benefits. Qualified pension and other post-retirement benefit income or costs are matched with amounts included in revenue resulting in zero impact to earnings. The 2024 Rate Order approves the continuation of several ratemaking mechanisms, including revenue decoupling and WNA, and establishes a number of new cost trackers and regulatory deferrals. It also includes an earnings sharing mechanism, gas safety and customer service performance metrics (including maintaining the Company's leak prone pipe replacement program), and provisions that will facilitate achievement of the emissions reduction goals of the CLCPA.

***Pennsylvania Jurisdiction***

Distribution Corporation's current delivery rates in its Pennsylvania jurisdiction were approved by the PaPUC in an order issued on June 15, 2023 with rates effective August 1, 2023 ("2023 Rate Order"). The 2023 Rate Order provided for, among other things, an increase in Distribution Corporation's annual base rate operating revenues of $23 million and authorized a new weather normalization adjustment mechanism.

On April 10, 2024, Distribution Corporation filed with the PaPUC a petition for approval of a distribution system improvement charge ("DSIC") to recover, between base rate cases, capital expenses related to eligible property constructed or installed to rehabilitate, improve and replace portions of the Company's natural gas distribution system. The DSIC petition was approved by the PaPUC on December 5, 2024, and on January 1, 2025, the Company initiated recovery of eligible costs on incremental rate base added after September 30, 2024. During the year ended September 30, 2025, Distribution Corporation recovered $0.9 million from customers.

***FERC Jurisdiction***

Supply Corporation's rate settlement was approved June 11, 2024 with rates effective February 1, 2024, and provides that Supply Corporation may make a rate filing for new rates to be effective at any time. As well, any party can make a filing under NGA Section 5. Supply Corporation has no rate case currently on file.

On March 17, 2025, FERC approved an amendment to Empire's 2019 rate case settlement, which provides for a modest reduction in Empire's transportation unit rates, effective November 1, 2025. This settlement amendment is estimated to decrease Empire's revenues on a yearly basis by approximately $0.5 million. Empire will not be able to file a new Section 4 rate case before April 30, 2027 and is required to file a Section 4 rate case by May 31, 2031.

## Note G — Income Taxes

The components of federal and state income taxes included in the Consolidated Statements of Income are as follows:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | | (Thousands) | |
| Current Income Taxes — | | | |
| Federal | $ 42,089 | $ 6,453 | $ 11,744 |
| State | 12,186 | 5,899 | 1,386 |
| Deferred Income Taxes — | | | |
| Federal | 90,881 | 894 | 106,801 |
| State | 30,393 | (3,504) | 44,602 |
| Total Income Taxes | $ 175,549 | $ 9,742 | $ 164,533 |

On July 4, 2025, the One Big Beautiful Bill Act ("OBBBA") was signed into law. The OBBBA makes permanent key elements of the Tax Cuts and Jobs Act, including 100% bonus depreciation related to the Integrated Upstream and Gathering segment, domestic research cost expensing, and the business interest expense limitation. Additionally, the OBBBA permits the inclusion of intangible drilling cost deductions in the calculation of the Corporate Alternative Minimum Tax. The Company has evaluated the OBBBA. The results of such evaluations are reflected within the Company's financial statements and the impacts were not material.

Total income taxes as reported differ from the amounts that were computed by applying the federal income tax rate to income before income taxes. The following is a reconciliation of this difference:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | | (Thousands) | |
| U.S. Income Before Income Taxes | $ 694,053 | $ 87,255 | $ 641,399 |
| Income Tax Expense, Computed at U.S. Federal Statutory Rate of 21% | $ 145,751 | $ 18,324 | $ 134,694 |
| State Income Taxes | 33,637 | 1,892 | 36,331 |
| Amortization of Excess Deferred Federal Income Taxes | (4,617) | (5,607) | (6,053) |
| Plant Flow Through Items | (5,070) | (6,135) | (2,856) |
| Stock Compensation | 2,245 | 1,758 | 957 |
| Miscellaneous | 3,603 | (490) | 1,460 |
| Total Income Taxes | $ 175,549 | $ 9,742 | $ 164,533 |

Significant components of the Company's deferred tax liabilities and assets were as follows:

| | At September 30 | |
|---|---|---|
| | 2025 | 2024 |
| | (Thousands) | |
| Deferred Tax Liabilities: | | |
| Unrealized Hedging Gains | $ 9,036 | $ 22,433 |
| Property, Plant and Equipment | 1,222,869 | 1,134,727 |
| Pension and Other Post-Retirement Benefit Costs | 72,691 | 59,877 |
| Other | 24,531 | 13,885 |
| Total Deferred Tax Liabilities | 1,329,127 | 1,230,922 |
| Deferred Tax Assets: | | |
| Tax Loss and Credit Carryforwards | (28,364) | (31,111) |
| Pension and Other Post-Retirement Benefit Costs | (54,071) | (49,622) |
| Other | (21,430) | (39,024) |
| Total Deferred Tax Assets | (103,865) | (119,757) |
| Total Net Deferred Income Taxes | $ 1,225,262 | $ 1,111,165 |

A valuation allowance for deferred tax assets, including net operating losses and tax credits, is recognized when it is more likely than not that some or all of the benefit from the deferred tax assets will not be realized. The Company, at each reporting date, assesses the realizability of its deferred tax assets, including factors such as future taxable income, reversal of existing temporary differences, and tax planning strategies. The Company considers both positive and negative evidence related to the likelihood of the realization of the deferred tax assets. As of September 30, 2025, the Company has determined that there is sufficient positive evidence to conclude that it is more likely than not that the deferred tax assets will be realized.

Tax carryforwards available at September 30, 2025, were as follows:

| Jurisdiction | Tax Attribute | Amount (Thousands) | Expires |
|---|---|---|---|
| Pennsylvania | Net Operating Loss | $ 422,900 | 2031-2045 |

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to $306.3 million and $305.6 million at September 30, 2025 and 2024, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of ratemaking practices, amounted to $89.2 million and $80.1 million at September 30, 2025 and 2024, respectively.

The Company is in the Bridge Plus Phase of the IRS Compliance Assurance Process ("CAP") for fiscal 2025. This phase requires the submission of supplemental documentation to the IRS and allows the IRS to conduct a pre-filing review of material tax positions and to provide preliminary feedback prior to the filing of the Company's federal income tax return. The CAP program is intended for taxpayers with a low risk of non-compliance who are cooperative and transparent with few, if any, material issues that require resolution. The federal statute of limitations remains open for fiscal 2022 and later years. The Company is also subject to various routine state income tax examinations. The Company's principal subsidiaries have state statutes of limitations that generally expire between three to four years from the date of filing of the income tax return. Net operating losses being carried forward from prior years remain subject to examination on a future return until they are utilized, upon which time the statute of limitation begins. The Company has no unrecognized tax benefits as of September 30, 2025, 2024, or 2023.

The IRS released guidance on April 14, 2023, providing a natural gas transmission and distribution property safe harbor method of accounting ("NGSH method") that taxpayers may use to determine whether expenses to repair, maintain, replace, or improve natural gas transmission and distribution property must be capitalized or be allowable as deductions for repairs. The Company elected this change in tax accounting method for Distribution Corporation with its fiscal 2023 consolidated tax return filing. The Company elected this same change in tax accounting method for Supply Corporation with its fiscal 2024 consolidated tax return filing. The financial statements herein reflect the amounts of what is intended to be treated as a repair for tax purposes rather than being capitalized and have been recorded in Income Tax Expense.

## Note H — Capitalization and Short-Term Borrowings

***Summary of Changes in Common Stock Equity***

| | Common Stock | | Paid In Capital | Earnings Reinvested in the Business | Accumulated Other Comprehensive Income (Loss) |
|---|---|---|---|---|---|
| | Shares | Amount | | | |
| | (Thousands, except per share amounts) | | | | |
| Balance at September 30, 2022 | 91,478 | $91,478 | $1,027,066 | $1,587,085 | $ (625,733) |
| Net Income Available for Common Stock | | | | 476,866 | |
| Dividends Declared on Common Stock ($1.94 Per Share) | | | | (178,095) | |
| Other Comprehensive Income, Net of Tax | | | | | 570,673 |
| Share-Based Payment Expense(1) | | | 18,746 | | |
| Common Stock Issued (Repurchased) Under Stock and Benefit Plans | 341 | 341 | (5,051) | | |
| Balance at September 30, 2023 | 91,819 | 91,819 | 1,040,761 | 1,885,856 | (55,060) |
| Net Income Available for Common Stock | | | | 77,513 | |
| Dividends Declared on Common Stock ($2.02 Per Share) | | | | (185,220) | |
| Other Comprehensive Income, Net of Tax | | | | | 39,584 |
| Share-Based Payment Expense(1) | | | 19,868 | | |
| Common Stock Issued (Repurchased) Under Stock and Benefit Plans | 333 | 333 | (1,955) | | |
| Share Repurchases Under Repurchase Plan | (1,146) | (1,146) | (13,187) | (50,823) | |
| Balance at September 30, 2024 | 91,006 | 91,006 | 1,045,487 | 1,727,326 | (15,476) |
| Net Income Available for Common Stock | | | | 518,504 | |
| Dividends Declared on Common Stock ($2.10 Per Share) | | | | (189,919) | |
| Other Comprehensive Loss, Net of Tax | | | | | (43,746) |
| Share-Based Payment Expense(1) | | | 17,306 | | |
| Common Stock Issued (Repurchased) Under Stock and Benefit Plans | 202 | 202 | (2,262) | | |
| Share Repurchases Under Repurchase Plan | (829) | (829) | (9,613) | (43,382) | |
| Balance at September 30, 2025 | 90,379 | $90,379 | $1,050,918 | $2,012,529 | $ (59,222) |

(1) Paid in Capital includes compensation costs associated with performance shares and/or restricted stock awards. The expense is included within Net Income Available for Common Stock, net of tax benefits.

***Common Stock***

The Company has various plans which allow shareholders, employees and others to purchase shares of the Company common stock. The National Fuel Gas Company Direct Stock Purchase and Dividend Reinvestment Plan allows shareholders to reinvest cash dividends and make cash investments in the Company's common stock and provides investors the opportunity to acquire shares of the Company common stock without the payment of any brokerage commissions in connection with such acquisitions. The 401(k) plans allow employees the opportunity to invest in the Company common stock, in addition to a variety of other investment alternatives. Generally, at the discretion of the Company, shares purchased under these plans are either original issue shares purchased directly from the Company or shares purchased on the open market by an independent agent. During 2025, the Company did not issue any original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan or the Company's 401(k) plans.

During 2025, the Company issued 128,028 original issue shares of common stock for restricted stock units that vested and 108,799 original issue shares of common stock for performance shares that vested. Holders of stock-based compensation awards will often tender shares of common stock to the Company for payment of applicable withholding taxes. During 2025, 71,394 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

The Company also has a director stock program under which it issues shares of Company common stock to the non-employee directors of the Company who receive compensation under the Company's 2009 Non-Employee Director Equity Compensation Plan, including the reinvestment of dividends for certain non-employee directors who elected to defer their shares pursuant to the dividend reinvestment feature of the Company's Deferred Compensation Plan for Directors and Officers (the "DCP"), as partial consideration for the directors' services during the fiscal year. Under this program, the Company issued 27,698 original issue shares of common stock during 2025. In addition, the Company issued 8,691 original issue shares of common stock to officers of the Company who elected to defer their shares pursuant to the dividend reinvestment features of the Company's DCP during 2025.

On March 8, 2024, the Company's Board of Directors authorized the Company to implement a share repurchase program, whereby the Company may repurchase outstanding shares of common stock, up to an aggregate amount of $200 million in the open market or through privately negotiated transactions, including through the use of trading plans intended to qualify under SEC Rule 10b5-1, in accordance with applicable securities laws and other restrictions.

During 2025, the Company executed transactions to repurchase 828,720 shares at an average price of $64.37 per share, for a total cost of $53.8 million (including broker fees and excise taxes). Share repurchases that settled during 2025 were funded with cash provided by operating activities and/or short-term borrowings. In light of the Company's agreement to acquire CenterPoint Ohio's natural gas utility, repurchases under the program have been suspended. The program has no fixed expiration date.

***Stock Award Plans***

The Company has various stock award plans which provide or provided for the issuance of one or more of the following to key employees: SARs, incentive stock options, nonqualified stock options, restricted stock, restricted stock units, performance units or performance shares.

Stock-based compensation expense for the years ended September 30, 2025, 2024 and 2023 was approximately $17.2 million, $19.8 million and $18.6 million, respectively. Stock-based compensation expense is included in operation and maintenance expense on the Consolidated Statements of Income. The total income tax benefit related to stock-based compensation expense during the years ended September 30, 2025, 2024 and 2023 was approximately $2.2 million, $2.5 million and $2.4 million, respectively. A portion of stock-based compensation expense is subject to capitalization under IRS uniform capitalization rules. Stock-based compensation of $0.1 million was capitalized under these rules during each of the years ended September 30, 2025, 2024 and 2023. The tax benefit related to stock-based compensation exercises and vestings was $0.1 million for the year ended September 30, 2025.

Pursuant to registration statements for these plans, there were 3,711,717 shares available for future grant at September 30, 2025. These shares include shares available for future options, SARs, restricted stock and performance share grants.

*Restricted Stock Units*

Transactions for 2025 involving nonperformance-based restricted stock units for all plans are summarized as follows:

| | Number of Restricted Stock Units | Weighted Average Fair Value per Award |
|---|---|---|
| Outstanding at September 30, 2024 | 438,193 | $ 46.70 |
| Granted in 2025 | 132,352 | $ 58.64 |
| Vested in 2025 | (128,028) | $ 49.14 |
| Forfeited in 2025 | (13,270) | $ 50.78 |
| Outstanding at September 30, 2025 | 429,247 | $ 49.53 |

The Company also granted 220,778 and 133,173 nonperformance-based restricted stock units during the years ended September 30, 2024 and 2023, respectively. The weighted average fair value of such nonperformance-based restricted stock units granted in 2024 and 2023 was $42.44 per share and $58.10 per share, respectively. As of September 30, 2025, unrecognized compensation expense related to nonperformance-based restricted stock units totaled approximately $8.3 million, which will be recognized over a weighted average period of 2.4 years.

Vesting restrictions for the nonperformance-based restricted stock units outstanding at September 30, 2025 will lapse as follows: 2026 — 149,295 units; 2027 — 126,726 units; 2028 — 78,002 units; 2029 — 18,928 units; 2030 — 11,258 units; and 45,038 units thereafter.

*Performance Shares*

Transactions for 2025 involving performance shares for all plans are summarized as follows:

| | Number of Performance Shares | Weighted Average Fair Value per Award |
|---|---|---|
| Outstanding at September 30, 2024 | 719,577 | $ 54.69 |
| Granted in 2025 | 239,042 | $ 55.43 |
| Vested in 2025 | (108,799) | $ 56.98 |
| Forfeited in 2025 | (206,823) | $ 61.05 |
| Change in Units Based on Performance Achieved | 9,478 | $ 53.47 |
| Outstanding at September 30, 2025 | 652,475 | $ 52.55 |

The Company also granted 361,729 and 202,259 performance shares during the years ended September 30, 2024 and 2023, respectively. The weighted average grant date fair value of such performance shares granted in 2024 and 2023 was $44.23 per share and $64.28 per share, respectively. As of September 30, 2025, unrecognized compensation expense related to performance shares totaled approximately $11.4 million, which will be recognized over a weighted average period of 2.3 years. Vesting restrictions for the outstanding performance shares at September 30, 2025 will lapse as follows: 2026 — 174,071 shares; 2027 — 243,279 shares; 2028 — 178,825 shares; 2029 - zero; 2030 - 11,256; and 45,044 shares thereafter.

The performance shares granted during the years ended September 30, 2025, 2024 and 2023 include awards that must meet a performance goal related to either relative return on capital over a three-year or five-year performance cycle (“ROC Performance Shares”), methane intensity and greenhouse gas emissions reductions over a three-year performance cycle (“Emissions Performance Shares”) or relative shareholder return over a three-year or five-year performance cycle (“TSR Performance Shares”).

The performance goal over the respective performance cycles for the ROC Performance Shares granted during 2025, 2024 and 2023 is the Company's total return on capital relative to the total return on capital of other companies in a group selected by the Compensation Committee ("Report Group"). Total return on capital for a given company means the average of the Report Group companies' returns on capital for each twelve-month period corresponding to each of the Company's fiscal years during the performance cycle, based on data reported for the Report Group companies in the Bloomberg database. The number of these ROC Performance Shares that will vest and be paid will depend upon the Company's performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value of the ROC Performance Shares is calculated by multiplying the expected number of shares that will be issued by the average market price of Company common stock on the date of grant reduced by the present value of forgone dividends over the vesting term of the award. The fair value is recorded as compensation expense over the vesting term of the award.

The performance goal over the respective performance cycles for the Emissions Performance Shares granted during 2025, 2024 and 2023 consists of two parts: reductions in the rates of intensity of methane emissions for each of the Company's operating segments, and reduction of the consolidated Company's total greenhouse gas emissions. The Company's Compensation Committee set specific target levels for methane intensity rates and total greenhouse gas emissions, and the performance goal is intended to incentivize and reward performance to the extent management achieves methane intensity and greenhouse gas reduction targets making progress towards the Company's 2030 goals. The number of these Emissions Performance Shares that will vest and be paid out will depend upon the number of methane intensity segment targets achieved and whether the Company meets the total greenhouse gas emissions target. The fair value of these Emissions Performance Shares is calculated by multiplying the expected number of shares that will be issued by the average market price of Company common stock on the date of grant reduced by the present value of forgone dividends over the vesting term of the award. The fair value is recorded as compensation expense over the vesting term of the award.

The performance goal over the respective performance cycles for the TSR Performance Shares granted during 2025, 2024 and 2023 is the Company's three-year (or five-year) total shareholder return relative to the three-year (or five-year) total shareholder return of the other companies in the Report Group. Three-year (or five-year) total shareholder return for a given company will be based on the data reported for that company (with the starting and ending stock prices over the performance cycle calculated as the average closing stock price for the prior calendar month and with dividends reinvested in that company's securities at each ex-dividend date) in the Bloomberg database. The number of these TSR Performance Shares that will vest and be paid will depend upon the Company's performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value price at the date of grant for the TSR Performance Shares is determined using a Monte Carlo simulation technique, which includes a reduction in value for the present value of forgone dividends over the vesting term of the award. This price is multiplied by the number of TSR Performance Shares awarded, the result of which is recorded as compensation expense over the vesting term of the award. In calculating the fair value of the award, the risk-free interest rate is based on the yield of a Treasury Note with a term commensurate with the remaining term of the TSR Performance Shares. The remaining term is based on the remainder of the performance cycle as of the date of grant. The expected volatility is based on historical daily stock price returns. For the TSR Performance Shares, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees. The following weighted average assumptions were used in estimating the fair value of the TSR Performance Shares at the date of grant:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| Risk-Free Interest Rate | 4.11 % | 4.36 % | 4.03 % |
| Remaining Term at Date of Grant (Years) | 2.82 | 2.98 | 2.80 |
| Expected Volatility | 23.2 % | 23.9 % | 31.6 % |
| Expected Dividend Yield (Quarterly) | N/A | N/A | N/A |

***Redeemable Preferred Stock***

As of September 30, 2025, there were 10,000,000 shares of $1 par value Preferred Stock authorized but unissued.

***Long-Term Debt***

The outstanding long-term debt is as follows:

| | At September 30 | |
|---|---|---|
| | 2025 | 2024 |
| | (Thousands) | |
| Medium-Term Notes(1): | | |
| 7.38% due June 2025 | $ — | $ 50,000 |
| Notes(1)(2)(3): | | |
| 2.95% to 5.95% due October 2026 to March 2035 | 2,400,000 | 2,350,000 |
| Delayed Draw Term Loan(4): | | |
| Variable Rate due February 2026 | 300,000 | 300,000 |
| Total Long-Term Debt | 2,700,000 | 2,700,000 |
| Less Unamortized Discount and Debt Issuance Costs | 17,139 | 11,757 |
| Less Current Portion(5) | 300,000 | 500,000 |
| | $ 2,382,861 | $ 2,188,243 |

(1) The Medium-Term Notes and Notes are unsecured.

(2) The holders of these notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade.

(3) The interest rate payable on $300.0 million of 4.75% notes, $300.0 million of 3.95% notes, $500.0 million of 2.95% notes and $300.0 million of 5.50% notes will be subject to adjustment from time to time, with a maximum of 2.00%, if certain change of control events involving a material subsidiary result in a downgrade of the credit rating assigned to the notes to below investment grade (or if the credit rating assigned to the notes is subsequently upgraded). The interest rate payable on $500.0 million of 5.50% notes and $500.0 million of 5.95% notes will be subject to adjustment from time to time, with a maximum adjustment of 2.00%, such that the coupon will not exceed 7.50% on the 5.50% notes and 7.95% on the 5.95% notes, if certain change in control events involving a material subsidiary result in a downgrade of the credit rating assigned to the notes to a rating below investment grade. A downgrade with a resulting increase to the coupon does not preclude the coupon from returning to its original rate if the Company's credit rating is subsequently upgraded.

(4) The interest rate on the delayed draw term loan, which is based on a weighted average SOFR interest rate, was 5.62% and 6.71% as of September 30, 2025 and September 30, 2024, respectively. The current weighted average locked-in interest rate is 5.43% until mid-December 2025.

(5) Current Portion of Long-Term Debt at September 30, 2025 consisted of a $300.0 million long-term delayed draw term loan that matures in February 2026. Current Portion of Long-Term Debt at September 30, 2024 consisted of $50.0 million of 7.38% medium-term notes and $450.0 million of 5.20% notes.

On February 19, 2025, the Company issued $500.0 million of 5.50% notes due March 15, 2030 and $500.0 million of 5.95% notes due March 15, 2035. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $495.2 million and $493.5 million, respectively. The proceeds of these debt issuances were used for general corporate purposes, including the March 6, 2025 redemptions of $450.0 million of the Company's 5.20% notes that were scheduled to mature in July 2025 and $500.0 million of the Company's 5.50% notes that were scheduled to mature in January 2026. The Company redeemed those notes for $450.8 million and $503.3 million, respectively, plus accrued interest. The remaining proceeds of the debt issuances were used to repay a portion of short-term borrowings the Company incurred to fund a trust for the benefit of holders of $50.0 million of 7.38% notes under the Company's 1974 indenture prior to the June 13, 2025 maturity date of these notes. Placing these funds in trust enabled the Company to cancel and discharge the 1974 indenture. This relieved the Company from its obligations to comply with the 1974 indenture's covenants. The funds were paid out of the trust on June 13, 2025 for the redemption of the $50.0 million of 7.38% notes, leaving no notes outstanding under the 1974 indenture.

The Company entered into its existing term loan agreement (the "Term Loan Agreement") on February 14, 2024, with six of the 12 banks that are lenders under the Credit Agreement. The Term Loan Agreement provides a $300.0 million unsecured committed delayed draw term loan facility with a maturity date of February 14, 2026, and the Company has the ability to select interest periods of one, three or six months for borrowings. In April 2024, pursuant to the delayed draw mechanism, the Company elected to draw a total of $300.0 million under the facility. After deducting debt issuance costs, the net proceeds to the Company amounted to $299.4 million. The Company used the proceeds for general corporate purposes, which included the redemption of outstanding commercial paper. Borrowings under the Term Loan Agreement currently bear interest at a rate equal to SOFR for the applicable interest period, plus an adjustment of 0.10%, plus a spread of 1.375%.

As of September 30, 2025, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $300.0 million in 2026, $600.0 million in 2027, $300.0 million in 2028, zero in 2029, $500.0 million in 2030, and $1.0 billion thereafter.

***Short-Term Borrowings***

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. The Company is a party to a syndicated Credit Agreement (as amended from time to time, the "Credit Agreement") that provides a $1.0 billion unsecured committed revolving credit facility. In January 2025, the Company and the banks in the syndicate consented to a second one-year extension of the maturity date of the Credit Agreement, such that the Company has aggregate commitments available in the full amount of $1.0 billion through February 23, 2029. In May 2025, the number of lenders under the Credit Agreement increased to twelve as a new lender joined the syndicate, assuming a portion of an existing lender's commitment.

The total amount available to be issued under the Company's commercial paper program is $500.0 million. The commercial paper program is backed by the Credit Agreement. The Company also has uncommitted lines of credit with financial institutions for general corporate purposes. Borrowings under these uncommitted lines of credit would be made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institution and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines. Other financial institutions may also provide the Company with uncommitted or discretionary lines of credit in the future.

At September 30, 2025, the Company had outstanding commercial paper of $150.2 million with a weighted average interest rate on the commercial paper of 4.64%. At September 30, 2024, the Company had outstanding commercial paper of $90.7 million with a weighted average interest rate on the commercial paper of 5.30%. The Company did not have any outstanding short-term notes payable to banks at September 30, 2025 and 2024.

***Debt Restrictions***

Both the Credit Agreement and the Term Loan Agreement provide that the Company's debt to capitalization ratio will not exceed 0.65 at the last day of any fiscal quarter. For purposes of calculating the debt to capitalization ratio, the Company's total capitalization will be increased by adding back 50% of the aggregate after-tax amount of non-cash charges directly arising from any ceiling test impairment occurring on or after July 1, 2018, not to exceed $400 million. Since that date, the Company recorded non-cash, after-tax ceiling test impairments totaling $797.0 million. As a result, at September 30, 2025, $398.5 million was added back to the Company's total capitalization for purposes of calculating the debt to capitalization ratio under the Credit Agreement and the Term Loan Agreement. In addition, for purposes of calculating the debt to capitalization ratio, the following amounts included in Accumulated Other Comprehensive Income (Loss) on the Company's consolidated balance sheet will be excluded from the determination of comprehensive shareholders' equity: all unrealized gains or losses on commodity-related derivative financial instruments, and up to $10 million in unrealized gains or losses on other derivative financial instruments. As a result of these exclusions, such unrealized gains or losses will not positively or negatively affect the calculation of the debt to capitalization ratio. At September 30, 2025, the Company's debt to capitalization ratio, as calculated under the agreements was 0.45. The constraints specified in the Credit Agreement and the Term Loan Agreement would have permitted an additional $3.61 billion in short-term and/or long-term debt to be outstanding at September 30, 2025 before the Company's debt to capitalization ratio exceeded 0.65.

The Company's present liquidity position is believed to be adequate to satisfy known demands. A downgrade in the Company's credit ratings could increase borrowing costs, negatively impact the availability of capital from banks, commercial paper purchasers and other sources, and require the Company's subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. If the Company is not able to maintain investment grade credit ratings, it may not be able to access commercial paper markets. However, the Company expects that it could borrow under its credit facilities or rely upon other liquidity sources.

The Credit Agreement and the Term Loan Agreement each contain a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the Credit Agreement or Term Loan Agreement, as applicable. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity.

## Note I — Fair Value Measurements

The FASB authoritative guidance regarding fair value measurements establishes a fair-value hierarchy and prioritizes the inputs used in valuation techniques that measure fair value. Those inputs are prioritized into three levels. Level 1 inputs are unadjusted quoted prices in active markets for assets or liabilities that the Company can access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly at the measurement date. Level 3 inputs are unobservable inputs for the asset or liability at the measurement date. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of September 30, 2025 and 2024. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

| Recurring Fair Value Measures | At Fair Value as of September 30, 2025 Level 1 | Level 2 | Level 3 | Netting Adjustments(1) | Total(1) |
|---|---|---|---|---|---|
| | (Dollars in thousands) | | | | |
| Assets: | | | | | |
| Cash Equivalents — Money Market Mutual Funds | $ 30,551 | $ — | $ — | $ — | $ 30,551 |
| Derivative Financial Instruments: | | | | | |
| Over the Counter Swaps — Gas | — | 62,190 | — | (33,615) | 28,575 |
| Over the Counter No Cost Collars — Gas | — | 24,149 | — | (12,805) | 11,344 |
| Foreign Currency Contracts | — | 144 | — | (675) | (531) |
| Other Investments: | | | | | |
| Balanced Equity Mutual Fund | 13,786 | — | — | — | 13,786 |
| Fixed Income Mutual Fund | 10,082 | — | — | — | 10,082 |
| Total | $ 54,419 | $ 86,483 | $ — | $ (47,095) | $ 93,807 |
| Liabilities: | | | | | |
| Derivative Financial Instruments: | | | | | |
| Over the Counter Swaps — Gas | $ — | $ 34,169 | $ — | $ (33,615) | $ 554 |
| Over the Counter No Cost Collars — Gas | — | 18,036 | — | (12,805) | 5,231 |
| Foreign Currency Contracts | — | 893 | — | (675) | 218 |
| Total | $ — | $ 53,098 | $ — | $ (47,095) | $ 6,003 |
| Total Net Assets/(Liabilities) | $ 54,419 | $ 33,385 | $ — | $ — | $ 87,804 |

| Recurring Fair Value Measures | At Fair Value as of September 30, 2024 Level 1 | Level 2 | Level 3 | Netting Adjustments(1) | Total(1) |
|---|---|---|---|---|---|
| | (Dollars in thousands) | | | | |
| Assets: | | | | | |
| Cash Equivalents — Money Market Mutual Funds | $ 29,238 | $ — | $ — | $ — | $ 29,238 |
| Derivative Financial Instruments: | | | | | |
| Over the Counter Swaps — Gas | — | 76,009 | — | (17,198) | 58,811 |
| Over the Counter No Cost Collars — Gas | — | 32,584 | — | (3,774) | 28,810 |
| Contingent Consideration for Asset Sale | — | 729 | — | — | 729 |
| Foreign Currency Contracts | — | 281 | — | (726) | (445) |
| Other Investments: | | | | | |
| Balanced Equity Mutual Fund | 19,523 | — | — | — | 19,523 |
| Fixed Income Mutual Fund | 17,374 | — | — | — | 17,374 |
| Total | $ 66,135 | $ 109,603 | $ — | $ (21,698) | $ 154,040 |
| Liabilities: | | | | | |
| Derivative Financial Instruments: | | | | | |
| Over the Counter Swaps — Gas | $ — | $ 22,206 | $ — | $ (17,198) | $ 5,008 |
| Over the Counter No Cost Collars — Gas | — | 3,501 | — | (3,774) | (273) |
| Foreign Currency Contracts | — | 726 | — | (726) | — |
| Total | $ — | $ 26,433 | $ — | $ (21,698) | $ 4,735 |
| Total Net Assets/(Liabilities) | $ 66,135 | $ 83,170 | $ — | $ — | $ 149,305 |

(1) Netting Adjustments represent the impact of legally-enforceable master netting arrangements that allow the Company to net gain and loss positions held with the same counterparties. The net asset or net liability for each counterparty is recorded as an asset or liability on the Company's balance sheet.

The following table presents impairments of assets associated with certain nonrecurring fair value measurements within Level 3 of the fair value hierarchy as of September 30, 2025, 2024 and 2023 (in thousands):

| Nonrecurring Fair Value Measures | Segment | Date of Measurement | Fair Value | Impairments Year Ended September 30, 2025 | 2024 | 2023 |
|---|---|---|---|---|---|---|
| Impairment of Assets: | | | | | | |
| Water Disposal Assets | Integrated Upstream and Gathering | December 31, 2024 | $ 12,880 | $ 33,453 | $ — | $ — |
| Northern Access Project | Pipeline and Storage | September 30, 2024 | $ 12,133 | — | 46,075 | — |
| Water Disposal Assets | Integrated Upstream and Gathering | September 30, 2024 | $ 3,000 | — | 9,362 | — |
| Total Impairment | | | | $ 33,453 | $ 55,437 | $ — |

*Water Disposal Assets*

In exploring the potential sale of certain water disposal assets during both the quarters ended December 31, 2024 and September 30, 2024, the Company determined that the fair market value of such assets was less than the recorded net book value resulting in impairment charges of $33.5 million and $9.4 million, respectively, that reduced the net book value to fair market value. These assets are used to dispose of water from operations in the Integrated Upstream and Gathering segment.

*Northern Access Project*

On February 3, 2017, Supply Corporation and Empire received FERC approval of the Northern Access project described herein. Substantial litigation ensued over the next several years concerning various federal and state authorizations for the project, with the majority of project development activities suspended pending resolution. These legal actions included, most recently, an appeal of FERC's June 2022 order granting Supply Corporation and Empire an extension of time to construct the project through December 31, 2024. In March 2024, the U.S. Court of Appeals for the D.C. Circuit issued an order affirming FERC's extension of time, with such order final as of late June 2024. Upon resolution of the extensive litigation, Supply Corporation and Empire began to assess next steps for the project, including a review of the status of necessary federal and state authorizations, as well as potential changes in expected capital expenditures and the related transportation rates that Supply Corporation and Empire needed to support the project. As a result of this review, and in accordance with the precedent agreements between the respective parties, Supply Corporation and Empire sent notifications to Seneca, the sole shipper for the project, indicating their intent to increase the project's firm transportation rates to account for the anticipated increase in capital expenditures to complete the project. Upon receipt, Seneca indicated it was unwilling to accept the revised transportation rates and intended to terminate the precedent agreements for the project. The precedent agreements were subsequently terminated on October 16, 2024. Accordingly, the Company determined it would no longer pursue construction of the Northern Access project and took an impairment charge of $46.1 million at September 30, 2024.

***Derivative Financial Instruments***

At September 30, 2025, the derivative financial instruments reported in Level 2 consist of natural gas price swap agreements, natural gas no cost collars, and foreign currency contracts, all of which are used in the Company's Integrated Upstream and Gathering segment. The fair value of the Level 2 price swap agreements and no cost collars is based on an internal cash flow model that uses observable inputs (i.e. SOFR based discount rates for the price swap agreements and basis differential information, if applicable, at active natural gas trading markets). The fair value of the Level 2 foreign currency contracts is determined using the market approach based on observable market transactions of forward Canadian currency rates.

The authoritative guidance for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2025, the Company determined that nonperformance risk associated with the price swap agreements, no cost collars and foreign currency contracts would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company's (assuming the derivative is in a loss position) credit default swaps rates.

Derivative financial instruments reported in Level 2 at September 30, 2024 also includes the contingent consideration associated with the sale of the Integrated Upstream and Gathering segment's California assets on June 30, 2022. The fair value of this contingent consideration was zero at September 30, 2025. The fair value of the contingent consideration was calculated using a Monte Carlo simulation model that uses observable inputs, including the ICE Brent closing price as of the valuation date, initial and max trigger price, volatility, risk free rate, time of maturity and counterparty risk.

## Note J — Financial Instruments

### *Long-Term Debt*

The fair market value of the Company's debt, as presented in the table below, was determined using a discounted cash flow model, which incorporates the Company's credit ratings and current market conditions in determining the yield, and subsequently, the fair market value of the debt. Based on these criteria, the fair market value of long-term debt, including current portion, was as follows:

| | At September 30 | | | |
|---|---|---|---|---|
| | 2025 Carrying Amount | 2025 Fair Value | 2024 Carrying Amount | 2024 Fair Value |
| | (Thousands) | | | |
| Long-Term Debt | $ 2,682,861 | $ 2,696,145 | $ 2,688,243 | $ 2,656,888 |

The fair value amounts are not intended to reflect principal amounts that the Company will ultimately be required to pay. Carrying amounts for other financial instruments recorded on the Company's Consolidated Balance Sheets approximate fair value. The fair value of long-term debt was calculated using observable inputs (U.S. Treasuries or SOFR for the risk-free component and company specific credit spread information — generally obtained from recent trade activity in the debt). As such, the Company considers the debt to be Level 2.

Any temporary cash investments, notes payable to banks and commercial paper are stated at cost. Temporary cash investments are considered Level 1, while notes payable to banks and commercial paper are considered to be Level 2. Given the short-term nature of the notes payable to banks and commercial paper, the Company believes cost is a reasonable approximation of fair value.

***Other Investments***

The components of the Company's Other Investments are as follows (in thousands):

| | At September 30 | |
|---|---|---|
| | 2025 | 2024 |
| | (Thousands) | |
| Life Insurance Contracts | $ 44,478 | $ 44,808 |
| Equity Mutual Fund | 13,786 | 19,523 |
| Fixed Income Mutual Fund | 10,082 | 17,374 |
| | $ 68,346 | $ 81,705 |

Investments in life insurance contracts are stated at their cash surrender values or net present value. Investments in an equity mutual fund and a fixed income mutual fund are stated at fair value based on quoted market prices with changes in fair value recognized in net income. The insurance contracts and equity mutual fund are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees. The fixed income mutual fund is primarily an informal funding mechanism for certain regulatory obligations that the Company has to Utility segment customers in its Pennsylvania jurisdiction, as discussed in Note F — Regulatory Matters, and for various benefit obligations the Company has to certain employees.

***Derivative Financial Instruments***

The Company uses derivative financial instruments to manage commodity price risk in the Integrated Upstream and Gathering segment. The Company enters into over-the-counter no cost collar and swap agreements for natural gas to manage the price risk associated with forecasted sales of natural gas. In addition, the Company also enters into foreign exchange forward contracts to manage the risk of currency fluctuations associated with transportation costs denominated in Canadian currency in the Integrated Upstream and Gathering segment. These instruments are accounted for as cash flow hedges. The duration of the Company's cash flow hedges does not typically exceed 5 years, and the foreign currency forward contracts also do not exceed 5 years.

The Company has presented its net derivative assets and liabilities as "Fair Value of Derivative Financial Instruments" on its Consolidated Balance Sheets at September 30, 2025 and September 30, 2024.

*Cash Flow Hedges*

For derivative financial instruments that are designated and qualify as a cash flow hedge, the gain or loss on the derivative is reported as a component of other comprehensive income (loss) and reclassified into earnings in the period or periods during which the hedged transaction affects earnings.

As of September 30, 2025, the Company had 414.3 Bcf of natural gas commodity derivative contracts (swaps and no cost collars) outstanding.

As of September 30, 2025, the Company was hedging a total of $44.1 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts.

As of September 30, 2025, the Company had $19.9 million of net hedging gains after taxes included in the accumulated other comprehensive income (loss) balance. Of this amount, it is expected that $35.7 million of unrealized gains after taxes will be reclassified into the Consolidated Statement of Income within the next 12 months as the underlying hedged transactions are recorded in earnings. The remaining unrealized loss will be reclassified into the Consolidated Statement of Income in subsequent periods.

**The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Year Ended September 30, 2025 and 2024 (Dollar Amounts in Thousands)**

| Derivatives in Cash Flow Hedging Relationships | Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) for the Year Ended September 30, | | Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income | Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income for the Year Ended September 30, | |
|---|---|---|---|---|---|
| | 2025 | 2024 | | 2025 | 2024 |
| Commodity Contracts | $ (1,795) | $ 286,392 | Operating Revenue | $ 46,957 | $ 217,012 |
| Foreign Currency Contracts | (1,371) | 502 | Operating Revenue | (1,066) | (357) |
| Total | $ (3,166) | $ 286,894 | | $ 45,891 | $ 216,655 |

*Credit Risk*

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company's counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions, no cost collars and applicable foreign currency forward contracts with eighteen counterparties of which thirteen are in a net gain position. On average, the Company had $3.0 million of credit exposure per counterparty in a gain position at September 30, 2025. The maximum credit exposure per counterparty in a gain position at September 30, 2025 was $8.7 million. As of September 30, 2025, no collateral was received from the counterparties by the Company. The Company's gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral, nor had the counterparties' credit ratings declined to levels at which the counterparties were required to post collateral.

Certain counterparties to the Company's outstanding derivative instrument contracts (specifically the over-the-counter swaps, over-the-counter no cost collars and applicable foreign currency forward contracts) had a common credit-risk related contingency feature. In the event the Company's credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit that could be extended to the Company when it is in a derivative financial liability position would either increase or decrease. A decline in the Company's credit rating, in and of itself, would not cause the Company to be required to post or increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company's outstanding derivative instrument contracts with a credit-risk contingency feature were in a liability position (or if the liability were larger) and/or the Company's credit rating declined, then hedging collateral deposits or an increase to such deposits could be required. At September 30, 2025, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $1.9 million according to the Company's internal model (discussed in Note I — Fair Value Measurements) and no hedging collateral deposits were required to be posted by the Company at September 30, 2025. Depending on the movement of commodity prices in the future, it is possible that these liability positions could swing into asset positions, at which point the Company would be exposed to credit risk on its derivative financial instruments. In that case, the Company's counterparties could be required to post hedging collateral deposits.

The Company's requirement to post hedging collateral deposits and the Company's right to receive hedging collateral deposits is based on the fair value determined by the Company's counterparties, which may differ from the Company's assessment of fair value.

**Note K — Retirement Plan and Other Post-Retirement Benefits**

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan). The Retirement Plan covers certain non-collectively bargained employees hired before July 1, 2003 and certain collectively bargained employees hired before November 1, 2003. Certain non-collectively bargained employees hired after June 30, 2003 and certain collectively bargained employees hired after October 31, 2003 are eligible for a Retirement Savings Account benefit provided under the Company's defined contribution Tax-Deferred Savings Plans. Costs associated with the Retirement Savings Account were $7.1 million, $6.5 million and $5.7 million for the years ended September 30, 2025, 2024 and 2023, respectively. Costs associated with the Company's contributions to the Tax-Deferred Savings Plans, exclusive of the costs associated with the Retirement Savings Account, were $9.8 million, $9.0 million and $8.2 million for the years ended September 30, 2025, 2024 and 2023, respectively.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The other post-retirement benefits cover certain non-collectively bargained employees hired before January 1, 2003 and certain collectively bargained employees hired before October 31, 2003.

The Company's policy is to fund the Retirement Plan with at least an amount necessary to satisfy the minimum funding requirements of applicable laws and regulations and not more than the maximum amount deductible for federal income tax purposes. The Company has established VEBA trusts for its other post-retirement benefits. Contributions to the VEBA trusts are tax deductible, subject to limitations contained in the Internal Revenue Code and regulations and are made to fund employees' other post-retirement benefits, as well as benefits as they are paid to current retirees. In addition, the Company has established 401(h) accounts for its other post-retirement benefits. They are separate accounts within the Retirement Plan trust used to pay retiree medical benefits for the associated participants in the Retirement Plan. Although these accounts are in the Retirement Plan trust, for funding status purposes as shown below, the 401(h) accounts are included in Fair Value of Assets under Other Post-Retirement Benefits. Contributions are tax-deductible when made, subject to limitations contained in the Internal Revenue Code and regulations.

The expected return on Retirement Plan assets, a component of net periodic benefit cost shown in the tables below, is applied to the market-related value of plan assets. The market-related value of plan assets is the market value as of the measurement date adjusted for variances between actual returns and expected returns (from previous years) that have not been reflected in net periodic benefit costs. The expected return on other post-retirement benefit assets (i.e. the VEBA trusts and 401(h) accounts), which is a component of net periodic benefit cost shown in the tables below, is applied to the fair value of assets as of the measurement date.

Reconciliations of the Benefit Obligations, Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions of the Retirement Plan and other post-retirement benefits are shown in the tables below. The components of net periodic benefit cost other than service cost are presented in Other Income (Deductions) on the Consolidated Statements of Income. The date used to measure the Benefit Obligations, Plan Assets and Funded Status is September 30 for fiscal years 2025, 2024 and 2023.

| | Retirement Plan | | | Other Post-Retirement Benefits | | |
|---|---|---|---|---|---|---|
| | Year Ended September 30 | | | Year Ended September 30 | | |
| | 2025 | 2024 | 2023 | 2025 | 2024 | 2023 |
| | (Thousands) | | | | | |
| **Change in Benefit Obligation** | | | | | | |
| Benefit Obligation at Beginning of Period | $ 822,306 | $ 768,750 | $ 813,828 | $ 321,025 | $ 274,278 | $ 299,283 |
| Service Cost | 4,092 | 4,197 | 5,187 | 519 | 434 | 587 |
| Interest Cost | 36,892 | 43,558 | 42,516 | 14,501 | 15,561 | 15,648 |
| Plan Participants' Contributions | — | — | — | 3,597 | 3,401 | 3,297 |
| Retiree Drug Subsidy Receipts | — | — | — | 1,514 | 1,208 | 2,969 |
| Actuarial (Gain) Loss | (17,232) | 72,016 | (27,313) | 17,072 | 54,443 | (20,789) |
| Benefits Paid | (66,395) | (66,215) | (65,468) | (27,644) | (28,300) | (26,717) |
| **Benefit Obligation at End of Period** | $ 779,663 | $ 822,306 | $ 768,750 | $ 330,584 | $ 321,025 | $ 274,278 |
| **Change in Plan Assets** | | | | | | |
| Fair Value of Assets at Beginning of Period | $ 823,985 | $ 784,712 | $ 845,205 | $ 496,065 | $ 455,702 | $ 461,438 |
| Actual Return on Plan Assets | 20,527 | 105,488 | 4,975 | 23,494 | 64,783 | 17,449 |
| Employer Contributions | — | — | — | 594 | 479 | 235 |
| Plan Participants' Contributions | — | — | — | 3,597 | 3,401 | 3,297 |
| Benefits Paid | (66,395) | (66,215) | (65,468) | (27,644) | (28,300) | (26,717) |
| **Fair Value of Assets at End of Period** | $ 778,117 | $ 823,985 | $ 784,712 | $ 496,106 | $ 496,065 | $ 455,702 |
| **Net Amount Recognized at End of Period (Funded Status)** | $ (1,546) | $ 1,679 | $ 15,962 | $ 165,522 | $ 175,040 | $ 181,424 |
| **Amounts Recognized in the Balance Sheets Consist of:** | | | | | | |
| Non-Current Liabilities | $ (1,546) | $ — | $ — | $ (3,706) | $ (3,511) | $ (2,915) |
| Non-Current Assets | — | 1,679 | 15,962 | 169,228 | 178,551 | 184,339 |
| Net Amount Recognized at End of Period | $ (1,546) | $ 1,679 | $ 15,962 | $ 165,522 | $ 175,040 | $ 181,424 |
| **Accumulated Benefit Obligation** | $ 765,747 | $ 804,916 | $ 751,912 | N/A | N/A | N/A |
| **Weighted Average Assumptions Used to Determine Benefit Obligation at September 30** | | | | | | |
| Discount Rate | 5.28 % | 4.97 % | 5.99 % | 5.30 % | 4.98 % | 5.99 % |
| Rate of Compensation Increase | 4.60 % | 4.60 % | 4.60 % | 4.60 % | 4.60 % | 4.60 % |

| | Retirement Plan | | | Other Post-Retirement Benefits | | |
|---|---|---|---|---|---|---|
| | Year Ended September 30 | | | Year Ended September 30 | | |
| | 2025 | 2024 | 2023 | 2025 | 2024 | 2023 |
| | (Thousands) | | | | | |
| **Components of Net Periodic Benefit Cost** | | | | | | |
| Service Cost | $ 4,092 | $ 4,197 | $ 5,187 | $ 519 | $ 434 | $ 587 |
| Interest Cost | 36,892 | 43,558 | 42,516 | 14,501 | 15,561 | 15,648 |
| Expected Return on Plan Assets | (58,587) | (68,343) | (66,593) | (26,144) | (26,642) | (25,612) |
| Amortization of Prior Service Cost (Credit) | 302 | 362 | 436 | (429) | (429) | (429) |
| Recognition of Actuarial (Gain) Loss(1) | 6,481 | (1,339) | (7,680) | 37 | (2,266) | (8,755) |
| Net Amortization and Deferral for Regulatory Purposes | (1,375) | 16,231 | 21,512 | (3,857) | 8,759 | 15,157 |
| Net Periodic Benefit Income | $ (12,195) | $ (5,334) | $ (4,622) | $ (15,373) | $ (4,583) | $ (3,404) |
| **Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30** | | | | | | |
| Effective Discount Rate for Benefit Obligations | 4.97 % | 5.99 % | 5.57 % | 4.98 % | 5.99 % | 5.56 % |
| Effective Rate for Interest on Benefit Obligations | 4.68 % | 5.93 % | 5.45 % | 4.69 % | 5.93 % | 5.45 % |
| Effective Discount Rate for Service Cost | 5.14 % | 6.01 % | 5.49 % | 5.21 % | 5.99 % | 5.35 % |
| Effective Rate for Interest on Service Cost | 4.96 % | 5.98 % | 5.53 % | 5.14 % | 6.01 % | 5.47 % |
| Expected Return on Plan Assets | 6.60 % | 7.40 % | 6.90 % | 5.40 % | 6.00 % | 5.70 % |
| Rate of Compensation Increase | 4.60 % | 4.60 % | 4.60 % | 4.60 % | 4.60 % | 4.60 % |

(1) Distribution Corporation's New York jurisdiction calculates the amortization of the actuarial loss on a vintage year basis over 10 years, as mandated by the NYPSC. All the other subsidiaries of the Company utilize the corridor approach.

The Net Periodic Benefit Cost (Income) in the table above includes the effects of regulation. The Company recovers pension and other post-retirement benefit costs in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorizations. Certain of those commission authorizations established tracking mechanisms which allow the Company to record the difference between the amount of pension and other post-retirement benefit costs recoverable in rates and the amounts of such costs as determined under the existing authoritative guidance as either a regulatory asset or liability, as appropriate. Any activity under the tracking mechanisms (including the amortization of pension and other post-retirement regulatory assets and liabilities) is reflected in the Net Amortization and Deferral for Regulatory Purposes line item above.

In addition to the Retirement Plan discussed above, the Company also has non-qualified benefit plans that cover a group of management employees whose income level has exceeded certain IRS thresholds or who have been designated as participants by the Chief Executive Officer of the Company. These plans provide for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee. The net periodic benefit costs associated with these plans were $4.6 million, $9.5 million and $8.3

million in 2025, 2024 and 2023, respectively. The components of net periodic benefit cost other than service costs associated with these plans are presented in Other Income (Deductions) on the Consolidated Statements of Income. The accumulated benefit obligations for the plans were $50.9 million, $57.5 million and $58.5 million at September 30, 2025, 2024 and 2023, respectively. The projected benefit obligations for the plans were $58.4 million, $66.0 million and $69.5 million at September 30, 2025, 2024 and 2023, respectively. At September 30, 2025, $11.6 million of the projected benefit obligation is recorded in Other Accruals and Current Liabilities and the remaining $46.8 million is recorded in Other Liabilities on the Consolidated Balance Sheets. At September 30, 2024, $14.1 million of the projected benefit obligation was recorded in Other Accruals and Current Liabilities and the remaining $51.9 million was recorded in Other Liabilities on the Consolidated Balance Sheets. At September 30, 2023, $13.1 million of the projected benefit obligation was recorded in Other Accruals and Current Liabilities and the remaining $56.4 million was recorded in Other Liabilities on the Consolidated Balance Sheets. The weighted average discount rates for these plans were 4.86%, 4.71% and 5.91% as of September 30, 2025, 2024 and 2023, respectively and the weighted average rate of compensation increase for these plans was 8.00% as of September 30, 2025, 2024 and 2023.

The cumulative amounts recognized in accumulated other comprehensive income (loss), regulatory assets, and regulatory liabilities through fiscal 2025, as well as the changes in such amounts during 2025, are presented in the table below:

| | Retirement Plan | Other Post-Retirement Benefits | Non-Qualified Benefit Plans |
|---|---|---|---|
| | | (Thousands) | |
| **Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities(1)** | | | |
| Net Actuarial Loss | $ (178,675) | $ (19,813) | $ (13,353) |
| Prior Service (Cost) Credit | (1,372) | 257 | — |
| Net Amount Recognized | $ (180,047) | $ (19,556) | $ (13,353) |
| **Changes to Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities Recognized During Fiscal 2025(1)** | | | |
| Increase in Actuarial Loss, excluding amortization(2) | $ (20,828) | $ (19,722) | $ (1,061) |
| Change due to Amortization of Actuarial Loss | 6,481 | 37 | 1,101 |
| Prior Service (Cost) Credit | 302 | (429) | — |
| Net Change | $ (14,045) | $ (20,114) | $ 40 |

(1) Amounts presented are shown before recognizing deferred taxes.
(2) Amounts presented include the impact of actuarial gains/losses related to return on assets, as well as the Actuarial Loss amounts presented in the Change in Benefit Obligation.

In order to adjust the funded status of its pension (tax-qualified and non-qualified) and other post-retirement benefit plans at September 30, 2025, the Company recorded a $23.8 million increase to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments and a $10.3 million (pre-tax) decrease to Accumulated Other Comprehensive Income.

The effect of the discount rate change for the Retirement Plan in 2025 was to decrease the projected benefit obligation of the Retirement Plan by $21.4 million. Other actuarial experience increased the projected benefit obligation for the Retirement Plan in 2025 by $4.2 million. The effect of the discount rate change for the Retirement Plan in 2024 was to increase the projected benefit obligation of the Retirement Plan by $69.6

million. The effect of the discount rate change for the Retirement Plan in 2023 was to decrease the projected benefit obligation of the Retirement Plan by $28.4 million.

The Company did not make any cash contributions to the Retirement Plan during the year ended September 30, 2025. The Company does not expect to make any contributions to the Retirement Plan in 2026.

The following Retirement Plan benefit payments, which reflect expected future service, are expected to be paid by the Retirement Plan during the next five years and the five years thereafter: $67.6 million in 2026; $66.9 million in 2027; $66.1 million in 2028; $65.1 million in 2029; $64.0 million in 2030; and $297.8 million in the five years thereafter.

The effect of the discount rate change in 2025 was to decrease the other post-retirement benefit obligation by $9.9 million. The health care cost trend rates were updated, which increased the other post-retirement benefit obligation in 2025 by $18.2 million. Other actuarial experience increased the other post-retirement benefit obligation in 2025 by $8.8 million, the majority of which was attributable to a revision in assumed per-capita claims cost, premiums, retiree contributions and retiree drug subsidy assumptions based on actual experience.

The effect of the discount rate change in 2024 was to increase the other post-retirement benefit obligation by $28.1 million. The healthcare cost trend rates were updated, which increased the other post-retirement benefit obligation in 2024 by $25.2 million. Other actuarial experience increased the other post-retirement benefit obligation in 2024 by $1.2 million, the majority of which was attributable to a revision in assumed per-capita claims cost, premiums, retiree contributions and retiree drug subsidy assumptions based on actual experience.

The effect of the discount rate change in 2023 was to decrease the other post-retirement benefit obligation by $10.7 million. The mortality improvement projection scale was updated, which decreased the other post-retirement benefit obligation in 2023 by $0.4 million. The health care cost trend rates were updated, which increased the other post-retirement benefit obligation in 2023 by $3.2 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2023 by $12.9 million, the majority of which was attributable to a revision in assumed per-capita claims cost, premiums, retiree contributions and retiree drug subsidy assumptions based on actual experience.

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 provides for a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D.

The estimated gross other post-retirement benefit payments and gross amount of Medicare Part D prescription drug subsidy receipts are as follows (dollars in thousands):

| | Benefit Payments | Subsidy Receipts |
|---|---|---|
| 2026 | $ 26,899 | $ (1,560) |
| 2027 | $ 27,556 | $ (1,574) |
| 2028 | $ 28,060 | $ (1,577) |
| 2029 | $ 28,344 | $ (1,577) |
| 2030 | $ 28,406 | $ (1,568) |
| 2031 through 2035 | $ 135,297 | $ (7,536) |

Assumed health care cost trend rates as of September 30 were:

| | 2025 | 2024 | 2023 |
|---|---|---|---|
| Rate of Medical Cost Increase for Pre Age 65 Participants | 7.25 % (1) | 6.25 % (2) | 6.25 % (3) |
| Rate of Medical Cost Increase for Post Age 65 Participants | 5.75 % (1) | 5.75 % (2) | 5.00 % (3) |
| Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits | 11.75 % (1) | 10.25 % (2) | 6.85 % (3) |
| Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement | 5.75 % (1) | 5.75 % (2) | 5.00 % (3) |
| Annual Rate of Increase in the Per Capita Medicare Part D Subsidy | 4.00 % (1) | 4.00 % (2) | 6.60 % (3) |

(1) It was assumed that this rate would gradually decline to 4% by 2050.
(2) It was assumed that this rate would gradually decline to 4% by 2049.
(3) It was assumed that this rate would gradually decline to 4% by 2048.

The Company made direct payments of $0.6 million to retirees not covered by the VEBA trusts and 401(h) accounts during the year ended September 30, 2025. The Company did not make any cash contributions to its VEBA trusts during the year ended September 30, 2025, and does not expect to make any contributions to its VEBA trusts in 2026.

***Investment Valuation***

The Retirement Plan assets and other post-retirement benefit assets are valued under the current fair value framework. See Note I — Fair Value Measurements for further discussion regarding the definition and levels of fair value hierarchy established by the authoritative guidance.

The inputs or methodologies used for valuing securities are not necessarily an indication of the risk associated with investing in those securities. Below is a listing of the major categories of plan assets held as of September 30, 2025 and 2024, as well as the associated level within the fair value hierarchy in which the fair value measurements in their entirety fall, based on the lowest level input that is significant to the fair value measurement in its entirety (dollars in thousands):

| | At September 30, 2025 | | | | |
|---|---|---|---|---|---|
| | Total Fair Value | Level 1 | Level 2 | Level 3 | Measured at NAV(6) |
| **Retirement Plan Investments** | | | | | |
| Domestic Equities(1) | $ 116 | $ 116 | $ — | $ — | $ — |
| Global Equities(2) | 79,470 | — | — | — | 79,470 |
| Domestic Fixed Income(3)(7) | 645,955 | — | 596,905 | — | 49,050 |
| International Fixed Income(4) | 9,609 | — | 9,609 | — | — |
| Real Estate (5) | 102,373 | — | — | — | 102,373 |
| Cash Held in Collective Trust Funds | 34,077 | — | — | — | 34,077 |
| Total Retirement Plan Investments | 871,600 | 116 | 606,514 | — | 264,970 |
| 401(h) Investments | (86,093) | (12) | (60,379) | — | (25,702) |
| Total Retirement Plan Investments (excluding 401(h) Investments) | $ 785,507 | $ 104 | $ 546,135 | $ — | $ 239,268 |
| Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash | (7,390) | | | | |
| **Total Retirement Plan Assets** | $ 778,117 | | | | |

| | At September 30, 2024 | | | | |
|---|---|---|---|---|---|
| | Total Fair Value | Level 1 | Level 2 | Level 3 | Measured at NAV(6) |
| **Retirement Plan Investments** | | | | | |
| Domestic Equities(1) | $ 37,984 | $ 37,984 | $ — | $ — | $ — |
| Global Equities(2) | 38,234 | — | — | — | 38,234 |
| Domestic Fixed Income(3)(7) | 681,755 | — | 633,600 | — | 48,155 |
| International Fixed Income(4) | 8,587 | — | 8,587 | — | — |
| Real Estate (5) | 109,383 | — | — | — | 109,383 |
| Cash Held in Collective Trust Funds | 41,709 | — | — | — | 41,709 |
| Total Retirement Plan Investments | 917,652 | 37,984 | 642,187 | — | 237,481 |
| 401(h) Investments | (83,682) | (3,500) | (59,166) | — | (21,016) |
| Total Retirement Plan Investments (excluding 401(h) Investments) | $ 833,970 | $ 34,484 | $ 583,021 | $ — | $ 216,465 |
| Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash | (9,985) | | | | |
| **Total Retirement Plan Assets** | $ 823,985 | | | | |

(1) Domestic Equities include mostly collective trust funds, common stock, and exchange traded funds.
(2) Global Equities are comprised of collective trust funds.
(3) Domestic Fixed Income securities include mostly collective trust funds, corporate/government bonds and mortgages, and exchange traded funds.
(4) International Fixed Income securities are comprised mostly of corporate/government bonds.
(5) Real Estate consists of investments held in a collective trust fund and a partnership.
(6) Reflects the authoritative guidance related to investments measured at net asset value (NAV).
(7) Domestic Fixed Income securities include $6.2 million and $8.5 million of derivative instruments used as part of the Company's overall liability-driven investment strategy as a way to assist in matching the duration of the assets of the Retirement Plan investments with its liability to plan participants as of September 30, 2025 and September 30, 2024, respectively.

| | At September 30, 2025 | | | | |
|---|---|---|---|---|---|
| | Total Fair Value | Level 1 | Level 2 | Level 3 | Measured at NAV(1) |
| **Other Post-Retirement Benefit Assets held in VEBA Trusts** | | | | | |
| Collective Trust Funds — Global Equities | $ 232,395 | $ — | $ — | $ — | $ 232,395 |
| Exchange Traded Funds — Fixed Income | 165,601 | 165,601 | — | — | — |
| Cash Held in Collective Trust Funds | 12,302 | — | — | — | 12,302 |
| Total VEBA Trust Investments | 410,298 | 165,601 | — | — | 244,697 |
| 401(h) Investments | 86,093 | 12 | 60,379 | — | 25,702 |
| Total Investments (including 401(h) Investments) | $ 496,391 | $ 165,613 | $ 60,379 | $ — | $ 270,399 |
| Miscellaneous Accruals (including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative) | (285) | | | | |
| **Total Other Post-Retirement Benefit Assets** | $ 496,106 | | | | |

| | At September 30, 2024 | | | | |
|---|---|---|---|---|---|
| | Total Fair Value | Level 1 | Level 2 | Level 3 | Measured at NAV(1) |
| **Other Post-Retirement Benefit Assets held in VEBA Trusts** | | | | | |
| Collective Trust Funds — Global Equities | $ 82,814 | $ — | $ — | $ — | $ 82,814 |
| Exchange Traded Funds — Fixed Income | 314,052 | 314,052 | — | — | — |
| Cash Held in Collective Trust Funds | 14,274 | — | — | — | 14,274 |
| Total VEBA Trust Investments | 411,140 | 314,052 | — | — | 97,088 |
| 401(h) Investments | 83,682 | 3,500 | 59,166 | — | 21,016 |
| Total Investments (including 401(h) Investments) | $ 494,822 | $ 317,552 | $ 59,166 | $ — | $118,104 |
| Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative) | 1,243 | | | | |
| **Total Other Post-Retirement Benefit Assets** | $ 496,065 | | | | |

(1) Reflects the authoritative guidance related to investments measured at net asset value (NAV).

The fair values disclosed in the above tables may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

For the years ended September 30, 2025 and September 30, 2024, there were no transfers from Level 1 to Level 2. For the years ended September 30, 2025 and September 30, 2024, there were no assets or liabilities measured at fair value and classified as Level 3.

The Company's assumption regarding the expected long-term rate of return on plan assets is 7.10% (Retirement Plan) and 6.10% (other post-retirement benefits), effective for fiscal 2026. The return assumption reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes projected capital market conditions and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets.

The long-term investment objective of the Retirement Plan trust, the VEBA trusts and the 401(h) accounts is to achieve the target total return in accordance with the Company's risk tolerance. Assets are diversified utilizing a mix of equities, fixed income and other securities (including real estate). Risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition. The assets of the Retirement Plan trust, VEBA trusts and the 401(h) accounts have no significant concentrations of risk in any one country (other than the United States), industry or entity. The actual asset allocations as of September 30, 2025 are noted in the table above, and such allocations are subject to change, but the majority of the assets will remain hedging fixed income assets in conjunction with the Company's liability driven investment strategy. Given the level of the VEBA trust and 401(h) assets in relation to the Other Post-Retirement Benefits, the majority of those assets are and will remain in fixed income securities.

Investment managers are retained to manage separate pools of assets. Comparative market and peer group performance of individual managers and the total fund are monitored on a regular basis, and reviewed by the Company's Retirement Committee on at least a quarterly basis.

The Company determines the service and interest cost components of net periodic benefit cost using the spot rate approach, which uses individual spot rates along the yield curve that correspond to the timing of each benefit payment in order to determine the discount rate. The individual spot rates along the yield curve are determined by an above mean methodology in that the coupon interest rates that are in the lower 50th percentile are excluded based on the assumption that the Company would not utilize more expensive (i.e. lower yield) instruments to settle its liabilities.

**Note L — Commitments and Contingencies**

***Environmental Matters***

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory requirements.

It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. At September 30, 2025, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites will be approximately $3.2 million. The Company's liability for such clean-up costs has been recorded in Other Liabilities on the Consolidated Balance Sheet at September 30, 2025. The Company has a regulatory liability of $1.8 million related to environmental clean-up costs at September 30, 2025 and is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental laws and regulations, new information or other factors could have an adverse financial impact on the Company.

***Other***

The Company, in its Utility segment and Integrated Upstream and Gathering segment, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $236.6 million in 2026, $75.8 million in 2027, $113.8 million in 2028, $123.2 million in 2029, $135.2 million in 2030 and $900.1 million thereafter. Gas prices within the gas purchase contracts are variable based on NYMEX prices adjusted for basis. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment's service territory, such costs will be recoverable from customers.

The Company, in its Pipeline and Storage segment, Integrated Upstream and Gathering segment and Utility segment, has entered into several contractual commitments associated with various pipeline, compressor and gathering system modernization and expansion projects. As of September 30, 2025, the future contractual commitments related to the system modernization and expansion projects are $58.1 million in 2026, $9.2 million in 2027, $5.6 million in 2028, $4.4 million in 2029, $4.5 million in 2030 and $4.6 million thereafter.

The Company, in its Integrated Upstream and Gathering segment, has entered into contractual obligations to support its development activities and operations in Pennsylvania, including hydraulic fracturing and other well completion services, well tending services, well workover activities, tubing and casing purchases, production equipment purchases, water hauling services and contracts for drilling rig services. The future contractual commitments are $180.8 million in 2026 and $25.9 million in 2027. There are no contractual commitments extending beyond 2027.

In addition to the regulatory matters discussed in Note F — Regulatory Matters, the Company is involved in other regulatory and litigation matters arising in the normal course of business. These other regulatory and litigation matters may include, for example, tax, regulatory or other governmental audits, inspections, investigations, negligence claims and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these other matters arising in the normal course of business could have a material effect on earnings and cash flows in the period in which they are resolved, an estimate of the possible loss or range of loss, if any, cannot be made at this time.

**Note M — Business Segment Information**

In the Company's 2024 Form 10-K and its Form 10-Q's for the first three quarters of 2025, the Company reported financial results for four segments: Exploration and Production, Pipeline and Storage, Gathering, and Utility. The division of the Company's operations into reportable segments is based upon a combination of factors including differences in products and services as well as regulatory environment. During the quarter ended September 30, 2025, the president and chief executive officer, who is the chief operating decision maker (CODM), determined that the Exploration and Production segment and Gathering segment should be treated as one operating segment. The CODM made this decision to provide more clarity for management and investors as to the interdependence of both Seneca and Midstream Company in bringing Appalachian natural gas to market. As a result of this decision, during the quarter ended September 30, 2025, the CODM began reviewing financial information of these three segments: Integrated Upstream and Gathering, Pipeline and Storage, and Utility. As a result, the Company is now reporting financial results for these three segments. Prior year segment information shown below has been recast to reflect this change in presentation.

The Integrated Upstream and Gathering segment is composed of the operations of Seneca and Midstream Company. Seneca is engaged in the exploration for and development of natural gas reserves in the Appalachian region of the United States. Midstream Company builds, owns and operates natural gas processing and pipeline gathering facilities in the Appalachian region, primarily providing gathering services to Seneca.

The Pipeline and Storage segment operations are regulated by the FERC for both Supply Corporation and Empire. Supply Corporation transports and stores natural gas for utilities (including Distribution Corporation), natural gas marketers, exploration and production companies (including Seneca) and pipeline companies in the northeastern United States markets. Empire transports and stores natural gas for major industrial companies, utilities (including Distribution Corporation) and power producers in New York State. Empire also transports natural gas for natural gas marketers and exploration and production companies (including Seneca) from natural gas producing areas in Pennsylvania to markets in New York and to interstate pipeline delivery points with access to additional markets in the northeastern United States and Canada.

The Utility segment operations are regulated by the NYPSC and the PaPUC and are carried out by Distribution Corporation. Distribution Corporation sells natural gas to retail customers and provides natural gas transportation services in western New York and northwestern Pennsylvania.

The data presented in the tables below reflects financial information for the segments and reconciliations to consolidated amounts. The CODM uses net income (loss) by segment, or income (loss) by segment before discontinued operations when applicable, to assess performance and allocate capital and other resources, considering actual-to-budget and actual-to-prior year variances on a monthly basis when making such decisions. The accounting policies of the segments are the same as those described in Note A — Summary of Significant Accounting Policies. Sales of products or services between segments are billed at regulated rates or at market rates, as applicable.

| | Year Ended September 30, 2025 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Integrated Upstream and Gathering | Pipeline and Storage | Utility | Total Reportable Segments | All Other | Corporate and Intersegment Eliminations | Total Consolidated |
| | (Thousands) | | | | | | |
| Revenue from External Customers(1)(2) | $ 1,184,136 | $ 276,131 | $ 817,274 | $ 2,277,541 | $ — | $ — | $ 2,277,541 |
| Intersegment Revenues | — | 151,470 | 355 | 151,825 | — | (151,825) | — |
| Total Revenues | 1,184,136 | 427,601 | 817,629 | 2,429,366 | — | (151,825) | 2,277,541 |
| Operation and Maintenance Expense(4): | | | | | | | |
| Upstream General and Administrative Expense | 75,280 | — | — | 75,280 | — | (223) | 75,057 |
| Lease Operating Expense | 50,665 | — | — | 50,665 | — | (5,817) | 44,848 |
| Gathering Operation and Maintenance Expense | 48,635 | — | — | 48,635 | — | (246) | 48,389 |
| All Other Operation and Maintenance Expense | 16,049 | 122,379 | 234,455 | 372,883 | — | 16,688 | 389,571 |
| Purchased Gas Expense(4) | — | — | 358,454 | 358,454 | — | (145,013) | 213,441 |
| Depreciation, Depletion and Amortization Expense(4) | 311,817 | 74,480 | 69,701 | 455,998 | — | 596 | 456,594 |
| Impairment of Assets (Significant Non-Cash Item)(4) | 141,802 | — | — | 141,802 | — | — | 141,802 |
| Interest Expense(4) | 76,633 | 45,509 | 42,969 | 165,111 | 536 | (9,813) | 155,834 |
| Interest Income | (1,445) | (6,085) | (2,284) | (9,814) | (11) | 3,809 | (6,016) |
| Income Tax Expense (Benefit)(4) | 121,095 | 39,748 | 15,653 | 176,496 | (245) | (702) | 175,549 |
| Other Expense (Income) Items(5) | 18,907 | 30,613 | 15,432 | 64,952 | 534 | (1,518) | 63,968 |
| Segment Profit: Net Income (Loss) | $ 324,698 | $ 120,957 | $ 83,249 | $ 528,904 | $ (814) | $ (9,586) | $ 518,504 |
| Expenditures for Additions to Long-Lived Assets | $ 605,433 | $ 121,798 | $ 189,961 | $ 917,192 | $ — | $ 909 | $ 918,101 |
| | At September 30, 2025 | | | | | | |
| | (Thousands) | | | | | | |
| Segment Assets | $ 3,701,646 | $2,412,747 | $2,534,289 | $ 8,648,682 | $ 8,704 | $ 61,718 | $ 8,719,104 |

| | Year Ended September 30, 2024 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Integrated Upstream and Gathering | Pipeline and Storage | Utility | Total Reportable Segments | All Other | Corporate and Intersegment Elimination | Total Consolidated |
| | (Thousands) | | | | | | |
| Revenue from External Customers(1) | $ 976,615 | $ 271,388 | $ 696,807 | $ 1,944,810 | $ — | $ — | $ 1,944,810 |
| Intersegment Revenues | — | 141,005 | 555 | 141,560 | — | (141,560) | — |
| Total Revenues | 976,615 | 412,393 | 697,362 | 2,086,370 | — | (141,560) | 1,944,810 |
| Operation and Maintenance Expense(4): | | | | | | | |
| Upstream General and Administrative Expense | 71,148 | — | — | 71,148 | — | (221) | 70,927 |
| Lease Operating Expense | 52,053 | — | — | 52,053 | — | (5,723) | 46,330 |
| Gathering Operation and Maintenance Expense | 36,140 | — | — | 36,140 | — | (237) | 35,903 |
| All Other Operation and Maintenance Expense | 15,529 | 116,335 | 222,142 | 354,006 | 17 | 12,835 | 366,858 |
| Purchased Gas Expense(4) | — | — | 283,215 | 283,215 | — | (133,153) | 150,062 |
| Depreciation, Depletion and Amortization Expense(4) | 316,762 | 74,530 | 65,261 | 456,553 | — | 473 | 457,026 |
| Impairment of Assets (Significant Non-Cash Item)(4) | 473,054 | 46,075 | — | 519,129 | — | — | 519,129 |
| Interest Expense(4) | 74,005 | 47,428 | 34,727 | 156,160 | 374 | (17,839) | 138,695 |
| Interest Income | (3,062) | (8,632) | (5,736) | (17,430) | — | 8,703 | (8,727) |
| Income Tax Expense (Benefit)(4) | (20,213) | 26,045 | 3,951 | 9,783 | (186) | 145 | 9,742 |
| Other Expense (Income) Items(5) | 18,240 | 30,942 | 36,713 | 85,895 | 412 | (4,955) | 81,352 |
| Segment Profit: Net Income (Loss) | $ (57,041) | $ 79,670 | $ 57,089 | $ 79,718 | $ (617) | $ (1,588) | $ 77,513 |
| Expenditures for Additions to Long-Lived Assets | $ 645,600 | $ 110,830 | $ 184,615 | $ 941,045 | $ — | $ 970 | $ 942,015 |
| | At September 30, 2024 | | | | | | |
| | (Thousands) | | | | | | |
| Segment Assets | $ 3,614,318 | $2,446,243 | $2,398,709 | $ 8,459,270 | $ 6,227 | $ (145,727) | $ 8,319,770 |

| | Integrated Upstream and Gathering | Pipeline and Storage | Utility | Total Reportable Segments | All Other | Corporate and Intersegment Eliminations | Total Consolidated |
|---|---|---|---|---|---|---|---|
| | Year Ended September 30, 2023 | | | | | | |
| | (Thousands) | | | | | | |
| Revenue from External Customers(1)(3) | $ 972,346 | $ 259,646 | $ 941,779 | $ 2,173,771 | $ — | $ — | $ 2,173,771 |
| Intersegment Revenues | — | 119,545 | 581 | 120,126 | — | (120,126) | — |
| Total Revenues | 972,346 | 379,191 | 942,360 | 2,293,897 | — | (120,126) | 2,173,771 |
| Operation and Maintenance Expense(4): | | | | | | | |
| Upstream General and Administrative Expense | 66,074 | — | — | 66,074 | — | (241) | 65,833 |
| Lease Operating Expense | 47,854 | — | — | 47,854 | — | (6,902) | 40,952 |
| Gathering Operation and Maintenance Expense | 33,650 | — | — | 33,650 | — | (255) | 33,395 |
| All Other Operation and Maintenance Expense | 9,327 | 106,654 | 208,539 | 324,520 | 21 | 14,035 | 338,576 |
| Purchased Gas Expense(4) | — | — | 548,195 | 548,195 | — | (110,600) | 437,595 |
| Depreciation, Depletion and Amortization Expense(4) | 276,867 | 70,827 | 61,450 | 409,144 | — | 429 | 409,573 |
| Interest Expense(4) | 69,306 | 43,499 | 34,233 | 147,038 | 157 | (15,309) | 131,886 |
| Interest Income | (3,793) | (7,052) | (6,296) | (17,141) | — | 5,662 | (11,479) |
| Income Tax Expense (Benefit)(4) | 123,924 | 34,489 | 7,267 | 165,680 | (164) | (983) | 164,533 |
| Other Expense (Income) Items(5) | 17,138 | 30,273 | 40,577 | 87,988 | 517 | (2,464) | 86,041 |
| Segment Profit: Net Income (Loss) | $ 331,999 | $ 100,501 | $ 48,395 | $ 480,895 | $ (531) | $ (3,498) | $ 476,866 |
| Expenditures for Additions to Long-Lived Assets | $ 841,020 | $ 141,877 | $ 139,922 | $ 1,122,819 | $ — | $ 754 | $ 1,123,573 |
| | At September 30, 2023 | | | | | | |
| | (Thousands) | | | | | | |
| Segment Assets | $ 3,710,155 | $2,427,214 | $2,247,743 | $ 8,385,112 | $ 4,795 | $ (109,647) | $ 8,280,260 |

(1) All Revenue from External Customers originated in the United States.

(2) Revenue from one customer of the Company's Integrated Upstream and Gathering segment, exclusive of hedging losses transacted with separate parties, represented approximately $258 million of the Company's consolidated revenue for the year ended September 30, 2025. This one customer was also a customer of the Company's Pipeline and Storage segment, accounting for an additional $16 million of the Company's consolidated revenue for the year ended September 30, 2025.

(3) Revenue from one customer of the Company's Integrated Upstream and Gathering segment, exclusive of hedging losses transacted with separate parties, represented approximately $208 million of the Company's consolidated revenue for the year ended September 30, 2023. This one customer was also a customer of the Company's Pipeline and Storage segment, accounting for an additional $14 million of the Company's consolidated revenue for the year ended September 30, 2023.

(4) The Company considers this line to be a significant expense.

(5) Consists of Property, Franchise and Other Taxes, Non-Service Pension and Post-Retirement Benefits Costs (Credits), Other (Income) Deductions, and Purchased Gas Expense for the Pipeline and Storage segment.

**Geographic Information**

| | At September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | (Thousands) | | |
| **Long-Lived Assets:** | | | |
| United States | $ 8,308,377 | $ 7,963,851 | $ 7,865,832 |

## Note N — Supplementary Information for Exploration and Production Activities (unaudited, except for Capitalized Costs Relating to Exploration and Production Activities)

The Company follows authoritative guidance related to exploration and production activities that aligns the reserve estimation and disclosure requirements with the requirements of the SEC Modernization of Oil and Gas Reporting rule, which the Company also follows. The SEC rules require companies to value their year-end reserves using an unweighted arithmetic average of first day of the month commodity price for each month within the twelve month period prior to the end of the reporting period.

The following supplementary information is presented in accordance with the authoritative guidance regarding disclosures about exploration and production activities and related SEC authoritative guidance.

***Capitalized Costs Relating to Exploration and Production Activities***

| | At September 30 | |
|---|---|---|
| | 2025 | 2024 |
| | (Thousands) | |
| Proved Properties(1) | $ 7,719,339 | $ 7,079,903 |
| Unproved Properties | 112,432 | 200,986 |
| | 7,831,771 | 7,280,889 |
| Less — Accumulated Depreciation, Depletion and Amortization | 5,374,360 | 5,004,299 |
| | $ 2,457,411 | $ 2,276,590 |

(1) Includes asset retirement costs of $233.9 million and $175.2 million at September 30, 2025 and 2024, respectively.

Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized. Although the timing of the ultimate evaluation or disposition of the unproved properties cannot be determined, the Company expects the majority of its acquisition costs associated with unproved properties to be transferred into the amortization base by 2030. It expects the majority of its development and exploration costs associated with unproved properties to be transferred into the amortization base by 2027. Following is a summary of costs excluded from amortization at September 30, 2025:

| | Total as of September 30, 2025 | Year Costs Incurred | | | |
|---|---|---|---|---|---|
| | | 2025 | 2024 | 2023 | Prior |
| | (Thousands) | | | | |
| Acquisition Costs | $ 103,508 | $ 1,277 | $ 8,136 | $ 86,038 | $ 8,057 |
| Development Costs | 8,464 | 6,267 | 1,077 | 922 | 198 |
| Exploration Costs | 460 | 460 | — | — | — |
| Capitalized Interest | — | — | — | — | — |
| | $ 112,432 | $ 8,004 | $ 9,213 | $ 86,960 | $ 8,255 |

***Costs Incurred in Property Acquisition, Exploration and Development Activities***

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | | (Thousands) | |
| **United States** | | | |
| Property Acquisition Costs: | | | |
| Proved | $ 13,680 | $ 17,069 | $ 33,190 |
| Unproved | 18,826 | 19,526 | 129,061 |
| Exploration Costs(1) | 21,562 | 53,519 | 10,055 |
| Development Costs(2) | 443,311 | 429,151 | 553,469 |
| Asset Retirement Costs | 58,680 | 46,017 | 8,363 |
| | $ 556,059 | $ 565,282 | $ 734,138 |

(1) Amounts for 2025, 2024 and 2023 include capitalized interest of zero, $0.1 million and zero respectively.
(2) Amounts for 2025, 2024 and 2023 include capitalized interest of zero, $0.7 million and $0.1 million, respectively.

For the years ended September 30, 2025, 2024 and 2023, the Company spent $246.3 million, $305.6 million and $342.0 million, respectively, developing proved undeveloped reserves.

***Results of Operations for Producing Activities***

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| **United States** | (Thousands, except per Mcfe amounts) | | |
| Operating Revenues: | | | |
| Gas (includes transfers to operations of $1,379, $1,557 and $1,957, respectively)(1) | $ 1,104,283 | $ 738,778 | $ 1,036,499 |
| Oil, Condensate and Other Liquids | 1,837 | 2,298 | 2,261 |
| Total Operating Revenues(2) | 1,106,120 | 741,076 | 1,038,760 |
| Production/Lifting Costs | 284,771 | 270,927 | 253,555 |
| Franchise/Ad Valorem Taxes | 18,267 | 13,468 | 17,532 |
| Accretion Expense | 7,721 | 5,992 | 5,673 |
| Depreciation, Depletion and Amortization ($0.61, $0.69 and $0.63 per Mcfe of production, respectively) | 261,712 | 270,648 | 235,694 |
| Impairment of Exploration and Production Properties | 108,348 | 463,692 | — |
| Income Tax Expense (Benefit) | 114,502 | (76,983) | 145,574 |
| Results of Operations for Producing Activities (excluding corporate overheads and interest charges) | $ 310,799 | $ (206,668) | $ 380,732 |

(1) There were no revenues from sales to affiliates for all years presented.
(2) Exclusive of hedging gains and losses. See further discussion in Note J — Financial Instruments.

***Reserve Quantity Information***

The Company's proved reserve estimates are prepared by the Company's petroleum engineers who meet the qualifications of Reserve Estimator per the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information" promulgated by the Society of Petroleum Engineers as of June 25, 2019. The Company maintains comprehensive internal reserve guidelines and a continuing education program designed to keep its staff up to date with current SEC regulations and guidance.

The Company's Vice President of Reservoir Engineering is the primary technical person responsible for overseeing the Company's reserve estimation process and engaging and overseeing the third party reserve audit. His qualifications include a Bachelor of Science Degree in Petroleum Engineering and over 15 years of Petroleum Engineering experience with independent oil and gas companies, licensure as a Professional Engineer and is a member of the Society of Petroleum Engineers.

The Company maintains a system of internal controls over the reserve estimation process. Management reviews the price, heat content, lease operating cost and future investment assumptions used in the economic model to determine the reserves. The Vice President of Reservoir Engineering reviews and approves all new reserve assignments and significant reserve revisions. Access to the reserve database is restricted. Significant changes to the reserve report are reviewed by senior management on a quarterly basis. Periodically, the Company's internal audit department assesses the design of these controls and performs testing to determine the effectiveness of such controls.

All of the Company's reserve estimates are audited annually by Netherland, Sewell & Associates, Inc. (NSAI). Since 1961, NSAI has evaluated gas and oil properties and independently certified petroleum reserve quantities in the United States and internationally under the Texas Board of Professional Engineers Registration No. F-002699. The primary technical persons (employed by NSAI) that are responsible for leading the audit include a professional engineer registered with the State of Texas (consulting at NSAI since 2019 and with over 6 years of prior industry experience in petroleum engineering) and a professional geoscientist registered in the State of Texas (consulting at NSAI since 2008 and with over 11 years of prior industry experience in petroleum geosciences). NSAI was satisfied with the methods and procedures used by the Company to prepare its reserve estimates at September 30, 2025 and did not identify any problems which would cause it to take exception to those estimates.

The reliable technologies that were utilized in estimating the reserves include wire line open-hole log data, performance data, log cross sections, core data, 2D and 3D seismic data and statistical analysis. The statistical method utilized production performance from both the Company's and competitors' wells. Geophysical data includes data from the Company's wells, third-party wells, published documents and state data-sites, and 2D and 3D seismic data. These were used to confirm continuity of the formation.

| | U.S. Appalachian Region | | |
|---|---|---|---|
| | Gas MMcf | | Oil Mbbl |
| **Proved Developed and Undeveloped Reserves:** | | | |
| September 30, 2022 | 4,170,662 | | 250 |
| Extensions and Discoveries | 670,438 | (1) | — |
| Revisions of Previous Estimates | 32,379 | | (4) |
| Production | (372,271) | (2) | (30) |
| Purchases of Minerals in Place | 33,876 | | — |
| September 30, 2023 | 4,535,084 | | 216 |
| Extensions and Discoveries | 601,679 | (1) | — |
| Revisions of Previous Estimates | 7,046 | | 8 |
| Production | (392,047) | (2) | (31) |
| September 30, 2024 | 4,751,762 | | 193 |
| Extensions and Discoveries | 632,536 | (1) | — |
| Revisions of Previous Estimates | 22,469 | | 15 |
| Production | (426,357) | (2) | (28) |
| September 30, 2025 | 4,980,410 | | 180 |
| **Proved Developed Reserves:** | | | |
| September 30, 2022 | 3,312,568 | | 250 |
| September 30, 2023 | 3,550,034 | | 216 |
| September 30, 2024 | 3,484,852 | | 193 |
| September 30, 2025 | 3,664,381 | | 180 |
| **Proved Undeveloped Reserves:** | | | |
| September 30, 2022 | 858,094 | | — |
| September 30, 2023 | 985,050 | | — |
| September 30, 2024 | 1,266,910 | | — |
| September 30, 2025 | 1,316,029 | | — |

(1) Extensions and discoveries include 163 Bcf (during 2023), 230 Bcf (during 2024) and 0 Bcf (during 2025), of Marcellus Shale gas (which exceed 15% of total reserves) in the Appalachian region. Extensions and discoveries include 507 Bcf (during 2023), 372 Bcf (during 2024) and 633 Bcf (during 2025), of Utica Shale gas (which exceed 15% of total reserves) in the Appalachian region.

(2) Production includes 190,290 MMcf (during 2023), 235,955 MMcf (during 2024) and 209,379 MMcf (during 2025), from Marcellus Shale fields. Production includes 180,750 MMcf (during 2023), 154,701 MMcf (during 2024) and 215,681 MMcf (during 2025), from Utica Shale fields.

The Company's proved undeveloped (PUD) reserves increased from 1,267 Bcfe at September 30, 2024 to 1,316 Bcfe at September 30, 2025. PUD reserves in the Utica Shale increased from 925 Bcfe at September 30, 2024 to 1,119 Bcfe at September 30, 2025. PUD reserves in the Marcellus Shale decreased from 342 Bcfe at September 30, 2024 to 197 Bcfe at September 30, 2025. The Company's total PUD reserves were 26.4% of total proved reserves at September 30, 2025, down from 26.7% of total proved reserves at September 30, 2024.

The Company's PUD reserves increased from 985 Bcfe at September 30, 2023 to 1,267 Bcfe at September 30, 2024. PUD reserves in the Utica Shale increased from 873 Bcfe at September 30, 2023 to 925 Bcfe at September 30, 2024. PUD reserves in the Marcellus Shale increased from 112 Bcfe at September 30, 2023 to 342 Bcfe at September 30, 2024. The Company's total PUD reserves were 26.7% of total proved reserves at September 30, 2024, up from 21.7% of total proved reserves at September 30, 2023.

The increase in PUD reserves in 2025 of 49 Bcfe is a result of 473 Bcfe in new PUD reserve additions. These additions were partially offset by 399 Bcfe in PUD conversions to developed reserves (145 Bcfe from the Marcellus Shale and 254 Bcfe from the Utica Shale), 18 Bcfe in PUD reserves removed for one PUD location due to schedule and pad layout changes and 7 Bcfe for adjustments to remaining PUD reserves.

The increase in PUD reserves in 2024 of 282 Bcfe is a result of 602 Bcfe in new PUD reserve additions and 76 Bcfe in upward revisions to remaining PUD reserves. These upward revisions were partially offset by 291 Bcfe in PUD conversions to developed reserves (all Utica Shale), and 105 Bcfe in PUD reserves removed for nine PUD locations due to schedule and pad layout changes.

The Company invested $246 million during the year ended September 30, 2025 to convert 399 Bcfe (415 Bcfe after revisions) of predominantly Marcellus and Utica Shale PUD reserves to developed reserves. This represents 31% of the net PUD reserves recorded at September 30, 2024. The Company developed 27 of 73 PUD locations in 2025.

The Company invested $306 million during the year ended September 30, 2024 to convert 291 Bcfe (374 Bcfe after revisions) of predominantly Marcellus and Utica Shale PUD reserves to developed reserves. This represents 30% of the net PUD reserves recorded at September 30, 2023. The Company developed 20 of 73 PUD locations in 2024.

In 2026, the Company estimates that it will invest approximately $295 million to develop its PUD reserves. The Company is committed to developing its PUD reserves within five years as required by the SEC's final rule on Modernization of Oil and Gas Reporting. Since that rule was adopted, and over the last five years, the Company developed 34% of its beginning year PUD reserves in fiscal 2021, 45% of its beginning year PUD reserves in fiscal 2022, 47% of its beginning year PUD reserves in fiscal 2023, 30% of its beginning year PUD reserves in fiscal 2024 and 31% of its beginning year PUD reserves in fiscal 2025.

At September 30, 2025, the Company does not have any proved undeveloped reserves that have been on the books for more than five years at the corporate level, country level or field level. All of the Company's proved reserves are in the United States.

**Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves**

The Company cautions that the following presentation of the standardized measure of discounted future net cash flows is intended to be neither a measure of the fair market value of the Company's exploration and production properties, nor an estimate of the present value of actual future cash flows to be obtained as a result of their development and production. It is based upon subjective estimates of proved reserves only and attributes no value to categories of reserves other than proved reserves, such as probable or possible reserves, or to unproved acreage. Furthermore, in accordance with the SEC's final rule on Modernization of Oil and Gas Reporting, it is based on the unweighted arithmetic average of first day of the month commodity price for each month within the twelve-month period prior to the end of the reporting period and costs adjusted only for existing contractual changes. It assumes an arbitrary discount rate of 10%. Thus, it gives no effect to future price and cost changes certain to occur under widely fluctuating political and economic conditions.

The standardized measure is intended instead to provide a means for comparing the value of the Company's proved reserves at a given time with those of other exploration and production companies than is provided by a simple comparison of raw proved reserve quantities.

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | (Thousands) | | |
| **United States** | | | |
| Future Cash Inflows | $12,243,757 | $ 8,514,126 | $11,947,345 |
| Less: | | | |
| Future Production Costs | 3,823,175 | 3,672,901 | 3,538,389 |
| Future Development Costs | 1,239,386 | 1,191,708 | 1,095,096 |
| Future Income Tax Expense at Applicable Statutory Rate | 1,719,387 | 826,094 | 1,867,457 |
| Future Net Cash Flows | 5,461,809 | 2,823,423 | 5,446,403 |
| Less: | | | |
| 10% Annual Discount for Estimated Timing of Cash Flows | 2,707,425 | 1,486,968 | 2,874,295 |
| Standardized Measure of Discounted Future Net Cash Flows | $ 2,754,384 | $ 1,336,455 | $ 2,572,108 |

The principal sources of change in the standardized measure of discounted future net cash flows were as follows:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| | (Thousands) | | |
| **United States** | | | |
| Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year | $ 1,336,455 | $ 2,572,108 | $ 5,448,330 |
| Sales, Net of Production Costs | (802,983) | (456,506) | (767,487) |
| Net Changes in Prices, Net of Production Costs | 1,716,936 | (1,829,714) | (3,918,392) |
| Extensions and Discoveries | 330,925 | (11,007) | 237,057 |
| Changes in Estimated Future Development Costs | 58,606 | 32,990 | (222,233) |
| Purchases of Minerals in Place | — | — | 34,346 |
| Sales of Minerals in Place | — | — | — |
| Previously Estimated Development Costs Incurred | 246,309 | 305,602 | 342,024 |
| Net Change in Income Taxes at Applicable Statutory Rate | (467,758) | 462,075 | 959,728 |
| Revisions of Previous Quantity Estimates | (7,374) | 19,216 | 33,192 |
| Accretion of Discount and Other | 343,268 | 241,691 | 425,543 |
| Standardized Measure of Discounted Future Net Cash Flows at End of Year | $ 2,754,384 | $ 1,336,455 | $ 2,572,108 |

## Item 9 *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

## Item 9A *Controls and Procedures*

**Evaluation of Disclosure Controls and Procedures**

The term “disclosure controls and procedures” is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company’s management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company’s management, including the Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the Company’s disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company’s Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of September 30, 2025.

**Management’s Annual Report on Internal Control over Financial Reporting**

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company’s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

The Company’s management assessed the effectiveness of the Company’s internal control over financial reporting as of September 30, 2025. In making this assessment, management used the framework and criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework,* published in 2013. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of September 30, 2025.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company’s consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company’s internal control over financial reporting as of September 30, 2025. The report appears in Part II, Item 8 of this Annual Report on Form 10-K.

**Changes in Internal Control over Financial Reporting**

There were no changes in the Company’s internal control over financial reporting that occurred during the quarter ended September 30, 2025 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

## Item 9B *Other Information*

During the quarter ended September 30, 2025, no director or officer (as defined in Rule 16a-1(f) promulgated under the Exchange Act) of the Company adopted or terminated any “Rule 10b5–1 trading arrangement” or any “non-Rule 10b5–1 trading arrangement,” as each term is defined in Item 408 of Regulation S-K.

## Item 9C *Disclosure Regarding Foreign Jurisdictions that Prevent Inspections*

None.

## PART III

### Item 10 *Directors, Executive Officers and Corporate Governance*

The Company will file the definitive Proxy Statement with the SEC no later than 120 days after September 30, 2025. The information concerning directors will be set forth in the definitive Proxy Statement under the headings entitled "Nominees for Election as Directors at the 2026 Annual Meeting of Stockholders" and is incorporated herein by reference. The information concerning corporate governance will be set forth in the definitive Proxy Statement under the heading entitled "Meetings of the Board of Directors and Standing Committees" and is incorporated herein by reference. Information concerning the Company's executive officers can be found in Part I, Item 1, of this report.

The Company has adopted a Code of Business Conduct and Ethics that applies to the Company's directors, officers and employees and has posted such Code of Business Conduct and Ethics on the Company's website, www.nationalfuel.com, together with certain other corporate governance documents. Copies of the Company's Code of Business Conduct and Ethics, charters of important committees, and Corporate Governance Guidelines will be made available free of charge upon written request to Investor Relations, National Fuel Gas Company, 6363 Main Street, Williamsville, New York 14221.

The Company intends to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding an amendment to, or a waiver from, a provision of its code of ethics that applies to the Company's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, and that relates to any element of the code of ethics definition enumerated in paragraph (b) of Item 406 of the SEC's Regulation S-K, by posting such information on its website, www.nationalfuel.com.

We have adopted insider trading policies and procedures applicable to our directors, officers, and employees, and have implemented processes for the Company, that we believe are reasonably designed to promote compliance with insider trading laws, rules, and regulations, and the New York Stock Exchange listing standards. A copy of our Insider Trading Policy is incorporated by reference in this Form 10-K as Exhibit 19.

### Item 11 *Executive Compensation*

The information concerning executive compensation will be set forth in the definitive Proxy Statement under the headings "Executive Compensation" and "Compensation Committee Interlocks and Insider Participation" and, excepting the "Report of the Compensation Committee," is incorporated herein by reference.

### Item 12 *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

**Equity Compensation Plan Information**

The equity compensation plan information will be set forth in the definitive Proxy Statement under the heading "Equity Compensation Plan Information" and is incorporated herein by reference.

**Security Ownership and Changes in Control**

***(a) Security Ownership of Certain Beneficial Owners***

The information concerning security ownership of certain beneficial owners will be set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

***(b) Security Ownership of Management***

The information concerning security ownership of management will be set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

***(c) Changes in Control***

None.

**Item 13** ***Certain Relationships and Related Transactions, and Director Independence***

The information regarding certain relationships and related transactions will be set forth in the definitive Proxy Statement under the headings "Compensation Committee Interlocks and Insider Participation" and "Related Person Transactions" and is incorporated herein by reference. The information regarding director independence will be set forth in the definitive Proxy Statement under the heading "Director Independence" and is incorporated herein by reference.

**Item 14** ***Principal Accountant Fees and Services***

The information concerning principal accountant fees and services will be set forth in the definitive Proxy Statement under the heading "Audit Fees" and is incorporated herein by reference.

## PART IV

**Item 15** ***Exhibits and Financial Statement Schedules***

**(a)1. Financial Statements**

Financial statements filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

**(a)2. Financial Statement Schedules**

All schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

**(a)3. Exhibits**

All documents referenced below were filed pursuant to the Securities Exchange Act of 1934 by National Fuel Gas Company (File No. 1-3880), unless otherwise noted.

| Exhibit Number | Description of Exhibits |
|---|---|
| 2 | Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession: |
| • | Securities Purchase Agreement, dated as of October 20, 2025, by and between the Company and CenterPoint Energy Resources Corp. (Exhibit 10.1, Form 8-K dated October 21, 2025) |
| 3(i) | Articles of Incorporation: |
| • | Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998; Certificate of Amendment of Restated Certificate of Incorporation dated March 14, 2005 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 2012) |
| • | Certificate of Amendment of Restated Certificate of Incorporation, as amended, of National Fuel Gas Company (Exhibit 3.1, Form 8-K dated March 16, 2021) |
| 3(ii) | By-Laws: |
| • | By-Laws of National Fuel Gas Company, as amended June 15, 2022 (Exhibit 3.1, Form 8-K dated June 17, 2022) |
| 4 | Instruments Defining the Rights of Security Holders, Including Indentures: |
| • | Description of Securities (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 2019) |
| • | Indenture dated as of October 1, 1999, between the Company and The Bank of New York Mellon (formerly The Bank of New York) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999) |
| • | Officers Certificate establishing 3.95% Notes due 2027, dated September 27, 2017 (Exhibit 4.1.1, Form 8-K dated September 27, 2017) |

| Exhibit Number | Description of Exhibits |
|---|---|
| • | Officers Certificate establishing 4.75% Notes due 2028, dated August 17, 2018 (Exhibit 4.1.1, Form 8-K dated August 17, 2018) |
| • | Officer's Certificate establishing 2.95% Notes due 2031, dated February 24, 2021 (Exhibit 4.1.1, Form 8-K dated February 24, 2021) |
| • | Officer's Certificate establishing 5.50% Notes due 2026, dated May 18, 2023 (Exhibit 4.1.1, Form 8-K dated May 18, 2023) |
| • | Officer's Certificate establishing 5.50% Notes due 2030 and 5.95% Notes due 2035, dated February 19, 2025 (Exhibit 4.1.1, Form 8-K dated February 19, 2025) |
| 10 | Material Contracts: |
| • | Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006) |
| • | Credit Agreement, dated as of February 28, 2022, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent (Exhibit 10.1, Form 8-K dated February 28, 2022) |
| • | Amendment No. 1 to Credit Agreement, dated as of May 3, 2022, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent (Exhibit 10.1, Form 10-Q dated May 6, 2022) |
| • | Credit Agreement Existing Maturity Date Extension Consent, dated January 28, 2025, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2025) |
| 10.1 | Amendment No. 2 to Credit Agreement, dated as of November 6, 2025, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent |
| • | Term Loan Agreement, dated as of February 14, 2024, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent (Exhibit 10.1, Form 8-K dated February 14, 2024) |
| 10.2 | Amendment No. 1 to Term Loan Agreement, dated as of November 6, 2025, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent |
| | Management Contracts and Compensatory Plans and Arrangements: |
| • | Standard Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company (other than Seneca) and an executive officer (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2008) |
| • | Form of Employment Continuation and Noncompetition Agreement between Seneca Resources Company, LLC and an executive officer of the Company employed by Seneca (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2024) |
| • | National Fuel Gas Company 2010 Equity Compensation Plan, as amended and restated December 7, 2023 (Exhibit 10.1, Form 8-K dated March 11, 2024) |
| • | National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2012) |
| • | National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2009) |
| • | National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997) |
| • | Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997) |

| Exhibit Number | Description of Exhibits |
|---|---|
| • | Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998) |
| • | Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999) |
| • | Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001) |
| • | Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005) |
| • | Amendment to National Fuel Gas Company Deferred Compensation Plan, dated December 14, 2020 (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2020) |
| • | National Fuel Gas Company Deferred Compensation Plan for Directors and Officers (Amended and Restated Effective September 1, 2021) (Exhibit 10.1, Form 8-K dated June 23, 2021) |
| • | Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005) |
| • | National Fuel Gas Company Tophat Plan, as amended September 20, 2007 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2007) |
| • | Amendment to National Fuel Gas Company Tophat Plan, dated December 14, 2020 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2020) |
| • | Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999) |
| • | Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999) |
| • | National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004) |
| • | National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 24, 2008 (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2008) |
| • | Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated June 1, 2010 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2010) |
| • | Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated August 13, 2015 (Exhibit 10.2, Form 10-K for the fiscal year ended September 30, 2015) |
| • | Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 14, 2020 (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2020) |
| • | National Fuel Gas Company 2009 Non-Employee Director Equity Compensation Plan, as amended and restated March 11, 2020 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2020) |
| • | Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2024) |

| Exhibit Number | Description of Exhibits |
|---|---|
| • | Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2024) |
| • | Form of Award Notice for Emissions Reduction Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2024) |
| • | Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2023) |
| • | Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2023) |
| • | Form of Award Notice for ESG Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2023) |
| • | Form of Award Notice for Retention Grant Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2023) |
| • | Form of Award Notice for Retention Grant Return on Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2023) |
| • | Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2022) |
| • | Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2022) |
| • | Form of Award Notice for ESG Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2022) |
| • | Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effected December 1, 2023 (Exhibit 10.6, Form 10-Q for the quarterly period ended December 31, 2023) |
| • | Retirement and Consulting Services Agreement, dated as of March 9, 2023, between National Fuel Gas Distribution Corporation and Karen M. Camiolo (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2023) |
| • | Consulting Services Agreement, dated as of June 13, 2025, between the Company and Donna L. DeCarolis (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2025) |
| 19 | Insider Trading Policies and Procedures: |
| • | Policy on Insider Trading in National Fuel Gas Company Securities, dated September 14, 2023 (Exhibit 19, Form 10-K for the fiscal year ended September 30, 2024) |
| 21 | Subsidiaries of the Registrant |
| 23 | Consents of Experts: |
| 23.1 | Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Company, LLC |
| 23.2 | Consent of Independent Registered Public Accounting Firm |

| Exhibit Number | Description of Exhibits |
|---|---|
| 31 | Rule 13a-14(a)/15d-14(a) Certifications: |
| 31.1 | Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act |
| 31.2 | Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act |
| 32•• | Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 97 | Policy Relating to Recovery of Erroneously Awarded Compensation: |
| • | National Fuel Gas Company Clawback Policy, effective December 1, 2023 (Exhibit 97, Form 10-K for the fiscal year ended September 30, 2024) |
| 99 | Additional Exhibits: |
| 99.1 | Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Company, LLC |
| 99.2 | Company Maps |
| 101 | Interactive data files submitted pursuant to Regulation S-T, formatted in Inline XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the years ended September 30, 2025, 2024 and 2023, (ii) the Consolidated Statements of Comprehensive Income for the years ended September 30, 2025, 2024 and 2023, (iii) the Consolidated Balance Sheets at September 30, 2025 and September 30, 2024, (iv) the Consolidated Statements of Cash Flows for the years ended September 30, 2025, 2024 and 2023 and (v) the Notes to Consolidated Financial Statements. |
| 104 | Cover Page Interactive Data File (embedded within the Inline XBRL document) |

• Incorporated herein by reference as indicated.

All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K.

•• In accordance with Item 601(b)(32)(ii) of Regulation S-K and SEC Release Nos. 33-8238 and 34-47986, Final Rule: Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, the material contained in Exhibit 32 is "furnished" and not deemed "filed" with the SEC and is not to be incorporated by reference into any filing of the Registrant under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing, except to the extent that the Registrant specifically incorporates it by reference.

## Item 16 *Form 10-K Summary*

None.

## Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

**National Fuel Gas Company**
**(Registrant)**

By /s/ D. P. Bauer
D. P. Bauer
President and Chief Executive Officer

Date: November 21, 2025

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

| Signature | Title | |
|---|---|---|
| /s/ D. F. Smith<br>D. F. Smith | Chairman of the Board and Director | Date: November 21, 2025 |
| /s/ D. H. Anderson<br>D. H. Anderson | Director | Date: November 21, 2025 |
| /s/ B. M. Baumann<br>B. M. Baumann | Director | Date: November 21, 2025 |
| /s/ D. C. Carroll<br>D. C. Carroll | Director | Date: November 21, 2025 |
| /s/ S. C. Finch<br>S.C. Finch | Director | Date: November 21, 2025 |
| /s/ J. N. Jaggers<br>J. N. Jaggers | Director | Date: November 21, 2025 |
| /s/ R. Ranich<br>R. Ranich | Director | Date: November 21, 2025 |
| /s/ J. W. Shaw<br>J. W. Shaw | Director | Date: November 21, 2025 |
| /s/ T. E. Skains<br>T. E. Skains | Director | Date: November 21, 2025 |
| /s/ R. J. Tanski<br>R. J. Tanski | Director | Date: November 21, 2025 |
| /s/ D. P. Bauer<br>D. P. Bauer | President and Chief Executive Officer and Director | Date: November 21, 2025 |
| /s/ T. J. Silverstein<br>T. J. Silverstein | Treasurer and Chief Financial Officer | Date: November 21, 2025 |
| /s/ E. G. Mendel<br>E. G. Mendel | Controller and Chief Accounting Officer | Date: November 21, 2025 |

# Directors

**David H. Anderson**
Director and former Chief Executive Officer of Northwest Natural Holding Company

**David P. Bauer**
President and Chief Executive Officer of National Fuel Gas Company

**Barbara M. Baumann**
President and Owner of Cross Creek Energy Corporation

**David C. Carroll**
Former President and Chief Executive Officer of GTI Energy

**Steven C. Finch**
Former President of Manufacturing and Director of Community Engagement at Viridi Parente, Inc.

**Joseph N. Jaggers**
Founder and former President, Chief Executive Officer and Chairman of Jagged Peak Energy Inc.

**Rebecca Ranich**
Former Director at Deloitte Consulting, LLP

**Jeffrey W. Shaw**
Former Chief Executive Officer and Director of Southwest Gas Corporation

**Thomas E. Skains**
Former Chairman of the Board, Chief Executive Officer and President of Piedmont Natural Gas Company, Inc.

**David F. Smith**
Chairman of the Board and former President and Chief Executive Officer of National Fuel Gas Company

**Ronald J. Tanski**
Former President and Chief Executive Officer of National Fuel Gas Company

# Corporate Leadership

**David P. Bauer**
President and Chief Executive Officer

**Michael D. Colpoys**
President, National Fuel Gas Distribution Corporation

**Joseph N. Del Vecchio**
President, National Fuel Gas Supply Corporation and Empire Pipeline, Inc.

**Justin I. Loweth**
President, Seneca Resources Company, LLC and National Fuel Gas Midstream Company, LLC

**Timothy J. Silverstein**
Treasurer and Chief Financial Officer

**Lee E. Hartz**
General Counsel and Secretary

**Martin A. Krebs**
Chief Information Officer

**Elena G. Mendel**
Controller and Chief Accounting Officer

**Meghan A. Corcoran**
Corporate Responsibility Officer

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# Investor Information

**Common Stock Transfer Agent and Registrar**

EQ Shareowner Services
P.O. Box 64854
St. Paul, MN 55164-0854
Telephone: 800-648-8166
Web: www.shareowneronline.com
Email: stocktransfer@equiniti.com

Change of address notices and inquiries about dividends should be sent to the Transfer Agent at the address listed above.

**National Fuel Direct Stock Purchase and Dividend Reinvestment Plan**

National Fuel offers a simple, cost effective method for purchasing shares of National Fuel stock. A prospectus, which includes details of the Plan, can be obtained by calling, writing or emailing the administrator of the Plan, EQ Shareowner Services, at the address listed above.

**Investor Relations**

Investors or financial analysts desiring information should contact:

**Timothy J. Silverstein**
Treasurer and Chief Financial Officer
Telephone: 716-857-6987

**Natalie M. Fischer**
Director of Investor Relations
Telephone: 716-857-7315
Email: FischerN@natfuel.com

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

**Additional Shareholder Reports**

Additional copies of this report, the 2025 Form 10-K and the 2025 Financial and Statistical Report can be obtained without charge by writing to or calling:

**Lee E. Hartz**
General Counsel and Secretary
Telephone: 716-857-7372

**Natalie M. Fischer**
Director of Investor Relations
Telephone: 716-857-7315

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

**Stock Exchange Listing**

New York Stock Exchange
(Stock Symbol: NFG)

**Trustee for Debentures**

The Bank of New York Mellon
Corporate Trust
240 Greenwich Street, 7 East
New York, NY 10286

**Annual Meeting**

The Annual Meeting of Stockholders will be held on Thursday, March 12, 2026, conducted via live webcast at www.virtualshareholdermeeting.com/NFG2026. Stockholders of record as of the close of business on January 12, 2026, will receive a formal notice of the meeting, proxy statement and proxy.

This Annual Report contains “forward-looking statements” as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements and important factors included in the Company’s Form 10-K at Item 7, MD&A, under the heading “Safe Harbor for Forward-Looking Statements,” and with the “Risk Factors” included in the Company’s Form 10-K at Item 1A. Forward-looking statements are all statements other than statements of historical fact, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, estimates of gas quantities, estimates of the time and resources necessary to meet emissions targets, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction and other projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words “anticipates,” “estimates,” “expects,” “forecasts,” “intends,” “plans,” “predicts,” “projects,” “believes,” “seeks,” “will,” “may” and similar expressions. Forward-looking statements include estimates of gas quantities. Proved gas reserves are those quantities of gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods and government regulations. Other estimates of gas quantities, including estimates of probable reserves, possible reserves, and resource potential, are by their nature more speculative than estimates of proved reserves. Accordingly, estimates other than proved reserves are subject to substantially greater risk of being actually realized. This Annual Report and the statements contained herein are submitted for the general information of stockholders and employees of the Company and are not intended to induce any sale or purchase of securities or to be used in connection therewith.
For up-to-date investor information, please visit the Investor Relations section of National Fuel Gas Company’s Corporate Web site at http://www.nationalfuel.com. If you would like to receive news releases automatically by email, simply visit the News section and subscribe.